**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**STATE OF GEORGIA**

**In Re:**

**Georgia Power Company's 2022 Rate Case ) Docket No. 44280**

**Hearing Room 110**

**Georgia Public Service Commission**

**244 Washington Street**
**Atlanta, Georgia**

**Tuesday, November 8, 2022**

**The above-entitled matter came on for hearing Pursuant to Notice at 9:30 a.m.**

**PRESENT WERE:**

**TRICIA PRIDEMORE, Madam Chair**
**TIM ECHOLS, Vice-Chairman**
**FITZ JOHNSON, Commissioner**
**LAUREN "BUBBA" MCDONALD, Commissioner**
**JASON SHAW, Commissioner**

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**I N D E X**


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|---|---|---|---|---|
| Robert L. Trokey<br>Ralph C. Smith | | | | |
| By Mr. Walsh | 1235 | | 1499 | |
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| By Ms. Brown | | 1415 | | |
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| By Mr. Ariza | | 1447 | | |
| By Mr. Mahan | | 1455 | | |
| By Mr. Marzo | | 1456 | | |

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|---|---|---|---|---|
| Stephen J. Baron<br>Leah Wellborn | | | | |
| By Mr. Ingraham | 1506 | | | |
| By Mr. Hewitson | | 1546 | | |

| WITNESSES: | DIRECT | CROSS | REDIRECT | RECROSS |
|---|---|---|---|---|
| Paul J. Alvarez<br>Dennis Stephens<br>Rajendrasinh "Raj" Rana | | | | |
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**P R O C E E D I N G S**

**MADAM CHAIR PRIDEMORE: Good morning. Call to order Docket No. 44280: Georgia Power Company's 2022 rate case.**

**With that, let's start with appearances.**

**MR. WALSH: Madam Chair, on behalf of the Public Interest Advocacy staff, Dan Walsh. And with me today, Preston Thomas with the Public Service Commission, and Griffin Ingraham with the Attorney's General Office. Thank you.**

**MR. MARZO: Madam Chair, Brandon Marzo, Steve Hewitson and Allison Pryor on behalf of Georgia Power Company.**

**MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy.**

**MR. GALLOWAY: Good morning, Madam Chair. Newton Galloway and Terri Lyndall on behalf of AACE. Thank you.**

**MADAM CHAIR PRIDEMORE: ChargePoint.**

**MR. FYKE: Good morning, Madam Chair. Lucas Fykes of the law firm of Keyes & Fox, LLP, on behalf of ChargePoint.**

**MADAM CHAIR PRIDEMORE: Commercial Group.**

**MR. JENKINS: Good morning, Commissioners. Alan Jenkins for the Commercial Group.**

**MADAM CHAIR PRIDEMORE: Concerned Ratepayers of Georgia.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: Concerned Ratepayers of Georgia.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: Concerned Ratepayers of Georgia.**

**He is not present.**

**Cypress Creek Renewables.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: Cypress Creek Renewables.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: Cypress Creek Renewables.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: Not present.**

**EVgo Services, LLC.**

**MR. VIJAYKAR: Good morning, Commissioners. Nikhil Vijaykar on behalf of EVgo Services, LLC.**

**MADAM CHAIR PRIDEMORE: Thank you.**

**Georgia Association of Manufacturers.**

**MR. JONES: Good morning, Madam Chair. Clay Jones on behalf of GAM.**

**MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments.**

**MS. BROWN: Good morning, Madam Chair. Alicia Brown on behalf of the Georgia Coalition of Local Governments.**

**MADAM CHAIR PRIDEMORE: Thank you.**

**Georgia Conservation Voters.**

**MS. SMITH: Good morning. Wan Smith in the stay of Deborah Opie on behalf of GCV.**

**MADAM CHAIR PRIDEMORE: Thank you.**

**Georgia Interfaith Power & Light.**

**MS. KYSOR: Good morning. Jill Kysor and Jen Whitfield on behalf of GIPL.**

**MADAM CHAIR PRIDEMORE: Georgia Solar Energy Industries Association, Solar Energy Industries Association, and Vote Solar.**

**MR. THOMASSON: Good morning, Commissioners. Scott Thomasson on behalf of Georgia SEIA, SEIA, and Vote Solar.**

**MADAM CHAIR PRIDEMORE: GA Solar.**

**Sorry. That's a different intervenor.**

**MR. THOMASSON: Yes.**

**MADAM CHAIR PRIDEMORE: Georgia Solar Energy Association, GA Solar.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: GA Solar.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: GA Solar, not present.**

**Georgia Watch.**

**MS. COYLE: Good morning, Commissioners. Liz Coyle on behalf of Georgia Watch.**

**MADAM CHAIR PRIDEMORE: Interstate Gas Supply.**

**MR. CARVER: Brad Carver, along with Adam Wise, on behalf of Interstate Gas Supply. Good morning, Madam Chair.**

**MADAM CHAIR PRIDEMORE: Good morning.**

**The Kroger Company.**

**MR. BOEHM: Good morning, Commissioners. Kurt Boehm for the Kroger Company.**

**MADAM CHAIR PRIDEMORE: MARTA.**

**MS. STRUM: Good morning, Commissioners. Kasey Sturm on behalf of MARTA.**

**MADAM CHAIR PRIDEMORE: Resource Supply Management.**

**MR. CLARKSON: Jim Clarkson representing Resource Supply Management.**

**MADAM CHAIR PRIDEMORE: Sierra Club.**

**MS. ARIZA: Good morning, Commissioners. Isabella Ariza and Robert Jackson on behalf of the Sierra Club.**

**WITNESS ROBINSON: SACE and Southface.**

**MR. DOWDY: Good morning, Madam Chair, Commissioners. Craig Dowdy and Steven Jones with Taylor English Duma on behalf of Southface and SACE.**

**MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association.**

**MR. MAHAN: Good morning, Commissioners. Simon Mahan for the Southern Renewable Energy Association.**

**MADAM CHAIR PRIDEMORE: United States Department of Defense and All Other Federal Executive Agencies.**

**MS. MEDLYN: Good morning, Commissioners. Emily Medlyn on behalf of the United States Department of Defense and all other Federal Executive Agencies.**

**MADAM CHAIR PRIDEMORE: Utility Management Services.**

**(No response.)**

**MADAM CHAIR PRIDEMORE: Okay. Got to step on them.**

**All right. Do I have any other housekeeping matters to come before us today to talk about before I talk about my own?**

**(No response.)**

**MADAM CHAIR PRIDEMORE: Any housekeeping?**

(No response.)

MADAM CHAIR PRIDEMORE: Okay. I know that I have -- two of the intervenors have filed for stipulated agreements with the other intervenors and the parties to be able to file their testimony and have it be a part of the record, but their witnesses have to be crossed. That is Southern Alliance for Clean Energy and Southface Energy Institute, correct, Mr. Dowdy?

MR. DOWDY: We are sending the emails to all parties this morning. But the company and Trout have agreed.

MADAM CHAIR PRIDEMORE: Okay. And Utility Management Services, so they are also sending -- setting up their stipulated witness testimony.

So if anybody has any comments about those things, now is your time to make those comments.

(No response.)

MADAM CHAIR PRIDEMORE: All right. Hearing none -- Mr. Marzo.

MR. MARZO: Yeah. Just one. Just for the record, to state for both. First, on the SACE motion, I had spoken with Mr. Dowdy. We had minimal cross, so we are -- not an objection to that particular request.

Similar with UMS, we did not have cross for that witness. And I indicated that to -- as well, to their counsel.

So I just wanted to make sure it's clear what the company had communicated.

MADAM CHAIR PRIDEMORE: Very good. Thank you, Mr. Marzo.

MR. JENKINS: Brandon reminded me for the Utility's -- UMS, is that --

MADAM CHAIR PRIDEMORE: Yes.

MR. JENKINS: UMS witness, the Commercial Group did have some questions about revenue erosion. We understand they're going to put a stipulated -- proposed stipulation into the record. And, with that, we're waiving.

MADAM CHAIR PRIDEMORE: Okay. Mr. Marzo.

MR. MARZO: Yeah. I just want -- I think the stipulation -- the only thing that's on the table right now as I'm aware with UMS is to not object to their witnesses not appearing.

So I just want to make it clear there is not a stipulation currently that's in effect or expected to be in effect for this proceeding -- this phase of this proceeding ends on any other issue, so --

MADAM CHAIR PRIDEMORE: Correct.

MR. MARZO: Yep.

MADAM CHAIR PRIDEMORE: Thank you.

All right. Any other housekeeping matters?

(No response.)

MADAM CHAIR PRIDEMORE: All right. The last one I have is that we have a packed schedule over the next three days. We're going to adjourn early today to allow everyone who's a part of this proceeding, the parties, intervenors, et cetera, and staff to vote. So today will be an earlier than usual day for us.

Expect a long day tomorrow, but we will start at 9:30 a.m. We're changing the PSO to where Thursday we will begin at 7:30 a.m. to allow enough time for all of the witnesses and all the cross to take place. So just let -- adjust your schedules, accordingly, so...

Very good. All right. With that, it's time for public witnesses. And so each public witness has three minutes to talk to the Commission.

We have a public witness policy that's posted. And we're glad that you're here and we look forward to all the things that you have to say.

With that, if you want to keep an eye on the clocks up here, that gives you your -- kind of your

countdown on your three minutes.

So in order of those that have signed up this morning, Mr. Clint Hancock, you're first.

MR. HANCOCK: Good morning, Madam Chair and Commission. My name is Clint Hancock, president of Jet Food Stores based -- it's a convenient store company based in Sandersville, Georgia. We're a second generation business that started in 1973. And we employ over 750 Georgians in our 52 locations throughout middle and south Georgia.

I also oversee Dominy Oil Company and Atkinson Oil Company, which are sister companies that provide wholesale fuels to over a hundred convenience stores throughout middle Georgia. And we also provide fuel and lubricants to our agricultural and industrial customers.

Many of you know Jim Tudor. And I had the privilege to serve as his president of the Georgia Association of Convenience Stores from 2010 to 2012. And I served as a board member for over 12 years.

Over the last several years, we've built four new locations and we're currently constructing two no -- larger-format stores in Hinesville and Baxley. And our focus is to serve rural Georgia communities with their daily needs for fuel, for food, for items

they need in their busy and active lives.

And I believe Jet Food Stores and our peers in the C store industry have the most convenient and well-placed locations to serve our communities as they travel each and every day.

There is no doubt as electricity evolves and becomes an important source of transportation fuel, C store locations in rural areas will be critical for the citizens of smaller towns in Georgia, as well as EV travelers that drive between Georgia's major cities.

Presently -- this is the main point -- there is no economic model that supports the investment for us to build the infrastructure to provide EV charging at our locations. It is my belief it will take programs like Make Ready to help business like ours make early entry into the EV charging market and fill the gap that will be desperately needed to give EV owners the range they need to travel our great state.

I'm also a member of a study group that is comprised of 14 noncompeting owners of businesses similar to ours. Each of these members are located in different states throughout the country. Each and every one of them are taking the same approach as we are with respect to sitting on the sideline until

there's an economically feasible plan in place to invest in the EV chargers.

I would like to offer our company as a willing and open-minded partner to the Georgia Public Service Commission as you work toward creating a fair and level playing field for the EV fueling future of Georgia. Thank you for the opportunity this morning to speak with you. And thank you for your service to our great state.

COMMISSONER McDONALD: I have a question, please.

MR. HANCOCK: Yes, sir.

MADAM CHAIR PRIDEMORE: You may.

COMMISSONER McDONALD: Do you support ratepayers investing in the development of EV charging stations throughout the state?

MR. HANCOCK: I'm not at the point where I could give you an honest answer on that. I've got a lot to learn when it comes to how all ratepayers that aren't EV customers should share. So I need more time and more information to be able to give you an answer, sir.

COMMISSONER McDONALD: Be thinking about it.

MR. HANCOCK: I will.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Hancock.

**MR. HANCOCK: Yes, ma'am.**

**MADAM CHAIR PRIDEMORE: Nice to meet you.**

**Alfred Blackmar.**

**MR. BLACKMAR: Good morning, Madam Commissioner and Commissioners. My name is Alfred Blackmar and I'm vice president of facilities at AFLAC based in Columbus, Georgia. AFLAC is an American insurance company and is the largest provider of supplemental health insurance in the United States. The company was founded in 1955 and is headquartered in Columbus, Georgia.**

**As I have a meeting here in Atlanta today for other business matters, I wanted to come by and spend a few minutes talking about our partnership with Georgia Power and thank you for this opportunity.**

**Several years ago, like many businesses, we began hearing from our stakeholders that we needed to be more aggressive in terms of carbon emission reductions, greenhouse gases. Through several relationships, we knew individuals at Georgia Power whose experience was very -- was very valuable to us in terms of thinking around carbon emissions. We reached out to have company representatives spend an extended amount of time with us thinking about how to strategically continue shaping our environmental**

sustainability platform over time.

In consultation with Georgia Power, we significantly improved our goal of converting company vehicles to EVs in the future. We installed charging stations on our campuses and plan to use EVs between Columbus and Atlanta as soon as that network is built out through Georgia Power's community charging efforts.

Participation in Georgia Power's renewable electricity programs enabled AFLAC to increase the amount of renewable electricity used at our Georgia-owned properties from less than 1 percent to a little over 10 percent. And we plan to increase that percentage to 100 percent by 2030. Increasing our involvement in Georgia Power's customer solar program is an important component in meeting our commitment as a corporation to be net zero by 2050.

As mentioned, we're a supplemental health insurance company. An insurance policy is a promise toward the future. Data is central to our business to enable us to fulfill those promises in the way that energy's reliability is central to our commitment to those who've entrusted their well-being to us.

We count on the reliability of electricity

provided by Georgia Power and recognize that as Georgia Power continues to reduce its own carbon emissions, it has furthered our effort to fulfill our commitments to our stakeholders. We have had many partners in our success over more than 67 years of our company's existence. And Georgia Power is one of those that has been critical to our success and the success of our customers, both in the fundamental service one would expect from an electric utility, but more broadly in terms of helping us solve environmental and sustainability challenges. I wanted to share how grateful we are to Georgia Power and for their help to advance our vision and for their dedication to our company and the communities we serve.

Thank you for allowing me to make these remarks.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Blackmar.

Jerald Mitchell.

MR. MITCHELL: Good morning, Commissioners. Thank you for your time and -- your time in allowing me to join you for this important session. I'm Jerald Mitchell. I'm the president and chief executive officer of the Chamber of Commerce in

Columbus, Georgia. And I previously worked in economic development at the Atlanta BeltLine, Inc., at the Savannah Economic Development Authority. Also at the Georgia Department of Economic Development. I also spent a portion of my career in the cable industry with Comcast NBCUniversal. And all of these roles have given me exposure to the economic depth of our state, business growth and needs, and in understanding of utilities and infrastructure.

For nearly two and a half years I've spent my professional time working in Columbus, Georgia, Georgia's second largest city. Our goal continues to be achieving economic excellence in ways that drive vibrant economies, improves our competitiveness and attractiveness for new industries, jobs and the capital investment associated with that.

Because of current and past investments in redevelopment in infrastructure, we are on a positive growth trajectory. Further, investments in our future through passing a recent SPLOST and a TSPLOST, worth a combined $1.1 billion, will continue to prove our commitment to remaining competitive and building assets that will take us well into the future.

In addition to the items previously mentioned, we've enjoyed an excellent partnership with the

Georgia Public Company in economic development. Their support in our efforts remain -- to remain prepared, evaluate sites, understand various industry dynamics as we present to prospective businesses or clients has been invaluable. While those steps are part of our day-to-day partnerships and they're a must, we can't remain economically viable without competitive power and infrastructure that is both available and reliable.

Georgia Power's support in ecotourism and the sports arena as the country's longest urban light-water rafting course was conceptualized and built in Columbus, has further put Columbus, or the Columbus region, on a path that can be sustained for decades to come. The removal of dams through environmental action and -- and a collaborative approach to river flows have been a consistent part of our area's successful partnership.

In fact, a major outcome that was just achieved in Columbus was the execution of the International Canoeing Federation's world kayaking cup or spring cup. That happened and it was a success largely attributable to infrastructure and partners. And Georgia Power has been an integral part of that.

We're currently experiencing an active pipeline

of economic development projects and they need competitively priced and reliable energy service. Automation and other digital processes are requiring several -- or servers and other competing capabilities that drive the need for previously mentioned reliability and competitive pricing.

We're seeing the needle move as it relates to building a pipeline of viable economic opportunities and understand that a key component of our competitiveness is reliable power infrastructure. Further, reliable partnerships that understand the needs, or partners that understand the needs of businesses are a must and we believe we have that.

We appreciate Georgia Power Company's support in economic development and the essential utility service that they provide. We fully appreciate and support measures required to help the company and our electric infrastructure remain strong.

Thank you so much.

MADAM CHAIR PRIDEMORE: Thank you, sir.

Carlos Fernandez.

MR. FERNANDEZ: Commissioners, my name is Carlos Fernandez. I'm a journeyman lineman and e-board representation for IBEW, which is International Brotherhood, Local 84.

**I started my apprenticeship in 2018 for Georgia Power, made journeyman lineman in 2021. And since then, I have done outside construction, traveled to dozens of states working storm restoration and line construction.**

**I currently work evening and nights on Georgia Power's system for a company called Fairway Electric. Prior to that, I was a fireman for 11 years at the City of Atlanta fire department.**

**I would like to express to you my concerns and insight on Georgia's electrical grid versus other states in which I have worked.**

**My background as a fireman, I've responded to multiple structure fires, motor vehicle accidents, wires down on houses, cars, and medical emergencies. Maintaining our power grid will provide a better chance for our first responders and good samaritans to stay safe in these situations.**

**You see, in the last three years I've been deployed to more than 14 different states in addition to Georgia. What I have witnessed in -- our across our nation is some utilities and the regulators try to get away with the idea a dollar not spent yields benefits for the customer. I would like to say -- I would like to suggest that is a faulty and**

short-sighted way of thinking about our electrical grid.

When utilities and regulators try to stretch the life of a state's electrical grid, it puts its citizens at risk. Overburdening the electrical network and utilities lead to a lack of reliance in the moments of greatest need.

As I've stated, I've worked in different states that do not have a reliable system. It is not uncommon for them not to have power for more than a week on a common thunderstorm. Their system is barely held together. They use anything they can whenever they can, which puts my fellow journeymen linemen at risk and the community, as well.

We've all seen the news stories of wildland fires that were started because of transmission and distribution systems overloaded and that have passed their life expectancy. The tragedies have occurred because of this, including the loss of life. So, yes, I do strongly recommend that we continue to invest in a reliable system.

I have also done restoration work in the great state of Georgia. And I am certain that you will have many witnesses throughout this process that may give you their -- that may give you their ideas of

why investing now or later would be good or bad.

I come to you as one who has been in the bucket and have seen crack pole tops, broken insulators, failing transformers, weakened crossarms, bad substations, failing substations. And the reliability in those states is very problematic. They have put -- beyond that, if the right equipment is not being installed or maintained, it puts my fellow journeymen linemen and general public at risk.

The job I've held in my career has been more than just a paycheck. It's been about public service. And as a former fireman, lineman, and labor leader, our communities are very important to me.

I understand when my friends and neighbors -- I understand why my friends and neighbors are concerned about the rising costs of living. I feel their pain. However, I'm certain to you that a strong, reliant electric grid is something that we cannot afford to compromise on.

Reliable energy is the very foundation of our strong economy. And a strong economy helps every community create jobs and provide upward mobility, improving schools, funding for emergency medical services, improving the infrastructure, and the list goes on.

My message to you today is you're doing a great job in investing in the state's energy infrastructure and I am in a unique position to make an observation given the miles I have traveled in maintaining an electrical grid system. Please continue your track record in doing such. Georgia's business expects it -- our community -- our large communities -- our large economic needs it. And my family is counting -- my family is counting on me coming home after a -- after a night's work throughout the night, throughout the weather.

I would just like to say thank you, Commissioners, for your time and your long range of thinking and the time of electrical -- in our electrical grid system.

COMMISSONER McDONALD: You have -- you highlighted some of the issues with bad insulators and crossarms, et cetera, et cetera, in your travels across. Have you found that in Georgia?

MR. FERNANDEZ: Yes, sir. We also have -- and it's due to weather and trees and they're barely holding on. So when we have bad weather and -- it's not fully failing, it's starting to -- that puts all of us back at -- back in risk.

There's been plenty of times as a fireman where

I've seen wires down on vehicles because of a tree fail, things aren't being able to --

COMMISSONER McDONALD: But that's not something that -- I'm talking about the infrastructure itself. Do you find, i.e., Georgia Power in not keeping up with the --

MR. FERNANDEZ: Georgia Power is doing it now. That's what my evening trouble crew is down doing is anything that we see that is failing to upgrade. And anything that's past its life expectancies, we are to upgrade it right now.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Fernandez.

Patty Durand.

MS. DURAND: Wow. So many compliments for Georgia Power and for this Commission. I wonder if that gentleman would say the same if he knew that in 2019 this Commission passed a rate case proceeding that was more expensive than the next ten utilities combined in the nation. And that this rate case proceeding puts Georgia Power in the top three, along with two California utilities, that you're fond of criticizing, Commissioner Pridemore.

And I wonder why you didn't tell the gentleman before this one that was talking about his climate

change and net zero goals -- wonder why you didn't tell him to go to China for his activism like you did the woman in -- at the February town hall meeting. Or why you didn't tell him not to worry about it like you did Ms. Bailey Carr when she was here asking you to Caraway about climate change.

What I'm here to talk about is that in 2009, Georgia Power came asking for permission to build a nuclear plant that they said would be on time and on budget; six years, $14 billion.

And here we are 13 years later and the plant is not done and it exceeds $30 billion. And now they say it will be online in 2023. And maybe it will. Let's hope it is.

If it is, it is inappropriate for them to increase rates to pay for Unit 3, 30 days after commercial operation, and Unit 4, 30 days after commercial operation, at the same time they're asking for this enormous rate increase, at the same time they're asking for a $2 billion fuel surcharge on natural gas.

That's too much in one year. And so my ask of you is to defer this rate case to a year that Plant Vogtle is also not coming online. Because this is not the fault of Georgia Power's captive ratepayers.

They should not have to bear the burden of that large of rate increases all in the same year.

It is the fault of Georgia Power's failure to deliver the project and failure to understand the actual costs and the actual schedule needs of the project.

So I'm asking you not to put billions of dollars upon billions of dollars all in the same year on rate increases. Thank you.

MADAM CHAIR PRIDEMORE: Tyrone Johnson.

MR. JOHNSON: Thank you to Ms. Pridemore for the opportunity to allow me to speak. It has been extremely arduous dealing with Georgia Power concerning forceful confiscation of my property in order to install their three -- three 7-foot by 7-foot by 5-foot boxes on an easement that is 15 feet wide by 55 feet adjacent to the west side of my property.

No doubt these three electrical boxes' size and location make them indispensable to the Georgia Power grid redevelopment project. Nowhere else in Druid Hills is there such a large concentration of these massive electric boxes.

The easement is too narrow and does not properly accommodate the enormous electrical boxes,

which impose a lien on my property on the west side of the boundary. The boxes require 10-foot clearance at the front and rear and state on all three boxes. This is physically impossible on an easement this size.

For forward -- for upward of -- until the end of September 22nd, when they installed their split-rail fences, Georgia Power has abused my right to do with my property as I see fit.

The fence is self-serving in that it allows them to continue to use my property at their will through the fence, which is what they wanted all along. Georgia Power subcontractors Irby Construction has threatened me while being parked in my front yard with their vans, bulldozers, and 40-foot forklifts, which require railroad ties to install and reinstall the boxes.

There has never been a dispute about the property line that was clearly marked by TRC field service representatives. The service that -- the surveyor came out on one particular day and put the markers and -- and poles back.

And the next morning the construction company came out. They immediately tore down the markers because they were 30 feet over the line. I have

photos -- I have photo evidence I would be happy to share with you.

Georgia Power's subcontractors piled 6-foot mounds of dirt on my yard around my 100-year-old trees, scarred them with their bulldozers. They would back the bulldozers up on the front of my yard on the Thursday in front of my picture window and then they would move them again Monday morning. Just leave them there.

They cut my cable. They informed me that I could not build a wall. And if I did, they would tear it down. Georgia Power deployed one of their many subcontractors to do all the necessary land acquisitions with their full faith and backing.

I suspect that in the case it was Irby Construction Company, based in Mississippi. Irby, armed with the power and the authority, set out to deliver at all costs a finished product, which Georgia Power would purchase from them at a later date. This helps to indemnify Georgia Power from the abuse and shabbiness that is used against Georgia landowners. Me.

During the project, Irby then used any renegade contractor that wanted -- they wanted with no regards for getting the job done. Chris Caldwell, the power

development vice president of Georgia Power, stated that they do not need -- do not own the project. But it will be acquired by Georgia Power in a neat, complete package at a later date.

One of the many land agents, Rob Shamimi (phonetic), informed me that they did not purchase the property that they did not need as they took and used my front yard any ways they saw fit against my continuous protest. Of course they don't and didn't need it as long as the entire package would be acquired by Georgia Power at a later date.

After Georgia Power stated -- started to upgrade its electrical distribution facilities to improve reliability, they identified the property as needed and installed equipment adjacent to mine. Three executives, I assume from Georgia Power or Irby, came out and decided come hell or high water that they were going to install those three massive boxes, even if the measurement of the easement made it physically impossible, as dictated by G&W Electric, the manufacturer of the boxes.

After quite a bit of construction was commenced, I received a blank offer from -- with no compensation filled out. On the southern corner of my property, which has a power pole that supports the

traffic light, which has been hit at least a dozen times in the 23 years that I have resided there, Georgia Power clearly has installed the new pole on my property with no guide -- with new guy-wires even further up on my property.

Georgia Power has previously always put the pole back in the same spot that the old pole was in, but this time they moved it further onto my property. They dug the hole one month before Georgia Power installed -- leaving a seven-and-a-half-foot deep hole covering -- uncovered and unsecured.

On Friday, July 8, Mitchell and the -- said that he could not place the power pole back in the same hole because it was supporting the traffic light. Mitchell further stated that South -- Southern Company, the parent company of Georgia Power, has an easement on the pole, which they do not. I could take it up -- and said that I could take it up with Southern Company.

I responded: Looks like Southern Company needs this property.

He said: I don't. Southern does.

At that time I spoke with Ms. Holly Caraway of Georgia Power and she said I could request a survey. I said I knew exactly where the line was and it was

clearly marked. Southern Company was on my property because the survey markers were still there.

I waited an entire month before getting back with Ms. Caraway and relented and asked for the survey. At that time she informed me that if the poles was on my property, it would be a legal matter and she would have to turn it over to the legal department.

In the meantime, the surveyor came out, just as I stated, and the pole was clearly being placed on the property. Again, this did not stop Georgia Power or its parent company, Southern, from installing the pole and an additional guy-wire even further up my property. Ms. Caraway ordered the survey. She has yet to get back with me.

Again, TRC field service surveyors came out, remarked the pole in the exact same spot where the existing flag and sticks are -- presently are. By the time one of the crew members -- by the way, one of the crew members installing the pole was very hostile and threatening and one of his crew members had to call him off. I have video of the incident.

Georgia Power has not considered me or my integral piece of property in the grid redevelopment equation. They -- there has been absolutely no

collaboration with me on this particular part since its inception.

Work with -- working with them has been a -- has not been an option that was extended or afforded me. I was completely ignored and run over. The only option left to me is to sell my property at 842 Atwood on the corner of Atwood and Ponce De Leon, which was extremely valuable to me before they disturbed my quiet enjoyment.

They have made my property even more valuable to me -- and me -- and them, per GW Electric, the manufacturer of the boxes. The specifics -- this specification makes it physically impossible to install those three boxes at the location. Finding another location would be -- the three boxes are right there all together. They can't find another location.

MADAM CHAIR PRIDEMORE: Mr. Johnson.

MR. JOHNSON: Yes.

MADAM CHAIR PRIDEMORE: So the Commissioners received your email that you sent us yesterday about this issue. And it's been forwarded to our consumer affairs division and they're reaching out to Georgia Power to try to see if there's something that they can do.

**MR. JOHNSON: Well, every time I speak to the subcontractors, you know, 12 guys standing there with shovels in their hand and then nobody -- nobody is saying who they are.**

**I asked them: Well, who is the -- who is -- who's the lead man on the thing?**

**And they say that they don't know. He hasn't -- he's not there or he's at another location and everything.**

**They have sidestepped me every stretch of the way and everything. They have not compensated me for it. They have taken the west side of my lot and everything.**

**Those boxes won't fit on the property per the manufacturer of the boxes. If -- they start -- they installed a split-rail fence so they can continue to use it over there on that side. And if -- and if I put a wall up, nobody -- no electrician will ever go back on that side of the wall that close.**

**They have a stick that's 10 feet long that breaks the power if they have to go into it. It's only seven and a half feet from my line. And if you open the doors, it's 3 feet. And the -- when you install a piece of property -- a permanent something on a piece of property, it's five and a half feet**

from the box and -- and it's right there on the line. It is 18 inches away from all the power that runs all the way through northeast Atlanta.

They need my property in order to just turn the power off on the boxes. They have had bulldozers, 40 -- there was a forklift 40 feet long that they used to install the boxes. 40 feet. A forklift and everything.

They come across my property. They've parked on my property. They have put bulldozers -- they've backed them up on my property on Thursday. They left them until Monday morning and everything.

They have been to terrible to me. Cut my cable. And they say they don't need my property. They want just the front portion of the property. My piece of Ponce De Leon.

MADAM CHAIR PRIDEMORE: Mr. Johnson, I hear the frustration in your voice. And I know that you've stated what's wrong. We have a process for it.

Our consumer affairs division management is very good, very capable. And so they're going to reach out to Georgia Power and put them in touch with you. And you'll have somebody from consumer affairs to work with you.

And so if you want to, you're welcome to email

me again. I know that you emailed all five of us yesterday and -- and I read your message. And I understand how frustrated you are, but we've got a process. And we're working on it; okay?

MR. JOHNSON: All right.

COMMISSIONER JOHNSON: Madam Chair --

MR. JOHNSON: No one -- no one on this Commission would allow somebody to back a bulldozer up on their front yard and leave it from Thursday to Monday morning. I mean, they just took my property.

COMMISSIONER JOHNSON: Madam Chair, if you don't mind.

Mr. Johnson, I appreciate your -- you coming in here this morning and I feel your frustration. If you will allow, Madam Chair, I will work with -- take the lead on this with our consumer affairs and we'll make sure -- we'll make this right.

MADAM CHAIR PRIDEMORE: Yeah.

COMMISSIONER JOHNSON: And I'll tell you, Mr. Johnson, there is a process that we must follow, that we must go through. So you will have to be patient, but I will tell you I'm going to follow up on this personally.

MR. JOHNSON: Thank you.

MADAM CHAIR PRIDEMORE: Yeah.

**MR. JOHNSON: I appreciate you hearing me.**

**MADAM CHAIR PRIDEMORE: Thank you, Mr. Johnson.**

**Ms. Joetta Burnette.**

**MS. BURNETTE: Good morning. I am hear to ask --**

**MADAM CHAIR PRIDEMORE: Ms. Burnette, so the court reporter needs to hear you. Can you push the microphone -- not the neck of it, but just push it down so it's closer to you so that she can hear you.**

**There you go. Thank you, Ms. Burnette.**

**MS. BURNETTE: I just came to ask a question. Will you all allow people to freeze to death because they cannot afford to pay their utilities bills? Will you all allow free heat for people on a limited income and -- because it will be cold this winter.**

**And can't you regulate the cost for those that cannot financially pay the bills?**

**And we need justice for climate. Climate justice right now. Because the climate is what keeps us healthy in the universe on earth. We need help for this. Justice for the climate.**

**Thank you.**

**MADAM CHAIR PRIDEMORE: Thank you, Ms. Burnette.**

**Alexander Draper.**

**MR. DRAPER: Good morning, Commission. Thanks for letting me speak. Alexander Draper, a long-time resident of Atlanta.**

**And just wanted to express two things. One around solar panel -- solar panels for individuals, as well as EV charging, just to share the experience of an individual consumer.**

**I've been trying to get solar panels on my house now for about 9 to 12 months. I've been looking at it for a long time. Financial incentives have not been great, but I've decided to go ahead and bite the bullet and know that the financial return may be longer than I'm in my house. But I want to do it.**

**I'm having to fight the historic board in my neighborhood -- or not fight them, but work with them to try to get this passed. And one of the things that concerns me is I'm willing to go through this trouble.**

**But when I look at net metering, that is clearly something that many, many consumers look at as the pivotal factor as the financial decision whether they're going to look at putting on solar. I think we all want to hopefully be able to have the choice. We certainly are not going to force anybody**

to choose this, but I think the -- giving people the ability to make a choice that makes sense for them financially, but also makes sense for them if they have a view on climate change is critically important.

So I would strongly encourage you to look heavily at how you look at net metering. Not just the short-term impact, but the long-term impact of installing -- getting more solar. Because, clearly, there's limited space in Atlanta, but there's a heck of a lot of rooftop space. That's a lot of space we could use to deliver clean, reliable power and make the investments there.

The other thing I will say on the EV side -- and this echoes what was said previously. I've been driving electric cars now for 12, 13 years. One of the first Nissan Leafs.

And, really, the first one was purely a short-term commuter car. It was getting kids back and forth to school. It was amazing how many people stopped and asked me: What's that car? What's the deal with that?

Then I would tell them -- I'd say: Yeah. But the range is 100.

And they're like: Ah. Well, we never do that.

Where are the charging stations?

I'm like: Well, there are really not a lot of charging stations.

Over the years -- I'm fortunate now that I have the ability to afford a Tesla. I will tell you, the brilliance of Elon Musk is not about the cars he builds, it was the infrastructure of the charging networks.

The reason Tesla is the most adopted is because I can -- I drive it to Kansas. I could drive it to California. We need to get infrastructure in place. Because, I will tell you, I get asked about electric cars by people from all walks of life, all over the place when I drive it. People want to adopt it.

We're building facilities. We're building battery power plants here in Georgia. Infrastructure needs to happen in order for this to move forward.

So I would strongly urge you to really think about your approach to net metering, how it impacts consumers. Not just the bottom line of Georgia Power, but the long-term health of our electric system, as well as affordable power.

And, also, please support the infrastructure to allow people to have a reliable way to get around in electric cars. Thank you very much.

**MADAM CHAIR PRIDEMORE: Thank you, sir.**

**Wan Smith.**

**MS. SMITH: Good morning. I'm going to forgo my comments because I'm staying in Deborah's absence representing GCV.**

**But I did have a question. Earlier you mentioned if anyone had any housekeeping items. In response to your change for Thursday, I have a housekeeping request.**

**Would now be an appropriate time to present that before the Commission or is there a more appropriate time for a housekeeping request in response to the change on Thursday morning?**

**MADAM CHAIR PRIDEMORE: Now is fine.**

**MS. SMITH: Would it be possible -- because there are a number of folks who are planning to travel from across the state for public comment, and 7:30 is so early, to start the general session at 7:30, but then to break for public comment at the originally scheduled time of 9:30 a.m. to give folks who are commuting from various parts of the state an opportunity to maintain the schedule that was previously posted and to drive from various portions of the state?**

**So to start at 7:30 with the hearing, to take a**

small break for that hour at 9:30 for public comment and then to continue through the course of the day?

MADAM CHAIR PRIDEMORE: Ms. Smith, I was actually going to do better than that. Because we have a committee schedule on Thursday, we're going to do committees and then we're going to do public comment. So they're going to have even a little bit more time.

MS. SMITH: Excellent.

Thank you, Commission.

MADAM CHAIR PRIDEMORE: Any other public witnesses?

(No response.)

MADAM CHAIR PRIDEMORE: Any other public witnesses?

(No response.)

MADAM CHAIR PRIDEMORE: All right. We will adjourn until 10:25 and then we'll be back.

(A recess was held from 10:15 a.m. until 10:25 a.m.)

MADAM CHAIR PRIDEMORE: Call to order Georgia Public Service Commission.

MR. WALSH: Thank you, Madam Chair. If I could raise one housekeeping matter that I neglected to do when you asked earlier.

The staff has asked that the panel of

Mr. Gorman and Mr. O'Donnell testify on Thursday.

MADAM CHAIR PRIDEMORE: And the Chair grants staff's request.

MR. WALSH: Thank you very much.

At this time the staff would like to call the panel of Rob Trokey and Ralph Smith on behalf of Public Interest Advocacy Staff.

Gentlemen, if you could remain standing and raise your right hand.

Thereupon,

ROBERT L. TROKEY,
RALPH C. SMITH,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WALSH:

Q Mr. Trokey, could you please state your full name for the record and by whom you're employed.

A (Witness Trokey) Robert Trokey and employed by the Georgia Public Service Commission's Public Interest Advocacy staff.

Q Mr. Smith, could you please state your full name for the record and by whom you're employed.

A (Witness Smith) My name is Ralph C. Smith and I'm employed by Larkin and Associates, PLLC.

Q Mr. Trokey, on October 20th, 2022, did you and Mr. Smith prefile or cause to be filed 140 pages of public

disclosure testimony in question-and-answer form?

A (Witness Trokey) Yes, we did.

Q On November 7th, did you prefile or cause to be prefiled an errata of your testimony?

A (Witness Trokey) We did.

Q Are there any other changes or corrections that you would like to make to the prefiled direct testimony at this time?

A (Witness Trokey) No.

Q Noting the corrections that were set forth in the erratas, if I were to ask you the same questions that are presented in your prefiled testimony, would your answers be the same?

A (Witness Trokey) Yes.

MR. WALSH: Madam Chair, I would ask that the public disclosure prefiled direct testimony of Mr. Trokey and Mr. Smith be copied into the record as if read from the witness stand.

MADAM CHAIR PRIDEMORE: So move.

(Whereupon, the prefiled direct testimonies of Robert L. Trokey and Ralph C. Smith follows:)

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the Matter of:** | **)** | |
| **GEORGIA POWER COMPANY'S** | **)** | **DOCKET NO. 44280** |
| **2022 RATE CASE** | **)** | |

# DIRECT TESTIMONY
# AND EXHIBITS
# OF
# RALPH C. SMITH
# AND
# ROBERT L. TROKEY

**ON BEHALF OF THE**

**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

**PUBLIC VERSION**

**October 20, 2022**

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

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RS/RT-18 Identification of amounts in the PHFFU account for which the projected "use" date in providing electric service is (1) 2030 or beyond or (2) 2040 or beyond.

RS/RT-19 Georgia Power's response from Docket Nos. 44160 and 44161 (2022 IRP) to STF-LA-1-44 concerning PHFFU.

RS/RT-20 Georgia Power's responses to STF-LA-2-117, STF-LA-2-118, and STF-LA-2-119 concerning Production Tax Credits.

RS/RT-21 Selected pages of Southern Company Services FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).

RS/RT-22 Georgia Power's Trade Secret response to STF-LA-2-111 (without attachment) concerning SCS Allocation Factors Using 2022 Statistics.

RS/RT-23 Selected pages of Southern Nuclear Operating Company FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).

RS/RT-24 Georgia Power's response to STF-LA-7-1 concerning DSM Carrying Costs.

RS/RT-25 Georgia Power's responses to STF-LA-2-101, 102, 115 and 116 concerning Excess Accumulated Deferred Income Taxes.

RS/RT-26 Georgia Power's responses to STF-LA-5-14, 5-15 and 8-13 concerning tax credits expected under the Inflation Reduction Act and impact of minimum corporate income tax provisions under that Act.

RS/RT-27 Georgia Power's response to STF-1-43 from Docket No. 44265 concerning SNOC's allocation percentages upon Plant Vogtle Units 3 and 4 being placed into service, currently projected to be March 2023 and December 2023, respectively.

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the Matter of:** | **)** | |
| **GEORGIA POWER COMPANY'S** | **)** | **DOCKET NO. 44280** |
| **2022 RATE CASE** | **)** | |

# DIRECT TESTIMONY OF RALPH C. SMITH AND ROBERT L. TROKEY

## I. INTRODUCTION

**Q. MR. SMITH, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am a certified public accountant and a senior regulatory utility consultant with the firm Larkin & Associates, PLLC, certified public accountants and regulatory consultants.

**Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?**

A. Yes. It is presented in Exhibit__(RCS-1). This exhibit summarizes my regulatory experience and qualifications.

**Q. MR. TROKEY, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Robert L. Trokey, 244 Washington St. SW, Atlanta, Georgia 30334.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am Director of the Electric Section at the Georgia Public Service Commission ("Commission").

**Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?**

A. Yes. It is presented in Exhibit RLT-1. This exhibit summarizes my regulatory experience and qualifications.

**Q. ON WHOSE BEHALF ARE YOU APPEARING?**

A. We are testifying on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("Staff").

## II. SCOPE AND PURPOSE OF TESTIMONY

**Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?**

A. The scope and purpose of our testimony is to present the Staff's overall traditional case revenue requirement position for Georgia Power Company ("Georgia Power" or "Company"), as well as Staff's recommended position regarding the Company's proposed Alternative Rate Plan ("ARP"), and Environmental Compliance Cost Recovery ("ECCR").[1] We also show the Company's Demand Side Management ("DSM") revenue requirement, and Municipal Franchise Fee ("MFF") revenue requirement, as well as Staff's corresponding recommendations on each of those. We also address the Company's proposal for a three-year alternative rate plan covering the years 2023, 2024

[1] The annual Coal Combustion Residuals ("CCR") Asset Retirement Obligations ("ARO") revenue requirements for 2023, 2024 and 2025 are reflected in Georgia Power Exhibit__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR).

and 2025, the history of previous Company rate plans, and recommendations for the principles and sharing mechanisms that should be applied, if the Commission chooses to allow for an alternative rate plan in the current rate cases, versus allowing a revenue requirement based on adjusted test year results.

**Q. IN CALCULATING THE STAFF'S RECOMMENDED OVERALL TRADITIONAL RATE CASE REVENUE REQUIREMENT POSITION, DID YOU INCORPORATE RECOMMENDATIONS MADE BY OTHER STAFF WITNESSES?**

A. Yes. We have incorporated the following recommendations of other Staff witnesses at this time:

- Ms. Jamie Barber's recommendations concerning the Company's *DSM revenue requirement* and adjustments thereto.
- Mr. Michael Gorman's recommended *capital structure*, *return on equity and cost rates for long-term debt.*
- Mr. Dante Mugrace's recommended adjustments to O&M expense.
- Mr. Steve Baron's and Ms. Leah Wellborn's recommended adjustments to forecasted revenues.
- Mr. Paul Alvarez's, Mr. Dennis Steven's and Mr. Raj Rana's recommended adjustments to Transmission and Distribution plant investment, and for the Distributed Energy Resource Management System.

**Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT OF YOUR TESTIMONY?**

A. In developing this testimony, we have relied upon our review and analysis of the Company's direct testimonies and accompanying exhibits; Minimum Filing Requirements; workpapers; responses to "STF-L&A" and "STF-PIA" and other Staff data requests; transcripts from the September 27-29, 2022 hearings; and other relevant financial documents and data.

## III. CASE OVERVIEW AND STRUCTURE OF TESTIMONY

**Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THIS CASE.**

A. This case was filed by the Company on June 24, 2022, in accordance with the Procedural and Scheduling Order in Docket No. 44280, and the requirements of the Short Order Adopting Settlement Agreement As Modified approved by the Commission in its Order dated December 31, 2019, in Georgia Power's 2019 rate case, Docket No. 42516. Georgia Power filed the instant rate case to obtain a Commission decision regarding its base rates prior to the expiration of the Accounting Order on December 31, 2019.

**Q. WHAT TEST PERIOD AND PLAN YEARS ARE USED IN THE COMPANY'S FILING?**

A. The Company's rate filing includes financial projections for the traditional, Commission-ordered test year of August 1, 2022 through July 31, 2023, as well as for an Alternative Rate Plan that encompasses the three calendar years 2023, 2024 and 2025.

**Q. WHAT CUMULATIVE BASE RATE REVENUE INCREASES HAS THE COMPANY PROPOSED FOR THE ALTERNATIVE RATE PLAN YEARS 2023-2025?**

A. The Company has proposed cumulative base rate revenue increases of approximately $2.9 billion, which includes traditional base rates, ECCR, DSM and MFF,[2] over the 2023-2025 alternative rate plan period as shown in the table below.

[2] See Table A on page 10.

| Description | 2023 ($ Millions) | 2024 ($ Millions) | 2025 ($ Millions) | 3 Year Total ($ Millions) |
|---|---|---|---|---|
| Company As-Filed Projected Revenue Requirement Deficiency by Year | $ 599 | $ 927 | $ 1,330 | $ 2,854 |

**Traditional Base Rates**

**Q. HOW DID THE COMPANY PROPOSE TO RECOVER THE REVENUE DEFICIENCY FOR THE TEST YEAR ENDING JULY 31, 2023?**

A. The rate filing indicates that the Company requests a revenue requirement increase of approximately $738.661 million rather than the $447.521 million revenue deficiency associated with the test year. The $738.661 million is based on a $426.415 million "levelized" revenue deficiency which the Company calculated based on calendar 2023 through 2025. This is shown on Company Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3. As shown there, Georgia Power first calculated a retail jurisdictional revenue deficiency for the test year of approximately $312.245 million. To that amount the Company added a "2023-2025 Levelization Adjustment" amount of $426.415 million[3], to derive its requested Levelized Revenue Deficiency Applicable to Traditional Base Rate Tariffs of $738.661 million, as shown on Company Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1, lines 1-3.

**Q. IS THE COMPANY'S PROPOSED RECOVERY OF A REVENUE DEFICIENCY BASED ON THE TRADITIONAL TEST YEAR APPROACH?**

A. No. The Company's rate request in this case is not based on the traditional ratemaking approach. Rather, it is based on an Alternative Rate Plan that uses projected data from an

[3] In the context of a traditional rate case, the Company has not provided any authority for allowing recovery of a "Levelization Adjustment" based on costs from future years beyond the Commission ordered test year.

alternative test year, calendar year 2023, as well as projections for calendar years 2024 and 2025. While the proposed Alternative Rate Plan has no termination date, the rate filing presents projected revenue requirement and associated rate change data for the first three years of the Plan, i.e., the years 2023, 2024 and 2025. This approach is very beneficial to the Company as it eliminates regulatory lag. The Company is only entitled to rates being set under the test year. Of course, if rates are set on a test year the Company may stay out as long as it wants and may file a rate case at any time. The Commission has the authority to order the Company to file a rate case at any time.

The revenue deficiency calculated by the Company (excluding the MFF) for the test year is $447.521 million as shown on Company Exhibit __ (APA/SPA/ADH/MBR-2, Schedule 1 Total Company), page 1 of 10.

The revenue deficiencies calculated by the Company (excluding the MFF) under the Alternative Rate Plan amount to approximately $584.204 million for 2023, $905.447 million for 2024 and $1.299 billion for 2025 as shown on Company Exhibit __ (APA/SPA/ADH/MBR-2, Schedule 1 Total Company), page 1 of 10.

As shown on Company Exhibit __(APA/SPA/ADH/MBR-2, Schedule 2, Traditional Base), page 3 of 3, the Company has calculated a traditional base rate tariff revenue deficiency of $461.367 million for 2023; a $717.966 million deficiency for 2024 and a $1.080 billion revenue deficiency for 2025.

As shown on Company Exhibit __ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 2 of 3, the Company proposes to "levelize" the traditional base rate tariff revenue deficiency of $461.367 million for 2023; a $717.966 million deficiency for 2024 and a $1.080 billion revenue deficiency for 2025, using a discount rate of 7.32%, to produce a "levelized" annual revenue deficiency of $738.661 million for 2023, 2024 and 2025.

As shown on Company Exhibit __ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, the Company proposes to adjust its calculated test year revenue requirement deficiency of $312.245 million under traditional base rate tariffs upward by $426.415 million to get to the 2023, 2024 and 2025 "levelized" revenue deficiency of $738.661 million per year. This is shown on Company Exhibit __ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 2 of 3, lines 1 through 3. This means that, under Georgia Power's proposal, the traditional base rates to become effective on January 1, 2023 will be designed to recover a revenue deficiency of $738.661 million per year, which is $426.415 million more than the $312.245 million revenue deficiency that the Company calculated for the test year.[4]

**Q. WHAT AMOUNT OF BASE RATE REVENUE DEFICIENCY HAS THE COMPANY PROPOSED FOR NEW RATES TO BECOME EFFECTIVE ON**

[4] The Company's calculated test year revenue deficiency of $312.245 million for traditional base rate tariffs is shown on Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, line 1; on page 2 of 3, line 3, and on page 3 of 3, column (3), line 4.

**JANUARY 1, 2023, AND HOW DOES THAT COMPARE WITH THE TEST YEAR AMOUNT?**

A. As shown in Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, the 2023-2025 "Levelized Revenue Deficiency" applicable to traditional base rates of $426.415 million (from line 2) is added to the $312.245 million for traditional base rate tariffs to produce a combined revenue deficiency of $738.661 million.

That $738.661 million is $426.415 million higher than the $312.245 million test year revenue deficiency applicable to traditional base rates that the Company shows on Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 3 of 3, line 4.

**Q. WHAT AMOUNT OF BASE RATE REVENUE INCREASES HAS THE COMPANY CALCULATED FOR THE TEST YEAR AND EACH PLAN YEAR?**

A. Company Exhibit __(APA/SPA/ADH/MBR-1, Schedule 1 Total Company) page 1 of 10 shows Georgia Power's computation of the retail revenue increases applicable to base rate tariffs including ECCR and DSM, excluding the MFF for the test year and each plan year as follows:

- Test Period: $447.521 million
- 2023: $584.204 million
- 2024: $905.447 million
- 2025: $1.299 billion

With the MFF included, the Company's calculated revenue requirement deficiency amounts by year for the 2023 through 2025 plan years is summarized from Table 2 at page 21 of the Abramovitz/Adams/Houston/Robinson panel testimony as follows:

**Table A - Company As-Filed Projected Revenue Requirement Deficiency**

| Company As-Filed Projected Revenue Requirement Deficiency by Year (In Millions of Dollars) | | | | |
|---|---|---|---|---|
| Effective Date | 2023 | 2024 | 2025 | 3 Year Total |
| Traditional Base (a) | $ 461 | $ 718 | $ 1,080 | $ 2,259 |
| ECCR | | | | |
| ECCR Traditional (b) | $ 29 | $ (12) | $ (25) | $ (8) |
| ECCR CRO ARO* (c) | $ 64 | $ 143 | $ 189 | $ 396 |
| DSM* (d) | $ 30 | $ 56 | $ 54 | $ 140 |
| MFF (e) | $ 14 | $ 22 | $ 31 | $ 67 |
| Total ($) | $ 599 | $ 927 | $ 1,330 | $ 2,854 |
| * As determined by the Commission through annual CCR ARO and DSM compliance filings | | | | |
| Note: Amounts may not sum to total due to rounding | | | | |
| Source: Abramovitz/Adams/Houston/Robinson Direct Testimony, page 21, Table 2 | | | | |
| | | | | |
| *See the following exhibits supporting Table A:* | | | | |
| (a) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base) Page 3 | | | | |
| (b) Exhibit_ (APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 2 | | | | |
| (c) Exhiibt__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 6 | | | | |
| (d) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 4 DSM) Page 1 | | | | |
| (e) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 5 MFF) Page 2 | | | | |

**Q. DOES TABLE A REPRESENT THE RATE INCREASES THAT THE COMPANY IS SEEKING?**

A. No. The rate increases for the 2023, 2024 and 2025 plan years that the Company is seeking are summarized below from Table 1 from page 9 of the Abramovitz/Adams/Houston/Robinson panel testimony, with three-year totals also shown:

**Table B - Company As-Filed Proposed Rate Adjustments**

| Company Proposed Rate Adjustments (in millions) - Company As-Filed | | | | |
|---|---|---|---|---|
| Effective Date | 1/1/2023 | 1/1/2024 | 1/1/2025 | 3 Year Total |
| Traditional Base (a) | $ 739 | $ - | $ - | $ 739 |
| ECCR | | | | |
| ECCR Traditional (b) | $ (1) | $ - | $ - | $ (1) |
| ECCR CRO ARO* (c) | $ 64 | $ 78 | $ 47 | $ 189 |
| DSM* (d) | $ 30 | $ 27 | $ (2) | $ 55 |
| MFF (e) | $ 20 | $ 2 | $ 1 | $ 23 |
| Total ($) | $ 852 | $ 107 | $ 45 | $ 1,004 |
| Cumulative ($) | $ 852 | $ 959 | $ 1,004 | $ 2,815 |
| * As determined by the Commission through annual CCR ARO and DSM compliance filings | | | | |
| Note: Amounts may not sum to total due to rounding | | | | |
| Source: Abramovitz/Adams/Houston/Robinson Direct Testimony, page 9, Table 1 | | | | |
| *See the following exhibits supporting Table A:* | | | | |
| (a) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base) Page 1 | | | | |
| (b) Exhibit_ (APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 1 | | | | |
| (c) Exhiibt__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) Page 6 | | | | |
| (d) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 4 DSM) Page 1 | | | | |
| (e) Exhibit__(APA/SPA/ADH/MBR-1, Schedule 5 MFF) Page 1 | | | | |

**Q. HAS THE COMPANY FILED A SUPPLEMENTAL FILING THAT HAS CHANGED ITS REVENUE DEFICIENCY AMOUNTS?**

A. Yes. On August 22, 2022, the Company filed a supplemental that had the overall net effect of increasing the Company's proposed January 1, 2023, 2024 and 2025 rate adjustments by approximately $37 million (from $852 million for 2023 to $889 million) for 2023; by $37 million for 2024 (from $959 million to $996 million) and by $37 million for 2025 (from $1.004 billion to $1.041 billion). The Company's corrected rate changes are summarized in the following table, which also shows three-year totals for the 2023-2025 alternative rate plan years:

**Table C - Company Updated Proposed Rate Adjustments**

| Company Proposed Rate Adjustments (in millions) - Company Supplemental | | | | |
|---|---|---|---|---|
| Effective Date | 1/1/2023 | 1/1/2024 | 1/1/2025 | 3 Year Total |
| Traditional Base (a) | $ 762 | $ - | $ - | $ 762 |
| ECCR | | | | |
| ECCR Traditional (b) | $ 5 | $ - | $ - | $ 5 |
| ECCR CRO ARO* (c) | $ 64 | $ 78 | $ 47 | $ 189 |
| DSM* (d) | $ 37 | $ 27 | $ (2) | $ 62 |
| MFF (e) | $ 21 | $ 2 | $ 1 | $ 24 |
| Total ($) | $ 889 | $ 107 | $ 45 | $ 1,042 |
| Cumulative ($) | $ 889 | $ 996 | $ 1,041 | $ 2,926 |
| Cumulative ($) Company As-Filed | $ 852 | $ 959 | $ 1,004 | $ 2,815 |
| Change from Company As-Filed | $ 37 | $ 37 | $ 37 | $ 111 |
| * As determined by the Commission through annual CCR ARO and DSM compliance filings | | | | |
| Note: Amounts may not sum to total due to rounding | | | | |
| Source: Supplemental Filing Transmittal Letter Dated August 22, 2022, Page 2 | | | | |

**Q. HAS THE COMPANY INDICATED WHAT CAUSED THE SUPPLEMENTAL CHANGES?**

A. Yes. As discussed in the Company's Supplemental Filing transmittal letter, the Company's supplemental filing reflects the revenue requirement impacts from various items included in the Final Order that was approved by the Commission in Georgia Power's 2022 Integrated Resource Plan ("2022 IRP") and DSM Certification proceedings in Docket Nos. 44160 and 44161.

**Q. WHAT SPECIFIC CORRECTIONS ARE REFLECTED IN GEORGIA POWER'S SUPPLEMENTAL FILING?**

A. The Company's transmittal letter lists the following revenue requirement impacts in its Errata filing:

- Defer Retirement Decision on Plant Bowen Units 1&2

- Update Plant Scherer ELG Capital Cost
- Update Capacity RFP PPA Additional Sum
- Update DG PPA Additional Sum
- Remove Wholesale to Retail Capacity Offer of 88 MWs related to Plant Yates Units 6&7 and Blocks 5&6
- Remove North Highlands Hydro Modernization Project
- Include DER Local Reliability and Constraints Pilot Projects
- Remove Tall Wind Research and Development Project
- Update DSM costs and additional sum, along with revenue impacts from the revised energy savings targets

**Q. HAVE THE ALL THE IMPACTS FROM THE COMPANY'S SUPPLEMENTAL FILING BEEN REFLECTED IN STAFF'S CALCULATIONS?**

A. Yes. Since Staff's analysis used as a starting point the Company's original filing, the Company's supplemental filing corrections have been reflected by Staff as adjustments. Specifically, Exhibit__(RS/RT-2) reflects the rate base adjustments from the Company's supplemental filing on Schedule E-1 and operating income adjustments from the supplemental filing on Schedule E-2.

**Q. WILL GEORGIA POWER CUSTOMERS ALSO BE FACING OTHER SIGNIFICANT INCREASES IN THEIR ELECTRIC UTILITY BILLS OVER THE 2023-2025 ALTERNATIVE RATE PLAN PERIOD?**

A. Yes. Customers will see their bills increase due not only to the base rate increase(s) for 2023-2025 under the alternative rate plan that are being addressed in the current Georgia Power rate case, and also will likely face other significant rate increases for the Company's recovery of fuel and purchased power costs, and additional rate increases related to Plant Vogtle Units 3 and 4 being placed into service, which is currently expected to occur prior to the end of the alternative rate plan period of 2023-2025. Staff's estimates to a typical residential customer based on what the Company may request for those additional increases could be as much as an additional $25 per month for fuel rates, an additional $5 per month for Vogtle Unit 3 and an additional $10 to $15 per month for Vogtle Unit 4, respectively.

**Q. HOW IS THE REST OF YOUR TESTIMONY STRUCTURED?**

A. The rest of our testimony is structured into several sections where various issues are addressed.

Section IV presents a summary of the Company's and Staff's recommended revenue requirement as determined based on the traditional ratemaking approach using the traditional test year August 1, 2022 through July 31, 2023 as well as for each of the plan years, 2023, 2024 and 2025, which are presented in Exhibit__(RS/RT-2).

Section V discusses the Environmental Compliance Cost Recovery tariff revenue deficiency proposed by the Company and calculated by Staff. Staff's calculation of the ECCR revenue requirement for the test year and each plan year is shown in

Exhibit__(RS/RT-3). This section also discusses how the Company's requested ECCR amount affects the revenue requirement, and Staff's recommended proposal.

Section VI of our testimony presents a summary of the DSM tariff revenue deficiency amounts for 2023, 2024 and 2025 using information from Docket Nos. 44160 and 44161 and supplied to us by Staff witness Jamie Barber. Staff's calculations of the DSM revenue deficiency amounts are shown in Exhibit__(RS/RT-4) and also reflect the application of Staff's recommended cost of capital in the calculation of carrying charges.

Section VII presents a summary of the MFF tariff revenue requirement, which is shown in Exhibit__(RS/RT-5), and the impacts of the pre-tax cost of capital and the traditional base rate, ECCR and DSM revenue deficiency amounts on the MFF revenue requirement deficiency that was proposed by the Company and as calculated by Staff.

Section VIII discusses the Company's proposed and Staff's adjusted revenue requirement for Coal Combustion Residuals ("CCR") Asset Retirement Obligations ("ARO") which are presented in Exhibit__(RS/RT-6).

Section IX discusses the organization of Staff's revenue requirement and adjustment schedules which are presented in Exhibit__(RS/RT-2) for the traditional rate case based on the test year ending July 31, 2023 and for each year, 2023-2025, in the alternative rate plan.

Section X discusses each of Staff's recommended adjustments that are shown in Exhibit __(RS/RT-2) on Schedules E-1 through E-38 and some areas that were reviewed by Staff but for which no adjustment is being made to the Company's filing.

Section XI addresses affiliate transactions including the charges between Georgia Power Company and its affiliates including Southern Company Services ("SCS") and Southern Nuclear Operating Company ("SNOC") charges to Georgia Power; and Georgia Power charges to affiliates.

Section XII addresses the incentive compensation plans of Georgia Power Company and affiliates, which includes stock-based compensation and the Performance Pay Plan.

Section XIII explains Staff's proposed principles and recommendations for the Alternative Rate Plan. This section includes a discussion of Staff's proposed earnings test, as well as Staff's recommendation that a step increase approach be used instead of the levelization approach that has been proposed by Georgia Power Company.

Finally, Section XIV presents a summary of recommendations.

**Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?**

A. Yes. In addition to our qualifications, which are in Exhibit RCS-1 and RLT-1, respectively, Staff has attached Exhibits RS/RT-2 through RS/RT-27 which contain responses to discovery and other materials referenced in our testimony.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-2?**

A. Exhibit RS/RT-2 presents Staff's calculations relating to the Traditional Revenue Requirement and Adjustment Schedules.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-3?**

A. Exhibit RS/RT-3 presents Staff's calculations concerning the ECCR Revenue Requirement.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-4?**

A. Exhibit RS/RT-4 presents Staff's calculations concerning the DSM Revenue Requirement.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-5?**

A. Exhibit RS/RT-5 presents Staff's calculations concerning the Municipal Franchise Fee Revenue Requirement.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-6?**

A. Exhibit RS/RT-6 presents Staff's calculations concerning the CCR ARO Compliance Revenue Requirement.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-7?**

A. Exhibit RS/RT-7 presents Georgia Power's responses to STF-LA-2-79, STF-LA-2-81, and STF-LA-2-92 and Trade Secret response to STF-LA-2-78 concerning Stock-Based Compensation.

**Q. WHAT ARE SHOWN IN EXHIBITS RS/RT-8, RS/RT-9, AND RS/RT-10?**

A. Exhibit RS/RT-8 presents Georgia Power's responses to STF-LA-3-1, STF-LA-3-2, STF-LA-3-3, and STF-LA-3-4 concerning Energy Direct Premium Packages.

Exhibit RS/RT-9 presents Georgia Power's response to STF-LA-2-56 concerning Executive Financial Planning.

Exhibit RS/RT-10 presents Georgia Power's response to STF-LA-2-25 concerning O&M Scrap Sales Proceeds.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-11?**

A. Exhibit RS/RT-11 presents Georgia Power's Trade Secret response to STF-LA-12-1 concerning Wireless Co-Location Revenues.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-12?**

A. Exhibit RS/RT-12 presents Georgia Power's response to STF-LA-8-18 concerning Depreciation Expense.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-13?**

A. Exhibit RS/RT-13 presents Georgia Power's responses to STF-LA-6-19, STF-LA-6-20, STF-PIA-1-3, STF-PIA-3-5, HR-1 and the Trade Secret response to STF-PIA-1-1 concerning Electric Vehicles Make Ready Program.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-14?**

A. Exhibit RS/RT-14 presents Georgia Power's response to STF-LA-2-120 concerning Electric Vehicles Community Charging Stations.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-15?**

A. Exhibit RS/RT-15 presents Georgia Power's Trade Secret responses to STF-PIA-4-4 and STF-WG-2-33 concerning Transmission and Distribution Plant Investment.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-16?**

A. Exhibit RS/RT-16 presents Georgia Power's Trade Secret response to STF-WG-2-3 concerning DERMS.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-17?**

A. Exhibit RS/RT-17 presents Georgia Power's 2021 FERC Form 1, pages 214, account 105, Plant Held for Future Use.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-18?**

A. Exhibit RS/RT-18 identifies amounts in the PHFFU account for which the projected "use" date in providing electric service is (1) 2030 or beyond or (2) 2040 or beyond.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-19?**

A. Exhibit RS/RT-19 presents Georgia Power's response from Docket Nos. 44160 and 44161 (2022 IRP) to STF-LA-1-44 concerning PHFFU.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-20?**

A. Exhibit RS/RT-20 presents Georgia Power's responses to STF-LA-2-117, STF-LA-2-118, and STF-LA-2-119 concerning Production Tax Credits.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-21?**

A. Exhibit RS/RT-21 presents Selected pages of Southern Company Services FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-22?**

A. Exhibit RS/RT-22 presents Georgia Power's Trade Secret response to STF-LA-2-111 (without attachment) concerning SCS Allocation Factors Using 2022 Statistics.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-23?**

A. Exhibit RS/RT-23 presents Selected pages of Southern Nuclear Operating Company FERC Form 60 for period of 2021 Q4 (cover, pages 307, 402).

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-24?**

A. Exhibit RS/RT-24 presents Georgia Power's response to STF-LA-7-1 concerning DSM Carrying Costs.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-25?**

A. Exhibit RS/RT-25 presents Georgia Power's responses to STF-LA-2-101, 102, 115 and 116 concerning Excess Accumulated Deferred Income Taxes.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-26?**

A. Exhibit RS/RT-26 presents Georgia Power's responses to STF-LA-5-14, 5-15 and 8-13 concerning tax credits expected under the Inflation Reduction Act and the Company's estimated impact of minimum corporate income tax provisions under that Act.

**Q. WHAT IS SHOWN IN EXHIBIT RS/RT-27?**

A. Exhibit RS/RT-27 presents Georgia Power's response to STF-1-43 from Docket No. 44265 concerning SNOC's allocation percentages upon Plant Vogtle Units 3 and 4 being placed into service, currently projected to be March 2023 and December 2023, respectively.

# IV. TRADITIONAL REVENUE REQUIREMENT SUMMARY

**Test Year and Plan Years**

**Q. WHAT TEST YEAR SHOULD BE USED TO DETERMINE THE COMPANY'S TRADITIONAL REVENUE REQUIREMENT IN THIS CASE?**

A. Under the Commission's February 6, 2020 Order Adopting Settlement Agreement as Modified in Docket No. 42516, the test period to be used in this case is from August 1, 2022 to July 31, 2023. The February 6, 2020 Order Adopting Settlement Agreement as Modified also required the Company to file testimony and exhibits required in a general rate case along with supporting schedules required by the Commission to support a "traditional" rate case by July 1, 2022, so that the Commission may consider whether to continue, modify, or discontinue the Alternative Rate Plan established in Georgia Power Company's 2019 Rate Case, Docket No. 42516 ("2019 Rate Case").

Both the Company and Staff have presented revenue requirement calculations using the test year ending July 31, 2023, as well as for calendar years 2023, 2024 and 2025, which comprise the Company's Alternative Rate Plan presentation in the current rate case.

**Q. WHAT IS THE DIFFERENCE BETWEEN THE COMPANY'S CALCULATED REVENUE DEFICIENCY FOR THE TEST YEAR ENDED JULY 31, 2023 AND FOR CALENDAR YEAR 2023?**

A. The Company's calculated a traditional base rate revenue deficiency of $312.245 million[5] for the test year ended July 31, 2023 is approximately $426.415 million less than its requested revenue increase amount for the calendar year 2023 of $738.661 million, as shown on Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 1 of 3, lines 1 through 3.

That $738.661 million base rate revenue increase that the Company has requested to become effective on January 1, 2023 based on its proposed alternative rate plan is $426.415 million more than the amount of the Company's calculated test year revenue deficiency applicable to traditional base rate tariffs of $312.245 million, which is shown on Company Exhibit__ (APA/SPA/ADH/MBR-1, Schedule 2 Traditional Base), page 3 of 3, column 3, line 4.

**Traditional Case Summary**

**Q. PLEASE SUMMARIZE STAFF'S FINDINGS AND CONCLUSIONS REGARDING GEORGIA POWER'S TRADITIONAL REVENUE REQUIREMENT BASED ON THE COMMISSION-ORDERED TEST YEAR ENDING JULY 31, 2023.**

A. Our findings and conclusions are as follows:

1. The traditional revenue requirement for Georgia Power in this rate case should be determined based on the use of the Commission-ordered test year ending July 31, 2023.

[5] This amount does not include ECCR, DSM and MFF.

2. The appropriate traditional test year average retail rate base is $24.039 billion which is $21.265 million higher than the Company's proposed traditional test year average retail rate base of $24.018 billion as shown on Staff Exhibit__(RS/RT-2), Schedule A, line 1 and Schedule B.[6]

3. The appropriate traditional test year retail operating income is $1.709 billion, which is $193.069 million higher than the Company's proposed test year traditional test year retail operating income of $1.516 billion as shown on Staff Exhibit__(RS/RT-2), Schedule A, line 4 and Staff Exhibit__(RS/RT-2), Schedule C.

4. The traditional test year overall rate of return for Georgia Power we used in this case is 6.84% as summarized on Staff Exhibit__(RS/RT-2), Schedule D and includes a fair return on equity of 9.45% and the 3.53% cost of debt as recommended by Staff witness Michael Gorman. Staff's overall cost of capital of 6.84% for the test year compares to Georgia Power's proposed overall rate of return of 7.70%, which includes a requested return on equity rate of 11.0%.

5. The appropriate income expansion factor (aka Gross Revenue Conversion Factor or GRCF) to be used for ratemaking purposes in this case is dividing by 74.606% or multiplying by 1.340378, as shown on Staff Exhibit__(RS/RT-2), Schedule A-1, page 1 of 2. This percentage compares with the Company's proposed factor of 74.606%. This factor reflects a federal income tax rate of 21% and a state income tax rate of 5.75%. The same income tax rates were used by both Georgia Power

[6] The rate base difference is impacted by various adjustments.

and Staff; however, Staff's factor is slightly lower than the Company's because Staff reflects a lower component for uncollectibles.

6. The recommended traditional test year ratemaking components outlined above would produce an annual Traditional Base Rate Tariff decrease (i.e., a revenue excess amount) of approximately $86.581 million. This is $534.102 million lower than Georgia Power's proposed traditional test year Traditional Base Rate Tariff deficiency of $447.521 million. These amounts are shown on Staff Exhibit __(RS/RT-2), Schedule A, line 7, in columns C, A, and G, respectively.

7. Georgia Power's proposed ECCR Tariff rider revenue deficiency has been adjusted by Staff as shown on Staff Exhibit__(RS/RT-3), and discussed in Section V of our testimony. While Georgia Power has proposed an ECCR Tariff revenue increase of $105.6 million for the test year, Staff has calculated a test year ECCR Tariff revenue deficiency of $68.9 million. The Company also proposed a "levelization" adjustment for the ECCR. Staff does not recommend a levelization adjustment for the ECCR. Without the levelization adjustment, Staff's recommended ECCR revenue deficiency of $68.9 million is about $36.7 million lower than the Company's proposed amount of $105.6 million. See Staff Exhibit__(RS/RT-2), Schedule A, line 8, columns A, C and G and Staff Exhibit__(RS/RT-3).

8. Georgia Power has proposed continuation of its DSM Tariff rider with an associated DSM Tariff revenue deficiency of $29.65 million for the traditional test year. Staff calculated a $36.98 million DSM revenue deficiency, which is about $7.3 million higher than the Company amount. See Staff

Exhibit__(RS/RT-2), Schedule A, line 9, columns A, C and G and Staff Exhibit__(RS/RT-4).

9. For the CCR ARO Compliance revenue requirement, Staff calculated $57.8 million for the test year and $61.7 million for 2023, as shown on Exhibit __(RS/RT-6). These amounts compare with, and are lower by $2.3 million and $2.8 million, respectively, than the Company's proposed test year amount of $60.0 million and the Company's proposed 2023 amount of $64.5 million. See Exhibit__(RS/RT-6), pages 2 and 3. For CCR ARO Compliance, Staff recommends using the 2023 revenue deficiency amount of $61.7 million, as shown on Exhibit__(RS/RT-6), page 3.

10. Staff recommends that the Company's proposed 2023-2025 levelization revenue requirement adjustment of $426.415 million to derive a levelized revenue deficiency amount of $738.661 million per year for 2023-2025 not be adopted. Rather, Staff recommends that a step-increase approach be used for a three-year rate plan. Staff Exhibit__(RS/RT-2), Schedule A, line 13, shows the calculated increases for 2024 and 2025. The Company should be required to file compliance filings prior to implementing step increases in each of those years, 2024 and 2025.

**Staff Test Year and Plan Year Adjustments-Estimated Revenue Requirement Impacts**

**Q. HAVE YOU PREPARED A TABLE OUTLINING THE APPROXIMATE REVENUE REQUIREMENT IMPACT OF EACH OF STAFF'S RECOMMENDED ADJUSTMENTS TO THE COMPANY'S PROPOSED TRADITIONAL REVENUE REQUIREMENT IN THIS CASE FOR THE TEST YEAR AND EACH PLAN YEAR?**

A. Yes, Table D is presented on the next page of this testimony from amounts that are shown in more detail on Staff Exhibit__(RS/RT-2), Schedule A-2, pages 1 through 4:

**Table D - Summary of Staff Traditional Base Rate Revenue Requirement Adjustments**

Georgia Power Company
Revenue Requirement Impact Summary (Also See Exhibit __(RS/RT-2), Schedule A-2)
Summary of Staff Adjustments and Adjusted Revenue Deficiency (Sufficiency)
(Thousands of Dollars)

| Line No. | Description | Staff Exh__(RS/RT-2) Detail Adjustment Schedules | Forecasted Test Year Ending 7/31/2023 | Calendar 2023 | Calendar 2024 | Calendar 2025 |
|---|---|---|---|---|---|---|
| 1 | Company Calculated Revenue Requirement Deficiency | | $ 447,521 | $ 584,204 | $ 905,447 | $ 1,299,024 |
| | **Staff Adjustments:** | | | | | |
| 2 | Return on Equity (9.45% vs. 11.00%), Capital Structur and Cost of Debt | A-2 | $ (277,265) | $ (292,322) | $ (419,429) | $ (442,745) |
| 3 | Adjustments and Corrections from GPC Supplemental/Update Filing* | E-1 & E-2 | $ 12,134 | $ 27,919 | $ 42,435 | $ 41,160 |
| 4 | Stock-Based Compensation | E-4 | $ (29,211) | $ (29,102) | $ (26,971) | $ (28,272) |
| 5 | Depreciation Expense and Accumulated Depreciation | E-12 | $ (30,033) | $ (51,698) | $ (50,008) | $ (47,074) |
| 6 | Property Tax Expense | E-37 | $ - | $ (2,269) | $ (7,230) | $ (12,745) |
| 7 | Transmission Plant Investment | E-30 | $ - | $ (15,013) | $ (42,673) | $ (72,735) |
| 8 | Distribution Plant Investment | E-31 | $ - | $ (15,048) | $ (46,078) | $ (80,017) |
| 9 | Intangible Plant Investment | E-32 | $ - | $ (456) | $ (2,630) | $ (6,613) |
| 10 | Transmission Plant - Depreciation Expense and Accumulated Depreciation | E-33 | $ - | $ (3,820) | $ (10,975) | $ (17,786) |
| 11 | Distribution Plant - Depreciation Expense and Accumulated Depreciation | E-34 | $ - | $ (4,544) | $ (14,095) | $ (23,279) |
| 12 | Distributed Energy Resource Management System (DERMS) - Amortization and Accumulated Amortization | E-35 | $ - | $ (950) | $ (5,630) | $ (13,673) |
| 13 | Depreciation Expense - Depreciation Rates Correction for Ft Benning and Ft Gordon | E-36 | $ 1,188 | $ 2,036 | $ 2,036 | $ 2,036 |
| 14 | Income Tax Credits Related to the Inflation Reduction Act | E-38 | $ - | $ (42,492) | $ - | $ (536) |
| | **Fall-Out Impacts from Other Adjustments:** | | | | | |
| 15 | Interest Synchronization | E-8 | $ 802 | $ 1,903 | $ (10,224) | $ (7,271) |
| 16 | Cash Working Capital | E-10 | $ (367) | $ (92) | $ (194) | $ 27 |
| 17 | Payroll Tax Expense | E-5 | $ (2,234) | $ (2,226) | $ (2,064) | $ (2,162) |
| 18 | Difference Due to Staff using a different Gross Revenue Conversion Factor | A-1, A-2 | $ (1) | $ - | $ - | $ - |
| | **Other Staff Adjustments:** | | | | | |
| 18 | Executive Financial Planning | E-7 | $ (468) | $ (468) | $ (467) | $ (467) |
| 19 | Forecasted Revenues | E-3 | $ (5,999) | $ (5,705) | $ (4,874) | $ (7,763) |
| 20 | Wireless Co-Location Revenues | E-11 | $ (404) | $ (434) | $ (521) | $ (628) |
| 21 | Energy Direct Premium Packages | E-6 | $ (1,166) | $ (1,177) | $ (1,210) | $ (1,242) |
| 22 | EV Investment | E-13, E-14 & E-15 | $ - | $ (4,298) | $ (8,068) | $ (11,857) |
| 23 | O&M Scrap Sales Proceeds | E-9 | $ (1,217) | $ (1,217) | $ (1,217) | $ (1,217) |
| 24 | O&M Expense - Transmission | E-16 | $ (10,693) | $ (4,183) | $ (3,223) | $ (3,918) |
| 25 | O&M Expense - Distribution | E-17 | $ (23,624) | $ 5,410 | $ (328) | $ (7,151) |
| 26 | O&M Expense - Customer Accounting | E-18 | $ (16) | $ 1,305 | $ (5,116) | $ (8,252) |
| 27 | O&M Expense - Demonstration & Selling Expenses | E-19 | $ (1,189) | $ (1,217) | $ (1,219) | $ (1,221) |
| 28 | O&M Expense - Administrative & General Salaries | E-20 | $ (253) | $ (184) | $ (83) | $ (25) |
| 29 | O&M Expense - Office Supplies and Expense | E-21 | $ (3,128) | $ - | $ - | $ - |
| 30 | O&M Expense - Outside Services Employed | E-22 | $ (7,100) | $ 941 | $ 2,322 | $ (3,263) |
| 31 | O&M Expense - Injuries and Damages | E-23 | $ (1,642) | $ 623 | $ (1,287) | $ (1,539) |
| 32 | O&M Expense - Employee Pensions and Benefits | E-24 | $ (13,676) | $ (13,517) | $ (13,235) | $ (12,956) |
| 33 | O&M Expense - Customer Service and Information | E-25 | $ (17,023) | $ (20,028) | $ (16,024) | $ (9,013) |
| 34 | O&M Expense - Miscellaneous General and Advertising | E-26 | $ (5,943) | $ (6,131) | $ (4,242) | $ (2,414) |
| 35 | O&M Expense - Maintenance of General Plant | E-27 | $ (1,823) | $ - | $ - | $ - |
| 36 | O&M Expense - Adjustment for Inflation | E-28 | $ - | $ (15,458) | $ (27,374) | $ (33,767) |
| 37 | Labor O&M Expense - Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime | E-29 | $ (113,750) | $ (101,536) | $ (72,662) | $ (92,984) |
| 38 | Staff Adjusted Rate Base Revenue Deficiency (Sum of lines 1 through 35 above) | | $ (86,580) | $ (11,244) | $ 152,889 | $ 387,659 |
| 39 | Staff Adjusted Base Rate Revenue Deficiency (Excess) | A, A-2 | $ (86,581) | $ (11,244) | $ 152,889 | $ 387,659 |
| 40 | Difference (rounding) | | $ 0 | $ 0 | $ (0) | $ 0 |

* These adjustments do not include the interest synchronization or rate of return impacts

Based on Staff's calculations the Company has excess revenues of $86.6 million and $11.2 million in the test year and calendar year 2023, respectively. For calendar 2024 and 2025 the Company has revenue deficiencies of $152.9 million and $387.7 million,

respectively.[7] Each Staff adjustment is discussed in additional detail in Section X of our testimony.

**Q. DOES STAFF RECOMMEND A LEVELIZED APPROACH FOR THE 2023–2025 PLAN YEAR REVENUE REQUIREMENT, AS PROPOSED BY GEORGIA POWER?**

A. No. As explained in more detail elsewhere in our testimony, Staff recommends a step-increase approach for years 2024 and 2025, not a levelization.

**Q. PLEASE SUMMARIZE STAFF'S RECOMMENDED REVENUE REQUIREMENT FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2023 AND CALENDAR 2023, 2024 AND 2025.**

A. As shown on Exhibit __(RS/RT-2), Schedule A, page 1, line 7, Staff's analysis shows that the Company has excess revenue at current rates for the traditional test year, and for calendar year 2023. Staff's analysis also shows the Company has a revenue deficiency for calendar years 2024 and 2025 at current rates. This is shown in detail on Staff Exhibit__(RS/RT-2), Schedule A, and Schedule A-2, pages 1 through 4.

[7] These values do not include MFF. Staff's calculated MFF revenue deficiencies are shown on Exhibit __(RS/RT-5) and are $4.7 million for the test year, $5.5 million for 2023, $14.1 million for 2024 and $21.8 million for 2025. If MFF is included, the Staff excess revenue amounts for the test year and 2023 would be reduced by the $4.7 million and $5.5 million MFF amounts, and the revenue deficiency amounts for 2024 and 2025 would be increased by the 2024 and 2025 MFF revenue deficiency amounts., respectively.

**Q. IF STAFF'S ANALYSIS REFLECTS EXCESS REVENUE FOR THE TEST YEAR AND 2023, THEN WHY IS STAFF NOT RECOMMENDING A RATE DECREASE FOR 2023?**

A. This is primarily based on considerations for rate stability. To avoid a reduction in rates on January 1, 2023 followed by what (other things being equal) would be a larger step increase in rates on January 1, 2024, Staff concluded that less fluctuation in rates would benefit ratepayers and the Company in this particular situation. Therefore, Staff recommends current rates be maintained through 2023. A step increase to be effective on January 1, 2024 should be addressed in a compliance filing to be made by the Company on October 1, 2023.

If the Company earns above the top end of the earnings band in 2023, as would be evaluated in the context of the Company's 2023 Annual Surveillance Report ("ASR"), Staff recommends that the excess should be used to recover deferred costs. Staff's proposed rate plan earnings band and sharing is addressed in additional detail in Section XIII of our testimony.

**Q. WHAT IS STAFF'S RECOMMENDATION FOR ADDRESSING THE EXCESS REVENUES IN THE TRADITIONAL TEST YEAR AND CALENDAR 2023?**

A. If the Commission concludes that the Company has excess revenue for the traditional test year and/or for calendar year 2023, as Staff shows, Staff recommends that the revenue excess be used for accelerated recognition of deferred costs in 2023 up to the amount of the revenue excess. As an illustration, Staff shows a base rate revenue excess of

approximately $86.6 million for the test year and $11.2 million for calendar year 2023.[8] On Exhibit__(RS/RT-2), Schedule B, pages 1 through 4, lines 35, 36 and 38 there are deferrals for various items that could be used for accelerated cost recognition, if the Commission concludes that the Company will have excess base rate revenues for 2023, as Staff has calculated. Some portion of these deferrals could potentially be recognized on an accelerated basis up to the amount of the revenue requirement excess associated with the excess earnings. That is, the excess revenues could be applied in 2023 to increase the amortization of the assets identified above. This could be done in the current rate case by making an adjustment, or determining the amount of excess earnings in 2023 could be reviewed in the context of the Company's 2023 ASR report, as described above.

[8] See, e.g., Exhibit__(RS/RT-2), Schedule A, columns C and D, respectively, line 7.

## V. ECCR TARIFF REVENUE DEFICIENCY SUMMARY

**Q. WHAT HAS THE COMPANY REQUESTED FOR THE ECCR?**

A. The Company is requesting a "levelized" revenue sufficiency of $1.08 million plus a revenue deficiency of $64.49 million for CCR ARO compliance for an overall revenue deficiency of $63.31 million to be collected through the ECCR tariff in 2023. The ECCR amount requested by the Company is based on a levelized amount for the three-year period of 2023 through 2025 and thus, under the Company's proposal, the ECCR revenue requirement would not be expected to change from January 1, 2023 through December 31, 2025.

**Q. WHAT IS THE BASIS FOR THE COSTS INCLUDED IN GEORGIA POWER COMPANY'S PROPOSED ECCR?**

A. The Company's ECCR revenue requirements for the plan years 2023 through 2025 are reflected on Exhibit__(APA/SPA/ADH/MBR-1, Schedule 3 ECCR). The Company's Abramovitz/Adams//Houston/Robinson panel direct testimony indicates that those are based on the projected environmental investments and expenses associated with the ECCR tariff in 2023, 2024 and 2025. Those projections are described as being consistent with the Company's environmental strategy that was filed with the Commission in the Company's 2022 IRP proceeding, Docket No. 44160. The Company states that the projected costs it proposes to be recovered through the ECCR tariff are set based on the compliance strategy that was approved in the 2022 IRP process. Further, changes in those cost projections will not impact the ECCR tariff rate unless such changes are approved by the Commission.

**Q. WHAT AMOUNTS OF ANNUAL ECCR REVENUE DEFICIENCIES HAS THE COMPANY CALCUATED FOR EACH YEAR?**

A. Page 2 of Company Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) shows a revenue deficiency for the ECCR tariff of $28.7 million for 2023 and revenue excesses of $11.5 million and $24.5 million in calendar years 2024, and 2025, respectively. However, the amounts Georgia Power has requested in the proposed Alternate Rate Plan for the ECCR tariff would begin recovery of the combined 2023 through 2025 levelized calendar year amounts on January 1, 2023.

**Q. DOES STAFF AGREE WITH GEORGIA POWER'S PROPOSED ECCR TARIFF REVENUE DEFICIENCY FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2023 OR FOR THE PLAN YEARS 2023 THORUGH 2025?**

A. Staff agrees with the continuation of the existing ECCR Tariff rider. However, Staff does not agree with the Company's proposed traditional test year ECCR Tariff revenue deficiency amount of $105.6 million, or with the Company's proposed ECCR revenue deficiency amounts for plan years 2023, 2024 or 2025.

**Q. WHAT AMOUNT OF ECCR REVENUE DEFICIENCY DOES STAFF RECOMMEND FOR THE TEST YEAR?**

A. As shown on Exhibit ___(RS/RT-3), page 3 of 12, Staff shows traditional test year ECCR Tariff revenue excess amounts of approximately $68.9 million, which is $36.7 million

lower than Georgia Power's proposed deficiency amount of $105.6 million. Staff is not recommending a levelized adjustment for the ECCR.

**Q. HOW DO STAFF'S RECOMMENDED ECCR REVENUE DEFICIENCY AMOUNTS FOR THE PLAN YEARS 2023 THROUGH 2025 COMPARE WITH THE COMPANY'S REQUEST?**

A. As shown on Exhibit ___(RS/RT-3), page 4 of 12, Staff's recommended ECCR revenue deficiency amounts for the plan years 2023 through 2025 are lower than the Company's requested amounts in each year.

- For 2023, the Staff ECCR recommended revenue deficiency is $60.6 million, which is about $32.6 million lower than the Company's calculated amount of $93.2 million.
- For 2024, the Staff ECCR recommended revenue deficiency is $91.0 million, which is about $40.0 million lower than the Company's calculated revenue excess amount of $131.0 million.
- For 2025, the Staff ECCR recommended revenue deficiency is $127.1 million, which is about $37.7 million lower than the Company's calculated revenue excess amount of $164.7 million.

Exhibit__(RS/RT-3), page 4 of 12 also shows differences related to the CCR ARO component on line 20.

**Q. WHY ARE THE STAFF RECOMMENDED AMOUNTS OF ECCR DEFICIENCY LOWER THAN THE COMPANY CALCULATIONS?**

A. As detailed on Exhibit __(RS/RT-3):

- Staff used a lower overall cost of capital based on the recommendations of Mr. Gorman;
- Staff reflected the impacts from the Company's supplemental filing;
- Staff's Income Expansion Factor for the test year differs slightly from the Company's due to an adjustment Staff has made to test year uncollectibles.

The calculations underlying Staff's recommended ECCR Tariff revenue deficiency amounts, and how they compare with Georgia Power's proposed amounts for the test year and for each plan year, 2023 through 2025, are shown on Staff Exhibit__(RS/RT-3).

**Q. IS THE ECCR REVENUE REQUIREMENT AFFECTED BY THE RETURN ON EQUITY AND COST OF CAPITAL?**

A. Yes. The cost of capital is an important input to the ECCR revenue requirement calculation.

**Q. DOES STAFF'S PROPOSED COST OF CAPITAL DIFFER FROM THE COST OF CAPITAL REQUESTED BY GEORGIA POWER COMPANY?**

A. Yes. As described in the testimony of Staff witness Gorman, Staff has recommended a 9.45% cost of equity. Mr. Gorman is recommending a capital structure that is different than the one requested by the Company. Each of these items affect the cost of capital. The result is that Staff is recommending an overall cost of capital for the future test year

and for each rate plan year, 2023 through 2025, that is lower than Georgia Power has requested.

**Q. IS THE ECCR REVENUE REQUIREMENT IMPACTED BY OTHER ADJUSTMENTS?**

A. Yes. The ECCR revenue requirement is also impacted by adjustments that affect environmental plant, depreciation, and O&M expense, as well as income taxes related to ECCR components, as shown on Exhibit __(RS/RT-3).

**Q. HOW HAVE YOU INCORPORATED THOSE IMPACTS INTO THE ECCR REVENUE REQUIREMENT?**

A. While the largest impact on the ECCR revenue requirement results from Staff's recommended cost of capital, other items affecting the ECCR have also been incorporated where such items could be readily identified from the details of the Company's errata filing and Staff's recommended adjustments.

**Q. WHAT REVENUE REQUIREMENTS DOES STAFF SHOW FOR THE ECCR FOR THE FUTURE TEST YEAR AND FOR 2023, 2024, AND 2025?**

A. As shown on Exhibit__(RS/RT-3), we have recalculated the ECCR revenue requirements for the forecasted test year and for each calendar year, 2023, 2024 and 2025 in the Company-proposed rate plan period. Staff's recalculated ECCR revenue requirements, and how they compare with the Company's request, are summarized below:

**Table E: ECCR Revenue Requirement Deficiency - Staff and Company Compared**

**COMPUTATION OF RETAIL REVENUE DEFICIENCY**
**APPLICABLE TO ENVIRONMENTAL COMPLIANCE COST RECOVERY (ECCR) TARIFF**
(Thousands of Dollars)

| | Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| Per Staff | $ 68,944 | $ 60,578 | $ 90,973 | $ 127,067 |
| Per Company | $ 105,626 | $ 93,186 | $ 131,004 | $ 164,746 |
| Difference | $ (36,682) | $ (32,608) | $ (40,031) | $ (37,679) |

Source: Staff Exhibit__(RS/RT-3), pages 3 and 4

**Q. DOES STAFF PROPOSE TO LEVELIZE THE ECCR REVENUE REQUIREMENTS?**

A. No. Staff has not reflected a "levelization" of the 2023 through 2025 ECCR revenue requirements, similar to the Company's proposed $46.8 million decrease. Rather, Staff recommends that annual ECCR revenue deficiency (or excess) amounts for 2024 and 2025 be established based on compliance filings to be made by the Company on October 1, 2023 and 2024, respectively. Because the ECCR is a separately identifiable tariff component, annual adjustments can be made for the annual changes in the ECCR revenue requirement. Thus, Staff proposes that the ECCR revenue requirement be reflected as annual rate changes, rather than a levelized approach.

**Q. PLEASE EXPLAIN WHAT AN EARNINGS TEST IS.**

A. An earnings test reviews the Company's earnings, typically calculated with various adjustments to reflect ratemaking treatments. In the current alternative rate plan, for example, the Company reports its results for each year in an Annual Surveillance Report ("ASR"), which is reviewed by Staff. The Company's earnings are reviewed to determine if they were below, within or above an established earnings band. Staff's specific

recommendations for resetting the earnings band are addressed in a Section XIII of our testimony.

**Q. DOES THE COMPANY'S ECCR PROPOSAL INCLUDE AN EARNINGS TEST?**

A. No.

**Q. DOES STAFF PROPOSE TO INCLUDE AN EARNINGS TEST AS PART OF ITS ECCR AND RATE PLAN RECOMMENDATIONS?**

A. Yes. We discuss Staff's proposed earnings test for the Rate Plan period in Section XIII of our testimony.

## VI. DSM TARIFF REVENUE DEFICIENCY SUMMARY

**Q. HOW HAS STAFF REFLECTED THE DSM TARIFF REVENUE DEFICIENCY FOR THE TRADITIONAL TEST YEAR ENDING JULY 31, 2023 AND FOR CALENDAR YEAR 2023?**

A. Staff supports the continuation of the existing DSM Tariff rider since the DSM program costs will be different each year and will vary by participation levels. For the test year and for calendar years 2023 through 2025, Staff has reflected a DSM tariff revenue deficiency in the following amounts, for which detailed calculations are shown on Exhibit ___(RS/RT-4);

- $36.9 million for the test year, which is about $7.3 million higher than the Company's requested $29.7 million.
- $37.0 million for 2023, which is about $7.4 million higher than the Company's requested $29.7 million.
- $64.0 million for 2024, which is about $7.5 million higher than the Company's requested $56.5 million.
- $62.1 million for 2025, which is about $8.1 million higher than the Company's requested $54.0 million.

Requiring the Company and Staff to agree on final program plans was part of a stipulation approved by the Commission in Docket Nos. 44160/44161. We are advised by Staff's DSM experts that these program plans will also drive the DSM revenue requirement for the plan years. The amounts for the 2024 and 2025 DSM revenue

requirements will ultimately be determined by the Commission through the Company's annual DSM filings.

**Q. DOES THE DSM TARIFF REVENUE REQUIREMENT INCLUDE A COMPONENT FOR CARRYING COSTS ON DEFERRALS?**

A. Yes. The Company's calculation of DSM carrying costs has been reproduced on Exhibit __(RS/RT-4), pages 9 and 10 of 17. The Staff's calculation of DSM carrying costs has been reproduced on that Exhibit on pages 11-12.[9] Pages 13-17 show the derivation of the Revenue Requirement carrying cost rate used by the Company and the comparable rates used by the Staff for the test year and for 2023, 2024 and 2025, respectively. The Staff carrying cost rates reflect Staff's recommended cost of capital.

[9] According to the response to STF-LA-7-1, the Company's carrying cost calculations include the correction of a transposition error in the carrying cost amounts reflected in Georgia Power's supplemental filing for the test period, 2023 and 2024. The transposition error did not impact 2025 carrying costs.

## VII. MUNICIPAL FRANCHISE FEE TARIFF

**Q. PLEASE PROVIDE SOME BACKGROUND ON THE COMPANY'S MFF TARIFF.**

A. In the 2007 Georgia Power Rate Case Order, the Commission ordered the establishment of the MFF tariff in accordance with the Commission's Order in Docket No. 21112. The MFF tariff initially reflected 50 percent of MFF revenues being collected from customers located within municipal areas covered by a franchise agreement and 50 percent being collected from all customers, regardless of location. However, over the years, the Company has experienced a shift with more of its total revenue coming from customers within municipalities. Because the MFF tariff is a percentage rate and is calculated based on each customer's total bill before sales taxes are applied, the percentage rate does not have to be changed even if revenues change.

**Q. WHAT CAUSES THE MFF TARIFFS TO CHANGE?**

A. As described on pages 30-31 of the Abramovitz/Adams//Houston/Robinson Direct Testimony, the primary components of the MFF tariff that could change from year to year are the amount of revenues collected relative to whether or not customers are receiving service within a municipality's boundaries. As customer demographics change, so would the respective MFF tariff.

**Q. WHAT HAS THE COMPANY REQUESTED FOR AN MFF TARIFF REVENUE REQUIREMENT?**

A. The Company's Abramovitz/Adams/Houston/Robinson panel's direct testimony at page 31 states that the Company is requesting approval of a $20 million increase to be effective January 1, 2023. The Company's calculation shown on Exhibit___(APA/SPA/ADH/MBR-1, Schedule 5 MFF) shows a total MFF revenue deficiency of $20.171 million for 2023. The Abramovitz/Adams/Houston/Robinson panel also stated that the Company would also propose to update the MFF tariff with an annual November 1 compliance filing, if needed, as provided in the current MFF tariff.

**Q. IS THE MFF TARIFF REVENUE REQUIREMENT INCREASE THAT THE COMPANY REQUESTED IMPACTED BY THE LEVEL OF THE BASE RATE AND ECCR REVENUE DEFICIENCY PROPOSED BY THE COMPANY?**

A. Yes.

**Q. IS STAFF'S RECOMMENDATION ON THE AMOUNTS OF BASE RATE AND ECCR REVENUE DEFICIENCY DIFFERENT THAN THE AMOUNTS INCLUDED IN THE COMPANY'S DIRECT CASE?**

A. Yes.

**Q. ARE THERE ANY OTHER DIFFERENCES BETWEEN THE STAFF AND COMPANY CASES RELEVANT TO THE CALCULATION OF THE MFF TARIFF REVENUE REQUIREMENT?**

A. Yes. Staff also shows a different amount of DSM revenue deficiency than was incorporated in Georgia Power's filing, as described above in Section VI of our

testimony. In addition, Staff's recommended weighted average cost of capital is lower than Georgia Power's request. This translates into a lower pre-tax weighted average cost of capital.

**Q. HAVE YOU CALCULATED THE MFF REVENUE REQUIREMENT DEFICIENCY TO REFLECT THE IMPACT OF THE DIFFERENCES IN PRE-TAX COST OF CAPITAL AND THE BASE RATE, ECCR AND DSM REVENUE DEFICIENCY AMOUNTS?**

A. Yes. On Exhibit__(RS/RT-5), page 3 of 4, we have reproduced the Company's MFF Revenue Requirement deficiency calculations. Exhibit__(RS/RT-5), page 4 of 4, which shows the Staff's calculations. The Staff calculations use the Staff's pre-tax weighted average cost of capital, base rate, ECCR and DSM revenue deficiency amounts. Staff's calculations produce an MFF revenue deficiency of $4.7 million for the test year, and $5.5 million for 2023, as calculated on Exhibit__(RS/RT-5), page 4. Differences between Company and Staff revenue deficiencies for MFF are summarizes on Exhibit__(RS/RT-5), page 2.

**Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSAL THAT THE MFF SHOULD BE UPDATED BY AN ANNUAL NOVEMBER 1 COMPLIANCE FILING, IF NEEDED, AS PROVIDED IN THE CURRENT MFF TARIFF?**

A. No. Staff recommends that the filing date for the updated MFF tariffs be on October 1, rather than November 1. The October 1 date is the date being used for other compliance filings (e.g., base rates, ECCR, DSM) to update rates.

## VIII. COAL COMBUSTION RESIDUALS ASSET RETIREMENT OBLIGATIONS REVENUE REQUIREMENT

**Q. HOW IS THE OBLIGATION FOR CCR COMPLIANCE RECORDED FOR ACCOUNTING PURPOSES AND RECOVERED FROM CUSTOMERS IN RATES?**

A. For accounting purposes, the Company's obligation for compliance with CCR regulations is recorded as an Asset Retirement Obligation. A related liability is also recorded to recognize the legal obligation to incur such costs. Historically, costs related to the remediation of ash ponds and landfills that have been used to store coal ash at plants that were still operational would have generally been included in the cost of removal/negative net salvage component of depreciation rates and would have been recovered over the estimated remaining life of the coal-fired generating plants. CCR compliance costs for coal-fired generating plants that have already been retired or are being retired before their previously estimated useful lives are being addressed for cost recovery. Both the Company and Staff have calculated revenue requirements related to the recovery of CCR costs in the current rate case proceeding. On Exhibit __(RS/RT-6) we have replicated the Company's calculated CCR ARO Compliance revenue deficiency amounts for the test year and for each plan year, 2023 through 2025, and also present Staff's calculated revenue deficiency amounts for each period for the CCR ARO Compliance. Staff's adjusted amounts differ from those calculated by the Company primarily because Staff has used witness Gorman's recommended cost of capital.

**Q. HOW DOES THE OBLIGATION FOR CCR COMPLIANCE IMPACT RATEPAYERS?**

A. The Company's expenditures for CCR compliance have consistently exceed revenues collected from ratepayers under ECCR. This creates unpaid balance that the Company earns a full return on including interest expense, return on equity (profit) and income taxes in addition to the direct cost for remediating coal ash ponds. The Company has projected to spend $320 million, $408 million and $510 million in 2023, 2024 and 2025, respectively, for CCR compliance. The revenues collected from ratepayers are estimated to be $237 million, $308 million and $345 million in 2023, 2024 and 2025, respectively. The unpaid balance is projected to grow to $365 million, $465 million and $630 million as of December 31, 2023, 2024 and 2025, respectively.[10] Georgia Power would collect approximately $26 million, $34 million and $45 million for profit and income taxes on the unpaid balance in 2023, 2024 and 2025, respectively.[11] The profit and income tax amounts are in addition to the interest expense on the portion of the unpaid CCR compliance balance that has been financed with debt.[12]

**Q. WAS GEORGIA POWER'S ENVIRONMENTAL COMPLIANCE STRATEGY APPROVED IN THE 2022 INTERATED RESOURCE PLAN (IRP)?**

[10] APA-SPA-ADH-MBR-1, Schedule 3 ECCR Supplemental.xlsx

[11] These values were calculated using Georgia Power's proposed ROE and capital structure.

[12] Staff estimates the return on the unpaid balance would be cut in half if coal ash pond remediation costs were securitized. For the portion of the CCR compliance costs for ash ponds at generating plants that have been retired, the unpaid balance is the result of the recovery of costs for units that are no longer providing electric service. A lower return would be more equitable as the Company would be compensated by financing the balance at less cost to ratepayers.

A. Yes. In the 2022 IRP Stipulation approved by the Commission, parties agreed that the Company would seek recovery of CCR costs in its 2022 base rate case. Staff reserved the right to challenge the Company's request for recovery in the 2022 base rate case, including, but not limited to, the amount to be recovered as reasonable and prudent, the period over which costs are recovered and the method by which the costs are recovered.

**Q. WHAT CCR ARO COMPLIANCE REVENUE DID THE COMPANY PROPOSE IN THIS CASE?**

A. Georgia Power has requested approval of CCR ARO Compliance Revenue Requirement Increases of $60.04 million for the test year, and $64.49 million, $142.51 million and $189.25 million for the years 2023 through 2025, respectively.[13] For each year 2023 through 2025, the Company requested recovery of CCR ARO costs through annual ECCR tariff updates. This is consistent with the methodology approved by the Commission in the 2019 base rate case. If CCR ARO compliance costs are lower than expected, the annual revenue requirement updates for 2024 and 2025 will also be lower.

**Q. WERE CONCERNS RAISED IN THE IRP REGARDING GEORGIA POWER'S ASH POND CLOSURE PLANS?**

A. Yes. Concerns were raised that Georgia Power's closure plans may not comply with EPA regulations at sites where ash is understood to be in contact with groundwater.

**Q. ARE THE COMPANY'S CLOSURE PLANS FINAL?**

[13] Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR Supplemental) Page 6

A. No. The Company indicated in its IRP that it will continue to refine and optimize its closure plans.[14]

**Q. DOES GEORGIA POWER MAINTAIN IT IS IN COMPLINACE WITH CLOSURE RULES, EVEN WITH ASH IN CONTACT WITH GROUNDWATER?**

A. In the hearing on Georgia Power's direct testimony, Mr. Womack was asked, "… if the company were to be found not incompliance with CCR rules, wouldn't you agree that it would be unreasonable to get recovery for those expenses through higher rates?" Mr. Womack responded, "I would deny -- your question is interesting, but it's also very speculative. And I -- I don't think it's appropriate for me to comment on it at all -- on that question at this time." He went on to say, "… We … are in compliance with current rules, federal and state."[15]

**Q. DOES STAFF HAVE REASON TO BELIEVE THE COMPANY'S CLOSURE PLANS MAY NOT COMPLY WITH U.S. EPA REGULATIONS?**

A. Yes. Georgia Power plans to close in place four impoundments where ash has been in contact with groundwater. There are unresolved disputes concerning what constitutes compliance.

**Q. HAS THE EPA INDICATED HOW IT VIEWS COMPLIANCE?**

[14] Docket No. 44160, Transcript Volume II P. 812, lines 23-25

[15] Docket No. 44280, September 27 Transcript, p. 169, lines 11-23.

A. Yes. The EPA issued a News Release on January 11, 2022 titled, "**EPA Takes Key Steps to Protect Groundwater from Coal Ash Contamination"** in which it restated, through proposed determinations, its:

> …**consistently held position that surface impoundments or landfills cannot be closed with coal ash in contact with groundwater.** Limiting the contact between coal ash and groundwater after closure is critical to minimizing releases of contaminants into the environment and will help ensure communities near these facilities have access to safe water for drinking and recreation.[16] (Emphasis Added).

**Q. WAS IT ACKNOWLEDGED IN THE 2022 IRP THAT THE UNITED STATES ENVIRONMENTAL PROTECTION DIVISION MIGHT REQUIRE GEORGIA POWER TO ALTER ITS CLOSURE PLANS FOR CERTAIN ASH PONDS?**

A. Yes. The approved stipulation in the 2022 IRP proceeding noted that the Company would continue to provide semi-annual reports to the Commission and provide notice to the Commission within 30 days of any determination by the Environmental Protection Division that would alter the Company's current plan from closing certain ash ponds in place.

**Q. IS STAFF MAKING A RECOMMENDATION IN THIS CASE TO ADJUST THE CCR ARO REVENUE REQUEST FOR THE COMPANY'S PROPOSED CLOSURES IN PLACE WHERE ASH HAS BEEN IN CONTACT WITH GROUNDWATER?**

A. No. However, this should not be taken to mean Staff believes closure in place with ash in groundwater complies with EPA regulations. Staff will reserve its recommendation on

[16] https://www.epa.gov/newsreleases/search/press_office/headquarters-226129

the prudence of these expenditures until such time as EPA or the courts have determined whether Georgia Power's closure plans comply with EPA regulations.

**Q. WILL GEORGIA POWER CONTINUE TO REFINE ITS COST ESTIMATES?**

A. Yes. As the closure plans are reviewed and approved by the Georgia Environmental Protection Division, and as closure technologies and alternatives improve, it is likely the cost estimates for closure will need to be updated. The Company is also continuing to explore beneficial use alternatives, which might offset some of the ash pond closure costs. Thus, it is reasonable to adopt Georgia Power's step increase approach for CCR ARO costs.

## IX. ORGANIZATION OF STAFF'S REVENUE REQUIREMENT AND ADJUSTMENT SCHEDULES

**Q. HOW ARE STAFF'S REVENUE REQUIREMENT AND ADJUSTMENT SCHEDULES ORGANIZED?**

A. Staff's revenue requirement and adjustment schedules for the traditional rate case, and each calendar year in the three-year plan are presented in Exhibit__(RS/RT-2). They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, A-2, B, B.1, C, C.1 and D. Exhibit__(RS/RT-2) also contains adjustment Schedules E-1 through E-38.

**Q. WHAT DOES EXHIBIT__(RS/RT-2), SCHEDULE A SHOW?**

A. Exhibit__(RS/RT-2), Schedule A presents a revenue requirement summary. Georgia Power's calculation of its proposed traditional test year revenue deficiency of $447.521 million is shown in column A, on line 7. Column A, lines 8 and 9, show Georgia Power's proposed revenue deficiency amounts of $105.626 million and $29.650 million for the ECCR and DSM tariffs, respectively. Georgia Power's Application shows a traditional base rate revenue deficiency of approximately $312.245 million after accounting for the ECCR and DSM tariff revenue deficiencies, as shown in column A, line 10. Exhibit__(RS/RT-2), Schedule A, Column B, presents summary information for the Company proposed Alternative Rate Plan, which covers calendar years 2023 through 2025. As shown on Exhibit__(RS/RT-2), Schedule A, Columns A and B, line 11, the Company also has requested an additional revenue increase of $426.415 million to be in effect on January 1, 2023, in arriving at its requested $738.661 million for the

levelization of its calculated 2023 through 2025 revenue requirements, which are shown on lines 11 and 12, respectively. The total January 1, 2023 revenue increase requested by the Company of $738.661 million is shown in Columns A and B, on line 12.

Columns C through F show the revenue requirement calculation that results from our recommendations and the recommendations of other Staff witnesses. Staff's base rate revenue deficiency for the traditional test year, and for each calendar year, 2023 through 2025, are shown on line 7. Staff's adjusted ECCR and DSM revenue deficiencies (excess) are shown on lines 8 and 9, respectively.[17] Line 10 shows Staff's traditional base rate revenue excess or deficiency amounts for the test year and for each plan year. As noted elsewhere, Staff is not proposing a levelization of 2023–2025 results. Staff total recommended base rate revenue excess or deficiency amounts for the test year and for each plan year are shown on line 12.

**Q. WHAT IS SHOWN ON SCHEDULE A-1 OF EXHIBIT__(RS/RT-2)?**

A. Schedule A-1, page 1, shows the derivation of the gross revenue conversion factor ("GRCF") for the test year ending July 31, 2023. This factor is used on Schedule A, line 6, to convert the net operating income deficiency or sufficiency into an equivalent revenue requirement amount. As shown on Exhibit__(RS/RT-2), Schedule A-1, page 1, column B, we have used a GRCF of 1.340378 to convert the earnings sufficiency for the 2023 rate year into a revenue deficiency amount. This GRCF is the equivalent of what

[17] As noted in Section VI, the DSM revenue requirements are subject to change.

the Company refers to as an Income Expansion Factor. The GRCF reflects the use of a 21% federal income tax rate and a 5.75% state income tax rate.

As shown on Schedule A-1, page 1 of 2, in column C, Staff's GRCF of 1.340378 or 74.60582% is slightly different than the Company's proposed GRCF because Staff has adjusted the uncollectibles factor.[18] Staff's adjustment to the uncollectibles factor is shown on lines 4 through 8 of Schedule A-1, page 1 of 2, in column C. Staff's proposed GRCF for test year differs slightly from the Company's proposed Income Expansion Factors because of Staff's adjustment for uncollectibles.

Schedule A-1, page 2, shows the derivation of the GRCF used for each plan year. The GRCFs used by Staff for each period are the same as the Company's proposed Income Expansion Factors for each period.

**Q. WHAT IS SHOWN ON SCHEDULE A-2?**

A. Schedule A-2 consists of 4 pages and shows a detailed reconciliation of the Company's requested and Staff's adjusted revenue requirements. Page 1 shows the reconciliation for the test year ending July 31, 2023. Pages 2-4 show the reconciliation for calendar years 2023, 2024 and 2025, respectively.

**Q. PLEASE BRIEFLY EXPLAIN SCHEDULES B AND C OF STAFF EXHIBIT__(RS/RT-2).**

[18] The adjustment to test year uncollectibles is discussed in the Direct Testimony of Staff witness Dante Mugrace.

A. The adjustments presented on Schedule A that impact rate base are shown on Schedule B. Schedule B.1 summarizes the Staff's recommended rate base adjustments. Exhibit__ (RS/RT-2) contains a Schedule B and B.1 for the test year ending July 31, 2023 as well as for each plan year, 2023, 2024 and 2025.

Schedules C presents adjusted net operating income. Schedule C.1 summarizes Staff's recommended adjustment to revenue and expenses applicable to the ratemaking analysis. Schedule C.1 also presents the impact on income tax expense resulting from each of Staff's recommended adjustments to pre-tax operating income. Exhibit__(RS/RT-2) contains a Schedule C and C.1 for the test year ending July 31, 2023 and for each calendar year (2023, 2024 and 2025) in the Company's proposed alternative rate plan.

**Q. WHAT IS SHOWN ON SCHEDULE D?**

A. Schedule D presents the capital structure and cost rates that we used to calculate Staff's recommended revenue requirement in this case. The Company's proposed cost of capital is shown for comparative purposes. The return on common equity of 9.45 percent on Schedule D is based on the recommendations of Staff witness Michael Gorman. Staff's recommended capital structure and the cost rates for long-term debt are sponsored by Staff witnesses Gorman. Schedule D has four pages. Page 1 shows the cost of capital for the test year ending July 31, 2023. Pages 2-4 show the cost of capital for each calendar year, 2023 through 2025, that is included in the Company's proposed alternative rate plan.

**Q. HOW ARE STAFF'S ADJUSTMENTS TO RATE BASE AND NET OPERATING INCOME PRESENTED?**

A. Staff's adjustments to rate base and net operating income for the test year ending July 31, 2023 and for each plan year (2023, 2024 and 2025) are summarized on Exhibit__(RS/RT-2), Schedules B.1 and C.1, respectively, as noted above. Each Staff adjustment is also shown on Exhibit__(RS/RT-2) on Schedules E-1 through E-38, and is discussed in Section X of our testimony.

## X. STAFF ADJUSTMENTS

**Overall Rate of Return**

**Q. HOW HAVE YOU REFLECTED THE OVERALL RATE OF RETURN RECOMMENDED BY STAFF WITNESSES MICHAEL GORMAN?**

A. On Staff Exhibit__(RS/RT-2), Schedule D, we have replicated Georgia Power's requested capital structure, capital cost rates, and resulting overall rate of return (from the Company's original filing before adjustments). The primary change to the Company's proposed overall rate of return determination is Mr. Gorman's recommended return on equity rate of 9.45% as opposed to Georgia Power's proposed return on equity of 11.0%, and the capital structure recommended by Mr. Gorman. Staff's recommended overall cost of capital for the test year is 6.84%, compared with Georgia Power's request of 7.70%. This is shown on Staff Exhibit__(RS/RT-2), Schedule D, page 1 of 4, column D, line 6. Staff's recommended overall cost of capital for the 2023, 2024 and 2025 plan years is summarized on Schedule D, pages 2 through 4 of 4, respectively.

**E-1, Company Supplemental Filing - Rate Base Adjustments**

**Q. GEORGIA POWER'S INITIAL RATE CASE FILING WAS ON JUNE 24, 2022. DID THE COMPANY SUPPLEMENTTHAT INITIAL FILING?**

A. Yes. On August 22, 2022, the Company filed a supplement to its initial rate case filing. Specifically, the supplemental filing reflects the revenue requirement impacts from various items included in the Final Order that was approved by the Commission in Georgia Power's 2022 Integrated Resource Plan ("2022 IRP") and DSM Certification proceedings in Docket Nos. 44160 and 44161.

**Q. WHAT SPECIFIC REVENUE REQUIREMENT IMPACTS ARE REFLECTED IN GEORGIA POWER'S SUPPLEMENTAL FILING?**

A. The Company's transmittal letter lists the following revenue requirement impacts in its supplemental filing:

- Defer Retirement Decision on Plant Bowen Units 1&2
- Update Plant Scherer ELG Capital Cost
- Update Capacity RFP PPA Additional Sum
- Update DG PPA Additional Sum
- Remove Wholesale to Retail Capacity Offer of 88 MWs related to Plant Yates Units 6&7 and Blocks 5&6
- Remove North Highlands Hydro Modernization Project
- Include DER Local Reliability and Constraints Pilot Projects
- Remove Tall Wind Research and Development Project
- Update DSM costs and additional sum, along with revenue impacts from the revised energy savings targets

**Q. DID THE COMPANY FILE A SCHEDULE WITH ITS SUPPLEMENTAL FILING WHICH REFLECTS THE REVENUE REQUIREMENTS LISTED ABOVE?**

A. Yes. The Company filed a schedule in Excel, which summarizes the incremental revenue requirement impacts that it made to its initial proposed revenue requirement as shown on Company Exhibit__(APA/SPA/ADH/MBR-1 Schedule 1 Total Company). Page 5 of the Company's schedule reflects the adjustments which impact the Company's retail rate

base. Specifically, page 5 of the Company's schedule reflects various adjustments to increase and/or reduce electric plant in service, accumulated depreciation, accumulated deferred income taxes ("ADIT") as well as other rate base items including (1) fuel and materials and supplies inventory, (2) minimum bank balances and prepayments, (3) prepaid pension asset, (4) operating reserves, and (5) Bowen and Scherer depreciation deferral. These adjustments increase retail rate base for the forecasted test year and the plan years by $9.524 million (test year), $16.781 million (2023), $19.352 million (2024) and $12.022 million (2025).

**Q. PLEASE EXPLAIN THE RATE BASE ADJUSTMENTS SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-1.**

A. Those adjustments reflect the retail rate base adjustments that are shown on page 5 of the Company's supplemental filing schedule. As shown on Staff Exhibit__(RS/RT-2), Schedule E-1, our adjustments increase the Company's retail rate base by $9.524 million, $16.781 million, $19.352 million and $12.022 million for the forecasted test year and plan years 2023, 2024 and 2025, respectively.

**Q. DID YOU ALSO MAKE ADJUSTMENTS RELATED TO THE COMPANY'S SUPPLEMENTAL FILING TO OPERATING INCOME?**

A. Yes. We also made adjustments related to the Company's operating income, which are reflected on Staff Exhibit__(RS/RT-2) and discussed in the next section of our testimony.

**E-2, Company Supplemental Filing - Operating Income Adjustments**

**Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-2.**

A. These adjustments to operating income are made pursuant to the Company's supplemental filing. Specifically, page 6 of the Company's supplemental filing schedule reflects various adjustments to (1) operating revenues, (2) O&M expense, (3) depreciation and amortization expense, (4) taxes other than income taxes and, (5) income taxes. The total of these supplemental adjustments reduces retail operating income for the forecasted test year and the plan years by $8.401 million (test year), $19.680 million (2023), $30.384 million (2024) and $29.908 million (2025).

**E-3, Forecasted Revenues**

**Q. PLEASE EXPLAIN THE ADJUSTMENT TO FORECASTED OPERATING REVENUES.**

A. The amounts shown on Exhibit__(RS/RT-2), Schedule E-3 were supplied by Staff witnesses Steven Baron and Leah Wellborn, who are recommending forecasted operating revenues at current rates that differ from those proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-3, incorporating Mr. Baron's and Ms. Wellborn's recommendations to forecasted operating revenues at current rates increases the Company's retail electric operating revenue by $5.991 million for the test year, $5.697 million for 2023, $4.867 million for 2024 and $7.752 million for 2025.

**E-4, Stock-Based Compensation**

**Q. PLEASE EXPLAIN THE ADJUSTMENT FOR STOCK-BASED COMPENSATION.**

A. This adjustment is shown on Exhibit__(RS/RT-2), Schedule E-4, and decreases pre-tax operating expenses by $29.172 million for the test year, $29.063 million for 2023, $26.933 million for 2024 and $28.230 million for 2025. This adjustment explained in additional detail in Section XII of our testimony, which addresses incentive compensation.

**E-5, Payroll Tax Expense**

**Q. PLEASE EXPLAIN THE ADJUSTMENT TO PAYROLL TAX EXPENSE.**

A. Staff's adjustment to the Company's payroll tax expense is made in conjunction with the adjustments that are being made to remove stock-based compensation. Based upon those recommended adjustments, as shown on Exhibit No.__(RS/RT-2), Schedule E-5, in column A, Georgia Power's proposed traditional test year payroll tax expense is reduced by $2.232 million.

For the years associated with the Company's proposed Alternative Rate Plan, payroll tax expense is reduced by $2.223 million, $2.061 million and $2.159 million in 2023, 2024 and 2025, respectively, as shown on Exhibit No.__(RS/RT-2), Schedule E-5, in columns B through D, respectively.

**E-6, Energy Direct Premium Packages**

**Q. PLEASE EXPLAIN THE COMPANY'S ENERGY DIRECT PREMIUM PROGRAM.**

A. Georgia Power commercial customers have electronic access to their energy use data through Energy Direct. Energy Direct is managed by a Southern Company Services product manager and the Southern Company Technology Organization in conjunction with operating company product managers as well as key account managers at each electric affiliate.

**Q. DOES THE COMPANY OFFER DIFFERENT PACKAGES ASSOCIATED WITH THE ENERGY DIRECT PROGRAM?**

A. Yes. The Company offers an Energy Direct Standard Package as well as enhanced Energy Direct usage packages, including Standard Plus, Premium, Premium Plus and Premium RT. Georgia Power provides all commercial customers access to the Energy Direct Standard Package at no charge. The enhanced Energy Direct packages are provided to commercial customers for a monthly subscription fee.[19]

**Q. HOW DOES GEORGIA POWER ACCOUNT FOR REVENUES AND EXPENSES ASSOCIATED WITH THE ENERGY DIRECT STANDARD AND PREMIUM PACKAGES?**

A. With regard to the Energy Direct Standard Package, according to the response to STF-LA-3-1, since the Standard Package is available at no charge, there are no revenues

[19] See the response to STF-LA-3-1.

associated with the Standard Package. However, expenses associated with the Standard Package are recorded in FERC account 908 and thus, are being included in the Company's retail cost of service.[20]

As it relates to the Premium Packages, according to the response to STF-LA-3-3, the revenues associated with the Premium Packages are recorded below-the-line in FERC account 415. Likewise, the expenses associated with the Premium Packages are also recorded below-the-line in FERC account 416.

**Q. HAS THE COMPANY EXPLAINED WHY THE ENERGY DIRECT PREMIUM PACKAGE REVENUE AND EXPENSES ARE UNREGULATED (I.E., RECORDED BELOW-THE-LINE) WHEN THE STANDARD PACKAGE EXPENSES ARE REGULATED (I.E., RECORDED ABOVE-THE-LINE)?**

A. Yes. In response to an informal Staff inquiry regarding this issue, the Company stated:

> Energy Direct provides a management tool for Commercial and Industrial customers. The standard package is available at no cost and is a Regulated Above the Line (ATL) service. The premium packages provide customers with additional data and have a monthly cost to customers. All revenue for EnergyDirect is unregulated below-the-line (BTL) because it is associated with premium packages.
>
> When EnergyDirect was launched, the Company allocated expenses based on the initial development costs incurred to stand up the EnergyDirect Program. At that time, it was determined that 70% of the Program's capital and O&M costs would have been incurred to develop the Regulated ATL Standard Package and 30% for the Unregulated BTL Premium Packages. This breakdown for program expenses continues. However, expenses that are incurred specifically to support the Unregulated offerings are charged 100% Unregulated BTL.

[20] See the response to STF-LA-3-2.

**Q. DO YOU AGREE WITH THE COMPANY'S ACCOUNTING TREATMENT WHEREBY THE REVENUES AND EXPENSES ASSOCIATED WITH THE ENERGY DIRECT PREMIUM PACKAGES ARE UNREGULATED (I.E., RECORDED BELOW-THE-LINE)?**

A. No. We do not agree with the Company's accounting treatment whereby the revenues and expenses associated with the energy direct premium packages are unregulated (i.e., below-the-line). Specifically, we do not see a valid distinction as to why the expenses associated with the Energy Direct Standard Package should be recorded above-the-line while the revenues and expenses associated with the Premium Packages should be recorded below-the-line. This treatment would appear to allow the Company to retain the pre-tax profits being earned on the Premium Packages.

**Q. WHAT IS STAFF'S RECOMMENDATION WITH REGARD TO THE RATEMAKING TREATMENT OF THE ENERGY DIRECT PREMIUM PACKAGES REVENUE AND EXPENSES?**

A. Staff recommends an adjustment to include the projected revenues and expenses associated with the Energy Direct Premium Packages in Georgia Power's net operating income for ratemaking purposes in the forecasted test year and in each of the rate plan years 2023-2025.

**Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT.**

A. Data requests STF-LA-3-3 and STF-LA-3-4 requested that the Company provide the revenues and expenses associated with the Energy Direct Premium Packages for the

forecasted test year and each rate plan year 2023 through 2025. Using the information provided in those responses, we calculated an adjustment whereby the net revenue associated with the Energy Direct Premium Packages is included in Georgia Power's net operating income.

Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-6, our recommended adjustment increases pre-tax operating income by $1.165 million for the forecasted test year, $1.176 million for 2023, $1.209 million for 2024 and $1.240 million for 2025.

**E-7, Miscellaneous Items / Executive Financial Planning**

**Q. PLEASE EXPLAIN THE EXECUTIVE FINANCIAL PLANNING ADJUSTMENT SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDUE E-7.**

A. In its response to STF-LA-2-56, the Company confirms that the proposed test year operating expenses include $470,015 associated with its executive financial planning program. This amount includes Georgia Power direct charges of $195,734 as well as charges allocated to Georgia Power by SCS and SNOC of $191,000 and $83,281, respectively. In addition, each plan year's operating expenses reflects similar executive financial planning costs in the categories noted above, including $468,984 in 2023, $469,609 in 2024 and $469,523 in 2025. This program provides personal financial planning, estate planning, investment advice and tax planning and preparation to Georgia Power's Chief Executive Officer, Chief Operating Officer, Vice-Presidents and Directors. We do not believe that the captive ratepayers of Georgia Power should pay for the charges associated with these types of top executive perks. Rather, we believe that the Company's stockholders should be made responsible for these costs. Our recommended

removal of these executive financial planning program costs from the forecasted test year and each plan year is reflected on Staff Exhibit__(RS/RT-2), Schedule E-7. A similar adjustment was recommended by Staff in prior Georgia Power rate cases.

**E-8, Interest Synchronization Adjustment**

**Q. PLEASE DESCRIBE GEORGIA POWER'S PROPOSED INTEREST SYNCHRONIZATION ADJUSTMENT SHOWN ON STAFF EXHIBIT__(RS/RT-2), SCHEDULE E-8.**

A. The Company is proposing that interest expenses to be used as a deduction in the calculation of the test year pro forma adjusted income taxes be based on the interest expenses that are implicit in its proposed overall rate of return. These pro forma interest expenses (referred to as the so-called "synchronized" interest expenses) are determined by multiplying the weighted cost of debt component of the overall rate of return times the rate base used in this case.

**Q. HAVE YOU DETERMINED THE STAFF-RECOMMENDED TRADITIONAL TEST YEAR SYNCHRONIZED INTEREST EXPENSES IN A SIMILAR MANNER?**

A. Yes. The Staff-recommended traditional test year synchronized interest expense amount, calculated in the same manner, is shown in the third column of Staff Exhibit__(RS/RT-2), Schedule E-8, page 1. Plan year synchronized interest adjustment amounts are shown on pages 2-4 of Schedule E-8.

**Q. WHY IS THE STAFF'S RECOMMENDED SYNCHRONIZED INTEREST AMOUNT DIFFERENT FROM GEORGIA POWER'S PROPOSED SYNCHRONIZED INTEREST AMOUNT?**

A. This disparity is due to the differences in the rate base levels used in Georgia Power's and Staff's respective recommendations and to the difference in the capital structure between Staff and the Company. These differences result in different synchronized interest expense amounts.

**Q. HOW DOES THIS DIFFERENCE IN THE TWO SYNCHRONIZED INTEREST EXPENSE LEVELS IMPACT GEORGIA POWER'S PROPOSED TRADITIONAL TEST YEAR AFTER-TAX RETAIL OPERATING INCOME?**

A. As shown on line 6 of Staff Exhibit__(RS/RT-2), Schedule E-8, page 1, adoption of Staff's recommended synchronized interest amount increases the Company's traditional test year retail income tax expense by $598,000 and decreases after-tax operating income by that same amount, i.e., by $598,000.

The interest synchronization adjustments for each plan year are shown on Schedule E-8, pages 2-4, respectively.

**E-9, O&M Scrap Sales Proceeds**

**Q. WHAT IS GEORGIA POWER'S PROCEDURE FOR RECORDING OBSOLETE AND/OR SCRAP MATERIAL SALES PROCEEDS?**

A. According to the response to STF-LA-2-25, the Company's for recording obsolete and/or scrap material sales proceeds is to credit salvage or O&M expense as appropriate for actual sales proceeds.

**Q. DID GEORGIA POWER INCLUDE ANY AMOUNTS FOR OBSOLETE AND SCRAP MATERIAL SALES PROCEEDS IN THE FORECASTED TEST YEAR AND IN EACH OF THE RATE PLAN YEARS COST OF SERVICE?**

A. No, it did not.

**Q. DID GEORGIA POWER EXPLAIN WHY IT DID NOT INCLUDE ANY AMOUNTS FOR OBSOLETE AND SCRAP MATERIAL SALES PROCEEDS IN THE FORECASTED TEST YEAR AND EACH OF THE RATE PLAN YEARS COST OF SERVICE?**

A. In its response to STF-LA-2-25, the Company stated that due to the uncertainty of obsolete and scrap material sales, no related proceeds are reflected in the forecasted test year or in each rate plan year 2023, 2024 and 2025.

**Q. DID GEORGIA POWER RECORD OBSOLETE AND/OR SCRAP MATERIAL SALES PROCEEDS IN EACH YEAR 2016 THROUGH 2021 AND IN 2022 TO DATE?**

A. Yes. In its response to STF-LA-2-25, the Company provided the O&M scrap sales proceeds for each year 2016 through 2021 and 2022 through May in the table below:

| Year | Amount |
|---|---|
| 2016 | $ 1,465,670 |
| 2017 | $ 1,149,340 |
| 2018 | $ 713,035 |
| 2019 | $ 737,674 |
| 2020 | $ 1,544,267 |
| 2021 | $ 1,369,796 |
| 2022 (through May) | $ 876,935 |
| | |
| Source: STF-LA-2-25 | |

As shown in the above table, Georgia Power recorded O&M scrap sales proceeds in each year 2016 through 2021 and in 2022 through May.

**Q. BASED ON GEORGIA POWER RECORDING O&M SCRAP SALES PROCEEDS IN EACH OF THE LAST SIX CALENDAR YEARS AND IN 2022 THROUGH MAY, IS IT REASONABLE TO CONCLUDE THAT THE COMPANY WILL RECORD O&M SCRAP SALES PROCEEDS IN THE FORECASTED TEST YEAR AND RATE PLAN YEARS?**

A. Yes.

**Q. HAS THE COMPANY PREVIOUSLY AGREED THAT A REPRESENTATIVE LEVEL OF O&M SCRAP SALES PROCEEDS SHOULD BE REFLECTED IN THE SETTING OF RATES?**

A. Yes. In the Company's errata filing dated September 25, 2007 in its 2007 rate case in Docket No. 25060, the Company agreed that a representative level of O&M scrap sales proceeds should be reflected in the setting of rates.

**Q. DID THE COMMISSION REACH A SIMILAR CONCLUSION IN A MORE RECENT GEORGIA POWER RATE CASE?**

A. Yes. In its Final Order in which the Commission approved the Stipulation in Georgia Power's 2010 rate case in Docket No. 31958, the Commission stated that it found Staff's adjustment to reflect a representative level of scrap sales proceeds to be reasonable. Specifically, in Section 6 on page 8 of its Final Order, the Commission stated:

> Lines 12-23 of the "Georgia Power Company Revenue Deficiency Table" consist of "Other Rate Base and Operating Income Adjustments." The Stipulation incorporates the Advocacy Staff's recommended adjustments for M&S Inventory Write-Off, 2010 ECCR Cost Deferral, Wholesale Capacity Sales Adjustment, **Proceeds from Scrap Sales**, Property Tax and Uncertain Tax Positions. The Commission finds that the resolution of these line items to be reasonable.
>
> (Emphasis supplied)

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR O&M SCRAP SALES PROCEEDS.**

A. In lieu of the Company providing forecasted amounts for O&M scrap sales proceeds for the test year and each of the rate plan years, Staff used the amounts noted above from the response to STF-LA-2-25 for the O&M scrap sales the Company recorded during the period January 2016 through May 2022. Specifically, Staff summed the scrap sales and divided the total by 77 months (six years from 2016-2021 plus five months of 2022) to derive a monthly amount of O&M scrap sales proceeds. This amount was then multiplied by 12 months to derive an annual amount of $1.224 million. Staff reflected this amount for the forecasted test year and each of the rate plan years.

As shown on Exhibit__(RS/RT-2), Schedule E-9, Staff's recommended adjustment reduces retail O&M expense by $1.216 million for the test year and each rate plan year 2023, 2024 and 2025.

**E-10, Cash Working Capital**

**Q. WHAT HAS THE COMPANY REQUESTED FOR CASH WORKING CAPITAL?**

A. For the future test year ending July 31, 2023, the Company has reflected negative cash working capital of $54.889 million, based on an updated lead-lag study that it conducted for purposes of this case.

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR CASH WORKING CAPITAL.**

A. As shown on Exhibit__(RS/RT-2), Schedule E-10, the only adjustments we are recommending to the Company's cash working capital in the current rate case result from adjustments that are being by Staff for certain cash operating expenses. As the result of having adjusted various cash operating expenses, the amount of cash working capital computed in Staff's case differs from the amounts that were presented in the Company's filing.

**E-11, Wireless Co-Location Revenues**

**Q. HAS GEORGIA POWER MADE ADJUSTMENTS TO REVENUE IN ITS ANNUAL SURVEILLANCE REPORTS RELATED TO ITS CO-LOCATION WIRELESS EQUIPMENT PROGRAM?**

A. Yes. Georgia Power has made adjustments to revenue in its Annual Surveillance Reports related to its Co-Location Wireless Equipment program. Specifically, the Company's adjustment in its ASR's (1) removes 50 percent of revenues net of program expenses associated with its transmission tower assets per the Commission's Order in Docket No. 25322, and (2) removes 40 percent of revenues net of expenses associated with small cell installations or macro cell development for retail facilities such as telecom towers and/or

land leases on the Company's regulated assets per the Commission's Order in Docket No. 36989.

**Q. WHEN WAS THE CO-LOCATION WIRELESS EQUIPMENT PROGRAM MOST RECENTLY ADDRESSED?**

A. The Co-Location Wireless Equipment program was most recently addressed in the Company's 2019 ASR. Specifically, as it relates to this issue in the 2019 ASR, the Commission stated:

> In 2019, the Company communicated to Staff a proposal to expand the Commission-approved colocation program to cover additional classes of facilities like distribution lighting poles and certain land that were not discussed in the Commission's Order in Docket No. 25322. This expansion related primarily to the ongoing development of 4G and 5G networks. For reporting purposes, the Company treated the colocation revenue as though it was from the Colocation Program approved in Docket No. 25322. Staff did not agree with this treatment and took the position that the Colocation Order applied only to Transmission Towers. After several discussions, the Staff and Company reached an agreement that will temporarily resolve this issue.
>
> As documented in Staff's Summary Report, the Company agreed to forego its share of telecommunication colocation revenue reported in the 2019 ASR. For purposes of the 2019 ASR, the adjustment reflected in Section 6, Workpaper 20 and Section 3, Income, which reflects sharing with the Company, will be reversed and the amount will be used to reduce regulatory assets in the priority set out in Paragraph 12 of the Stipulation in Docket 42516. In years 2020 – 2022 the Company will continue to apply 50/50 sharing for collocation revenue resulting from the collocation of telecommunications equipment on transmission towers.
>
> For years 2020 – 2022 the Company agreed any revenue reported from the collocation program associated with small cell installations on the Company's regulated assets will be allocated for ASR Reporting purposes 60% to ratepayers and 40% retained by the Company. The 60/40 sharing allocation will also be used for macro cell development on retail facilities such as telecom towers and land leases.
>
> Staff and the Company agreed that the Colocation Program and sharing percentages may be reevaluated in the Company's next base rate case. For the purpose of settlement, the Company and Staff agree to make a good faith

effort to resolve any dispute around the sharing of colocation revenues prior to August 1, 2021, in order to allow for any resolution, should one be reached, to be included in the Company's next base rate case.

**Q. DID GEORGIA POWER INCLUDE AMOUNTS RELATED TO THE CO-LOCATION WIRELESS EQUIPMENT PROGRAM IN THE FORECASTED TEST YEAR AND RATE PLAN YEARS?**

A. Yes. In its Trade Secret response to STF-LA-12-1, the Company provided the following projected amounts for co-location revenue recorded in FERC account 456[21]: [redacted]

**Q. ARE THE AMOUNTS SHOWN ABOVE SUBJECT TO THE GEORGIA POWER'S PROPOSAL TO CONTINUE THE 60/40 SHARING ALLOCATION?**

A. Yes. Through informal communications with the Company, Georgia Power stated that it projects all wireless co-location revenues for the test period and rate years 2023-2025 to come from retail assets other than transmission towers, thus the Company applied the 60/40 sharing percentage. In addition, the Company stated that it applies the sharing percentage to the revenues net of program expenses so that the so-location revenues included in the retail cost of service are net of such expenses. However, this 60/40

[21] [redacted]

sharing allocation was temporary under the 2019 ASR Order and the Company has not explained why it is appropriate as on a going forward basis.[22]

**Q. IS STAFF MAKING A RECOMMENDATION RELATED TO THE CO-LOCATION WIRELESS EQUIPMENT PROGRAM IN THE CURRENT CASE PURSUANT TO THE COMMISSION'S RECOMMENDATION IN THE 2019 ASR?**

A. Yes. Staff recommends that the revenue sharing allocation related to the Co-Location Wireless Equipment Program be updated whereby 80% of such revenues be allocated to ratepayers with the Company retaining the remaining 20% of co-location net revenues. Georgia Power is already earning a return on the regulated assets in rate base. Georgia Power's return on these assets, and the associated expenses (financing, depreciation, taxes, O&M) are paid for by ratepayers. When these rate based assets are deployed to generate additional revenue, the revenue should be used to benefit ratepayers.

As shown on Exhibit__(RS/RT-2), Schedule E-11, Staff applied an 80/20 sharing percentage to the net co-location revenues, which results in an adjustment to increase pre-tax operating income by $404,000 for the test year, $433,000 for 2023, $520,000 for 2024 and $626,000 for 2025.

[22] For example, when the Commission approved the sharing of transmission co-location revenues, one of the considerations appears to have been giving the Company an incentive to allow co-locations when it was not required to do so that there would be revenue to share. The Company has not explained how such any incentive is needed here.

**E-12, Depreciation Expense and Accumulated Depreciation - New Depreciation Rates**

**Q. DID STAFF CALCULATE AN ADJUSTMENT TO THE COMPANY'S PROPOSED DEPRECIATION EXPENSE FOR THE TEST YEAR AND EACH RATE PLAN YEAR TO REFLECT THE NEW DEPRECIATION RATES THAT STAFF IS RECOMMENDING?**

A. The amounts shown on Exhibit__(RS/RT-2), Schedule E-12, page 1, are adjustments to the Company's proposed depreciation expense amounts in the test year and in each plan year which were calculated based on the depreciation rates supplied by Staff witness Lance Kaufman. Mr. Kaufman is recommending new depreciation rates that differ from those proposed by Georgia Power in the Company's depreciation study for production plant, transmission plant, distribution plant and general plant.

**Q. WHAT IS THE IMPACT OF USING THE NEW DEPRECIATION RATES THAT ARE BEING RECOMMENDED BY STAFF WITNESS KAUFMAN?**

A. As shown on Exhibit__(RS/RT-2), Schedule E-12, page 1, line 19, Georgia Power's proposed depreciation expense is reduced by $31.434 million for the test year, $54.117 million for 2023, $57.236 million for 2024 and $59.513 million for 2025. Details are shown on Exhibit__(RS/RT-2), Schedule E-12, pages 3-18.

**Q. DID GEORGIA POWER'S DEPRECIATION STUDY INCLUDE DEPRECIATION RATES FOR INTANGIBLE PLANT?**

A. No. Through informal communications in an email dated October 17, 2022, Georgia Power advised that intangible plant was excluded from its depreciation rate study as it is

not subject to a depreciation rate. Rather, the Company stated that software and other intangible assets are amortized over a five-year period.

**Q. ARE THERE CORRESPONDING ADJUSTMENTS TO ACCUMULATED DEPRECIATION?**

A. Yes. There are corresponding adjustments to accumulated depreciation related to production plant, transmission plant, distribution plant and general plant. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-12, page 1, line 46, Georgia Power's proposed depreciation expense has been reduced, and accumulated depreciation has been correspondingly reduced on a cumulative basis reflecting the average rate base approach (thus increasing rate base) by $15.741 million for the test year, $27.206 million for 2023, $83.023 million for 2024 and $141.383 million for 2025.

**E-13, Electric Vehicles Make Ready Program**

**Q. HAS GEORGIA POWER INCLUDED COSTS RELATED TO ELECTRIC TRANSPORTATION ACTIVITIES IN ITS FILING?**

A. Yes. As stated by Mr. Womack in his direct testimony:

> Over the next three years, we will increase our investments in community electric vehicle ("EV") charging facilities and necessary electric transportation infrastructure upgrades to support customer EV charging. In addition to these capital infrastructure upgrades, our rate request includes expenses for administrative costs, infrastructure maintenance, and various rebates for homebuilders and residential and commercial customers to accommodate growth in EV charging across the state.[23]

[23] Direct Testimony of Christopher C. Womack, 10:9-14

**Q. HOW MUCH HAS THE COMPANY REQUESTED FOR ELECTRIC TRANSPORTATION ACTIVITIES IN ITS FILING?**

A. The Company requested $30 million annually for EV capital infrastructure spending in each plan year 2023 through 2025, as detailed in the STF-PIA-3-5 Attachment which is replicated below:

GEORGIA POWER COMPANY
ELECTRIC VEHICLE INFRASTRUCTURE

| | Actual | | Budget | | | |
|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
| Capital Infrastructure Upgrades | $ 2,001,778 | $ 5,986,332 | $ 14,000,000 | $ 30,000,000 | $ 30,000,000 | $ 30,000,000 |
| Administrative Costs | $ 1,453,275 | $ 1,069,422 | $ 1,084,037 | $ 1,920,826 | $ 2,242,116 | $ 2,565,869 |
| Infrastructure Maintenance | - | - | - | 42,872 | 68,392 | 68,928 |
| Rebates | 473,377 | 507,526 | 514,520 | 2,815,000 | 2,879,745 | 2,945,979 |

**Q. WHAT PORTION OF THE $30 MILLION OF ANNUAL EV INFRASTRUCTURE SPENDING REPRESENTS SPENDING FOR THE COMPANY'S PROPOSED ELECTRIC TRANSPORTATION "MAKE READY" PROGRAM?**

A. The Company has requested $27 million per year for 2023 through 2025, for a proposed capital budget of $81 million for the rate plan.[24] The proposed capital budget of $81 million in total for the Make Ready program for years 2023 through 2025 includes projects in the following categories:[25]

[24] See the response to STF-LA-6-19.

[25] Ibid

| Description | Amount (in Millions) |
|---|---|
| Waitlisted | $5.90 |
| Pipeline | $20.60 |
| Anticipated New | $54.50 |
| Total | $81.00 |

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING ELECTRIC TRANSPORTATION MAKE READY?**

A. The Make Ready program proposed by Georgia Power Company in this docket should be denied and the associated costs be removed for ratemaking purposes. Investments needed to provide an unregulated service to private groups should be paid for by the business or organization wanting to provide that unregulated service. This is true whether or not the unregulated charging service is private or available to the public. As with investments associated with regulated public utilities, the costs should be recovered from cost-causers. The general body of ratepayers should not be subjected to paying for private assets that primarily benefit Make Ready participants. The program, if continued for the next decade, will increase the revenue requirement by close to half a billion dollars.

**Q. WHY IS THE MAKE READY PROGRAM NOT IN THE PUBLIC INTEREST?**

A. The Make Ready program obligates captive electric service customers to subsidize the provision an unregulated service, electric vehicle charging. The vast majority of retail electric customers do not own electric vehicles and will not own EVs this decade. Additionally, Make Ready equipment is only needed in order to provide unregulated charging services to a small set of Georgia Power's customers. The equipment is not used and useful in providing regulated retail electric service to Georgia Power's customers. As noted in the response to STF-HR-1-2, "To date, nearly all of the total Make Ready

program spend (over 99%) is for the funding of equipment on the customer side of the meter." Make Ready results in co-ownership of unregulated EV charging stations by the monopoly utility. The monopoly utility is allowed to profit now, not only on assets used and useful in the provision of retail electric service, but also on unregulated assets fully funded by customers who do not have a choice of providers.

**Q. WHAT MAKE READY SPENDING WAS APPROVED FOR GEORGIA POWER IN THE 2019 RATE CASE AND WHAT WAS APPROVED?**

A. Georgia Power received approval of Make Ready spending in the 2019 Rate Case of $6 million per year. The issue was not litigated, and interveners did not have the opportunity to submit positions into the record. The $6 million per year for Make Ready was added to a settlement agreement reached between certain interveners. Item 30 from the 2019 Rate Case Settlement, which was ultimately approved by the Commission, stated:

> 30. The funds for electric vehicle infrastructure will be allowed as proposed by the Company with an additional $6 million per year to be invested in support of wire and transformer upgrades for customer sited charging stations.

**Q. WHAT SPENDING WAS AUTHORIZED BY THE APPROVED SETTLEMENT?**

A. The annual budget was specifically authorized to support "wire and transformer upgrades". The Company's implementation of the program, however, has exceeded the scope of uses specified in the stipulation agreement. Rather than limit the program to wire and transformer upgrades, which would reasonably be expected to be on the Company's side of the meter, Georgia Power spent 99% of the authorized funds on equipment on the customer's side of the meter as noted above.

**Q. DO GEORGIA POWER RATEPAYERS HAVE THE ABILITY TO USE THE CHARGERS AT THE MAKE READY LOCATIONS?**

A. The Company did not provide a response to Staff's informal question asking if the public may charge at the Make Ready locations. Staff's understanding, based on conversations with Company personnel, is that there is no obligation for chargers located at Make Ready sites to be made available to the public. Further, Staff understands that Georgia Power does not have a list of which Make Ready charging locations, if any, are open to the public. Thus, with limited exceptions, ratepayers responsible for paying the cost of Make Ready assets, over at least the next decade, will not be able use the charging stations. It appears the vast majority of the charging stations will be private, and not open to the ratepayers who would pay for the supporting assets.

**Q. DOES THE COMPANY EARN A PROFIT ON MAKE READY SPENDING?**

A. Yes. Make Ready equipment, which is used to provide unregulated charging service that has been installed to date, is included in the regulated rate base. As a result, the Company earns a return on the equity portion of the investment.

**Q. DO RATEPAYERS PAY FINANCING CHARGES ON DEBT RAISED TO FUND MAKE READY INFRASTRUCTURE?**

A. Yes.

**Q. DO RATEPAYERS ALSO PAY TAXES ON THE REVENUE COLLECTED TO FUND MAKE READY INFRASTRUCTURE?**

A. Yes.

**Q. DO GEORGIA POWER RATEPAYERS BENEFIT FROM THE PROGRAM?**

A. Other than car dealerships[26] that receive Make Ready assistance, there is no obligation for these charging stations to provide service to the public. The Company does not have a list, for example, of Make Ready sites that are open to the public for charging. There is also no evidence that the Make Ready sites will result in incremental load on the system that would fully recover the revenue requirement associated with the cost of Make Ready expenditures. The Company has not demonstrated that revenue collected through the Make Ready program will offset costs to ratepayers.

**Q. WHICH GEORGIA POWER CUSTOMERS ARE RECEIVING THE BENEFITS OF MAKE READY?**

A. As noted below, Georgia Power has not disclosed the names and locations of Make Ready locations. In Response to STF-PIA-1-1, the Facility Types for Make Ready participants was provided. These include:

1. Airport
2. College/University
3. Commercial Office/Workplace
4. Entertainment/Hospitality
5. Industrial
6. Mass Transit
7. Medical Campus
8. Multi-family/Apartment/Condo/Mixed-Use Development
9. Municipality
10. Other Commercial Business/Retail
11. Seaport
12. Supply Chain/Logistics

[26] STF-LA-6-20 Attachment B.docx

Participants include airlines, hotels, private golf clubs, private schools, automobile dealerships, luxury condominiums, and multi-national corporations with annual revenues well over a billion dollars.

**Q. IS ANY OF THE REVENUE REQUIREMENT ON THE ELECTRIC TRANSPORTATION MAKE READY CAPITAL INVESTMENT BEING DIRECTLY RECOVERED FROM MAKE READY PARTICIPANTS WHO BENEFIT FROM THE PROGRAM?**

A. No.[27]

**Q. WHERE WOULD ELECTRIC VEHICLE OWNERS CHARGE IF THE MAKE READY PROGRAM IS DISCONTINUED?**

A. In the absence of additional Make Ready enabled charging stations, Electric Vehicle owners will continue to charge primarily at home. They will also charge at new and existing stations being developed competitively across the state without Make Ready funding. It is expected that fueling stations and convenience stores are interested in deploying charging stations, even without funding from Georgia Power ratepayers.

**Q. WHAT COSTS ARE BEING PASSED TO GEORGIA POWER'S RETAIL ELECTRIC CUSTOMERS?**

[27] STF-PIA-1-3

A. The revenue requirement for the Make Ready program includes the capital expenditures to purchase and install the equipment, a rate of return to Georgia Power Company, depreciation, and taxes and the operating and maintenance expense of the program.

**Q. HOW LONG WILL RATEPAYERS BE OBLIGATED TO PAY FOR THE MAKE READY EQUIPMENT?**

A. Staff understands that the initial term for a participant is one year, with automatic renewals for ten years. It's not known what happens with the assets and program after ten years. Staff believes the revenue requirement will continue to be collected from ratepayers as long as the assets are owned and maintained by Georgia Power. Alternatively, the assets could be removed from the program or sold to the participant at market value.

**Q. ARE THERE OTHER REASONS TO NOT MANDATE THAT RATEPAYERS SUBSIDIZE ELECTRIC VEHICLE CHARGING VIA THE MAKE READY PROGRAM?**

A. Yes. The long-term success of the electric vehicle charging market depends on making it a competitive free market. Make Ready creates an uneven playing field for providers of Electric Vehicle Charging services, and gives Georgia Power the ability to select winners and losers in the charging station market. More importantly, GPC customers should have the economic freedom to only pay for the retail electric service they need. Customers who have no alternative for their electric service should not be required to also pay for other Georgia Power customers to have private Electric Vehicle charging stations.

**Q. ARE THESE MAKE READY ASSETS OWNED AND MAINTAINED BY GEORGIA POWER, AND PAID FOR BY RATEPAYERS, USED AND USEFUL IN THE PROVISION OF REGULATED RETAIL ELECTRIC SERVICE?**

A. No. The assets are only used to provide electric vehicle charging, which is currently not regulated.

**Q. HAS THE COMPANY IDENTIFIED THE MAKE READY LOCATIONS?**

A. In data request STF-PIA-1-1, Staff requested that the Company identify the ET Make Ready sites. In its response, the Company provided the "Premise Company" and "Contact Address". Make Ready assets are owned and maintained by Georgia Power. As such, the location of these assets should not be designated as trade secret. With very rare exception, the locations of Company-owned assets have not previously been withheld from the public. Staff subsequently requested the Company provide the addresses of the Make Ready projects as public disclosure information and without trade secret designation. The Company responded by indicating that by virtue of being collocated with participating Make Ready Customers, revealing the Make Ready sites would disclose customer information (i.e. which of its customers are Make Ready participants). Although Staff has recommended the Make Ready Program be discontinued, if the Commission chooses to approve the program, it should do so with full transparency required. The names and addresses of the participants should be disclosed, and the Company should also be required to identify which locations are available to the public for charging.

**Q. IS IT CONCERNING THAT GEORGIA POWER IS NOT WILLING TO IDENTIFY THE MAKE READY SITES, AND THAT MAKE READY PARTICIPANTS DO NOT WANT IT KNOWN THEY ARE RECEIVING THE MAKE READY SUBSIDY?**

A. Yes. It is concerning that the Make Ready locations have not been disclosed. While Staff understands the need to protect customer data in general, the participation in Make Ready should not fall into a category of private customer information. It is concerning the ratepayers who would pay for the monopoly utility to own and operate charging stations for the private benefit of other customers are not afforded the opportunity to know which customers are benefiting and where the funds are being deployed. Staff also notes that participants in the Make Ready Program have each agreed to the ET Make Ready Program Terms and Conditions, which includes the following provision:

> 6. Electric Transportation Data and Information. The Participant acknowledges and agrees that Georgia Power's collection of data associated with the Project is critical to the evaluation of the Make-Ready Program. The Participant hereby grants Georgia Power unrestricted access and use of all data collected by the ET Infrastructure. The Participant agrees to allow Georgia Power, its agents and representatives to use data gathered as part of the Make-Ready Program for use in regulatory reporting, ordinary business use, industry forums, case studies, or other similar activities, in accordance with applicable laws and regulations.

Participants have already granted Georgia Power use of data associated with its project. The address of the project is collected and is a component of how the program is structured, whether projects approved are geographically diverse and how charging may differ between various locations.

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE THE CAPITAL COSTS ASSOCIATED WITH THE EV MAKE READY PROGRAM.**

A. As shown on Staff Exhibit__(RS/RT-2), Schedule E-13, our recommended adjustment is in two parts. The first part of our adjustment is to remove the rate base components, which are comprised of plant in service and accumulated depreciation. The impact of removing the plant in service components of the EV Make Ready program results in retail electric rate base being decreased by $13.500 million, $40.500 million and $67.500 million for plan years 2023, 2024 and 2025, respectively.

In addition, as shown on Staff Exhibit__(RS/RT-2), Schedule E-14 (line 7), the second part of our rate base adjustment reduces retail electric accumulated depreciation (thus increasing rate base) by $196,000, $978,000 and $2.543 million for plan years 2023, 2024 and 2025, respectively. Our adjustments to accumulated depreciation were derived by our adjustment to depreciation expense, which is calculated by applying the Distribution depreciation rate that was supplied by Staff witness Lance Kaufman. As shown on Exhibit__(RS/RT-2), Schedule E-13 (lines 8-9) our adjustment reduces jurisdictional depreciation expense by $391,000, $1.173 million and $1.956 million for plan years 2023, 2024 and 2025, respectively.

**E-14, Electric Vehicles Community Charging Stations**

**Q. WHAT PORTION OF GEORGIA POWER'S $30 MILLION REQUEST REPRESENTS SPENDING FOR COMMUNITY CHARGING STATIONS?**

A. The projected capital expenditures for infrastructure upgrades for the Community Charging program is $3 million per year for years 2023 through 2025. Capital

expenditures for the Community Charging program include but are not limited to EV chargers, wires, panels, conduit, transformers, and labor.[28]

**Q. HAS THE COMPANY IDENTIFIED ALL COSTS AND REVENUES FOR EV CHARGING FACILITIES THAT ARE INCLUDED IN RATE BASE, REVENUE AND OPERATING EXPENSES FOR THE FORECASTED TEST YEAR AND FOR CALENDAR YEARS 2023-2025?**

A. Yes. In its response to STF-LA-2-120 Attachment, the Company provided the amounts summarized in the following table as being included in the forecasted test year and for calendar years 2022 through 2025:

| EV Charging Stations | | | | | | |
|---|---|---|---|---|---|---|
| | FERC Account | Test Year (Jul-22 - Jul-23) | 2022 | 2023 | 2024 | 2025 |
| **Rate Base (13-month average)** | | | | | | |
| Plant in Service | 101 | $ 8,689,293 | $ 7,364,160 | $ 9,849,806 | $ 12,849,806 | $ 15,849,806 |
| Accumulated Depreciation | 108 | (138,236) | (25,420) | (247,619) | (574,729) | (989,319) |
| ADITs | 282 | (1,003,749) | (877,250) | (1,099,098) | (1,378,891) | (1,722,723) |
| Net Rate Base | | $ 7,547,308 | $ 6,461,491 | $ 8,503,089 | $ 10,896,186 | $ 13,137,764 |
| | | | | | | |
| **Operating Income** | FERC Account | Test Year (Aug-22 - Jul-23) | 2022 | 2023 | 2024 | 2025 |
| Revenue | 456 | $ (348,019) | $ (345,000) | $ (350,175) | $ (355,428) | $ (362,536) |
| O&M Expense | 908 | 416,353 | 407,940 | 422,528 | 437,846 | 453,940 |
| Depreciation Expense | 403 | 242,837 | 196,351 | 283,370 | 370,850 | 458,330 |

**Q. IN YOUR OPINION, SHOULD GEORGIA POWER BE AUTHORIZED TO MAKE ADDITIONAL CAPITAL INVESTMENTS IN THE COMMUNITY CHARGER PROGRAM?**

A. No, they should not. First, the table above clearly demonstrates the current and future charging stations will not generate enough revenue to cover O&M expense and

[2828] STF-LA-6-19

depreciation, much less the return on capital and income taxes associated with the investment. The Community Charging stations are being subsidized by all ratepayers including the vast majority who do not own an electric vehicle, and are not expected to own an electric vehicle in the next decade. Continuation of the program, and increasing the annual capital expenditures to $3 million annually will result in additional costs to ratepayers that exceed the programs revenue.

Second, the competitive market is expected to provide, with assistance from federal funding and grants, a significant number of new charging stations throughout the state, including those being installed by companies risking their own capital. It would be unfair and inappropriate regulatory policy to allow Georgia Power to expand its monopoly to build more EV charging facilities at the expense of ratepayers. To the extent that EV charging stations being used for the purpose of fueling the Company's fleet of vehicles that are used in the provision of providing service, such costs may be appropriate for recovery from ratepayers assuming the investment was prudent and economic, as these are used and useful. However, as discussed above, the Company's plan for the $9 million investment in EV charging facilities over the term of plan years 2023-2023, is largely centered on making such charging facilities available to portions of the general public that have EVs. Also, the rates that the Company is charging for EV charging for the service are insufficient to recover the costs, given the low utilization of the chargers. Staff recommends that the costs associated with the Company’s Community Charging Stations program should not approved. Staff has therefore made an adjustment to remove the costs and revenues associated with the EV charging facilities.

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO REMOVE THE CAPITAL COSTS ASSOCIATED WITH THE EV CHARGING FACILITIES.**

A. As shown on Staff Exhibit__(RS/RT-2), Schedule E-14, our recommended adjustment is in two parts. The first part of our adjustment is to remove the rate base components, which are comprised of plant in service and accumulated depreciation. The impact of removing the plant in service components of the EV charging facilities results in retail electric rate base being decreased by $1.500 million, $4.500 million and $7.500 million for plan years 2023, 2024 and 2025, respectively.

In addition, as shown on Staff Exhibit__(RS/RT-2), Schedule E-14 (line 7), the second part of our rate base adjustment reduces retail electric accumulated depreciation (thus increasing rate base) by $22,000, $109,000 and $283,000 for plan years 2023, 2024 and 2025, respectively. Our adjustments to accumulated depreciation were derived by our adjustment to depreciation expense, which is calculated by applying the Distribution depreciation rate that was supplied by Staff witness Lance Kaufman. As shown on Exhibit__(RS/RT-2), Schedule E-14 (lines 8-9) our adjustment reduces jurisdictional depreciation expense by $43,000, $130,000 and $217,000 for plan years 2023, 2024 and 2025, respectively.

**<u>E-15, Operation and Maintenance ("O&M") Expense – Electric Vehicle Infrastructure</u>**

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO EV CHARGING EXPENSES?**

A. As indicated in response to STF-PIA-3-5, the Company has proposed to include the following expenses in the 2023-2025 rate plan years:

| Description | 2023 | 2024 | 2025 |
|---|---|---|---|
| Administrative Costs | $1,920,826 | $2,242,116 | $2,565,869 |
| Infrastructure Maintenance | 42,872 | 68,392 | 68,928 |
| Rebates | 2,815,000 | 2,879,745 | 2,945,979 |
| Total O&M Expense per Company | 4,778,698 | 5,190,253 | 5,580,776 |
| | | | |
| Source: STF-PIA-3-5 | | | |

**Q. WHAT AMOUNTS HAS THE COMPANY BOOKED IN PRIOR YEARS RELATED TO EV CHARGING EXPENSES?**

A. In its response to STF-PIA-3-5 the Company stated that it booked the following EV Charging expenses for the years 2020, 2021 and 2022:

| Description | 2020 | 2021 | 2022 |
|---|---|---|---|
| Administrative Costs | $1,453,275 | $1,069,422 | $1,084,037 |
| Rebates | 473,377 | 507,526 | 514,520 |
| Total O&M Expense per Company | 1,926,652 | 1,576,948 | 1,598,557 |
| | | | |
| Source: STF-PIA-3-5 | | | |

**Q. WHAT IS STAFF'S POSITION ON THE COMPANY'S REQUEST TO EXPAND EV CHARGING PROGRAMS?**

A. As discussed previously in our testimony, Staff is recommending no ratepayer-funded expansion in EV charging programs. The Company's past expenditures should generally be sufficient for the test year and each of the rate plan years.

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO O&M EXPENSE RELATED TO THE EV INFRASTRUCTURE.**

A. We calculated a three-year average of the 2020-2022 administrative costs and applied this amount to each rate year. In addition, we accepted the Company's projected amounts for infrastructure maintenance. Finally, we multiplied the 2022 amount for rebates by two

and applied the result to each rate plan year. As shown on Exhibit__(RS/RT-2), Schedule E-15, the impact of our adjustments results in retail O&M expense being decreased by $2.505 million, $2.891 million and $3.281 million for plan years 2023, 2024 and 2025, respectively.

**E-16 through E-29, O&M Expense Adjustments**

**Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULES E-15 THROUGH E-29.**

A. The amounts shown on Exhibit__(RS/RT-2), Schedules E-16 through E-29 are discussed in detail in the Direct Testimony of Staff witness Dante Mugrace who is recommending various adjustments to O&M expense. Specifically, Mr. Mugrace is recommending adjustments for the following O&M expenses:

- Schedule E-16 – O&M Expense - Transmission
- Schedule E-17 – O&M Expense - Distribution
- Schedule E-18 – O&M Expense – Customer Accounting
- Schedule E-19 – O&M Expense – Demonstration and Selling Expenses
- Schedule E-20 – O&M Expense – Administrative & General Salaries
- Schedule E-21 – O&M Expense – Office Supplies and Expense
- Schedule E-22 – O&M Expense – Outside Services Employed
- Schedule E-23 – O&M Expense – Injuries and Damages
- Schedule E-24 – O&M Expense – Employee Pensions and Benefits
- Schedule E-25 – O&M Expense – Customer Service and Information
- Schedule E-26 – O&M Expense – Miscellaneous General and Advertising

- Schedule E-27 – O&M Expense – Maintenance of General Plant
- Schedule E-28 – O&M Expense – Adjustment for Inflation
- Schedule E-29 – Labor O&M Expense – Vacancy Rate, Employee Levels, Performance Pay Plan and Overtime

The specific adjustments to these O&M expense accounts are shown on the referenced schedules in Exhibit__(RS/RT-2).

**E-30, Transmission Plant Investment**

**Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULE E-30.**

A. The adjustments shown on Exhibit__(RS/RT-2), Schedule E-30 are discussed in detail in the Direct Testimony of Staff witnesses Paul Alvarez, Dennis Stevens and Raj Rana who are recommending adjustments to capital spending for transmission plant related to the GRID Investment Program proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-30, incorporating Messrs. Alvarez, Stevens and Rana's recommendations reduces the Company's retail electric transmission plant in service by $163.745 million for 2023, $484.508 million for 2024 and by $820.811 million for 2025. Messrs. Alvarez, Stevens and Rana are not recommending any adjustments to the forecasted test year.

**E-31, Distribution Plant Investment**

**Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULE E-31.**

A. The adjustments shown on Exhibit__(RS/RT-2), Schedule E-31 are discussed in detail in the Direct Testimony of Staff witness Paul Alvarez, Dennis Stevens and Raj Rana who are recommending adjustments to capital spending for distribution plant related to the

GRID Investment Program proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-31, incorporating Messrs. Alvarez, Stevens and Rana's recommendations reduces the Company's retail electric distribution plant in service by $164.124 million for 2023, $523.165 million for 2024 and by $902.988 million for 2025. Messrs. Alvarez, Stevens and Rana are not recommending any adjustments to the forecasted test year.

**E-32, Distributed Energy Resource Management System ("DERMS")**

**Q. PLEASE EXPLAIN THE ADJUSTMENTS SHOWN ON SCHEDULE E-32.**

A. The adjustments shown on Exhibit__(RS/RT-2), Schedule E-32 are discussed in detail in the Direct Testimony of Staff witness Paul Alvarez, Dennis Stevens and Raj Rana who is recommending adjustments to capital spending for intangible plant related to the Distributed Energy Resource Management System ("DERMS") proposed by Georgia Power. As shown on Staff Exhibit__(RS/RT-2), Schedule E-32, incorporating Messrs. Alvarez, Stevens and Rana's recommendations reduces the Company's retail electric intangible plant in service by $4.974 million for 2023, $29.858 million for 2024 and by $74.633 million for 2025. Messrs. Alvarez, Stevens and Rana are not recommending any adjustments to the forecasted test year.

**E-33, Transmission Plant - Depreciation Expense and Accumulated Depreciation**

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-33.**

A. The adjustments shown on Schedule E-33 reflect corresponding adjustments to retail electric depreciation expense and accumulated depreciation which relate to Messrs. Alvarez, Stevens and Rana's recommended adjustments to capital spending for

transmission plant investment. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-33, line 5, retail electric depreciation expense for transmission is reduced $3.997 million for 2023, $11.831 million for 2024 and $20.047 million for 2025. The adjustments to depreciation expense use the transmission depreciation rate being recommended by Staff witness Kaufman.

In addition, as shown on Exhibit__(RS/RT-2, Schedule E-30, line 8, retail electric accumulated depreciation is reduced (thus increasing rate base) by $1.998 million for 2023, $9.910 million for 2024 and $25.846 million for 2025.

**E-34, Distribution Plant - Depreciation Expense and Accumulated Depreciation**

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-34.**

A. The adjustments shown on Schedule E-34 reflect corresponding adjustments to retail electric depreciation expense and accumulated depreciation which relate to Messrs. Alvarez, Stevens and Rana's recommended adjustments to distribution plant investment. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-34, line 3, retail electric depreciation expense for transmission is reduced $4.755 million for 2023, $15.159 million for 2024 and $26.164 million for 2025. The adjustments to depreciation expense use the distribution depreciation rate being recommended by Staff witness Kaufman.

In addition, as shown on Exhibit__(RS/RT-2, Schedule E-34, line 4, retail electric accumulated depreciation is reduced (thus increasing rate base) by $2.378 million for 2023, $12.335 million for 2024 and $32.996 million for 2025.

**E-35, Intangible Plant - Amortization Expense and Accumulated Amortization for DERMS**

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-35.**

A. The adjustments shown on Schedule E-35 reflect corresponding adjustments to retail electric amortization expense and accumulated amortization which relate to Messrs. Alvarez, Stevens and Rana's recommended adjustments to remove the Company's proposed capital spending for DERMS investment, which the Company records as intangible plant. Specifically, as shown on Exhibit__(RS/RT-2), Schedule E-35, line 3, retail electric amortization expense for intangible plant is reduced $995,000 for 2023, $5.972 million for 2024 and $14.927 million for 2025. The adjustment to intangible plant amortization expense uses the five-year amortization rate for intangible plant that the Company identified it was using in response to informal follow-up by Staff.

In addition, as shown on Exhibit__(RS/RT-2, Schedule E-35, line 6, retail electric accumulated amortization is reduced (thus increasing rate base) by $497,000 for 2023, $3.972 million for 2024 and $14.390 million for 2025.

**Q. WHY IS INTANIBLE PLANT BEING AMORTIZED RATHER THAN HAVING A DEPRECIATION RATE APPLIED TO IT?**

A. As discussed previously, in an email received by Georgia Power dated October 17, 2022, the Company stated that it records the DERMS investment to intangible plant FERC account 303, but that intangible plant was excluded from the Company's depreciation rate study because it not subject to a depreciation rate. Rather, software and other intangible assets are amortized by the Company over a five-year period. Therefore, as

shown on Exhibit__(RS/RT-2), Schedule E-35, Staff's adjustment to remove the proposed DERMS investment from intangible plant is amortized over five years rather than by having a deprecation rate applied.

**E-36, Depreciation Expense – Depreciation Rates Correction for Fort Benning and Fort Gordon**

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT ON SCHEDULE E-36.**

A. In the Company's response to STF-LA-8-18, discrepancies were noted between the depreciation rates proposed by Georgia Power in Attachment A to the response to STF-LA-8-18 and what was reflected in the Company's depreciation study for its Fort Benning and Fort Gordon solar facilities. Through an informal inquiry, Georgia Power advised that due to a formula error in its depreciation rate calculations, the depreciation rates reflected in its filing for Fort Benning and Fort Gordon were 2.584% and 0%, respectively. However, Appendix A to the depreciation study reflects depreciation rates of 2.835% and 2.820% for the Fort Benning and Fort Gordon solar facilities, respectively, which the Company confirmed are the correct rates to apply. The Company stated that it did not make this correction in its supplemental filing, thus their proposed depreciation expense is understated. Therefore, we are making an adjustment to reflect this correction.

As shown on Exhibit__(RS/RT-2), Schedule E-36, applying the correct depreciation rates to the Fort Benning and Fort Gordon solar facilities increases retail electric depreciation expense by $1.186 million for the test year and by $2.033 million for each plant year 2023, 2024 and 2025.

**E-37, Property Tax Expense**

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPERTY TAX EXPENSE.**

A. Staff's recommended adjustments decrease retail electric plant in service as it relates to the EV Make Ready Program, EV Community Charging Stations, and the adjustments to Transmission, Distribution and Intangible plant in service, requiring a corresponding adjustment to reduce retail electric property tax expense.

As shown on Exhibit__(RS/RT-2), Schedule E-37, the sum of the aforementioned adjustments to retail electric plant in service are multiplied by property tax rates that were supplied by Staff witness Dante Mugrace. After applying the retail electric jurisdictional factors, Staff's adjustment reduces retail electric property tax expense by $2.266 million for 2023, $7.219 million for 2024 and $12.726 million for 2025.

**Excess Accumulated Deferred Income Taxes**

**Q. DID THE COMPANY HAVE EXCESS ACCUMULATED DEFERRED INCOME TAXES?**

A. Yes. The Company's responses to STF-LA-2-101, STF-LA-2-102, STF-LA-2-115 and STF-LA-2-116 provide information on the Company's Excess Accumulated Deferred Income Taxes ("EADIT"). The Company will have completed its amortization of unprotected EADIT in 2022, and will continue to have amortization of protected EADIT in plan years 2023 through 2025, as shown in the above-noted responses.

**Q. IS STAFF RECOMMENDING ANY ADJUSTMENT FOR EADIT AMORTIZATION IN THE CURRENT RATE CASE?**

A. No. The amortization of the unprotected EADIT through December 2022 is consistent with the treatment provided for in the Commission Order in Docket No. 42516, which provided that the Company would amortize the benefit of unprotected EADIT for the benefit of customers over the three-year period ending December 2022, as further explained in the Company's response to STF-LA-2-115.

The amortization or protected EADIT is subject to certain normalization requirements, which include utilizing the average rate assumption method ("ARAM") to amortize the protected EADIT. The use of the ARAM for protected EADIT results in that being amortized in annual amounts that can differ from year to year in total such that the protected EADIT gets amortized over a period that approximates the remaining useful life of the utility plant to which the protected EADIT is attributable. The Company will continue to be amortizing the protected EADIT using the average rate assumption method which is required by the Internal Revenue Service. Accordingly, the Company has projected protected EADIT amortization of approximately $66 million for the test year and for 2023, and approximately $67 million for 2024 and approximately $69 million for 2025, which have been reflected in the Company's filing as a reduction to income taxes. Because the impacts of the continuing amortization of protected EADIT using the ARAM appears to have been properly and reasonably reflected in the Company's application, Staff is not recommending any further adjustments related to protected EADIT amortization in the current rate case.

**E-38, Energy Storage and Solar Production Tax Credits under the Inflation Reduction Act**

**Q. DOES THE COMPANY EXPECT TO HAVE ENERGY STORAGE AND SOLAR PRODUCTION TAX CREDITS UNDER THE INFLATION REDUCTION ACT OF 2022?**

A. Yes. The Company's responses to STF-LA-5-14 and, STF-LA-5-15, indicate that the Company expects to have energy storage tax credits of $31.7 million in 2023 and solar production tax credits of $0.4 million in 2025 under the Inflation Reduction Act.

**Q. HAS STAFF REFLECTED ADJUSTMENTS TO INCOME TAXES FOR THOSE EXPECTED ENERGY STORAGE TAX CREDITS AND SOLAR PRODUCTION TAX CREDITS?**

A. Yes. As shown on Exhibit__(RS/RT-2), Schedule E-38, Staff has reduced income tax expense by $31.7 million in 2023 for the expected impact of the energy storage tax credits of $31.7 million in 2023 and reduced income tax expense in 2025 by $0.4 million for the expected solar production tax credits. As explained in the Company's response to STF-LA-5-14(b) concerning Energy Storage Credits and Solar Credits:

> b. At this time, the Company has identified approximately $33 million of total potential benefits for 2022 through 2025 for the Commission's consideration related to projected, qualified renewable and electric vehicle investments. Listed below are the capital investments, along with estimated tax savings by year for 2022 through –2025, of the incremental benefits the Company has identified from the IRA, with related assumptions.

| Capital Investments (in millions) | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| Energy Storage | $ - | $ 105.6 | $ - | $ - |
| Solar Qualifying for Production Tax Credits | $ - | $ - | $ - | $ 32.7 |
| EV Chargers | $ 2.0 | $ 3.0 | $ 3.0 | $ 3.0 |

| Potential Tax Credits (in millions) | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| Energy Storage Credits | $ - | $ 31.7 | $ - | $ - |
| Solar Credits | $ - | $ - | $ - | $ 0.4 |
| EV Charger Credit Amortization | $ 0.1 | $ 0.2 | $ 0.2 | $ 0.3 |

Energy Storage Credits: The IRA provides Investment Tax Credits ("ITC") for standalone energy storage systems, no longer requiring it to be paired with and charged by solar generation. The Company believes the 65 MW Mossy Branch battery storage project, which is projected to be on-line in 2023, will qualify for a 30% ITC. The IRA also gives an "opt-out" from the existing ITC normalization, which permits the Company to recognize the full ITC benefit in the year the project goes into service, thereby providing a benefit to customers by lowering the levelized cost of electricity over the life of the project as compared to the cost under the existing ITC normalization option. In order to take advantage of this "opt out" option offered in the IRA, the Commission must specifically approve the "opt-out" option. The Company's calculation above assumes that the full $31.7 million of estimated credit resulting from the normalization opt-out option would be recognized in 2025.[29]

Solar Credits: The IRA provides a PTC option, which may be utilized instead of the existing normalized ITC for solar investments. The Company estimates the PTC option will provide an approximate $0.4 million of additional benefits for customers in 2025 on projected self-build ash pond solar investments compared to the normalized ITC option.

[29] The Company confirmed in response to an informal follow-up that this should state 2023, not 2025.

Note that the Company's table shows the $31.7 million for Energy Storage Credits in 2023, whereas the last sentence in the Company's response to STF-LA-5-114(b) concerning those credits states that: "The Company's calculation above assumes that the full $31.7 million of estimated credit resulting from the normalization opt-out option would be recognized in 2025." In response to a Staff informal request for clarification from the Company about the latter date, the Company confirmed that this should be for 2023, as shown in the Company's table, not in 2025, which apparently was a typo. Accordingly, Staff has reflected the $31.7 million in Energy Storage Credits as a reduction to income tax expense in 2023.

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**Q. DOES THE COMPANY ALSO EXPECT TAX CREDITS FOR EV CHARGERS?**

A. Yes. The Company's response to STF-LA-5-114(b) also indicates that the Inflation Reduction Act extends and modifies the tax credit for alternative fuel refueling property. The Act provides for a 30% investment tax credit for alternative fuel refueling property placed into service through 2032 and increases the credit limitation to $100,000 per EV charger. The Company is required to normalize the EV charger related investment tax credits over the life of the assets, and has indicated that it expects an additional $0.8 million of total EV investment tax credit amortization in 2022-2025. The Company's response to STF-LA-5-14(b) indicates the amount of ITC amortization that is expected for each year. In general, the annual ITC amortization for each year would reduce income tax expense in that year.

**Q. HAS STAFF REFLECTED A REDUCTION TO INCOME TAX EXPENSE FOR THE EV CHARGER RELATED INVESTMENT TAX CREDIT AMORTIZATION THAT GEORGIA POWER HAS IDENTIFIED AS AN ADDITIONAL $0.8 MILLION OF TOTAL AMORTIZATION IN 2022-2025?**

A. No. Consistent with Staff's recommendation that ratepayers not be required to pay for EV Charger related investment costs projected by the Company for 2023 through 2025, Staff has not reflected amortization of additional EV Charger related ITC as a reduction to income tax expense in the 2023 through 2025 plan years. However, if some portion of the Company's projected investment for EV charging for the 2023 through 2025 plan years were to be allowed to be charged to ratepayers, under those circumstances, Staff believes that reflecting the impact of the amortization of the related ITC from that EV Charger investment as a reduction to income tax expense would be appropriate.

**Q. DID STAFF ASK THE COMPANY ABOUT OTHER POTENTIAL IMPACTS FROM THE INFLATION PROTECTION ACT ON INCOME TAXES?**

A. Yes. Staff data request STF-LA-8-13 asked the Company about a minimum federal corporate income tax provision of the Inflation Protection Act, specifically whether that is expected to have any impact on the Company's income taxes for any plan years. The Company's response to STF-LA-8-13 states that:

> The minimum corporate income tax rate provisions of the Inflation Reduction Act are effective beginning in 2023. The Company is currently awaiting further guidance from the U.S. Department of the Treasury on the corporate minimum tax; however, at this time, the Company does not expect to pay any corporate minimum income taxes for years 2023 through 2025.

Based on the Company's response to STF-LA-8-13, it does not appear that the corporate minimum tax provisions in the Inflation Protection Act are expected to result in the Company paying any corporate minimum taxes for years 2023 through 2025.

**Production Tax Credits**

**Q. DID THE COMPANY HAVE PRODUCTION TAX CREDITS IN 2021?**

A. Yes. The Company's response to STF-LA-2-117 indicates that the Company had $9,878 of Production Tax Credits ("PTCs") related to hydro generation in 2021. The Company's response to STF-LA-2-119 indicates that the Company had PTCs related to hydro units in a carry-forward position at both December 31, 2020 and December 31, 2021 of $743,661.

**Q. DOES THE COMPANY ANTICIPATE PTC'S FROM VOGTLE UNITS 3 AND 4?**

A. Yes. The Company's response to STF-LA-2-118 indicates that it projects receiving PTCs for Vogtle Units 3 and 4 of $26.1 million in the forecasted test year, $58.7 million in 2023 and $127.6 million in both 2024 and 2025. However, that response also indicates that the PTC's for Vogtle Units 3 and 4 are excluded from the Company's filing.

**Q. HAS STAFF MADE AN ADJUSTMENT TO REFLECT PTC'S IN THE TEST YEAR OR PLAN YEARS?**

A. No. The amount of hydro PTCs in 2021 was fairly small and the Company's response to STF-LA-2-118 indicates that $0 PTCs are expected in 2022. While an adjustment could potentially be made to reflect some amount of hydro PTCs in the test year and plan years, it appears that the amount would be de minimus, so Staff has not made an adjustment.

As noted in the Company's response to STF-LA-2-118, PTCs related to Vogtle Units 3 and 4 are expected to be very significant -- the Company projects $58.7 million for 2023 and $127.6 million in both 2024 and 2025, and will need to be factored in when costs for Vogtle Units 3 and 4 are reflected in base rates, i.e., if the projected in-service dates of March 2023 and December 2023, respectively, hold up, in the context of addressing the Vogtle Unit 3 and 4 related rate increase. However, in the context of the current rate case, the in-service costs of Vogtle Units 3 and 4 have been excluded. Staff is therefore not proposing an adjustment to reflect PTCs from Vogtle Units 3 and 4 in the 2024 or 2025 plan years for purposes of computing the Company's base rate revenue requirement in the current case.

**Plant Held for Future Use**

**Q. WHAT AMOUNT OF PLANT HELD FOR FUTURE USE ("PHFFU") HAS THE COMPANY REFLECTED IN RATE BASE?**

A. The Company reflected approximately $106.5 million of PHFFU in rate base in the test year and in 2023, $106.4 million in 2024 and $106.3 million in 2025.

**Q. WHAT AMOUNT OF PHFFU IS SHOWN ON THE COMPANY'S 2021 FERC FORM 1?**

A. The Company's 2021 FERC Form 1 shows $106,608,388 of PHFFU. A copy of that page is presented in Exhibit __(RS/RT-17).

**Q. WHAT IS SHOWN IN EXHIBIT__(RS/RT-18)?**

A. Exhibit RS/RT-18 uses information from the Company's 2021 FERC Form 1 concerning Plant Held for Future Use (see, e.g., Exhibit RS/RT-17) to identify the cost of PHFFU that show an "expected use" date of (1) 2030 or beyond and (2) 2040 or beyond. As shown there, of the $106.6 million of PHFFU, approximately $91.6 million or 86% has an "expected use" date of 2030 or beyond and approximately $64.2 million or 60% has an "expected use" date of 2040 or beyond. If PHFFU were to be included in rate base to earn a full return for investors for multi-decade periods, the cost to ratepayers will add up to significant amounts.

**Q. WHAT ARE STAFF'S CONCERNS REGARDING THE COMPANY'S PHFFU?**

A. Staff is concerned that the "expected use" dates keep getting pushed off further and further into the future, such that land acquired for future use is sitting in the PHFFU account and being included in rate base to earn a return for investors for extended multi-decade periods in some instances. A large portion of the Company's PHFFU at December 31, 2021 for example has projected use dates of 2030 or beyond, and over 60% of the total PHFFU cost is for projects which have "expected use" dates of 2040. Additionally, the PHFFU includes about $22.9 million for a future generating plant site in Stewart County, Georgia; however, the Company has no plans to construct generation there, nor has the Commission approved the construction of a new generating plant at that site. To the extent that the Company does not have firm plans at this time to construct a new generating plant on the Stewart County site within a reasonable planning period, Staff recommends that the Company evaluate whether the costs of that site should be transferred to a non-utility property account.

**Q. DID THE COMMISSION ADDRESS PHFFU IN THE COMPANY'S 2019 RATE CASE IN DOCKET NO. 42516?**

A. Yes. The Commission addressed PHFFU in the Company's 2019 rate case in Docket No. 42516. Specifically, pursuant to the Settlement Agreement reached in that case, as noted in Section 9 (pages 8-9) of the Commission's Short Order Adopting Settlement as Modified, the Commission stated:

> With the exception of easements and right of ways, Generation and Transmission property in Plant Held for Future Use ("PHFFU") that has been held in PHFFU account for 15 consecutive years shall undergo review during the first IRP proceeding the 15th year that such property has been held in PHFFU. Distribution property in PHFFU that has been held in PHFFU account for 15 consecutive years shall undergo review during the first base rate proceeding following the 15th year that such property has been held in PHFFU. In the respective proceeding, the Company will be required to present the specific plan for the property(s) that has exceeded 15 consecutive years in PHFFU. The Commission will decide the matter in that proceeding.

**Q. IS STAFF RECOMMENDING AN ADJUSTMENT TO PHFFU IN THE CURRENT PROCEEDING?**

A. Not at this time. As described in the passage above from the Commission's Short Order Adopting Settlement as Modified in Docket No. 42516, the Company will be required to present a specific plan for any Generation and Transmission properties that have been held in PHFFU for a period that has exceeded 15 consecutive years in the 2025 IRP. In addition, the Commission's directive will also apply to Distribution property that has been held in PHFFU for a period exceeding 15 years in Company's next base rate case proceeding.

# XI. AFFILIATE CHARGES TO GEORGIA POWER COMPANY AND GEORGIA POWER COMPANY CHARGES TO AFFILIATES

## Overview of Affiliate Charges from Southern Company Services and Southern Nuclear Operating Company to Georgia Power Company

**Q. PLEASE DESCRIBE THE COSTS THAT GEORGIA POWER INCURS INDIRECTLY THROUGH CHARGES FROM SOUTHERN COMPANY SERVICES AND SOUTHERN NUCLEAR OPERATING COMPANY.**

A. In addition to the charges that it incurs directly, Georgia Power incurs costs from two affiliated centralized service companies, SCS and SNOC. These two affiliates provide management and technical services to both regulated and non-regulated Southern Company affiliates. These two affiliates charge Georgia Power and the other Southern Company affiliates directly for services provided specifically to each affiliate and then allocate the remaining indirect costs incurred each year to all appropriate affiliates on the basis of various allocation factors.

The SCS cost and allocation methodologies are detailed in the SCS Cost Control and Accountability Manual ("SCS CAM"), which is revised each year to reflect more recent data and changes in the Southern Company affiliate chart. The Company has designated the SCS CAM as Trade Secret information.

The SNOC cost and allocation methodologies are detailed in the SNOC Classification of Accounts Manual ("SNOC CAM"), which is also revised each year to reflect more recent data and any other accounting or allocation changes. The Company does not consider the SNOC CAM to be trade secret information.

**Southern Company Services Charges to Georgia Power Company**

**Q. PLEASE DESCRIBE THE SCS COST ALLOCATION METHODOLOGIES.**

A. SCS provides services to numerous Southern Company affiliates pursuant to Service Agreement contracts entered into between SCS and each of those affiliates, including Georgia Power. The SCS Service Agreement with Georgia Power states that SCS will provide to Georgia Power the following services at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations.

The costs incurred by SCS are tracked through work orders. Work orders are unique accounts in which the costs for various SCS work activities are collected. The costs then are charged from these work orders to the Southern Company affiliates that use those specific services or cause those costs to be incurred by SCS. For those costs that are not directly charged to the various affiliates for services provided specifically to an affiliate or affiliates, SCS applies an allocation factor to each work order. These factors are used to allocate the SCS work order costs to each affiliate that caused the costs to be incurred. For calendar year 2021, SCS used 21 basic allocation factors to charge costs to the various affiliates. We have attached a description of these allocation factors provided by SCS in its Form 60 public filing with the Federal Energy Regulatory Commission ("FERC") as our Exhibit__(RS/RT-21). We do not propose any adjustments for the allocation factors selected and applied by SCS as discussed below.

**Q. DOES SCS REPORT THE COSTS THAT IT CHARGES TO EACH OF THE OTHER SOUTHERN COMPANY AFFILIATES?**

A. Yes. SCS files a Form 60 with the FERC each year, which details the costs that it incurred and the amounts that it charged to the other Southern Company affiliates. SCS reported in its 2021 Form 60 at page 307 that it incurred and billed $1.945 billion in costs. SCS charged Georgia Power $662.99 million of those costs, or 34.09 percent of the total incurred by SCS:

| Description | Amount | Reference |
|---|---|---|
| SCS Total Amount Billed in 2021 | $ 1,944,673,043 | (1) |
| Billed to Georgia Power Company | $ 662,988,379 | (1) |
| | | |
| Percentage of Total SCS Billed to Georgia Power Company | 34.09% | |
| | | |
| (1) SCS FERC Form 60 for year 2021, page 307 | | |

Georgia Power charged the $662.99 million to various capital and expense accounts.

**SCS Allocation Factors Using 2022 Statistics**

**Q. HOW DID THE SCS POPULATE THE ALLOCATION FACTORS IN THE YEARS PRIOR TO 2017?**

A. In the years prior to 2017, for Fixed Percentage Allocations, SCS used statistics that were based on a single year with a one-year lag. For example, in Georgia Power's 2013 rate case in Docket No. 36989, the 2014 SCS allocations in the Company's projected test year in that prior rate case were based on 2012 statistics, thus the charges included in the Company's expenses were based on outdated data. As a result, it was necessary to make an adjustment to the SCS allocation factors using more recent data.

**Q. DOES SCS STILL USE STATISTICS BASED ON A SINGLE YEAR WITH A ONE-YEAR LAG IN DETERMING ITS ALLOCATION FACTORS?**

A. No. As explained in the SCS FERC Form 60 for 2021 at page 402, SCS uses statistics based on previous year statistics. For example, the SCS allocations in 2021 were based on 2020 statistics. In the Company's response to STF-LA-2-111, which asked whether SCS has updated any of its allocation factors for use in 2022, the Company provided supporting calculations for each SCS allocation factor as of May 2022. In Attachment SCS-LA-2-111, the data on which the SCS allocation factors for May 2022 was calculated was based on 2021 statistics.[30]

**Q. DID YOU REVIEW THE SCS CHARGES TO GEORGIA POWER TO ENSURE THAT NO LOBBYING EXPENSE, CHARITABLE CONTRIBUTIONS OR OTHER BELOW-THE-LINE AMOUNTS WERE INCLUDED IN TEST YEAR EXPENSES?**

A. Yes. We confirmed through discovery that SCS identifies all such charges and that Georgia Power did not include these below-the-line amounts in test year expenses.

**Q. DID YOU REVIEW THE SCS CHARGES TO GEORGIA POWER FOR CERTAIN INCENTIVE COMPENSATION COSTS?**

A. Yes. We address this issue in another section of our testimony. It is not limited to the SCS charges to Georgia Power, and also includes similar costs incurred directly by

[30] The Excel file attachment to the response to STF-LA-2-111 provided supporting calculations for each SCS allocation factor as of May 2022, which was based on 2021 statistics.

Georgia Power, and incentive compensation costs charged to Georgia Power Company from Southern Nuclear Operating Company.

**Southern Nuclear Company Charges to Georgia Power Company**

**Q. PLEASE DESCRIBE THE SNOC COST ALLOCATION METHODOLOGIES.**

A. SNOC provides services to both Georgia Power and Alabama Power Company in support of the Hatch, Vogtle and Farley nuclear generating facilities in Georgia and Alabama. The Service Agreement between SNOC and Georgia Power states that SNOC will provide the following nuclear-related services to Georgia Power at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations.

Similar to SCS, SNOC collects the costs it incurs in numerous work orders. For many of the work orders, the costs are charged directly to the individual generating facilities because the SNOC activities are performed specifically for certain facilities. The remaining costs are charged two-thirds to Georgia Power and one-third to Alabama Power based on the number of plant sites (see additional discussion below). SNOC has other allocation factors available, but uses the number of plant sites for administrative simplicity.

**Q. DOES SNOC HAVE ANY SUBSIDIARIES?**

A. Yes. On February 23, 2006, SNOC organized a wholly-owned subsidiary, Southern Nuclear Development, LLC ("SND"), to manage Southern's new nuclear generation development activities. On July 1, 2006, SNOC organized Southern Nuclear Services, LLC ("SNS"), a wholly-owned subsidiary. SNS assumed a contract with Pooled Equipment Inventory Company ("PEICo") from Southern Management Development, Inc., an affiliated company. The contract provides for SNS to receive a fixed monthly fee from PEICo in exchange for providing the following services: project management; quality assurance; storage, maintenance, and insurance; and administration.

**Q. ARE SOME OF SNOC'S COSTS ALLOCATED TO THOSE SUBSIDIARIES?**

A. Yes.

**Q. DOES SNOC ALSO REPORT THE COSTS THAT IT CHARGES TO GEORGIA POWER AND ALABAMA POWER?**

A. Yes. SNOC also files a Form 60 with the FERC each year, which details the costs that it incurred and the amounts that it charged to Georgia Power and Alabama Power and other affiliates such as SCS, and the SNOC subsidiaries, SND and SNS. SNOC reported in its 2021 Form 60 at page 307 that it incurred $1.172 billion in costs. SNOC charged Georgia Power $906.2 million of those costs, consisting of both capital and expense amounts.

**Q. HOW DOES SNOC ALLOCATE COSTS?**

A. As described on page 402 of SNOC's 2021 FERC Form 60, for SNOC corporate departments and functional areas benefitting all operating plants, the SNOC costs are allocated using a Plant Basis Method, which is determined by dividing one plant by the total number of plants. The use of the number of plant sites allocation factor generally benefits Georgia Power through lower charges compared to alternative allocation factors that are available and could have been used.

**Q. BASED ON SNOC CHARGES BEING ALLOCATED USING THE PLANT BASIS METHOD, DOES GEORGIA POWER CURRENTY RECEIVE A TWO-THIRDS ALLOCATION OF SNOC CHARGES BASED ON HAVING FOUR OF THE SIX OPERATING NUCLEAR UNITS?**

A. Yes. As noted above, SNOC provides services to both Georgia Power and Alabama Power Company. Georgia Power owns Hatch Units 1 and 2 and Vogtle Units 1 and 2 whereas Alabama Power Company owns Farley Units 1 and 2. As a result, since Georgia Power owns four of the six nuclear units currently operating, it receives a two-thirds share of the SNOC allocated costs.

**Q. HAS THE COMPANY INDICATED WHEN IT EXPECTS VOGTLE UNITS 3 AND 4 TO ACHIEVE COMMERCIAL OPERATION?**

A. Yes. In its response to STF-LA-2-118, the Company stated that the projected in-service date for Vogtle Unit 3 is March 2023 and the projected in-service date for Vogtle Unit 4 is December 2023.

**Q. WILL THE SNOC PLANT BASIS ALLOCATION FACTOR BE UPDATED WHEN VOGTLE UNITS 3 AND 4 ACHIEVE COMMERCIAL OPERATION?**

A. Yes. According to the response to STF-1-43 in Docket No. 44265, upon Vogtle Unit 3 achieving commercial operation (currently expected to be March 2023), the SNOC allocations will be as follows:

| | |
|---|---|
| Alabama Power Plant Farley Unit 1 | 14 1/7% |
| Alabama Power Plant Farley Unit 2 | 14 1/7% |
| Georgia Power Plant Hatch Unit 1 | 14 1/7% |
| Georgia Power Plant Hatch Unit 2 | 14 1/7% |
| Georgia Power Plant Vogtle Unit 1 | 14 1/7% |
| Georgia Power Plant Vogtle Unit 2 | 14 1/7% |
| Georgia Power Plant Vogtle Unit 3 | 14 1/7% |
| Total SNOC Allocation | 100.00% |

In addition, upon Vogtle Unit 4 achieving commercial operation (currently expected to be December 2023), the SNOC allocations will be as follows:

| | |
|---|---|
| Alabama Power Plant Farley | 25% |
| Georgia Power Plant Hatch | 25% |
| Georgia Power Plant Vogtle Units 1&2 | 25% |
| Georgia Power Plant Vogtle Units 3&4 | 25% |
| Total SNOC Allocation | 100% |

**Q. DID YOU REVIEW THE SNOC CHARGES TO GEORGIA POWER FOR THE TEST YEAR?**

A. Yes. We have adjusted for the SNOC charges included in the test year for the stock-based incentive compensation expense. We address the stock-based incentive compensation expense in another section of our testimony.

**Georgia Power Company Charges to Other Affiliates**

**Q. PLEASE DESCRIBE THE SERVICES PROVIDED BY THE COMPANY TO OTHER SOUTHERN COMPANY AFFILIATES.**

A. Georgia Power operates and maintains the generating facilities that are owned by Southern Power Company ("Southern Power") and physically located in Georgia. These Southern Power generating facilities are located at Plants Dahlberg, Franklin and Wansley.

**Q. PLEASE DESCRIBE THE METHODOLOGY EMPLOYED BY GEORGIA POWER TO DETERMINE THE COSTS OR PRICES CHARGED TO OTHER SOUTHERN COMPANY AFFILIATES FOR THE SERVICES IT PROVIDES.**

A. The Company generally charges the cost it incurs to provide the services to the other affiliates, although certain of its service agreement contracts with the other affiliates include a test of that cost against market to guard against subsidization of its non-regulated affiliates. For example, the Company's service agreement with Southern Power states that: "As compensation for such services or the market value thereof, whichever is higher."

Although the methodology for quantifying cost is not defined in the Company's Service Agreement contracts with the other affiliates, we have reviewed the methodology used by the Company for charges to the other affiliates. The Company determines its "cost" on a comprehensive basis. Cost includes the direct costs to provide the services, including a return of and on all investment costs, and indirect costs, including labor payroll taxes, benefits, and other corporate overheads. The overheads include an allocation of administration and general expenses, which in turn include amounts initially charged to Georgia Power by SCS.

**Georgia Power Company Charges to Southern Power**

**Q. DID YOU REVIEW THE COMPANY'S PROCEDURES FOR CHARGING COSTS TO SOUTHERN POWER COMPANY?**

A. Yes. The previous agreement between Georgia Power and Southern Power was terminated in August 2007, and replaced with a new service contract. Under the service contract, the Company provides and bills Southern Power for specifically requested services.

The Georgia Power General Accounting Procedure ("GAP") 58 describes accounting for work performed by Georgia Power Company on behalf of other companies. The methodology used by Georgia Power to charge Southern Power appears to be comprehensive and includes Georgia Power overheads, both those incurred directly by Georgia Power and those incurred indirectly through charges to Georgia Power from SCS.

GAP 58 at pages 1 and 2 states in part that:

> Upon request, the Company may provide services to associated companies within Southern Company. Reference "Requesting Services" for the types of services provided. The associated companies are Southern Company Services, Alabama, Gulf[31] and Mississippi Power Companies, Southern Telecom, Southern Company Management Development, Southern LINC Wireless, Southern Power, and Southern Nuclear. With the acquisition of Southern Company Gas, the associated companies now also include GAS and its subsidiaries.
>
> The Company may also provide resources and employees to companies not part of The Southern Company (non-associated companies). This includes any government agencies, other utilities, industrial businesses, etc.

[31] Gulf Power Company was sold to NextEra Energy on January 1, 2019.

Company policies and guidelines documented in this procedure apply to associated operating companies and non-associated companies. When a particular process varies between the companies, GAP 58 will be the authority.

GAP 58 at page 4 states that:

> In accordance with Georgia Public Service Commission (GPSC) guidelines, Docket No. 9355-U, the Company may provide services, properties and resources to associated companies on an actual cost basis (which includes a provision for applicable overheads).
>
> These services to associated companies, excluding SPC, include but are not limited to: website design, sale of materials associated with a service, printing, communication materials, fleet operations, calibration, substation outages, equipment repair, intercompany awards, training activities, etc.
>
> Per the Services Agreement between SPC and GPC dated August 1, 2007, services available to SPC include labor, environmental, general construction and advisory, property accounting and other services requested by SPC.
>
> For non-associated companies, services available and the cost of those services are in accordance with the contract price & terms.
>
> When specifically requested, the Company may also loan employees to other companies. These employees will be under the sole supervision and control of that company until the assigned work is completed.

GAP 58 at page 5 describes the billing for such services as follows:

> Under a cost plus basis:
>
> - The requesting company pays the amount based on actual charges to the job, which may be more or less than the original estimate. For Southern Company Gas, if costs exceed the original estimate by more than 120%, written approval must be obtained from GAS for the extra costs.
> - Construction services for non-associated companies are billed under this method.
>
> Under contract price billing:
>
> - The requesting company pays the estimated amount, regardless of the actual cost.

- Non-construction services for non-associated companies are billed under this method.

The Company has indicated that it is following the above-described guidance; however, this was not reviewed in detail concerning budgeted amounts for the projected test year or rate year costs.

## XII. INCENTIVE COMPENSATION

**Q. PLEASE IDENTIFY THE SOUTHERN COMPANY INCENTIVE COMPENSATION PLANS, THE COSTS OF WHICH ARE INCLUDED IN THE COMPANY'S TEST YEAR EXPENSES.**

A. Southern Company has one primary incentive compensation plan, the Southern Company Omnibus Incentive Compensation Plan, but three types of incentive compensation programs pursuant to that plan. These programs are the Performance Pay Program ("PPP"), and the Long-Term Incentive Program, which is comprised of Performance Shares Units ("PSU") and Restricted Stock Units ("RSU"). Georgia Power's response to STF-LA-2-78(a)[32] provided the following descriptions of these plans:

| Program Name | Description |
|---|---|
| Performance Pay Program | The Company's annual performance program rewards achievement of operational goals, earnings per share and GPC net income. A target percentage of base pay is established for each employee based on his/her classification and grade level for target-level performance. All employees except a small number of sales-commission employees are eligible to participate. |
| Long-Term Incentive Program | The Long-Term Incentive Program is a long-term, target-based, variable pay program for granting equity compensation awards that are paid in shares of common stock of Southern Company. The objective of the Long-Term Incentive Program is to promote strong long-term business results by rewarding continued employment and value drivers that distinguish our performance in the utility industry. Employees classified as exempt under FLSA with a minimum salary range of $132,299 (Grade 9) or greater are eligible. A long-term performance target percentage of base pay is established for each employee based on his/her grade level. Further, this target percent is allocated between performance shares (70%) and restricted stock units (30%). |
| | |
| | |

[32] See Exhibit RS/RT-7 for copies of Company responses to Staff discovery relating to incentive compensation and stock-based compensation.

**Stock Based Compensation**

**Q. DID THE COMPANY PROVIDE DOCUMENTATION WHICH DESCRIBES ITS LONG-TERM INCENTIVE PROGRAM?**

A. Yes. A copy of the 2022 Southern Company Long-Term Incentive Program ("LTIP") was provided in Trade Secret Attachment STF-LA-2-78 Attachment C to the response to STF-LA-2-78.

**Q. WHAT IS THE PURPOSE OF THE LTIP?**

A. On page 2 of the LTIP, under the heading "Program Purpose" it states:

**[*BEGIN TRADE SECRET*]**

[redacted]

**[*END TRADE SECRET*]**

**Q. PLEASE DESCRIBE THE SPECIFIC STOCK BASED COMPENSATION PROGRAMS.**

A. The PSUs and the RSUs together constitute the Company's long-term incentive compensation programs for higher level employees at Georgia Power, SCS and SNOC. Specifically, as discussed on page 3 of the LTIP, **[*BEGIN TRADE SECRET*]** [redacted]

[redacted] **[*END TRADE SECRET*]**

Georgia Power's response to STF-LA-2-78, attached hereto as Exhibit__(RS/RT-7), provided, among other information, the dollar amounts for the test year ending July 31, 2023 as well as for calendar years 2023, 2024 and 2025 for each of the long-term incentive compensation programs.

**Q. IN PRIOR RATE CASES, THE COMPANY'S LONG-TERM INCENTIVE PROGRAM INCLUDED STOCK OPTIONS. ARE STOCK OPTIONS INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT IN THE CURRENT PROCEEDING?**

A. No. According to the Company's response to STF-LA-2-92, in 2014 the Southern Company discontinued granting stock options and the program is no longer active. As a result, there are no costs related to stock options included in the Company's revenue requirement for the test year ending July 31, 2023 or in the rate plan years 2023-2025 in the current proceeding.

**Q. PLEASE DISCUSS THE PERFORMANCE SHARE UNITS AND HOW THEY FUNCTION RELATIVE TO THE FINANCIAL PERFORMANCE OF SOUTHERN COMPANY.**

A. Page 7 of the LTIP it states that **[*BEGIN TRADE SECRET*]** [redacted][33]

**Q. PLEASE DESCRIBE THE CREDIT QUALITY THRESHOLD GOAL.**

[33] [redacted]

[redacted]

**[*END TRADE SECRET*]**

**Q. PLEASE DISCUSS THE RESTRICED STOCK UNITS AND HOW THEY FUNCTION RELATIVE TO THE FINANCIAL PERFORMANCE OF SOUTHERN COMPANY.**

A. As noted above, **[*BEGIN TRADE SECRET*]** [redacted]

[redacted]

**[*END TRADE SECRET*]**

**Q. HAD GEORGIA POWER REMOVED STOCK-BASED COMPENSATION EXPENSE FROM ITS ANNUAL SURVEILLANCE REPORTS IN THE YEARS SUBSEQUENT TO THE 2013 RATE CASE?**

A. Yes. In Georgia Power's ASRs that were filed for calendar years 2014 through 2019, the Company had removed stock-based compensation pursuant to the Commission's Order in Docket No. 36989. The Commission adopted a Settlement Agreement in its Order Adopting Settlement Agreement dated December 23, 2013. In the Findings of Fact section of that Order, the Commission identified adjustments that had been recommended by Staff in Georgia Power's 2013 rate case and included as provisions to the Settlement Agreement. One such adjustment was to remove stock-based compensation from the Company's ASR going forward. Specifically, on page 9 of the Commission's Order, the Commission, referencing Exhibit A to the Settlement Agreement, states in part:

> Paragraphs 2 and 3 of the Settlement Agreement describe and provide that the Annual Surveillance Report ("ASR") will be filed by the Company by March 15 of the year following the reporting year. The Commission finds

that the adjustments to the Company's initial filing agreed to in the Settlement Agreement, itemized in Exhibit A to the Settlement Agreement and further described above, shall be applied for ASR filing purposes for each year of the ARP. Specifically, to be included in the ASR are the Stock Based Compensation adjustment (line 11) and the Miscellaneous Adjustments (line 15). The Stock Based Compensation adjustment would be reported as the actualized amount and the Miscellaneous Adjustments would be reported as the amount agreed to in the Settlement Agreement of $14,175,000.

**Q. DID GEORGIA POWER REMOVE STOCK-BASED COMPENSATION EXPENSE FROM ITS ANNUAL SURVEILLANCE REPORTS IN 2020 AND 2021?**

A. No. Georgia Power did not remove stock-based compensation from its Annual Surveillance Reports in 2020 and 2021.

**Q. WHAT WAS THE REASON FOR GEORGIA POWER NOT REMOVING STOCK-BASED COMPENSATION EXPENSE FROM ITS ANNUAL SURVEILLANCE REPORTS IN 2020 AND 2021?**

A. The 2019 base rate case settlement in Docket No. 42516 that was approved by the Commission provided for the inclusion of stock-based compensation within retail cost of service under the 3-year alternate plan. However, Staff was not a party to the Company's 2019 rate case settlement, and in fact had recommended the removal of the costs of stock-based compensation from retail cost of service in Docket No. 42516. In its post-hearing brief in Docket No. 42516, Staff stated that the Company incurs the costs of stock-based compensation in an effort to improve Southern Company's financial performance for the benefit of shareholders rather than for the benefit of ratepayers. Specifically, Staff stated:

For instance, the purpose of these incentives is not to improve customer service or meet other regulated utility service requirements. To the contrary, the objectives of maximizing shareholder value on the one hand and minimizing costs to ratepayers on the other hand, are generally opposed to each other. And the fact that maximizing shareholder value frequently does not serve the ratepayer interest of lower rates for the service shows the fatal flaw in the argument that these financial incentives should be seen as merely part of a compensation package, and as such, should be recovered from ratepayers.

**Q. WHAT DOES STAFF RECOMMEND IN THE CURRENT GEORGIA POWER RATE CASE?**

A. As is explained below, Staff recommends that the PSU expense and the RSU expense be removed from retail jurisdictional operating expenses for purposes of establishing the Company's revenue requirement in the current rate case. As a matter of regulatory principle, ratepayers should not be required to pay executive or management compensation that is based on the performance of Southern Company's stock price, or which has the primary purpose of benefitting shareholders and/or to align the interests of participants in the stock-based compensation plans with those of such shareholders.

**Q. SHOULD THE COMMISSION INCLUDE THE PSU AND RSU EXPENSE IN THE REVENUE REQUIREMENT?**

A. No. The stock-based incentive compensation expenses for these programs should not be included in the revenue requirement. The cost of these incentive compensation programs is incurred to improve the Southern Company financial performance for the benefit of shareholders, not to improve customer service or meet other regulated utility service requirements. In fact, the objectives of maximizing shareholder value on the one hand and minimizing costs to ratepayers on the other hand, are generally opposed to each

other. In addition, the hypothetical stock performance pursuant to the PSU should not be considered expense for ratemaking purposes because dividends are considered in the determination of the required return on common equity and stock performance is a component of shareholder return.

**Q. HAVE YOU QUANTIFIED THE EFFECT OF YOUR RECOMMENDATIONS TO DISALLOW THE STOCK-BASED INCENTIVE COMPENSATION EXPENSE FOR THE PSU AND RSU?**

A. Yes. The effect is to reduce Georgia Power's forecasted test year retail operating expenses by $29.172 million. This quantification includes the costs directly incurred by the Company of $10.922 million and the affiliate charges of $13.033million from SCS and $5.217 million from SNOC for these stock-based compensation programs. The quantifications and the source of the data that we relied on for these quantifications are detailed on Exhibit__(RS/RT-2), Schedule E-4.

In addition, as it relates to the Company's alternative rate plan, the effect of removing the expense for the PSU and RSU is to reduce retail operating expenses by $29.063 million, $26.933 million, and $28.230 million for calendar years 2023, 2024 and 2025, respectively. Of these amounts, $10.666 million, $9.641 million and $10.251 million reflect costs directly incurred by Georgia Power. Likewise, $13.096 million, $12.206 million and $12.553 million reflect affiliate charges from SCS and $5.301 million, $5.085 million and $5.425 million reflect affiliate charges from SNOC.

**Q. PLEASE EXPLAIN THE ADJUSTMENT CALCULATION SHOWN ON EXHIBIT__(RS/RT-2), SCHEDULE E-4.**

A. Exhibit__(RS/RT-2), Schedule E-4 has four pages, one for the test year and one for each plan year, showing the adjustment amounts. The total amounts, O&M expense ratio and O&M expense for the PSU and the RSU are from (or were derived from) the Company's responses to STF-LA-2-78, STF-LA-2-79 and STF-LA-2-81 as shown in columns B, C, and D, respectively. For the test year, as shown on Exhibit__(RS/RT-2), Schedule E-4, page 1, line 11, the total adjustment reduces retail operating expense by $29.172 million. Pages 2, 3 and 4 of Schedule E-4 present similar information for plan years, 2023, 2024 and 2025, respectively.

**Performance Pay Plan**

**Q. HAS THE COMPANY INCLUDED AMOUNTS RELATED TO ITS PERFORMANCE PAY PLAN IN THE CALCULATION OF ITS REVENUE REQUIREMENT IN THE FORECASTED TEST YEAR ENDING JULY 31, 2023 AS WELL AS FORECASTED CALENDAR YEARS 2023, 2024 AND 2025?**

A. Yes. The Company has included amounts related to its Performance Pay Plan ("PPP") in the calculation of its revenue requirement for the forecasted test year ending July 31, 2023 as well as forecasted calendar years 2023, 2024 and 2025. Specifically, the table below summarizes the amounts of PPP expense included in Georgia Power's retail operating expense for the forecasted test year ending July 31, 2023 as well as the forecasted calendar years 2023, 2024 and 2025:

| Description | 7/31/2023 ($000's) | 2023 ($000's) | 2024 ($000's) | 2025 ($000's) |
|---|---|---|---|---|
| GPC Directly Incurred PPP Expense Charged to O&M | $ 50,029 | $ 51,033 | $ 53,204 | $ 55,395 |
| SCS PPP Expense Allocated to GPC Charged to O&M | $ 30,874 | $ 31,506 | $ 32,421 | $ 33,561 |
| SNOC PPP Expense Allocated to GPC Charged to O&M | $ 34,433 | $ 36,632 | $ 38,042 | $ 39,330 |
| Total PPP Expense Charged to O&M | $ 115,336 | $ 119,171 | $ 123,667 | $ 128,286 |
| | | | | |
| Source: STF-LA-2-81 | | | | |

As shown in the table above, for the forecasted test year ending July 31, 2023, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $115.336 million. Of this amount, $50.029 million reflects directly incurred PPP expense, $30.874 million reflects PPP expense allocated from SCS and $34.433 million reflects PPP expense allocated from SNOC.

For forecasted calendar year 2023, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $119.171 million. Of this amount, $51.033 million reflects directly incurred PPP expense, $31.506 million reflects PPP expense allocated from SCS and $36.632 million reflects PPP expense allocated from SNOC.

For forecasted calendar year 2024, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $123.667 million. Of this amount, $53.204 million reflects directly incurred PPP expense, $32.421 million reflects PPP expense allocated from SCS and $38.042 million reflects PPP expense allocated from SNOC.

For forecasted calendar year 2025, the Company's revenue requirement includes directly incurred PPP expense in O&M totaling $128.286 million. Of this amount, $55.395

million reflects directly incurred PPP expense, $33.561 million reflects PPP expense allocated from SCS and $39.330 million reflects PPP expense allocated from SNOC.

**Q. HOW WAS THE PPP INCENTIVE COMPENSATION EXPENSE ADDRESSED IN THE COMPANY'S PREVIOUS RATE CASES?**

A. In Georgia Power's 2007 rate case, Docket No. 25060, Staff had recommended that Georgia Power's PPP be reduced to reflect a 100 percent payout, rather than the payout target in excess of 100 percent that Georgia Power had included in the cost of service. The Company's PPP expense was addressed in the base rate proceeding by including the amount proposed by Georgia Power in the cost of service in a settlement. In Georgia Power's 2010 rate case, Docket No. 31958, consistent with the ultimate treatment from Docket No. 25060, Staff accepted the amount proposed for PPP by Georgia Power and did not make an adjustment. Similarly, in Georgia Power's 2013 and 2019 rate cases, (Docket Nos. 36989 and 42516), consistent with the treatment in previous rate cases, Staff accepted the amount proposed for PPP by Georgia Power and did not make an adjustment.

**Q. IS ANOTHER WITNESS FOR STAFF RECOMMENDING AN ADJUSTMENT TO REDUCE THE PPP INCENTIVE COMPENSATION EXPENSE IN THE COMPANY'S CURRENT RATE CASE?**

A. Yes. As discussed in detail in his Direct Testimony, Staff witness Dante Mugrace is recommending an adjustment to remove a portion of the PPP incentive compensation expense from O&M expense in the current proceeding.

## XIII. RATE PLAN PRINCIPLES AND RECOMMENDATIONS

**Multi-Year Rate Plans Versus Traditional Test Year Based Ratemaking**

**Q. HOW IS AN ALTERNATIVE RATE PLAN DIFFERENT FROM A TRADITIONAL RATE CASE ORDER IN TERMS OF EARNINGS ABOVE THE ROE BAND?**

A. Under a traditional rate case order, the Company could earn in excess of an authorized ROE without the ratepayers receiving any rate reductions or any benefit from the application of earnings above the top of the rate band. While the Commission would have the authority to bring the Company in under a Rule Nisi proceeding to reduce its rates, such a proceeding would take a significant amount of time and any order reducing rates would be prospective in nature.

**Q. HOW IS THE ALTERNATIVE RATE PLAN DIFFERENT FROM A TRADITIONAL RATE CASE ORDER IN TERMS OF EARNINGS BELOW THE AUTHORIZED ROE OR LOWER ROE BAND?**

A. Under a traditional rate case order, the Company could earn less than the authorized ROE and would not have any recourse except to file a rate case. Any relief would be prospective in nature.

**Q. HOW DOES TRADITIONAL RATEMAKING COMPARE WITH A MULTI-YEAR RATE PLAN IN TERMS OF WHEN THE COMPANY FILES RATE CASES?**

A. Under a traditional rate case order, the Company would be able to file another rate case whenever it deemed appropriate, and the Commission would have the ability to bring

Georgia Power in for a Rule Nisi to address any overearnings. Some such costs, such as projected increased costs for 2024 and 2025, did not fall within the test year period for this docket, and those costs could have fallen within the test year period of a subsequent rate case filing.

**Q. HOW CAN A MULTI-YEAR RATE PLAN PROVIDE FOR RATE STABILITY?**

A. The accounting order/rate plan can provide ratepayers with rate stability and certain benefits depending on how it is structured. Unless the Company's earnings are projected to drop below the bottom of the earnings band, the Staff proposed alternative rate plan for the current case (similar to previous rate plans) would prohibit Georgia Power from filing for a rate increase until a date provided for in the rate plan. However, the Company would have the option to petition the Commission to increase rates up to lower band if its projected earnings would fall below the lower band. Also, the plan may include step increases which increase rates rather than stabilizing rates. While there are certain advantages in step increases there are tradeoffs including only considering certain cost that are increasing rather than all cost which may include some cost that are decreasing. If a three-year rate plan were to be approved, the Company would be prohibited from increasing rates (other than the two step increases) prior to January 1, 2026, unless it were projected to earn below the bottom end of the allowed earnings band.

**Q. IS HAVING A THREE-YEAR RATE PLAN A BENEFIT TO THE COMPANY?**

A. Yes. Having a rate plan that is approved by the Commission and agreed to by the Company benefits the Company. One benefit is that the first-year revenue requirement

could be based on calendar year 2023, rather than upon the statutory test year ending July 31, 2023. The Company's filing shows a traditional base rate revenue deficiency of approximately $312.2 million based on the July 31, 2023 test year,[34] and a base rate revenue deficiency of approximately $431.4 million[35] for calendar year 2023 as well as revenue deficiencies of $718.0 million and $1.080 billion for 2024 and 2025.[36] Thus, the time shifting of the revenue requirement basis for the first year of new rates has a monetary benefit to the Company.[37]

**Earnings Test and Earnings Band-History**

**Q. HAVE YOU PREPARED A TABLE SUMMARIZING HOW THE EARNINGS SHARING HAS WORKED FOR RATEPAYERS AND THE COMPANY OVER THE PAST SEVERAL YEARS?**

A. Yes. This is summarized in the following table for 2007 through 2021, based on ASR results:

[34] See, e.g., Exhibit__(APA/SPA/ADH/MBR-1 Schedule 2 Traditional Base), page 3 of 3, column (3) line 4.

[35] Id. At column (4), line 4.

[36] Id. At columns (5) and (6), line 4.

[37] Presumably, the time shifting benefit is not limited to the first year. If the Company filed additional traditional cases effective for 2024 and 2025, the test years for those cases would similarly lag the calendar year test years that a 3-year plan would allow.

**Georgia Power Company Historical Earnings Sharing Based on Annual Surveillance Reports**

| Year | ROE Reported in ASR Filing | Lower End of Earnings Band | Upper End of Earnings Band | Adjusted ROE | ROE Above Upper End of Earnings Band | ROE used to Set Revenue Requirement in Rate Case | Adjusted ROE Above ROE used to Set Revenue Requirement | Accounting Adjustment Related to Preventing Under-Earnings | | Earnings Above Top End of Band ($ millions) | Amount Refunded to Customers ($ millions) | Stewart County Regulatory Asset | CCR ARO Regulatory Asset | Amount of Excess Earnings Retained by Company ($ millions) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2007 | 11.36% | 10.25% | 12.25% | 11.52% | N/A | 11.25% | 0.27% | | | | | | | |
| 2008 | 12.11% | 10.25% | 12.25% | 12.20% | N/A | 11.25% | 0.95% | | | | | | | |
| 2009 | 9.75% | 10.25% | 12.25% | 9.75% | N/A | 11.25% | | $ 1.46 | [a] | | | | | |
| 2010 | 10.15% | 10.25% | 12.25% | 10.15% | N/A | 11.25% | | $ 3.30 | [a] | | | | | |
| 2011 | 11.72% | 10.25% | 12.25% | 11.72% | N/A | 11.15% | 0.57% | | | | | | | |
| 2012 | 11.99% | 10.25% | 12.25% | 11.99% | N/A | 11.15% | 0.84% | | | | | | | |
| 2013 | 11.43% | 10.25% | 12.25% | 11.44% | N/A | 11.15% | 0.29% | | | | | | | |
| 2014 | 12.12% | 10.00% | 12.00% | 12.14% | 0.14% | 10.95% | 1.19% | | | $ 16.96 | $ 11.31 | | | $ 5.65 |
| 2015 | 11.52% | 10.00% | 12.00% | 11.55% | N/A | 10.95% | 0.60% | | | | | | | |
| 2016 | 12.46% | 10.00% | 12.00% | 12.49% | 0.49% | 10.95% | 1.54% | | | $ 65.40 | $ 43.60 | | | $ 21.80 |
| 2017 | 11.91% | 10.00% | 12.00% | 12.04% | 0.04% | 10.95% | 1.09% | | | $ 3.55 | $ 2.37 | | | $ 1.18 |
| 2018 | 13.17% | 10.00% | 12.00% | 13.18% | 1.18% | 10.95% | 2.23% | | | $ 153.10 | $ 102.07 | | | $ 51.03 |
| 2019 | 12.88% | 10.00% | 12.00% | 12.88% | 0.88% | 10.95% | 1.93% | | | $ 123.24 | $ 61.62 | $ 48.79 | $ 12.83 | $ - |
| 2020 | 11.89% | 9.50% | 12.00% | 11.89% | N/A | 10.50% | 1.39% | | | $ - | $ - | | | $ - |
| 2021 | 12.09% | 9.50% | 12.00% | 12.09% | 0.09% | 10.50% | 1.59% | | | $ 14.17 | $ 5.67 | | $ 5.67 | $ 2.83 |
| | | | | | | | | | Totals | $ 376.41 | $ 226.62 | $ 48.79 | $ 18.50 | $ 82.50 |
| | | | | | | | | | Percent of Totals | 100.00% | 60.21% | 12.96% | 4.91% | 21.92% |

Notes

[a] $2.2 and $0.972 million restored to the accrued removal cost regulatory liability account in 2010 and 2009, respectively, based on Staff's recommended adjustments.

The Commission's Short Order Adopting Settlement Agreement beginning January 1, 2020, expended the earnings band to 9.5% lower/12% upper. It also changed the sharing percentage to reflect 40% to customers, 40% to regulatory assets, and 20% to the Company.

In 2019, the Company did not retain a portion of the dead band overage. It was used to reduce the Stewart County regulatory asset and to reduce the CCR ARO regulatory asset account

As shown in the above table, the Company has consistently earned well above its authorized ROE in every year except during the Great Recession in 2009 and 2010. In the 2014-2021 period, the Company has reported about $376.4 million of revenues representing earnings above the top end of the ROE band. Over 60 percent of that, or approximately $226.6 million was for refunds to ratepayers, 13 percent, or approximately $48.9 million was allocated to the Stewart County regulatory asset, five percent, or approximately $18.5 million, was allocated to the CCR ARO regulatory asset, while the Company retained the remaining 22 percent, or approximately $82.5 million.

## Staff Rate Plan Recommendations

**Q. HAVE YOU PREPARED A SUMMARY OF STAFF'S RECOMMENDED 2023, 2024 AND 2025 PLAN YEAR REVENUE DEFICIENCY (OR EXCESS) AMOUNTS?**

A. Yes. The following table shows Staff's recommended 2023, 2024 and 2025 plan year revenue deficiency (or excess) amounts.

| Staff Calculated Revenue Requirement Deficiency/(Excess) by Year (Millions of Dollars) | | | | | |
|---|---|---|---|---|---|
| | Exhibit_(RS/RT-2) | | | | |
| Effective Date | Schedule A Reference | 1/1/2023 | 1/1/2024 | 1/1/2025 | Total |
| Traditional Base Rates Revenue Deficiency/(Excess) | Line 10 | $ (109) | $ (2) | $ 199 | $ 88 |
| ECCR Revenue Deficiency | Line 8 | $ 61 | $ 91 | $ 127 | $ 279 |
| DSM Revenue Deficiency | Line 9 | $ 37 | $ 64 | $ 62 | $ 163 |
| Total Deficiency/(Excess) | | $ (11) | $ 153 | $ 388 | $ 529 |

**Q. IS STAFF RECOMMENDING THE RATE INCREASES AND DECREASES SHOWN IN THE ABOVE-TABLE?**

A. No. As shown on Exhibit __(RS/RT-2), Schedule A, on lines 7 and 12, Staff shows revenue excesses for the test year and 2023. Staff is recommending no change for 2023 and that the Company be required to file compliance filings on October 1, 2023 and October 1, 2024 for the step increases to become effective on January 1, 2024 and January 1, 2025, respectively.

**Q. PLEASE EXPLAIN STAFF'S RATE PLAN RECOMMENDATIONS.**

A. As described above in our testimony, Staff recommends that revenue changes for January 1, 2024 and 2025 for base rates as well as the ECCR rates be applied as step adjustments, rather than charged on a levelized basis to retail ratepayers beginning on January 1, 2023. Staff also recommends that the Company continue to update its estimated costs for ECCR and for CCR ARO Compliance cost recovery, and that the Company file by October 1, of 2023 and 2024, respectively, for ECCR and CCR ARO revenue requirements for 2024 and 2025, respectively.

Staff also recommends that an earnings test be applied, with an ROE band of 200 basis points centered around Staff's recommended 9.45% ROE, as described below.[38]

Staff further recommends that earnings above the top end of the earnings band be applied for the accelerated recovery of deferred costs and regulatory assets, rather than the two-thirds/one-third sharing which had been incorporated in some prior rate plans.[39]

**Step Increase Approach**

**Q. DOES STAFF RECOMMEND A STEP-APPROACH FOR THE 2024 AND 2025 INCREASED REVENUE REQUIREMENTS?**

A. Yes. Staff believes that a step-approach involving interim filings during the 2023-2025 three-year plan period would be far preferable to approving a levelized revenue requirement under the circumstances present in the current Georgia Power rate case. The Commission has employed step increases effectively in the context of three-year plans, including for the Company's recovery additional revenue requirements associated with Plant McDonough Units 4 and 5 in compliance with the Commission's 2010 Rate Case Order in Docket No. 31958.

[38] 200 basis point bands centered around a midpoint ROE have previously been used by the Commission in Dockets 25060 and 18300.

[39] For example, in Docket 25060 one-third was used to pay down the ECCR and two-thirds went to rate reductions. In 42516, the Company sharing was limited to 20%.

**Q. WHAT ARE THE REASONS FOR RECOMMENDING A STEP INCREASE APPROACH, RATHER THAN A LEVELIZED APPROACH TO THE THREE-YEAR RATE PLAN?**

A. First, customers should not be required to pay for 2024 and 2025 revenue requirements starting January 1, 2023, i.e., before the related costs have been incurred, especially during a period when the economy could be entering into a recession. Also, the Company has projected that Plant Vogtle Unit 3 will be in commercial operation by March 2023 and Unit 4 by December 2023. Currently, the Company is collecting from ratepayers portions of the financing cost for those units while they are under construction. The Company continues to incur construction costs and AFUDC. While those dates might be delayed, the Vogtle Unit 3 and 4 rate impacts, once more fully recognized, are anticipated to be substantial.[40]

Furthermore, Staff has concerns about some of the large items in the 2024 and 2025 revenue requirements. Under a levelized approach, ratepayers would incur the costs related to these items beginning January 1, 2023. These items include recognition of cost increases that are occurring in 2024 and 2025 beyond levels projected for 2023. These concerns, coupled with the uncertainties about the timing of cost incurrence, warrant a cautious approach to determining appropriate revenue requirements for the Company for the 2024 and 2025 plan years.

[40] Plant Vogtle Units 3&4 being placed into commercial operation could increase base rate revenue requirements by approximately $1 billion per year assuming no additional delays or cost overruns or Commission disallowances. This would be offset by approximately $200 million per year from termination of the Nuclear Construction Cost Recovery tariff.

**Q. PLEASE EXPLAIN ANY POTENTIAL IMPACT ON ENVIRONMENTAL COSTS PROJECTED FOR 2024 AND 2025 FROM ANY CHANGES TO THE RULES AND/OR COMPLIANCE DATES.**

A. The timing and level of certain environmental costs, such as plant retirements and environmental retrofits that have been addressed in the 2022 IRP, could be affected if any revisions are made to environmental regulations, including the compliance date.

**Q. ALTHOUGH THE COMPANY HAS INDICATED THAT IT WOULD PREFER A LEVELIZED THREE-YEAR RATE PLAN, DID THE COMPANY ACKNOWLEDGE THAT A STEP-INCREASE APPROACH COULD BE USED FOR THE INCREASED REVENUE REQUIREMENTS FOR 2024 AND 2025?**

A. Yes. During the hearings on Georgia Power's direct case, the Company acknowledged that estimates can become less reliable the further out into the future they extend. (Tr. 292.) Using a Step-Increase will more accurately reflect the revenue requirement for each year. Moreover, while the Company would prefer its proposed levelized approach, it acknowledged that an alternative would be to step-up the increases over the three-year period covered by the projected test years for 2023, 2024 and 2025. (Tr. 292).

**Q. HAS THE COMMISSION PREVIOUSLY DIRECTED THE COMPANY TO FILE INTERIM RATES THAT WOULD BECOME EFFECTIVE DURING THE TERM OF A THREE-YEAR ACCOUNTING ORDER?**

A. Yes. For example, as provided for in the approved stipulation and Commission Order in Docket No. 31958, the Company filed to increase rates effective in 2012 and 2013. On

November 1, 2011, the Company filed updated Demand Side Management (DSM) Residential and Commercial tariffs for approval. These tariffs were approved by the Commission, allowing the Company to collect its updated DSM revenue requirement. At the same time, the Company also updated its Nuclear Construction Cost Recovery (NCCR) tariff to collect $258.6 million for projected 2012 financing costs associated with Plant Vogtle Units 3 and 4. The effective date of those tariff updates was January 1, 2012.

**Q. THE COMPANY IS REQUESTING $2.9 BILLION IN ADDITIONAL REVENUES FOR THE THREE YEAR PERIOD 2023 – 2025 IN THIS PROCEEDING. WHAT SHOULD THE COMMISSION CONSIDER WHEN EVALUATING THE COMPANY'S REQUEST?**

A. The Company's proposed base rate increase is the first of four increases customers will be subject to during 2023 and 2024. The other three increases are Vogtle Unit 3 being placed in service in 2023, fuel rate increase in 2023, and Vogtle Unit 4 being placed in service in 2024. Staff has estimated the total impact on a typical residential customer of the Company's requests could be in the range of $55 to $60 per month or approximately 45 percent increase. Some of the increases are for cost recovery of items such as fuel that are mandatory. Other increases are for recovery of capital investment proposed in this rate case that is discretionary. The Commission may want to closely scrutinize the discretionary costs in this proceeding so to mitigate the cumulative impact of the four increases in customer bills in the 2023 through 2025 rate plan period.

**Q. IN PAST DOCKETS THE COMMISSION HAS APPROVED ANNUAL STEP INCREASES BETWEEN BASE RATE CASES. WHAT SHOULD THE COMMISSION TAKE INTO ACCOUNT IF IT APPROVES ANNUAL STEP INCREASES UNDER A THREE YEAR ANNUAL ACCOUNTING PLAN IN THIS PROCEEDING?**

A. The Company is proposing a very large increase in rate base over the three period 2023 – 2025 tied to large annual capital investment. Given the Company's history with capital projects, some the capital investment may not be placed in rate base as the Company has forecast. If the Company were to overestimate how quickly capital projects would be completed, the Company's rate base would also be overestimated. This would result in rates substantially higher than necessary to allow the Company an opportunity to earn a fair return. Staff recommends the Company provide actual detailed retail rate base as of September 30 of each year and revised detailed projected retail rate base for upcoming year(s) in step increase filings.

**Application of Earnings Above Top End of Band**

**Q. PLEASE ADDRESS THE STAFF'S RECOMMENDATION CONCERNING EARNINGS SHARING WITHIN THE AUTHORIZED EARNINGS BAND.**

A. As part of the alternative rate plan, Staff recommends that an earnings sharing mechanism should continue to apply, but with certain modifications/improvements from how it has been applied under the Stipulation in Georgia Power's last rate case. While Georgia Power's earnings band in the past has been a 200 basis point range in its last three rate cases, Staff recommends narrowing of the earnings band. For purposes of this

plan Staff recommends a band of 8.45% to 10.45% which would allow the Company to retain all revenues up to 1.0% above Staff's recommended authorized ROE.

**Q. HOW DOES STAFF RECOMMEND THAT EARNINGS ABOVE THE TOP END OF THE BAND BE APPLIED?**

A. As noted above, Staff proposes an ROE band of 8.45% to 10.45% above which is 100 basis points below and above the 9.45% ROE recommended by Staff witness Gorman. Any earnings above the band should be used to pay down Georgia Power's regulatory assets. This band is symmetrical in terms thresholds unlike the previous band of 9.5% to 12.0% with a set point of 10.5%. This band strikes a more equitable balance between the ratepayers and the Company. The consequences of breaching the band under Staff's proposal would also be more equitable. The lower band effectively places a floor underneath the Company's earnings – guaranteeing the Company a minimum return. It is only fair that all earnings that exceed the upper band be retained to the benefit of customers.

## XIV. SUMMARY OF STAFF RECOMMENATIONS

**Q. PLEASE SUMMARIZE STAFF'S RECOMMENDATIONS.**

A. Staff shows a revenue excess for the test year ending July 31, 2023 and for calendar year 2023. Staff recommends no traditional base rate change for January 1, 2023. Staff recommends that the Company file compliance filings on October 1, 2023 for a January 1, 2024 step increase and on October 1, 2024 for a January 1, 2025 step increase.

Staff has made the following recommendations:

1. Accept the adjustments identified by the Company in its supplemental filing.
2. Accept the adjustments described in our testimony for the test year and each plan year for calculating the revenue requirement excess or deficiency (or excess) for traditional base rates (as shown in Exhibit __RS/RT-2), for the ECCR (as shown in Exhibit __RS/RT-3), for DSM (as shown in Exhibit __RS/RT-4), for Municipal Franchise Fees (as shown in Exhibit __RS/RT-5), and for CCR ARO Compliance (as shown in Exhibit __RS/RT-6).
3. The traditional revenue requirement for Georgia Power in this rate case should be determined based on the use of the Commission-ordered test year ending July 31, 2023.
4. The appropriate traditional test year average retail rate base is $24.039 billion which is $21.265 million higher than the Company's proposed traditional test year average retail rate base of $24.018 billion.

5. The appropriate traditional test year retail operating income is $1.709 billion, which is $193.069 million higher than the Company's proposed test year traditional test year retail operating income of $1.516 billion.
6. The appropriate traditional test year overall rate of return for Georgia Power in this case that Staff used 6.84% and includes a fair return on equity of 9.45% and the capital structure as recommended by Staff witness Michael Gorman.
7. The appropriate income expansion factor to be used for ratemaking purposes in the test year in this case is 74.606% and 74.602%, 74.596% and 74.593% for 2023, 2024 and 2025, respectively.
8. That rates be set using the traditional test year ratemaking components.
9. That the Company's proposed 2023-2025 levelization revenue requirement adjustment of $426.4 million to derive a levelized revenue deficiency amount of $738.7 million per year for 2023-2025 (not including CCR ARO Compliance) not be adopted. Rather, Staff recommends that a step-increase approach be used if a three-year rate plan is adopted.
10. That current rates be maintained through 2023.
11. That the revenue excess in 2023 be used for accelerated recognition of deferred costs in 2023 up to the amount of the revenue excess.
12. Continuation of the existing DSM tariff rider, reflecting Staff's carrying cost rates and Staff's recommended cost of capital.
13. Prior to requesting ECCR cost recovery each year, the Company should refine the estimate as much as possible.

14. That the Commission not pre-approve a level of ECCR cost recovery for years 2024 and 2025 in the current rate case, but rather that the Company making an annual compliance filing to update the ECCR spending and estimates each year on October 1 of the preceding year for ECCR rates to become effective the following January 1.

15. That the Commission not pre-approve a level of CCR ARO cost recovery for years 2024 and 2025 in the current rate case, but rather that the Company making an annual compliance filing to update the CCR ARO spending and estimates each year on October 1 of the preceding year for CCR ARO rates to become effective the following January 1.

16. Prior to requesting CCR ARO cost recovery each year, the Company should refine the estimate as much as possible.

For the rate plan, Staff also recommends:

- an earnings band of 8.45% to 10.45%, i.e., extending 100 basis points below and above Staff's recommended ROE of 9.45%.
- application of earnings above the 10.45% top end of Staff's recommended earnings band to the recovery of Company deferred costs and regulatory assets.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

MR. WALSH: And, Madam Chair, I would ask that the errata to their testimony be marked for identification with the next staff exhibit number, which I believe is Staff Exhibit No. 11.

(The document referred to was marked for identification as Staff Exhibit 11.)

MADAM CHAIR PRIDEMORE: So moved. So marked.

MR. WALSH: Madam Chair, if Mr. Thomas could approach, he can circulate a copy of that errata for the Commissioners and to the parties.

MADAM CHAIR PRIDEMORE: You may approach.

BY MR. WALSH:

Q Mr. Trokey, did you and Mr. Smith also prefile or cause to be prefiled 27 public disclosure exhibits, which were marked as RS/RT-1 through 27?

A (Witness Trokey) We did, yes.

Q Okay. Do you have any changes or corrections to make to those exhibits at this time that were not already identified in the errata?

A (Witness Trokey) No.

Q Okay. On November 3rd, 2022, did you file two supplemental exhibits marked as RS/RT-28 and 29?

A (Witness Trokey) Yes.

Q Mr. Smith, could you briefly explain why you filed those supplemental exhibits?

A (Witness Smith) Yes. Some information came in after our testimony had been finalized concerning company responses to some informal inquiries that staff had made to obtain better information in order to address a couple of the staff witness recommendations. One batch pertained to electric vehicles and the other one pertained to transmission and distribution capital spending. So we wanted to get those in to have a more complete record.

Q Thank you.

MR. WALSH: Madam Chair, I ask that the public disclosure version of the exhibits RS/RT 1 through 29 be marked for identification with the next 29 staff exhibit numbers, which I believe would be 12 through 30.

MADAM CHAIR PRIDEMORE: So marked.

MR. WALSH: Thank you.

(The documents referred to were marked for identification as Staff Exhibits 12 through 40.)

BY MR. WALSH:

Q Mr. Trokey, did you and Mr. Smith also prefile or cause to be prefiled 140 pages of trade secret testimony in question-and-answer form on October 20th, 2022?

A (Witness Trokey) Yes.

Q Other than the corrections that were set forth in the errata, are there any changes or corrections that you

would like to make at this time to your prefiled trade secret information?

A (Witness Trokey) No, we do not.

Q If I were to ask you the same questions that are presented in the prefiled trade secret testimony, your answers would be the same, noting the changes in the errata?

A (Witness Trokey) Yes.

Q Okay. Did you also prefile or cause to be prefiled trade secret exhibits, along with the trade secret testimony?

A (Witness Trokey) Yes.

Q Do you have any changes or corrections to the trade secret exhibits that aren't already noted in the errata?

A (Witness Trokey) We do not.

MR. WALSH: Okay. Madam Chair, I would ask that the prefiled trade secret testimony of Mr. Trokey and Mr. Smith, along with the trade secret exhibits, be marked for identification as Staff Exhibit No. 31?

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 41.)

BY MR. WALSH:

Q Mr. Smith, did the staff prepare a summary of

its testimony?

A (Witness Smith) Yes, we have a summary.

Q And did you also prefile demonstrative exhibits in connection with the -- the testimony?

A (Witness Smith) We had five demonstrative exhibits.

MR. WALSH: Madam Chair, I would ask that the panel be permitted to proceed with the summary of its testimony at this time.

MADAM CHAIR PRIDEMORE: Please go ahead.

MR. SMITH: Good morning, Chair and Commissioners.

The scope and purpose of our testimony covers several areas. We present the staff's overall traditional rate case revenue requirement position for Georgia Power Company for the test year ending July 31st, 2023, as well as staff's revenue requirement recommendations for calendar years 2023, 2024 and 2025, which are the years covered in the company's proposed Alternative Rate Plan.

Our starting point for the analysis was the company's original rate case filing and the company's updates to its filing which were filed on August 22nd, 2022. Referring to Smith/Trokey Demonstrative Exhibit 1, the company's originally filed request for

rate plan years is summarized there. That is also shown on Table B from page 11 of our direct testimony.

As shown there, for the three plan years, 2023 through 2025, the company's requested increased revenues which total to about $2.815 billion. The company's supplemental filing, which is summarized on Table C from page 12 of our direct testimony, and is also shown in Demonstrative Exhibit 1, shows the updated totals of 889 million for 2023, 996 million for 2024, and 1.041 billion for 2025, which total to about 2.926 billion in increased revenues for that three-year plan period.

A comparison without the municipal franchise fee revenue requirement component is presented in Demonstrative Exhibit 4. Staff's equivalent numbers are negative 11 million, positive 153 million and positive 388 million for plan years 2023, 2024 and 2025, respectively, which total the 529 million. The 529 million is about 2.329 billion less than the comparable company amount of 2.858 billion.

The staff's adjusted results for the test year and for the three years in the 2023 through 2025 plan period also are shown on Exhibit RS/RT-2 that was filed with our direct testimony. Demonstrative

Exhibit 2, which was based on Exhibit RS/RT-2 pages 5 through 8, summarizes the staff's adjustments for the test year and each plan year. Page 1 of 5 of that demonstrative exhibit summarizes the staff adjustments by staff witness panel.

To illustrate the sponsorship of various adjustments based on recommendation of the various staff witness panels, we will refer to staff's 2023 plan year adjustment amounts. As shown on Demonstrative Exhibit 2, on line 8 in Column B, staff's 2023 adjustments totaled to a revenue requirement impact of approximately 595.448 million. Of that approximately $595 million amount, the breakout of the approximate revenue requirement impacts is summarized by staff witness panel to show that.

About 292.3 million of the staff's adjustments to the 2023 plan year are the result of staff witness Michael Gorman's recommendations for rate of return and capital structure.

About 30.5 million of revenue requirement impact to the 2023 plan year are the result of Wired Group recommendations concerning transmission and distribution capital spending and the Distributed Energy Resource Management System, or DERMS,

D-E-R-M-S.

About 5.7 million results from the recommended adjustments to revenue at current rates from staff witnesses Steve Baron and Leah Wellborn.

About 58.7 million results from the adjustments that we are sponsoring on the Smith/Trokey panel.

About 156.5 million results from adjustments to O&M expense that are recommended by staff witness Dante Mugrace.

We should note that staff adjustment E-15 for O&M expense for EV infrastructure with a 2023 revenue requirement impact of about $2.5 million was listed in Demonstrative Exhibit 2 as being sponsored by Mr. Mugrace. However, the Smith/Trokey panel covered that adjustment in our direct testimony and we are available to address questions about that adjustment.

About 51.7 million results from the recommendations for new depreciation rates that are sponsored by staff witness Lance Kaufman. We applied the new depreciation rates recommended by Mr. Kaufman to identify impacts on depreciation expense and fallout impacts on accumulated depreciation.

As shown on page 1 of 5 of Demonstration Exhibit 2, line 8, staff's adjustments reduce the test year revenue requirement by about 534.1 million;

reduce the 2023 plan year revenue requirement by about 595.4 million; reduce the 2024 plan year revenue requirement by about 752.6 million; and reduce the 2025 plan year revenue requirement by about 911.4 million.

Demonstrative Exhibit 3 shows the staff adjusted results for each of the three plan years as summarized by the traditional base rate revenue requirement deficiency or excess, the ECCR revenue requirement deficiency, and the DSM revenue deficiency.

For 2023, staff shows a net revenue excess of about 11 million; for 2024, a net revenue deficiency of about 153 million; and for 2025 a net revenue deficiency of about 388 million. The total net revenue deficiency for the plan years 2023 through 2025 based on staff's adjusted results is about 529 million. These amounts are exclusive of the MMF revenue requirement.

Demonstrative Exhibit 4 presents a comparison of the company's adjusted results and staff's adjusted results for the test year and each plan year, excluding the MMF revenue requirements. For the test year, in contrast with the company's revenue deficiency of about 460 million, staff shows a

revenue excess of about 87 million, which is about 546 million less than the company's amount.

Comparison of the staff and company recommended amounts for each plan year, exclusive of MMF, are also presented in Demonstrative Exhibit 4. For the plan years, instead of the company's requested increases, which total about 2.858 million without the MMF, staff shows revenue increases of about 529 million, which is about 2.329 billion lower for the 2023 through '25 alternative rate period.

As previously mentioned, we present staff's adjusted traditional rate base revenue requirement in our Exhibit RS/RT-2. We present staff's adjusted revenue requirement for the company's Environmental Compliance Cost Recovery in our Exhibit RS/RT-3.

We present staff's adjusted Demand Side Management Tariff Revenue Deficiency for the test year and for plan years 2023 using information from staff witness Jamie Barber. Our RS/RT-4 also presents information on DSM revenue requirements for plan years '24 and '25; however, the DSM revenue requirements for those years are not being set in this rate case and will be established in annual filings from the company.

We recalculate the Municipal Franchise

Fee-related revenue deficiency in our Exhibit RS/RT-5.

We address the revenue -- revenue component of coal combustion residuals asset retirement obligation in our Exhibit RS/RT-6.

The CCR ARO revenue requirement uses a three-year amortization approach that is similar to the company's proposal. The cost of capital being recommended by staff witness Gorman impacts the amount of CCR revenue requirement that we have calculated on Exhibit RS/RT-6.

Moving on to another topic, we address affiliated transactions. Staff's review of Georgia Power's affiliated transactions included review of the charges that Georgia Power receives from a number of affiliates, such as Southern Company Services and Southern Company Nuclear.

One of the Southern Nuclear cost allocations to Georgia Power Company is based on the number of nuclear units on the Southern system. Currently there are six nuclear-generating units: Vogtle 1 and 2, Hatch 1 and 2, and Farley 1 and 2. Georgia Power owns four and Alabama Power owns two.

When Vogtle Units 3 and 4 go into commercial operation, which the company's website indicates is

**expected to be in the first quarter of 2023 and the third or fourth quarter of 2023, respectively, that will change the Southern Nuclear cost allocation.**

**Georgia Power's allocation will change from the current 4/6ths, to 5/7ths, and eventually to 6/8ths, accordingly. The operating costs for Vogtle Units 3 and 4 are not included in this rate case, but will be addressed in future filings from the company.**

**Concerning income taxes, our direct testimony addresses various income tax issues, including the impacts from the Tax Cuts and Jobs Act of 2017, which reduced the federal corporate income tax rate from 35 percent to 21 percent, and the Inflation Reduction Act, which became law in August '22 and has provisions that could provide tax credits for certain types of investments, which generally become effective starting in 2023.**

**Our general conclusion is that income taxes appear to have been appropriately handled. We have adjusted income taxes for impacts from staff's adjustments to expenses that affect taxable income, and to reflect the expected impact from tax credits that were enabled by the Inflation Reduction Act, which became law after the company filed its rate case.**

On Exhibit RS/RT-2 and Schedule E-38, we have made an adjustment to reflect the expected impact from energy storage and solar federal income tax credits. In Exhibit RS/RT-26, which was filed with our direct testimony, that included the company's responses to various staff data requests, including expected impacts from the Inflation Reduction Act, including the impacts from various tax credits.

It should be noted, as we discuss on pages 98 -- 97 and 98 of our direct testimony, that Georgia Power is also projecting additional federal income tax credits relating to electric vehicle infrastructure investment.

We did not reflect the impact of the EV-related tax credits to be consistent with the staff recommendation that EV investment costs related to the Make Ready and Community Charging programs not be charged to the general body of Georgia ratepayers who do not use those facilities.

Finally, concerning the alternative rate plan, our direct testimony presents staff's recommendations for an alternative rate plan. To put the alternative rate plan in context, staff has presented historical information on earnings sharing in a table that is presented on page 130 of our direct testimony, that

was also reproduced in Demonstrative Exhibit 5. That table covers the years 2007 through 2021. That information is based on amounts reported in the company's annual surveillance reports.

For the years 2014 through 2021, as shown in that table, the company had approximately 376.4 million in earnings above the top end of its earnings band, of which about 226.6 million was refunded to customers, 48.8 million was applied to recovery of the Stewart County regulatory asset, about 18.5 million was applied to the CCR ARO regulatory asset recovery, and about 82.5 million was retained by the company.

Demonstrative Exhibit 5 also includes some high-level calculations of the amount of revenues collected above the ROE set point from 2014 through 2021, which amount to about $1.613 billion.

The alternative rate plans have been somewhat beneficial to customers and very beneficial to the company. Staff recommends, if a three-year rate plan is approved in the current case, that it be based on annual step adjustments and not on a levelization of revenue requirements that have been projected by the company into the future for calendar years '24 and '25.

**Staff recommends that the Commission reject the company's proposed levelization of the revenue requirement for the three years 2023 through 2025, and rates to become effective January 1st, 2023.**

**Customers should not be required to pay for 2024 and 2025 revenue requirement changes starting on January 1st, 2023. Staff believes that a step approach involving interim filings for the 2024 and 2025 portions of the three-year rate plan period would be more reasonable and would be preferable to approving a levelized revenue requirement under the circumstances present in the current Georgia Power rate case.**

**Staff recommends that the company make compliance filings on October 1st, 2023 and 2024 to implement the step increases in rates to be effective on January 1, 2024 and 2025, respectively.**

**As part of the alternative rate plan, staff recommends that an earnings-sharing mechanism should continue to apply, but with certain improvements to strike a more reasonable balance between customers and the company.**

**While Georgia Power's earnings band in some of its past rate cases has used a 200-basis-point range, and the current band is 250 basis points, from 9.5**

percent to 12 percent.

For purposes of the 2023 through 2025 rate plan, staff recommends a band of 200 basis points, from 8.45 percent to 10.45 percent, with the band being symmetrical around the 9.45 percent return on equity that is being recommended by staff witness Gorman.

Staff recommends that all of the earnings above the top end of the band be credited against deferred cost recovery, rather than being split on the basis of a one-third to the company, two-thirds to ratepayers basis.

That concludes our summary.

MADAM CHAIR PRIDEMORE: Questions from Commissioners?

VICE-CHAIRMAN ECHOLS: Yeah. A couple.

Thank you, Madam Chair.

Now, on page 135 you mentioned the 45 percent increase from the three contributors: The rate case, the Vogtle, and the fuel. So what impact on that 45 percent would the suggested ROE that you all are offering, that band of 8.45 to 10.45, on 137 where you mentioned that, what impact would that have on the 45 percent?

Would it knock it down to 43? 41? Do you have

a -- do you have a number that if we adjusted that band down?

MR. SMITH: We don't have a number at our fingertips. The band itself would not just solely affect that, but the set point would. So using staff witness Gorman's 9.45 versus the company's requested ROE, which I think was about 11 percent, that would result in lowering the revenue requirement in this base rate case.

VICE-CHAIRMAN ECHOLS: So let me just ask you a general question. In times of rising interest rates, which we haven't seen really over the last decade, would utility ROEs typically go up or down in times of rising interest rates just as a matter of principle?

MR. SMITH: I think that's probably a better question for staff witness Gorman. I think in general some of the cost of capital estimation methods, like the CAPM method, uses a risk-free cost, plus an increment for risk above that rate. So if interest rates go up, the interest-free rate would tend to go up in accordance with the general market. But those questions would probably be more appropriately directed to staff witness Gorman, who is sponsoring the ROE.

**VICE-CHAIRMAN ECHOLS: All right. So in 2016 we didn't have a rate case, as you may remember, due to the acquisition of AGL by Southern Company. That was part of the -- part of the deal there.**

**And, in fact, we rebated fuel money twice to customers. I mean, it was a very great time for customers in '15 and '16.**

**So, in your opinion, was skipping that rate increase part of the culprit now?**

**Is it part of what's got us into this 45 percent increase that we're looking at?**

**MR. SMITH: I don't think so. I think what's got us into this current situation are a number of factors. The company has made a lot of capital investment, which is being reflected to some extent in this base rate case.**

**In terms of the impact of fuel prices, those have gone up a lot in 2022. We've had a pretty good run of several years with extremely low natural gas prices, which has helped save customers a lot. Billions of dollars in fuel costs.**

**But that era has now ended, you know, with Russia's invasion of Ukraine and prices for natural gas and ONG just skyrocketing. You know, that -- it looks like that's going to be around for a while now**

with higher fuel costs.

And costs of other types of fuel has gone up, you know, similar -- not necessarily in the exact same trajectory, but just about every type of fuel has gone up. Coal, you know, fuel oil, gasoline prices. I mean, everybody is seeing that whenever they -- if they're still driving a gas-fueled vehicle every time they pull into the gas station. So fuel prices have gone up and it looks like they're going to stay up for a while.

The company's investment and increases in operating expenses I think are what are contributing a lot to the current traditional base rate case -- rate increase request.

VICE-CHAIRMAN ECHOLS: So in 2019 in our rate case we didn't really get a heads-up that there were massive grid upgrades that were going to be needed in the future. Not that I remember. Where the sky is falling and we've got to do all of this stuff or we're putting our grid in jeopardy.

Do you have any theory on why we didn't get that heads-up then and maybe start making adjustments earlier?

MR. SMITH: I think the 2019 case was based on the company's budgets and forecasts for 2020, 2021

and 2022. And they did have investments in there for T&D. So, I mean, I recognize that the investment level in T&D is, you know, different in the current case.

And there's a staff panel -- I call them lawyer group, but it's basically Paul Alvarez and, I think, one other person.

MR. TROKEY: Dennis Stephens.

MR. SMITH: Yeah. And they'll be up later. But they're probably in a better position to address investments in the T&D grid.

VICE-CHAIRMAN ECHOLS: All right, all right. One more question for now. Item 10, which is on line 17 on page 139 where you're listing recommendations, you suggest keeping current rates in place through 2023. You're talking about the current rates that we have today; is that right?

MR. SMITH: Well, the rates in 2023 would be set in this rate case.

VICE-CHAIRMAN ECHOLS: Uh-huh.

MR. SMITH: So as part of a three-year rate plan, 2023 would be the first year in that three-year rate plan. And our testimony of this staff panel is recommending that the Commission use its discretion and try to keep the 2023 portion of that rate plan

down as low as possible.

We've made a bunch of adjustments and there's also this issue of whether you should levelize the entire three-year revenue requirement and kind of front load it into 2023.

We're recommending that you don't levelize the entire three-year rate plan revenue requirement, but that you try to keep 2023 as low as you can and then they have step increases for 2024 and 2025. So I think that's what that point is referring to.

VICE-CHAIRMAN ECHOLS: And it's because of the trifecta of increases; right? Vogtle, plus the fuel?

Is that your primary rationale for suggesting that?

MR. SMITH: We're cognizant that there will be further increase for Vogtle Unit 3 and 4, and plus for fuel cost increases. But even within the context of this base rate increase request, the Commission can minimize the impact on 2023 by adopting the staff recommendation to use a step-increase approach, rather than the company's proposal for levelizing the entire three-year increase into a much larger rate increase which would take effect in January 1st of 2023.

VICE-CHAIRMAN ECHOLS: All right. Thank you

very much.

COMMISSONER McDONALD: Mr. Smith, you talked about fuel costs. And we don't have to have too long of a memory to reflect back when natural gas just -- we can say months ago, not necessarily years ago -- was in the $2.75, $3 range. And, of course, the cost of gasoline, et cetera, and oil.

You tiptoed around those increases to -- very carefully. Would you consider saying that it's caused by the national administration that we've seen these energy costs increase so rapidly over a short period of time?

MR. SMITH: I think there's a variety of causes to that. I know for a while there we were, like, producing a lot more energy in the country. And I think that, you know, the additional drilling has been maintained, but they haven't gone ahead and drilled a lot of new wells to get more natural gas and oil, which is available. So they somewhat maintained, but not aggressively gone after additional energy sources that are available within the U.S.

Obviously, the -- Russia's invasion of Ukraine has caused havoc in the world energy markets. Back in -- I think it was January or February of 2021,

Texas had this big winter weather event. A lot of their infrastructure froze up. They refer to that as Winter Storm Uri.

But during, like, about a week, natural gas prices just went insanely high, if you could even get natural gas out of certain producing basins, such as the Permian basin.

So a lot of factors I think are combining to contribute to higher energy costs. The Texas thing resolved after a couple of weeks and prices have declined, but not back down to the, you know, 2 to $3 level for MMBTU.

MADAM CHAIR PRIDEMORE: Any other Commissioner questions?

(No response.)

MADAM CHAIR PRIDEMORE: Mr. Walsh.

MR. WALSH: Madam Chair, if there are no further Commissioner questions prior to cross, I wanted to correct an error I made in the numbering of the exhibits. I'm afraid I have contributed to the hurtful stereotype that attorneys can't do math.

It should have been -- RS/RT 1 through 29 should have Staff Exhibits 12 through 40. I said 12 through 30. It should have been 12 through 40. And so the trade secret version of their testimony should

have been Staff Exhibit 41.

MADAM CHAIR PRIDEMORE: Okay.

MR. WALSH: The only other thing I was going to ask, may Mr. Thomas approach the panel to provide a supporting document related to their testimony that we believe they inadvertently neglected to include in what they bring up to the stand?

MADAM CHAIR PRIDEMORE: Go ahead, Mr. Thomas.

Your motion is so marked. Through 40, and then 41 for trade secret.

MR. WALSH: Thank you, Madam Chair. The panel is available for cross.

MADAM CHAIR PRIDEMORE: All right. Before we begin cross, just a couple of things. It's stated when you filed to be an intervenor that the procession of this hearing and all hearings is really important. If you have already heard your question asked and answered, please don't ask it again. That is one of the things when you go back and watch hearings, like I frequently do, what I see is the same questions being asked by multiple intervenors.

So I recognize that your clients have you here to do a job, but you're going to get the same answer again. And so it just speeds things along. So please just refrain from it; otherwise, we're going

to stop you.

The second thing, too, is that when you come up to cross, if you represent a body of individuals, whether it be an association with fewer than ten members, please state who is part of your group. That has continued to come up where people believe that they're intervening or they say that they're intervening in a case and there's no way that this Commission and staff would have any idea that they were because they're intervening under a different name, such as, you know, AAA Locksmith. So please make sure that you state who the members are if your group has fewer than ten members.

All right. With that, cross-examination.

MR. MARZO: Madam Chair, as normal procedure, we would request to go last for cross.

MADAM CHAIR PRIDEMORE: Okay. So moved.

Americans for Affordable Clean Energy.

MR. GALLOWAY: Madam Chair, no questions.

MADAM CHAIR PRIDEMORE: Okay. ChargePoint.

MR. FYKE: No questions, Your Honor.

MADAM CHAIR PRIDEMORE: Commercial Group.

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: EVgo Services.

CROSS-EXAMINATION

BY MR. VIJAYKAR:

Q Good morning.

A (Witness Smith) Good morning.

A (Witness Trokey) Good morning.

Q My name is Nikhil Vijaykar and I'm an attorney for EVgo Services. How are you?

A (Witness Smith) Very well.

A (Witness Trokey) Not bad.

Q I'm sorry. I wasn't able to see from where I was sitting. Who is Mr. Smith and who is Mr. Trokey?

A (Witness Smith) Smith.

A (Witness Trokey) Trokey.

Q Okay. Thank you. I just want to make sure I'm looking at the right people.

I just have a couple of quick questions for you this morning. And I'm going to ask you to turn to the portion of your testimony that concerns the company's Make Ready program proposal. And just to direct you to that portion of your testimony, I'm looking at pages 72 and onwards in the testimony.

If you could just let me know when you're there.

A (Witness Smith) We're there.

A (Witness Trokey) We're there.

Q Great.

So Mr. Smith and Mr. Trokey, you testified regarding the company's electric transportation Make Ready program. And you state at page 74 that: The program, if continued for the next decade, will increase the revenue requirement by close to half a billion dollars.

Do you see that?

A (Witness Trokey) Yes.

Q Okay. So just some table setting. Do you agree that the company has not proposed to continue its Make Ready program for half a decade at this time?

A (Witness Trokey) I would say that as I understand the program, the participants would be eligible to remain in the program for the next ten years. And they have a terms and condition agreement with the company that they would enter into and that would renew each year. In this case, they have requested a three-year program and funding.

Q And on the funding, you understand that the proposal as it stands is to increase the capital budget for the program by $81 million; correct?

A (Witness Trokey) That's correct. 27 million a year for the rate period.

Q Gotcha. So moving to page 78 of your testimony, again staying with the Make Ready program, I want to direct you to the question starting at line 11 on that

page about where EV owners would charge if the Make Ready program were discontinued.

Do you see that?

A (Witness Trokey) Yes.

Q Okay. So you state that in the absence of additional Make Ready-enabled charging stations, EV owners will continue to charge primarily at home; is that correct?

A (Witness Trokey) Yes.

Q So just to be clear, you're referring here to charging through an existing conventional 120-volt electrical outlet, commonly called Level 1 charging, or maybe Level 2 charging, if the customer has that charging facility at home; is that fair to say?

A (Witness Trokey) I would say Level 1, Level 2 charging stations primarily. Now, a lot of the participants in the Make Ready program are commercial businesses and they would charge with either Level 1 or DC fast chargers.

Q Understood.

So, in other words, the customer will charge at home where they have the ability to charge at home; correct?

A (Witness Trokey) Correct. Most customers will and do charge primarily at home. I've heard approximately 80 percent of charging occurs at home and not at community charging stations.

Q And who have you heard that from?

A (Witness Trokey) McKinsey report.

Q Okay. Is that in the record here?

A (Witness Trokey) I don't know that it is referenced.

Q Okay. Fair to say that not all customers have access to charging at their home?

A (Witness Trokey) I'm sorry. Was the question that not all customers have the ability to charge at home?

Q Yes.

A (Witness Trokey) Yes. That's correct.

Q Okay. So those customers without access to charging at their home, you would agree that those might include customers living in apartments and other multiunit dwellings?

A (Witness Trokey) In some cases, right. Apartment dwellers, multifamily dwellings. The residents at those locations may not have the ability. In some cases they do have the ability and they have the opportunity to charge at home. But it depends on the specific location.

Q Uh-huh. And for those customers without access to charging at their home, for example, customers in multiunit dwellings, fair to say that it might be helpful to have public charging close to their home?

A (Witness Trokey) In some cases, yeah. I would say that's a convenience factor. I think we just need to

also back up and think about who we're talking about in terms of customers. I think the owners of electric vehicles who need to charge outside of their home, those represent a very small portion of Georgia Power's customers.

So I'm assuming you're talking about customers being customers who need to charge and own an electric vehicle. Is that -- that's my understanding of the question.

Q So let me clarify my question or maybe restate it.

For a customer who doesn't have access to charging at their home -- so we're just limiting to customers in that bucket -- fair to say that it would be helpful for them to charge at public charging facilities outside of their home?

A (Witness Trokey) Yeah. For customers who own an electric vehicle and want to charge and they live in a location that does not have a garage, for instance, or an electrical hookup, Level 1 or Level 2, at that location, it is a convenience for them to be able to charge within the community close to their house.

MADAM CHAIR PRIDEMORE: I'm just going to remind the witnesses, the faster that you get your answers out, the faster this goes. So I know we've asked the same question three different ways and the

answer is yes, yes, and yes. So just for the sake of moving things along, at this rate we're going to be here until Sunday.

So go ahead, sir.

MR. VIJAYKAR: That's actually all I have.

MADAM CHAIR PRIDEMORE: Oh, very good.

MR. VIJAYKAR: Thank you.

MADAM CHAIR PRIDEMORE: Thank you.

Georgia Association of Manufacturers.

MR. JONES: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments.

MS. BROWN: Yes, ma'am.

VICE-CHAIRMAN ECHOLS: Mr. Trokey, while Savannah is stepping to the podium -- the City of Savannah -- Alicia is stepping to the podium, did you know that one of the biggest expenditures in the Make Ready program came just 9/10th of a mile from the Port gate to enable the Port fueling center to tee up the charging of electric semi vehicles and drayage trucks and box trucks?

Are -- were you aware that -- that one of the biggest expenditures out of that -- one of the customers that benefited the greatest was that facility?

Did you know that? Have you heard of the Port fueling center?

MR. TROKEY: Yes, I'm familiar with it.

VICE-CHAIRMAN ECHOLS: Yeah, so --

MR. TROKEY: So I've seen the locations, right, of the charging station.

VICE-CHAIRMAN ECHOLS: So it's really more about commercial entities than it is homes or, you know, Nissan Leafs or anything else like that.

MR. TROKEY: Well, that's correct. That's a good point. The Make Ready program is not available to residential customers. It's only to commercial customers, multifamily dwellings, governments. So, right, it -- this is primarily for those beneficiaries of the Make Ready.

VICE-CHAIRMAN ECHOLS: And once things are made ready, right, over a large scale -- on a large-scale basis, which is what they're proposing here, I mean, we're -- wouldn't you think we would have a decreasing need for Make Ready as we -- as we get everything stood up, you know, for this with our commercial customers?

I mean, doesn't it make sense that it's going to go down in the future and not up?

MR. TROKEY: One would hope. During the last

case, $6 million per year was approved. This case, the company is requesting 27 million per year. So it -- we don't know what their request might be in the future.

But I will say there are a significant number of businesses who might be interested in participating in the program. So I -- I could also see a scenario in which the company continues to request additional funds because it does subsidize the installation of electric vehicles at these locations. And staff is making the case that we don't think electric utility customers should be required to pay for that service.

In many cases, the service is not available to the public. It's only available to that private business, for instance. And so the public can't go and take advantage of being able to charge at those locations.

VICE-CHAIRMAN ECHOLS: Even though we know that charging overnight provides greater grid efficiency and essentially puts downward pressure on rates with greater grid efficiency; right?

MR. TROKEY: It does. And I think for residential customers, that's where the 80 percent charging would occur primarily overnight. And what

we don't know about the Make Ready program or the community charging program is, you know, what those load factors would be and what time of day would those businesses and other participants in the program be charging, so -- but certainly overnight charging is beneficial.

VICE-CHAIRMAN ECHOLS: And the last question. I mean, if we give a price signal to Amazon and they're plugging their 50 -- their 100 Rivian package delivery vehicles in at the time of their choosing and we give them a signal that it's going to be cheaper if they plug in at 11:01 p.m. or midnight or 1:00 a.m., do you think they'll follow that signal?

MR. TROKEY: I think we can handle -- right. We can send that signal via the rates. And you don't necessarily have to have other ratepayers, you know, pay for the Make Ready installation of, you know, their chargers for a company like Amazon. However, yeah, through rates I think it's helpful to have time of use and incentives to charge at the appropriate times.

VICE-CHAIRMAN ECHOLS: Thank you.

MADAM CHAIR PRIDEMORE: Ms. Brown.

CROSS-EXAMINATION

BY MS. BROWN:

Q Good morning, Panel. I'm Alicia Brown with the Georgia Coalition of Local Governments, which is the city of Atlanta, City of Savannah, City of Decatur, DeKalb County and Athens-Clarke County unified government.

If I can keep you in the same section of your testimony and direct you to page 74, beginning in line 5.

A (Witness Trokey) Okay.

Q You state that investments needed to provide an unregulated service to private groups should be paid for by the business or organization wanting to provide that unregulated service.

Just to clarify, do any Georgia Power customers provide a regulated service?

A (Witness Trokey) I would think at some level, there's -- there are many regulations. Telecommunication services are regulated. So I think the answer is yes. For the most part, they are not. Like, I mean, a Kroger selling its goods, it's not a regulated service. And neither is electric vehicle charging.

Q Okay. So none of -- no other customers -- no one else but Georgia Power provides regulated electric service?

A (Witness Trokey) Within their territory. Obviously there are EMCs and municipal utilities that provide service, as well. And customers also self-generate

and use that power at their locations.

Q Okay. So isn't it true that all of the investments that Georgia Power makes are made to support the provision of unregulated services?

A (Witness Trokey) I think the question can be answered two ways. One is it's providing electric service, which is regulated, to a host of different types of businesses and residential customers; right?

At the same time, you know, Make Ready is different in the fact that it's -- only has one use, which is electric vehicle charging. So the equipment that's been approved under the 2019 rate case Make Ready program and what's being requested in this program, that equipment is not used to serve the general body of electric utility customers. It's used and needed only to provide electric vehicle charging.

In some cases, as well, I would say that even on Georgia Power's system, there are assets that are used primarily, say on the distribution lines, it might only serve one customer, as well.

Q Okay. So if a government or a business decides that they want to convert their fleet, they would be taking service under a retail tariff; is that correct?

A (Witness Trokey) That's correct. They would be taking service under a regulated retail service. And

staff's testimony is that it would be more appropriate for the city or the business making that decision to pay for the cost of those upgrades which benefits them, rather than having electric vehicle -- or, excuse me, electric utility customers in another region of the state pay for that and subsidize that.

Q Okay. So I've been in two of these proceedings now. The company's pretty adamant about avoiding cost shifting. It comes up every time we talk about rooftop solar, community solar, energy efficiency.

What is the company's position on the cost-shifting argument that you're making in this case?

A (Witness Trokey) I can't speak to the company's position on those.

MR. MARZO: Objection, Madam Chair.

I mean, the company has witnesses. They can testify to the company's position. It's in written testimony, as well. These witnesses should not be asked to speculate on the company's position.

MADAM CHAIR PRIDEMORE: Sustained.

MS. BROWN: May I rephrase?

MADAM CHAIR PRIDEMORE: Go ahead.

BY MS. BROWN:

Q Has the staff inquired of the company whether charging is in the public interest?

A (Witness Trokey) Staff has had a number of conversations with Georgia Power. And I believe in the 2019 rate case order itself there is language regarding the public interest.

Staff's case has not changed from the 2019 rate case to this case. So staff's position is that it's not in the public interest to have electric utility customers subsidize an unregulated service.

Q Are you familiar with the staff data request Staff PIA 35 in which you specifically -- or the staff specifically asked the company how Make Ready is in the public interest?

A (Witness Trokey) I'm familiar -- I recall asking a question about that.

Q Okay. Would you -- do you recall the company saying that Make Ready passed the ratepayer impact measure?

MR. WALSH: Madam Chair, if she -- counsel has copies of the response, could the panel see it in responding to the question?

MS. BROWN: May I?

MADAM CHAIR PRIDEMORE: Do you?

MS. BROWN: Yes, ma'am.

MADAM CHAIR PRIDEMORE: You may.

MS. BROWN: It's front and back.

MR. TROKEY: Thank you.

BY MS. BROWN:

Q Have you found the portion I'm referencing? I believe it's on the top of the back page.

A (Witness Trokey) Yes.

Q Okay. So is the company asserting that the Make Ready program passes the ratepayer impact measure?

A (Witness Trokey) In this response, it indicates that depending on the respective customer tariff, the company's rate impact measure analysis of the program indicates that it would put downward pressure on rates.

I would add that the staff requested the company's study as a hearing request and what was provided was a one-sheet list of those various rates. Some would show upward pressure on rates, some would show downward pressure on rates. Staff did not believe that study really fully supports the assertion that it would have downward pressure on rates.

The other aspect that I would add is that we do have data from the community charging program. And in that program the revenue is not sufficient to cover even the operating and maintenance expense. So the revenue from the charging stations is not covering those expenses.

So that is putting upward pressure on rates and staff also opposes continuing the community charging program as well for that purpose. But I don't think there is

sufficient evidence in the record to support the Make Ready program putting downward pressure on rates.

Q Without having the data in front of you, just from your experience working on the staff, do programs or policies that result in the sale of 4 kilowatt-hours generally put downward pressure on rates?

A (Witness Trokey) It partially depends on the time of use of that program. In this case, staff fundamentally is opposed to a subsidy from regulated electric customers to subsidize an unregulated service.

There's a lot of good programs. There's a lot of things that are beneficial to the state of Georgia, to, you know, the public interest. That doesn't mean that electric utility customers should pay for those with -- on their bill.

Q But more generally, EV charging is increasingly seen as an economic development tool. We've had car dealerships come in for public comment and we know that hotels, gas stations are wanting to get into this space.

Isn't it common practice for utilities across the country to make investments for the sake of economic development?

A (Witness Trokey) I don't know that I can answer with respect to across the country. I do know in a number of states there's legislation that, you know, obligates the

spending, but I can't say generally.

Q Okay. And then turning now to page 79, looking specifically at lines 18 and 19.

A (Witness Trokey) Okay.

Q You make the case that Make Ready creates an uneven playing field for providers of electric vehicle charging services. How does Make Ready create an uneven playing field?

A (Witness Trokey) So not every business or government or condominium association that wishes to have EV charging services will qualify for the Make Ready program. And it would be a burden on ratepayers to make this available to all of Georgia Power's commercial customers, residential customers at multifamily dwelling.

So the unlevel playing field is that as a matter of the way the program is administered and set up, only a certain number of -- of participants or beneficiaries will receive the Make Ready funding to support their vehicle charging station. So you could very simply have a situation where one business qualifies and is approved for participation in the program, but across the street, their competitor does not. And so there's an unlevel playing field because the cost to one electric vehicle charging station is subsidized by electric ratepayers; for the other business, it's not.

Q And what would be some of those criteria that would disqualify someone?

A (Witness Trokey) So my understanding, for instance, is that, you know, if you're a third-party provider and you're not the site host, you may not qualify currently. If -- if you're not aware of the program, you might not apply.

If you apply and you applied late after other customers who've already applied -- like with the 2019 rate case, there's a wait list of customers who are interested. So I'm sure there are many different factors that would disqualify. Residential customers would not qualify.

Q But any existing commercial Georgia Power customer can apply?

A (Witness Trokey) Any nonresidential customer, correct.

Q Okay. And one last question for you. If you can look at page 74, lines 16 and 17.

A (Witness Trokey) Okay.

Q You say that the vast majority of retail electric customers will not own EVs in this decade.

Do you have to personally own an EV to benefit from Make Ready, or does it also affect things like public transit, car share programs, et cetera?

A (Witness Trokey) So the customer does not have

to personally own an electric vehicle. I know there are some situations where if it's an apartment complex or condominium association, not every customer -- not every Georgia Power residential customer will own an electric vehicle. Some of the other beneficiaries of the program may not individually own.

I would say the majority -- it appears that the majority of the beneficiaries are commercial customers. And so they may be charging a fleet or EVs that are owned by that business. However, the public will not have access -- who do have electric vehicles, say a residential customer, wouldn't necessarily be able to go to these locations and charge.

Q But let's say I rode a MARTA bus and they now have electric buses. It's putting downward pressure on fuel costs and maintenance.

Am I not benefiting from Make Ready investments to support those buses?

A (Witness Trokey) It certainly lowers the cost for charging of those buses. And staff's position is that the very fact that so many customers of Georgia Power do not own electric vehicles, that they may not afford to have a car. They may have to take a bus. They may have to walk, you know. Take Uber when it's available and they can afford it.

And those customers should not be required to pay for MARTA, a local government, or any business -- commercial business who's for profit for them to have the luxury of having an electric vehicle charging station.

MS. BROWN: All right. Thank you.

MADAM CHAIR PRIDEMORE: Georgia Conservation Voters.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Conservation Voters.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Conservation Voters.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light.

VICE-CHAIRMAN ECHOLS: Mr. Trokey, before she comes up, just a couple of questions. So I'm not trying to embarrass you or your colleague.

But do you own an electric car?

MR. TROKEY: I do not.

VICE-CHAIRMAN ECHOLS: Have you ever charged an electric car?

MR. TROKEY: I have not.

VICE-CHAIRMAN ECHOLS: Okay. Have you ever

ridden in a Lyft ride share, or Uber?

MR. TROKEY: Yes, I have. Yes.

VICE-CHAIRMAN ECHOLS: Okay. So at the Atlanta airport, right, there's lot of ride shares; right?

You would think?

MR. TROKEY: I -- I'm sure that's the case.

VICE-CHAIRMAN ECHOLS: Yeah. So there's 50 electric Chevrolet Volts that run out of Forest Park, Georgia. They were previously running out of the Cox Automotive site at 2244 Metropolitan, six miles from here. And the public -- the flying public that comes back in that orders a Lyft on their app very well may be picked up by one of those Chevrolet Volts.

And do you know how many fast chargers there are at the Atlanta airport in all of that space?

Do you want to take a guess?

MR. TROKEY: I will not take a guess. I don't know.

VICE-CHAIRMAN ECHOLS: Zero. Zero.

So in order for those cars to operate, they needed a lot of fast chargers in and around Hartsfield, between Hartsfield and downtown, and downtown. Because running a Chevrolet Volt on a Lyft -- you know, as a Lyft driver for, you know, 12 or 15 rides a day, you are going through the electricity.

**And you need fast chargers.**

**And so would you say that building fast chargers with Make Ready on customer sites between here and Hartsfield would have a public benefit, knowing that there are 50 Volts running down there needing power and needing it quickly?**

**Do you consider that a public benefit?**

**WITNESS TROKEY: I -- I would say staff is not opposed to the electric vehicle market or electric vehicles themselves. And we don't disagree there may be benefits to those businesses that host charging stations and benefits to, you know, electric vehicle owners.**

**We're saying it should not be the responsibility of electric utility customers to meet that need. We believe the free market can handle the development of those charging stations. And we believe a competitive industry is the best way to meet those needs.**

**VICE-CHAIRMAN ECHOLS: So Cox Automotive at their 2244 property wanted to put in six public facing fast chargers to service those Volts because it's between here and the airport. It's halfway in between.**

**The infrastructure was so bad on Metropolitan.**

It's an opportunity zone. It's blighted. It was so bad that they had to spend about a half a million dollars in their own Make Ready moneys, this is before we approved the program, just to be able to get the power delivered to the property.

So if Georgia Power is telling us that the grids -- that a lot of grid infrastructure is coming to the end of its useful life, then it seems like to make a Georgia Power customer pay for replacing something that's 30 years old or 40 years old just because they want to get chargers, I mean, it doesn't seem logical or fair to me. Does it you?

To have the customer have to take something that needed to be replaced anyway, and because now they're going to bring in a megawatt of power so they can offer public facing chargers, now they're going to have to pay the full retail price for that infrastructure without the Make Ready program.

MR. TROKEY: I appreciate the question. And I don't know all the details of that specific situation. I would say that the way the Make Ready program has operated, 99 percent of the investment has occurred on the customer's side of the meter.

So these are not distribution assets that need to be upgraded under Georgia Power's program. So I

think that's one of our additional fundamental concerns we have with the way the program is operated.

Now, regarding distribution assets, I would say there are also occasions in which a customer would request an upgrade to their service or their service to be moved from overhead to underground in which those changes are only being requested because of that one customer's, you know, request to Georgia Power. And so in those cases that customer is asked to pay for those investments, even if it's on Georgia Power's side.

And, say, with a line extension for a customer who might live in an area where you don't already have electric service, that customer -- the company will pay for a portion of that; however, that customer would bear the responsibility of paying the cost of the line extension.

But I do understand that it can be expensive to install these.

VICE-CHAIRMAN ECHOLS: Thank you.

MS. KYSOR: GIPL has no questions for this panel.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Kysor.

Georgia Solar Energy Industries. How would you

like me to shorten this, Mr. Thomasson?

MR. THOMASSON: We go with GASEIA, SEIA and Vote Solar.

MADAM CHAIR PRIDEMORE: So we're just going to say GASEIA.

MR. THOMASSON: That works for me.

MADAM CHAIR PRIDEMORE: Go ahead.

MR. THOMASSON: And, for the record, we do have more than ten members so I'm not going to name them.

MADAM CHAIR PRIDEMORE: Okay.

CROSS-EXAMINATION

BY MR. THOMASSON:

Q Good morning, gentlemen. I've only got a couple quick questions on your recommendations about the earnings band at the very end of your testimony on pages 136 and 137. I'll give you a moment.

Staff is recommending narrowing the earnings band from recent rate cases and making the earnings band symmetrical again; is that correct?

A (Witness Trokey) Yes.

Q Could you expand briefly on why a narrower and symmetrical band is more equitable, as you say in your testimony, for customers?

A (Witness Trokey) It does offer the symmetrical 1 percent above and below the midpoint of the band, which

has been the earnings band previously prior to the 2019 rate case. We think a return to a 1 percent, plus or minus above the midpoint, is more appropriate.

We think not allowing a one and a half percent earnings allowance above the midpoint incentivizes the company to manage the funds of ratepayers more appropriately.

Q Just to clarify, the 200 basis points was prior to '19, but in 2019 there was a 250-basis-point range; is that correct?

A (Witness Trokey) My understanding it was a 200 basis point previously.

Q Mr. Walsh set the bar low for lawyers doing math, so I don't want to double down on it.

A I would have to just locate the exhibit.

Q Well, you mention on page 137, lines -- I picked up the wrong one. Oh, yeah. Lines 9 and 10. That the band was 9.5 percent to 12 percent, which would be two and a half percent; is that --

A (Witness Trokey) In the 2019 rate case, that's what --

Q That was sort of an anomaly from the 200 or a break from the 200?

A (Witness Trokey) Right.

A (Witness Smith) We do have a chart on page 130

that was also reproduced as one of our demonstrative exhibits that shows the earnings bands from 2007 up through 2021.

Q Okay. I just wanted to clarify the 2019.

A (Witness Smith) Most of the period it was 200 basis points, but in the last rate case it was 250.

Q In making this recommendation, did staff consider an even narrower earnings band, say, 100 basis points, plus or minus 50?

A (Witness Trokey) Yes, we did.

Q Okay. And what's your opinion about why 100 is more equitable than 50 or 200?

A (Witness Trokey) I would say initially it's a movement back gradually to where we were prior to the 2019 rate case. There are certainly benefits to narrowing it more.

We thought it would be appropriate, given the full context of staff's recommendations, that that would be an appropriate band, 200 basis points.

Q Did staff also consider the company's request for a higher equity share of 56 percent in its proposed capital structure and incorporating that into its band recommendation?

A (Witness Trokey) So, yeah, the question is probably more appropriate to Mr. Gorman; however, there were

a variety of equity positions that were considered.

Q And then just a similar question about your recommendation for revenues above the top band. Could you explain why paying down regulatory assets is a more equitable solution or a policy for customers than what we have now?

A (Witness Trokey) Certainly. So the company is afforded keeping the earnings above the midpoint, the set point, up to the top of the earnings band. And that certainly awards them with sufficient return on their investment greater than what would be determined to be an appropriate return or a reasonable -- a just and reasonable return.

So above that the staff believes the additional earnings should be used to pay down regulatory assets. And staff would -- or ratepayers would benefit from that by not having to pay additional costs in the future.

Q Okay.

A (Witness Smith) When the regulatory assets are recovered, then that would move them from rate base. So they'd no longer linger in rate base upon which ratepayers pay a return on.

Q So that's lowering the liability for customers?

A (Witness Smith) Yeah. Currently the company shares in some of the earnings above the top end of the

band. So what staff is proposing is that anything above the top band --

Q Be 100 percent?

A (Witness Smith) -- be applied to recovery of regulatory assets. And the company has a large amount of, dollar amount of those. So that should help ratepayers by getting those out of rate base sooner rather than later.

MR. THOMASSON: Those are all the questions. Thank you.

MADAM CHAIR PRIDEMORE: Georgia Watch.

Go ahead, Commissioner.

COMMISSIONER JOHNSON: Would that -- would that also incent Georgia Power?

Your last --

MR. TROKEY: The last question?

MR. SMITH: They're getting their -- they're getting recovery of their regulatory asset costs sooner rather than later. So it gives them a cash recovery of that sooner rather than later. Then they don't earn a return on it anymore, but that's a trade-off.

COMMISSIONER JOHNSON: Okay. Thank you.

Thank you, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Watch.

MS. COYLE: Good morning, Mr. Smith,

Mr. Trokey. Nice to see you again. I have just a few questions.

CROSS-EXAMINATION

BY MS. COYLE:

Q To begin, could you -- and this may be in your bio -- in your bio part of your testimony, but remind me, about how many rate cases have you participated in the past, Mr. Smith?

A (Witness Smith) How many Georgia Power rate cases?

Q Yes, that's right. These rate cases, Georgia Power rate cases.

A (Witness Smith) Boy.

Q Going back to like the first year?

A (Witness Smith) Going back to like 2010 and I think then maybe going back even a decade prior to that we participated in a couple.

Q And Mr. Trokey?

A (Witness Trokey) As a witness, I believe three or four rate cases. As a staff member, you know, maybe a dozen or more.

Q And have you -- either of you participated in fuel cost recovery proceedings in the past?

A (Witness Trokey) Yes.

Q And about how many?

A (Witness Trokey) A dozen.

A (Witness Smith) Going back a decade or more, yes.

Q So quite a few for both of you.

And now, staff is estimating in your testimony a potential rate impact of 55 to $60 on the average residential customer bill; is that correct?

A (Witness Trokey) That's an estimate, yes.

Q Okay. And so thinking back to the past rate cases you've participated in and also fuel cost recovery cases you've participated in, do you ever recall customers facing in a single two- to three-year period a 45 percent increase or an increase of 45 to $60 on their bill every month?

A (Witness Trokey) I have not.

A (Witness Smith) I don't think so. But I know there were a couple pretty rough periods in the past, too, so...

Q So would you say what is before the Commission right now is a pretty, a really dramatic increase that is -- customers could be facing in the next three years?

Extremely unusual; highly unusual impact to customers' bills?

A (Witness Trokey) It's a very large dollar revenue requirement request.

A (Witness Smith) Concerning both sides of the rate case increase and then these other increases coming down the pike between 2023 or shortly thereafter.

COMMISSONER McDONALD: Is that increase or that cost of fuel, is Georgia Power responsible for that?

MR. TROKEY: So, yeah, one component of the increase that was referenced is fuel. Georgia Power does not control the market price of fuel. So, no, they are not responsible for that. The other component being Vogtle 3 and 4. But we do have the upcoming fuel case and Vogtle cases.

Considering those costs, and, you know, staff's case is essentially there's a large number of discretionary spending items within the request and it's a -- it's a time to consider really the importance of how much do you -- should you approve and how much do you need to approve.

MS. COYLE: Thank you. That was -- that is where I was heading with my questioning, too. Thank you, Commissioner McDonald.

BY MS. COYLE:

Q So in the fuel cost proceeding, is there some -- we understand that there is a large unrecovered balance in fuel cost and that there is an expectation that the company will file in February a separate proceeding to

consider what the impact on customers' bills will be from the unrecovered fuel balance; is that correct?

A (Witness Trokey) That's correct. They are required to file by the end of February.

Q And does the dollar amount you estimate -- is there some discretion in there?

Does this Commission have discretion or is that fully a pass-through and that full amount has to be put on customers' bills shortly after the proceeding in February?

A (Witness Trokey) I would say the discretion is the period over which you amortize the under-recovered fuel balance. It can be a longer period of time or shorter period of time and that will impact the increase.

Q And are there -- and as you have answered earlier questions about some of the factors going into the increase in fuel costs, is one of those factors the war in Ukraine?

A (Witness Smith) Indirectly. I mean, the causes that -- fuel prices have gone up quite a bit for just about every type of fuel. The world's market has changed.

You know, there's -- supply is limited and there's a lot of demand. Prices have gone up and they have come down a little bit, but it looks like they're going to remain at higher levels than we have seen in the last few years.

Q And so, in your expertise in this area, would you believe that we would continue to experience over the next few years quite a bit of volatility in the fuel price?

MR. MARZO: Madam Chair, I think Ms. Coyle has taken what is a brief line in the testimony and now turned it into a discussion about fuel case payout in some months next year.

We have gone well beyond what their testimony is about in terms of base rate days. I've let the questions before objecting -- I have let her ask some fuel questions. We're now getting into the details of a fuel case.

MADAM CHAIR PRIDEMORE: I don't know how we can ask questions about a fuel case that hasn't been filed yet. So there's plenty of meat in their testimony for you to ask questions in this case.

MS. COYLE: Thank you.

BY MS. COYLE:

Q So setting aside that there will be a fuel cost proceeding later in the year, it's staff's expectation that that will be a significant impact on customers' bills going -- in 2023 and beyond?

A (Witness Trokey) Yes.

Q And it's staff's opinion that there are items -- is it staff's opinion that there are items in the

proposed base rate increase that are more discretionary where the Commissioners could take action in their decision to put some lower pressure on rates to offset some of the --

MR. MARZO: Asked and answered, Madam Chair. The reason I allowed her to ask the questions earlier without objecting was to give her an opportunity to ask the questions. We're now revisiting all those questions.

MADAM CHAIR PRIDEMORE: Come on, Ms. Coyle.

MS. COYLE: Thank you.

BY MS. COYLE:

Q So staff is recommending that -- staff finds that the company will earn excess revenue in 2023; is that correct?

A (Witness Smith) That's what our -- after all our adjustments, yes.

Q But you still propose no change in rates in 2023; is that correct?

A (Witness Smith) Yes.

Q And is one of those reasons to prevent rate shock for customers in 2024 and 2025 when some of the additional costs will go in?

A (Witness Smith) I think that's a different concern.

Q That's a different concern?

Could you say a little bit more about that?

A (Witness Smith) Yeah. Keeping rates stable, rather than having a relatively modest reduction as of January 1st, 2023, I think our main concern was maintaining rate stability and rate -- the rate shock impact from the total impact in this case and the subsequent increases. I think it's a separate issue and a separate concern.

Q But a moderate reduction in rates in 2023 would be something that the Commission could consider?

A (Witness Smith) If they adopt virtually all the staff recommendations, then that would be the result.

Q And that -- would that be another way that it could lessen the significant increase of all the other factors that you've testified about, Vogtle 3 and 4 and fuel costs?

A (Witness Smith) It is not what we recommend. Having a decrease would lessen the impact of 2023.

Q Just one second.

So Mr. Thomasson asked you some questions about the -- where is the page? I'm not finding the page.

Okay. So I -- the company has -- with the -- could you say more about your recommendation to use the -- if there are excesses in revenue above the earnings band that you recommend to use those for accelerated depreciation of deferred costs, how does that translate -- how would that

compare to, say, for example, letting ratepayers get some of that money back on their power bills?

A (Witness Smith) Well, the ratepayers wouldn't get the money back as a refund, but they would avoid having to pay additional financing costs, including an income tax gross up on these regulatory assets.

Q Will they --

A (Witness Smith) It gets the regulatory assets off the books and they don't have to pay financing costs. Anymore and it applies the entire amount of the earnings over the top end of the band against the regulatory assets as opposed to sharing it in some other manner, like giving ratepayers two-thirds and letting the company keep the other third, which produces even higher earnings for the company.

Q Would the -- would the scenario you're recommending, then, have any immediate, quantifiable benefit on customers' bills over this three-year period or is that more of a long-term benefit to customers?

A (Witness Smith) It would tend to avoid some increment of additional return on rate base over that three-year period and then beyond, as well.

Q Okay. So would that be -- there would not be an immediate benefit on customers' bills?

A (Witness Smith) If you use the band that staff is recommending, so that could be an immediate benefit. And

if you set rates using the ROE that staff witness Gorman is recommending, that would be an immediate benefit because that would reduce the amount of rate increase by a significant amount. I mentioned the exact amount in my summary and we have it in our testimony. But that would be -- that would be an immediate benefit to customers.

Q So staff is making other recommendations for the Commission to consider to provide that, you know, almost immediate benefit in customers' bills while looking at some long-term improvements, as well, with your recommendation on how to treat any excess above the earnings band?

A (Witness Smith) We believe it could be an immediate benefit from some of the staff recommendations. And it could be a longer-term benefit from the alternative rate plan that staff has proposed.

Q Thank you.

And then on page 136, lines 13 and 14, when you're recommending the step increase -- I'm sorry. At the very beginning.

Okay. In -- you are recommending that the Commission approve, rather than a levelized, a step increase to rates?

A (Witness Smith) Correct.

Q Okay. And did this -- is that how the Commission ordered the rate increase in the 2019 rate case?

A (Witness Smith)I believe so.

Q Okay. And are there -- when the company had the step increase filings in this last three-year period, were there -- there were proceedings, were there not?

A (Witness Smith) There were filings. I'm not sure.

Q Filings?

A (Witness Smith) They were reviewed by staff. I'm not sure how -- and they were approved by the Commission.

Q But they --

A (Witness Smith) I'm not sure what kind of proceeding they had.

Q But there weren't separate proceedings for intervenors and parties to weigh in?

A (Witness Trokey) Correct. There were no separate proceedings.

Q And --

A I should just clarify that certainly staff's recommendation in each of those increases was presented at an energy committee and parties had an opportunity if following to comment on staff's recommendation.

Q So you've testified -- and just looking at your, a summary of your recommendations on page 139, one of them is that the rates be set using the traditional test

year rate-making components, which is not something that the company is proposing in its filing this time around, but you are; correct?

That the rates be set based on the test year?

A (Witness Smith) That's one of the recommendations. You know, we are cognizant that the Commission has approved and the company has asked for and has implemented these three-year rate plans going back well over a decade. So we have recommendations to address the alternative rate plans, as well.

Q Okay. But the Commission definitely does have the opportunity to go back to the traditional rate test year rate setting as they have -- maybe it hasn't happened in the last decade, but they could certainly do that in this case?

A (Witness Smith) It's our understanding they could, yes.

Q Is it your recommendation?

A (Witness Smith) It's one of our recommendations.

Q And is that another way that -- given the size of this proposed increase and all the other factors that could increase people's power bills, that this is a really unique time that it could make a lot of sense to go with this approach?

A (Witness Smith) It has some benefits and some

drawbacks doing it -- using a traditional test year versus an alternative rate plan. So there are some benefits and some tradeoffs.

Q Okay. And on page 140, you're talking about the ECCR cost recovery and recommending that, again, the Commission require the company to make an annual compliance filing?

That has happened in past years; is that correct?

A (Witness Smith) Correct.

Q And that's not only a filing, but are there proceedings related to that?

A (Witness Trokey) There are no proceedings.

MS. COYLE: Okay. No proceedings.

And that's my last question. Thank you.

MADAM CHAIR PRIDEMORE: Interstate Gas Supply does not have cross. They let me know before they left.

Kroger Company.

MR. BOEHM: No questions, Your Honor. Thank you.

MADAM CHAIR PRIDEMORE: MARTA.

MS. STRUM: No questions. Thank you.

MADAM CHAIR PRIDEMORE: Resource Supply Management.

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club.

MS. ARIZA: Good morning, Commissioners. Good morning, panel. Can you hear me okay?

MADAM CHAIR PRIDEMORE: Speak into the mic and please straighten the neck of it for us. It worked better. This part. There you go.

MS. ARIZA: Thank you.

For the record, Isabella Ariza on behalf of the Sierra Club. And I have a few questions for you staying on the EV portion of your testimony.

CROSS-EXAMINATION

BY MS. ARIZA:

Q So on page 84, lines 12 through 16, you state that the only instance in which you'd support Georgia Power's investments in charging infrastructure is if it's to power their only fleet; is that right?

A (Witness Smith) Well, I'm on page 84. What was the line number?

Q It's 12 through 16.

A (Witness Trokey) I would comment that, yeah, in the past staff's position has been to support the fleet of Georgia Power's electric vehicles that serves customers, you know, on the regulated business, that it would be appropriate for those costs to be recovered.

Q Okay. And do you believe that that is in the best interest of ratepayers?

A (Witness Smith) We believe it's part of the company providing electric service to ratepayers.

Q Is it in the best interest of ratepayers?

A (Witness Trokey) Yes, it is.

Q How about Georgia Power providing charging infrastructure for public fleets, wouldn't that also be beneficial for ratepayers?

A (Witness Trokey) Certainly there could be scenarios in which a customer of Georgia Power would benefit from that fleet having the opportunity to charge; however, for the body of ratepayers staff's position is that, no, it is not in the public interest to have electric utility customers pay for those services.

Q Okay. Thank you.

If the Commission decides to allow recovery of costs associated with the Make Ready program, would you agree that Georgia Power should be required to focus its efforts on providing Make Ready to public entities like public schools?

A (Witness Trokey) Staff doesn't have a position on it. We haven't studied the prioritization. We're familiar with the fact that a number of parties are interested in prioritizing Make Ready if it is approved.

Staff thinks that -- staff believes additional dialogue and discussions should take place if any Make Ready funds are approved. But staff does not support the program.

Q Okay. I will ask you: Are you aware that some rural and low-income school districts in Georgia will receive millions of dollars under the bipartisan infrastructure law to buy electric school buses?

A (Witness Trokey) Yes.

Q Are you aware that those awards provide very limited funding for charging infrastructure?

A (Witness Trokey) I'm not aware of what is provided.

A (Witness Smith) I'm not either.

MS. ARIZA: Could I approach with an exhibit?

MADAM CHAIR PRIDEMORE: Please. Quickly.

MS. ARIZA: And I'll have this marked as Sierra Club Exhibit 3, please, because -- because I marked it that way.

MADAM CHAIR PRIDEMORE: So marked as 3. Thank you, Mr. Jackson.

(The documents referred to were marked for identification as Sierra Club Exhibits 2 and 3.)

MS. ARIZA: Thank you.

MR. WALSH: Madam Chair, I think I will propose a conditional objection to the extent that the

panel -- if the panel is familiar with the document, then I don't mind the questions going forward.

But if the panel is not familiar with the document, then I would object to them just reading a portion of it.

MADAM CHAIR PRIDEMORE: For the record, this is a chart. And I think that based upon the ease of read that the panel should be able to look at the chart to make answers to questions.

MS. ARIZA: I'm sorry. I should -- is this the document that they have?

MADAM CHAIR PRIDEMORE: In light of --

MR. JACKSON: You have 2 and 3 now.

MADAM CHAIR PRIDEMORE: SC-2 you should be able to answer questions. It's a chart. We allow that regularly.

If you need a minute with 3, you can take a minute.

MR. WALSH: I'm sorry. I don't think I have 2.

MS. ARIZA: I'm sorry. I just -- the last question is about 3. I'm sorry that I got you 2.

BY MS. ARIZA:

Q Have you seen this document before?

A (Witness Trokey) I don't recall.

A (Witness Smith) Were they provided in response

to a data request?

Q No. So then I will move on.

If I may address quickly the impact to the revenue requirement that you referred to before regarding charging infrastructure expenditures.

Ms. Brown asked you about Georgia Power's RIM analysis. Do you recall that?

A (Witness Trokey) Yes.

Q Could you expand on why you disbelieve that, the results of that RIM analysis?

A (Witness Trokey) It's not a question of believing the results, I guess. I think there's not sufficient -- it's not sufficient to really interpret and to understand. Staff does not have access to the assumptions that are behind that -- that page of information.

So we don't -- we can't vet that information and say whether or not it's accurate, what the impacts are. But it doesn't impact really staff's recommendation which is fundamentally that electric utility ratepayers should not subsidize unregulated charging services.

Q Okay. But did you calculate how much revenue the company will make as a result of increased sales of electricity associated with EV charging?

A (Witness Trokey) No. And I think that's one of our concerns is that it is not clear that it's possible to

calculate that. Because it's not clear which of these charging stations would be built, even without the Make Ready program, and which would not. So I don't know that there's data available.

Q There is no data available in this docket or in general to prove that revenues from EV charging can offset the cost of providing charging infrastructure?

A (Witness Trokey) I can't speak about it in general. I would say in this docket certainly there's not sufficient evidence that the -- that the revenue to Georgia Power Company will offset the additional cost to customers.

Q Okay. So am I correct in understanding that your opposition to Georgia Power investing in EV charging infrastructure is based on the lack of information that Georgia Power is able to provide to date?

A (Witness Trokey) No. I mean, really it's a fundamental issue. It's whether or not there should be a competitive free market for electric vehicle charging stations or whether or not customers who are captive -- excuse me -- captive electric monopoly customers or an electric service should also have to pay as part of their rates the cost of private electric vehicle charging --

Q Okay.

A -- for businesses. It's not a regulated service. And so it's not a matter of information about

whether or not there's a ratepayer impact.

MADAM CHAIR PRIDEMORE: Ms. Ariza, I'm going to stop you right there. That question has been asked and answered so many times. And we're going to adjourn for -- we are just going to take a recess for lunch. I've watched paint dry faster than this hearing is going.

We have 22 panels to get to and three days to do it. And so I'm going to encourage you all, while you enjoy your lunch, that the attorneys work with your witnesses and speed up the answers.

If it's yes, it's yes. If it's no, it's no. Nobody gets paid by the word around here. And so it's important that we keep it moving; okay?

We are going to come back at 1:00.

(A recess was held from 12:00 p.m. until 1:00 p.m.)

MADAM CHAIR PRIDEMORE: All right. We are back on the record. Witnesses, you are still under oath. Go ahead, Ms. Ariza.

MS. ARIZA: Thank you.

CROSS-EXAMINATION (Continued)

BY MS. ARIZA:

Q Hello, again. Before lunch, you were saying that your opposition to EV charging isn't based so much in

the lack of information, but on the importance of the free market; right?

A (Witness Trokey) Roughly, that's correct.

Q Thank you. And I will address the market portion of that in a minute, but I just wanted to make sure that if you were certain that having Georgia Power invest on charging infrastructure on --

(Electronic interference.)

MADAM CHAIR PRIDEMORE: Go ahead.

BY MS. ARIZA:

Q If you are certain that having Georgia Power invest on charging infrastructure puts downward pressure on rates, would you support that investment?

A (Witness Trokey) No.

Q Okay. Let me ask you three more questions. Are you aware that in other states, such as Maryland, Wisconsin and Virginia, public service commissions have opened EV investigatory dockets to explore what the utilities' role in the market should be?

A (Witness Trokey) Yes.

Q Would you recommend this Commission open a similar EV investigatory docket?

A (Witness Trokey) No.

Q Okay. And finally, on page 80, lines 19 to 22, you state that if the Commission chooses to approve the Make

**Ready program, it should do so with full transparency required.**

**Are there any other transparency requirements you would encourage the PSC to require?**

**A (Witness Trokey) Yes. So one being the information that's provided at the charging stations. The location of the charging stations, whether or not they are available for public charging.**

**Q Okay. So --**

**A (Witness Trokey) And I do want to say that if any Make Ready is approved, there are improvements that should be made prior to approving that. That's part of staff's recommendation is to not approve the program; however, in its current form, staff does not support it.**

**Q Okay.**

**MS. ARIZA: No further questions. Thank you.**

**MADAM CHAIR PRIDEMORE: Very good. SASE?**

**MR. JONES: No questions, Madam Chair.**

**MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association?**

**CROSS-EXAMINATION**

BY MR. MAHAN:

**Q Good afternoon, panel. I have one question for you.**

**Did staff evaluate the rate impact associated**

with the implementation of the Southeastern Energy Exchange market?

A (Witness Smith) We didn't on our panel, no.

A (Witness Trokey) No, we did not.

Q Thank you.

MADAM CHAIR PRIDEMORE: United States Department of Defense and all other executive agencies?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: Utility Management Services?

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Power?

CROSS-EXAMINATION

BY MR. MARZO:

Q Good morning, panel -- or good afternoon, Panel. Brandon Marzo on behalf of the Georgia Power Company. This is not all for you, so -- I heard some moans in the room when I pulled the box out.

I do have some questions, and I may refer to this box periodically, but this will hopefully last the remainder of the week.

First off, I think you helped me out with cutting some cross, Mr. Trokey and Mr. Smith, with your demonstrative exhibits. Is it fair to say that your

testimony includes the calculation of all the staff's adjustments to the company's rate request?

A (Witness Smith) We have incorporated all the adjustments in RC2 and the other exhibits. Some of the calculations were done by other staff witnesses; and we received other information, for example, the recommended depreciation rates from Staff Witness Kaufman. And we took his recommended depreciation rates and made calculations for the impact on depreciation.

Q Okay. I think you kind of got to my next question, Mr. Smith. So when I look at your -- for your example -- for example, your demonstrative Exhibit No. 2 that lays out the staff witnesses and the adjustments, if I look at that table and I want to ask, for example, questions related to equity and capital structure and cost to capital and ROE, I assume those all go to Mr. Gorman. Is that correct?

A (Witness Smith) Mr. Gorman is the witness for the recommended return on equity and also for the capital structure. That would be correct.

Q Okay. Am I correct that return on equity, capital structure and cost of debt by far are the largest adjustments to base rates being made by staff in this case?

A (Witness Smith) That would be correct.

Q Okay. And if -- is it also correct to say that

your testimony is relying on Mr. Gorman's recommendation for that input?

A (Witness Smith) Yes.

Q Yes. Okay. And I assume that -- well, similarly, if I -- if you recall, Mr. Gorman similarly presented testimony on cost of capital in the 2019 rate case; correct?

A (Witness Smith) Correct.

Q And in that case, that was also a large adjustment made by staff; is that correct?

A (Witness Smith) I believe it was the largest impact on revenue; correct.

Q And now they are also -- you mentioned to Mr. Kaufman for depreciation, so if I've got questions regarding depreciation, I will refer those to Mr. Kaufman; correct?

A (Witness Smith) If it's questions concerning his recommended depreciation rates, yes, that should go to Mr. Kaufman. If you have some issue with how we used his rates to calculate the impact on depreciation, that's our responsibility.

Q So you took his rates and made the calculations to adjust it for your tables; correct?

A (Witness Smith) Correct.

Q Okay. And so, finally, if I -- there are a

number of O&M adjustments. I know you and Mr. Trokey have a few of them. But the vast majority of O&M adjustments -- which I think on your table on page 26, are shown from lines 23 to 37. If I have got questions about those, I assume I refer those to Mr. Mugrace?

A (Witness Trokey) That's correct.

A (Witness Smith) Yes, except I tried to clarify that the O&M adjustment related to the electric vehicle infrastructure, Mr. Trokey and me are probably the appropriate witnesses for questions about that particular adjustment.

Q Yeah.

A (Witness Smith) I know we had listed it for Mr. Mugrace, but we are probably the better panel for that.

Q Yeah. Over the course of this morning, that became apparently very clear to me that you are, in fact, the EV panel. So I do appreciate that. But I don't -- fortunately don't have as many questions on that, because I think a lot of them were asked, but I do appreciate that, Mr. Smith.

Now, you are the panel that's supporting the staff's proposal for the ARP; correct?

A (Witness Smith) Correct.

Q And do you agree for there to be a three-year rate plan in this case, the company would have to agree to

it?

MR. WALSH: Madam Chair, I am only going to object to the extent that asks for a legal conclusion. The Panel can answer to the extent that they feel they are able to answer the question.

MADAM CHAIR PRIDEMORE: Rephrase your question.

MR. MARZO: Sure.

BY MR. MARZO:

Q I believe I have asked this question to you before in prior cases.

Do you agree that for there to be a three-year rate plan in this case, the company would have to agree to it?

A (Witness Smith) The way the rate plans have been done, the company agrees to it and the Commission approves it before they are implemented.

Q And otherwise -- am I correct, Mr. Smith, that we would otherwise have a traditional rate case?

A (Witness Smith) If no agreement can be obtained on the alternative rate plan, the fall-back option is to have the traditional rate case and set the revenue requirement using that.

Q Okay. I think you were asked some questions this morning about a traditional rate case, and it's my understanding that under a traditional rate case framework,

the company could come back here every year in lieu of sort of the three-year rate plans that we have been operating under; correct?

A (Witness Smith) If it believes that it's not able to earn a reasonable return or that it has growing investment, it certainly could.

Q Now, would you agree with me that the Commission has approved alternative rate plans that have included levelized increases in prior cases?

A (Witness Smith) In some instances I think they used a levelized approach. In others, they used the step approach, like in the 2019.

Q Okay. So it has varied over the history of these alternative rate plans; correct?

A (Witness Smith) It has varied, yes.

Q So when we talk about whether there are step increases or levelized increases for the range of the ROE band for this alternative rate plan, these are all elements of the alternative rate plan that the company must agree to and the Commission ultimately must approve; correct?

A (Witness Smith) Those would be some of the key parameters, yes.

Q Okay. And to the extent there have been recommendations by staff and other parties regarding modifications to the current ARP, those modifications would

first have to be agreed to by the company; correct?

To the best of your knowledge. I'm not asking --

MR. WALSH: Right. I just -- I think he's not offering a legal opinion as to the Commission's authority to order the rate plan. That's all I wanted to make clear.

MADAM CHAIR PRIDEMORE: I don't see anything legal about the question.

MR. WALSH: When the question is that the company would have to agree, I just didn't want it to be construed that the Commission didn't have the legal authority. I am not trying to raise the issue. I am just saying this wouldn't be the panel.

MR. MARZO: And I'm not -- I am sorry, Mr. Walsh.

I am not trying to tie Mr. Walsh's ability to brief that issue if it ever becomes a legal issue. I think they've agreed previously. So I will move on, Madam Chair.

MADAM CHAIR PRIDEMORE: Go ahead.

BY MR. MARZO:

Q Now, you are aware that the Commission has consistently approved three-year ARPs since 1995; correct?

A (Witness Smith) For a long time. I don't

know -- I don't know the starting date was 1995, but certainly for a long time.

Q Okay. And can we agree that the alternative rate plans approved by this Commission have been a key component of constructive regulatory environment here in Georgia?

A (Witness Smith) I think we'd agree with that.

Q And can we agree that this constructive regulatory environment has been a critical component to supporting the growth and population of businesses in Georgia?

A (Witness Smith) Generally agree, yes.

Q And are you aware that Georgia was voted the top place to do business for the ninth consecutive year?

A (Witness Smith) I wasn't aware of that, but I was kind of anticipating the horn-blowing section, so...

A (Witness Trokey) I think there are a variety of publications that issue these rankings, and there may be one that had Georgia at the top. I am not familiar with the -- I don't have that information in front of me. But I am also aware of other rankings and, fortunately, I think Georgia is usually in the top 10.

Q Okay. Well, I actually have a copy of Georgia.org's press release on the matter and wanted to ask you some questions on it, so this might be an appropriate

time to do that.

Madam Chair, could I approach?

MADAM CHAIR PRIDEMORE: You may approach.

MR. MARZO: This is from Georgia.org, and it's titled "Georgia Named Number 1 for Business for Unprecedented Ninth Year."

Madam Chair, I would ask that it be marked as GPC Exhibit 35.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as GPC Exhibit 35.)

BY MR. MARZO:

Q Gentlemen, I will give you a chance to review that. And this is from September 28th, 2022.

And I have highlighted some passages that I would like for you to read, and then I will ask you some questions.

MADAM CHAIR PRIDEMORE: I would like the witnesses to read these aloud.

MR. MARZO: Yes, Madam Chair, I would as well.

MADAM CHAIR PRIDEMORE: Thank you.

BY MR. MARZO:

Q If you would, read the highlighted sections.

MADAM CHAIR PRIDEMORE: Sections, please.

A (Witness Smith) "Georgia tied for first place

in energy availability and costs. Area Developments 2022 Top States for Doing Business results reflect the rankings that states received based on scores in the following categories: Overall cost of doing business, cooperative and responsive state government, favorable regulatory environment, corporate tax environment, business incentives, competitive labor environment, workforce development programs, logistics and infrastructure, access to capital and project funding, available real estate, energy availability and costs, speed of permitting, and site readiness programs. Georgia placed in the top 10 for all 13 categories."

BY MR. MARZO:

Q Now, would you agree with me, gentlemen, that both the favorable regulatory environment as well as the availability of the energy and costs are noted specifically as key components for Georgia's success in attracting businesses?

A (Witness Smith) They are some of those components; correct.

COMMISSIONER MCDONALD: Mr. Marzo, do you -- is this an indicator of attracting businesses to Georgia or does this also include existing businesses in Georgia?

MR. MARZO: I believe it's both, Commissioner

McDonald. I believe the regulatory constructive environment here that's been provided by this Commission has shown over time, since 1995 going forward, quite frankly, that a very strong environment is here for both.

MADAM CHAIR PRIDEMORE: Go ahead.

BY MR. MARZO:

Q Now, can we also agree that during the time period that Georgia Power has operated under its constructive regulatory environment, Georgia has not only attracted businesses, but Georgia Power has also continued to provide high levels of customer satisfaction and has received awards for residential and business service?

A (Witness Smith) That's our general understanding, yes.

Q Okay. And I would like to hand you a chart that I provided to the Commission in the 2019 rate case, and I want to provide it to you as updated through this particular rate period.

I will show it to your counsel and provide it to you.

MR. MARZO: Madam Chair, may I approach?

MADAM CHAIR PRIDEMORE: You may approach.

MR. MARZO: Madam Chair, I would like to ask that this chart, which is titled "Georgia Power

Awards and Rankings," be marked as GPC Exhibit No. 36.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as GPC Exhibit 36.)

BY MR. MARZO:

Q And, gentlemen, I don't want to belabor this point. Obviously this is a chart similar to the one that I showed you in the 2022 rate case that was also entered in as Georgia Power Exhibit No. 33, but I have updated it to include what has occurred since the last ARP was approved.

And would you agree with me that when we look specifically in the areas of residential/business customer service, there have been awards won by the company, both in 2020, 2021, 2021 again for residential trusted business brands, trusted business brand in 2021, residential easiest to do business in 2020. J.D. Powers Best Practices in COVID-19 Communications Award, and also continues -- Georgia Power continues to be ranked as one of the top utilities in economic development by Site Selection Magazine. Does that all sound correct?

A (Witness Trokey) According to this, it appears to be correct. Staff is not familiar with the underlying details behind these.

I guess I would say, you know, we certainly

appreciate Georgia Power's service to its customers. I think it's important to recognize that the customers are paying for that service. And Georgia Power has had the opportunity to earn, above its midpoint, a reasonable rate of return.

So I -- you know, even with respect to doing business in Georgia, the purpose of our case is to help minimize those costs and make it even more affordable to do business in the state. So, you know, I think businesses will be more attracted to Georgia if they have lower rates.

But we do appreciate the fact that Georgia Power does regularly receive these recognitions.

Q And I appreciate that, Mr. Trokey; and I guess my concern is, if you are going to propose radical changes to the way that alternative rate plans have worked, isn't it important to understand what those radical changes might do to the way that the company is able to do business in the state?

A (Witness Trokey) I don't think we have proposed radical changes.

Q Okay. Well, let's talk a little bit about that. Before we get there, would you agree that the financial health of the utility is a major factor in a utility's ability to accrue capital to invest in transmission, distribution, and generation to serve

customers?

A (Witness Trokey) It's a factor. And we have a witness, Mr. O'Donnell, who can speak to that.

Q And would you agree, as you did in 2019, that financially unhealthy and unstable utilities do not provide superior customer service?

A (Witness Trokey) I think our recommendation, the company will have the means to continue to provide excellent customer service.

Q Well, would it surprise you the company disagreed with your position on that?

A (Witness Trokey) It would not surprise me.

Q Okay. Now, am I correct that the ROE approved by the Commission since 2007 has ranged from 11.25 percent to 10-1/2 percent; correct?

A (Witness Smith) I think that's correct, yes.

Q And I believe there was some discussion earlier about your chart on page 130 that kind of depicts the history of the alternate rate plans, I believe, from 2007 forward.

A (Witness Trokey) Correct.

A (Witness Smith) Correct.

Q Am I correct that the earnings bands used in the ARP since 2007, they have been set at the upper limit at or above 12 percent and a lower limit between 10.25 and 9.5

percent; correct?

A (Witness Trokey) Yes, the upper end has been set at 12 percent.

Q And would you agree with me that over time there has been only gradual movements in ROE and the bands set by this Commission in these alternative rate plans?

A (Witness Smith) There has been some gradual downward movement.

Q And it is fair to say that stability and gradualism have been essential components of the ARPs as demonstrated by your chart?

A (Witness Smith) Our chart demonstrates the history for 2007 through 2021.

Q Okay. And it shows gradual changes; correct?

A (Witness Smith) We would agree to that characterization.

Q Now, Mr. Smith and Mr. Trokey, you testified in Georgia Power's 2019 rate case; correct?

A (Witness Smith) Correct.

Q And the company also proposed a continuation of the three-year ARP in that case; correct?

A (Witness Smith) Continuation of a three-year ARP --

Q Three-year ARP plan.

A (Witness Smith) -- for the three years that

were being addressed in that case; correct.

Q Isn't it also true that in the 2019 rate case, like in this case, the largest adjustment made by staff was to return on equity and capital structure?

A (Witness Smith) There was a large adjustment in the 2019 case for ROE, and I think we also had a recommendation for moving the band down in that case.

Q Okay. And I'm going to touch the band in a moment, but I appreciate that, Mr. Smith.

In 2019, the PIA staff also sponsored the testimony of Mr. Gorman on ROE in that case, and this panel made recommended changes to the ARP structure; correct?

A (Witness Trokey) Yes.

A (Witness Smith) We did make changes, and Mr. Gorman was the return-on-equity witness.

Q Now, in 2019 rate case, Mr. Gorman recommended a 9.2 percent ROE of 51 percent equity. And that was roughly 175 basis points below the 10.95 the company was operating under; correct?

A (Witness Trokey) That sounds correct.

Q And can we agree the significant movement in ROE proposed by staff in the 2019 rate case was not consistent with the gradualism in ROE that we just talked about that's depicted on your chart?

A (Witness Smith) I think it was consistent with

what Mr. Gorman saw in the market for capital at that point. It wasn't consistent with what the company was recommending for ROE.

Q Okay. And you were not surprised that Mr. Coyne obviously disagrees with Mr. Gorman on that fact; right?

A (Witness Smith) We understand there is a disagreement as to what the market cost of capitalization is in this particular case, and there was in the last case as well.

Q Now, in that case, staff recommended an earnings band from 9.2 percent to 10.5 percent; correct?

A (Witness Smith) Correct.

Q And that recommendation was 150 basis points below the top of the earnings band that the company was operating under; is that correct, in 2019?

A (Witness Smith) It went down to 9.2 percent. So that would have lowered the band from 10 percent at that point, was the low end of the band. So it would have lowered it by 80 basis points.

Q Okay. And can you agree with me in looking at the chart that you have depicted on page 130 that there are not significant movements like that -- like those that were recommended in 2019 and are being recommended in this case?

A (Witness Smith) It has been stuck at a pretty

high level, and we view that as kind of being unfair to the ratepayers.

Q And ultimately, gentlemen, would you agree with me that the Commission considered all the evidence in the 2019 rate case and ordered a 10.5 percent ROE and 56 percent equity, which is very consistent with the gradualism that we talked about thus far?

A (Witness Smith) I don't know about gradual. I think it was closer to the company's position than the staff's recommendations.

Q And when I refer to "gradualism," Mr. Smith, I'm just simply looking at the depiction that staff provided on page 130, which shows very gradual movements over time.

A (Witness Trokey) So the outcome certainly of these cases depicts gradualism. And, you know, the -- staff's position is that the company has consistently earned above its midpoint of its authorized ROE.

And so in this case, our witness on the ROE can certainly speak to that in more detail. But, you know, gradualism is a concern. What staff is trying to address in this case as well is what's discretionary. And, you know, certainly it's a choice -- the Commission has the authority to set an ROE that will allow a just and reasonable return. And staff's position is that 9.45 percent would -- is just and it's reasonable.

Q And you understand, Mr. Trokey, that when we talk about setting ROEs in this case, we're talking about what's just and reasonable and what's necessary to meet an investors' expectations. So that's not discretionary as you described. Is that fair?

A (Witness Trokey) To the extent that, yes, 9.45 would meet investors' expectations, then that would be, you know, further expanded on by our ROE witnesses.

Q Or 11 percent could meet investors' expectations?

MR. WALSH: Madam Chair, we are presenting Mr. Gorman and Mr. O'Donnell later in the week to respond to questions about return on equity. This panel can answer questions about the band, but I think the cross-questions at this point are really focusing more on the appropriate return on equity and this would not be the panel for those questions.

MR. MARZO: Madam Chair, I realize that, and I'm not trying to ask them the technical questions related to ROE, but obviously Mr. Gorman is an independent outside expert who has provided his independent opinion.

In terms of the alternate rate plan and what's the appropriate alternate rate plan and what's constructive and what won't be destructive to

Georgia, that's something that falls in the full bailiwick of Commission staff, and that includes Mr. Gorman's recommendations.

So I'm not going to ask them to, you know, go down to the technical levels of Mr. Gorman's recommendations, but I was hoping I could talk to them about the significant fact that it's a huge adjustment from what's been done historically here at this Commission.

MADAM CHAIR PRIDEMORE: I will allow it because Mr. Trokey is the head of the electric staff and he hires the experts that are the witnesses that sit in that box. So -- just as long as it's not technical.

MR. MARZO: It won't be.

MADAM CHAIR PRIDEMORE: His testimony.

MR. MARZO: I will be very efficient, Madam Chair.

BY MR. MARZO:

Q In fact, I will actually have some questions for you on the earnings band and I will go ahead and ask you right now, Mr. Trokey --

COMMISSIONER MCDONALD: Mr. Marzo, before we get away from the discussion on the ROE, back in your witness, in the first round of this discussion on the rate case, I asked the -- your witness, Mr. Coyne --

is that his --

MR. MARZO: Mr. Coyne.

COMMISSIONER MCDONALD: I asked him: Where does management fit into the process in balancing with the ROE. And his reply was -- and I am reading this from the docket, that he says, "You are not going to operate the company or have an impact on the company's ability to live up to the expectations for it other than set that hurdle."

That hurdle being the ROE.

And then the company's management responsibility is to live within that framework and operate as efficiently and as effectively as it can.

So when you -- again, this Commission sets the ROE. And then it's requirement for the company to operate within the framework of that ROE. And that's your witness.

MR. MARZO: That's absolutely correct, Commissioner McDonald. And I think that we are not disagreeing on that point at all. We don't expect the Commission to give us anything. I think the company's position is we -- ROEs are set.

We are not guaranteed to earn those ROEs. We have to do what we need to do to efficiently and effectively run the company for the benefit of our

customers in order to do that. And you give us a range in which to operate in.

And I think what I am asking Mr. Trokey and Mr. Smith about is that when you change that dynamic fundamentally, does that destroy the constructive relationship that -- both how we are viewed externally, but also internally how the company is able to do that.

And so I don't think we are disagreeing at all, Commissioner McDonald, what you are saying.

MADAM CHAIR PRIDEMORE: Go ahead, Mr. Marzo.

BY MR. MARZO:

Q Now, the company -- in this case, Mr. Trokey -- I will cut to the chase -- in this case, you have recommended -- the staff has recommended an 8.5 percent to 10.45 percent earnings band; correct?

A (Witness Trokey) That's right.

Q And so staff's recommended adjustment of 155 basis points from the top of the current band the company operates under; correct?

A (Witness Trokey) Yes.

Q And can we agree that such a significant move in the band is inconsistent with the bands that have been agreed to in prior ARPs?

A (Witness Trokey) I don't know about

inconsistent. I would say it's consistent with, you know, prior recommendations from staff on what's just and reasonable and what affords the company an opportunity to earn its authorized rate of return.

Q Well, for example, you proposed a reduction to the band in 2013 to 2019 of a similar proportion and that was not included in this ARP. That was not included in those alternate rate plans or approved by this Commission; correct?

A (Witness Smith) Correct.

Q And in this case, you are also proposing a cap on earnings at 10.45 percent, with no sharing above the band; is that correct?

A (Witness Trokey) There is no cap on earnings at 10.45 percent. I think that's what I heard.

Q Let's explore that. My understanding from your recommendation is that anything over 10.45 percent, those funds would go 100 percent to customers. Is that correct?

A (Witness Trokey) That's correct. So -- I am sorry. The aspect I'm speaking to is, right, the -- the revenue would still be collected by the company. The debt revenue above the upper end of the band should flow to the benefit of ratepayers. You know, if 9.45 percent is a just and reasonable rate, certainly 10.45 is higher than that by a full percentage point.

Q And so that's the elimination of sharing as an incentive for the company; correct?

A (Witness Trokey) Well, the company keeps 100 percent of the earnings above the set point of the ROE, so -- there is already a sharing there. The company keeps 100 percent up to that 10.45 percent, which it has done for the past number of years. And then above that, then there is an additional amount to pay down regulatory assets.

Q And I guess my point, Mr. Trokey, is that historically, there is this band that the company operates in, has to operate efficiently in, and then anything above that band, there has been some level of sharing, which is currently 80 percent to customers and 20 percent to the company. And your recommendation in this case would eliminate that; is that correct?

A (Witness Trokey) I think there have been times when 100 percent has been returned to customers. I believe the company has agreed to it on those occasions. But, yeah, there have -- typically, you will have a sharing with the company above that band historically, and the staff's case does not include that.

Q Okay. Can you point me to an ARP where the company agreed to 100 percent of sharing above the band? Are you referring -- let me ask the question this way, to be fair to you. Are you referring to instances where through

stipulations the parties have agreed to share more --

A (Witness Trokey) That's correct.

Q -- than what's required?

A (Witness Trokey) That's correct.

Q Okay. Are you aware that the bottom of staff's band at 8.45 percent in this case is below even the bottom of Mr. Gorman's ROE range?

A (Witness Trokey) I'm not sure. I don't recall what his -- the bottom of his range is. But that could be.

Q Okay. You don't recall him having a 9 to 9.9 ROE range?

A (Witness Trokey) That sounds correct.

Q Okay. Fair enough. And I promised Mr. Walsh I would stay out of ROE questions, so I will leave some of that for Mr. Gorman.

Well, let me just ask this last question. I mean, does it seem consistent with the gradual approach this Commission has taken with regard to adjusting the cost back would be in the appropriate earnings band for the company to have to earn 105 basis points less under your proposal than it would have today before it could file a rate case?

A (Witness Trokey) Can you repeat the question? I mean, you're asking is staff's case reasonable? I think staff's case is reasonable. I --

Q Okay. Fair enough, Mr. Trokey.

Most of my -- probably to your satisfaction -- most of my EV questions have been asked. I do have a couple left. And I just want to understand some of what I heard today. I think most of my set questions have been already asked.

Now, in response to questions, I believe primarily from Sierra Club, I believe you stated, Mr. Trokey, that it didn't matter whether or not the EV program passes the RIM test because there's just a fundamental disagreement between the staff and the company about whether or not there should even be an EV program.

Is that fair?

A (Witness Trokey) I think it's fair. I mean, I -- staff does not think there's evidence to support that there is downward pressure on rates. But staff fundamentally does not agree with having Georgia Power's customers pay for an unregulated service and essentially to co-own these charging stations, you know, with private businesses and then earn a return on that.

Q Okay. And as it pertains to the RIM test, can we agree that you may disagree as to whether or not it puts downward pressure on customers' rates, but you understand the staff's -- the company's panel has testified that it did.

So at the end of the day, have you put forward

testimony in this case to refute that assertion?

A (Witness Trokey) I believe the company would have the burden to show whether or not it's putting downward pressure on rates. Staff has not performed an independent study. We don't have the access to the company's data. We asked for their study in order to review it, and we got a one-page listing of potential impacts by various rates. But that said, I think there are a number of assumptions that would go into even those calculations that we have not had access to.

Q Now, Mr. Trokey, I believe we had a similar discussion in the 2019 rate case, and I won't bore the Commission with going all the way through that discussion because I think they've heard a lot about EV today, but do you recall that I asked you in that case ultimately, is this a policy issue for the Commission?

Do you recall that?

A (Witness Trokey) I don't recall specifically from that case. Staff does not agree with the policy. It wasn't -- Make Ready, for instance, was not an issue that was litigated in the 2019 rate case. And Georgia Power has asked to increase it from 6 million a year to 27 million a year. And so, you know, staff's position is -- is clear. But I -- ultimately, there is a decision for the commissioners to make, because Georgia Power has requested

approval of its program.

So I believe the Commission does need to make a decision.

MR. MARZO: Madam Chair, if I could, I would like to approach --

MADAM CHAIR PRIDEMORE: You may approach.

MR. MARZO: -- Mr. Trokey.

What I am handing to Mr. Walsh and to Mr. Trokey and Mr. Smith is the final order in Docket No. 42516, which is the 2019 rate case. And this is the one that was filed February 6, 2020.

I would just ask the Commission to take notice of it. We don't need to mark it.

MADAM CHAIR PRIDEMORE: Noticed.

Do you have a question?

MR. MARZO: I do. I was going to let the witnesses have a chance to review that.

A (Witness Smith) I have read the highlighted parts.

A (Witness Trokey) We are ready.

BY MR. MARZO:

Q Okay. So as we talked before, in 2019 I think we had the discussion that this ended up being a policy decision. So if you look at this order, am I correct, Mr. Trokey, that the Commission did, in fact, make a policy

determination and found that it was important to approve the cost for the EV program and, in fact, I will say even gone -- went beyond that to say that the Commission finds that such costs must not be examined in isolation and so was not limiting that decision to just a RIM analysis but was looking at it more broadly as a policy decision for building infrastructure for the state.

Is that a fair recitation?

A (Witness Trokey) Yes. I think the order speaks for itself.

Q And I was trying not to have you read it, which is why -- well, if you want to read it, I was trying to be polite to the Commission. Not to read that long paragraph.

A (Witness Trokey) I guess all I would say is, right, this is an order of the Commission. The language is here. These issues were not litigated. The benefits were not quantified in the 2019 rate case. So I -- you know, obviously staff does not disagree with the, you know, Commission's findings.

COMMISSIONER MCDONALD: Mr. Trokey, was that $6 million -- and Commissioner Echols, you might -- wasn't it a pilot project? Wasn't it considered that?

VICE CHAIRMAN ECHOLS: No. No, it wasn't. I think -- I think we did this because it really gave

skin in the game for companies that instead of just giving them chargers, you know, companies were getting the back end of it, the Make Ready, but the companies that were getting it still had to pay for their own chargers. So we weren't giving them the chargers. We were just helping them accomplish the goal, because sometimes the Make Ready stuff has a chilling effect on whether or not the folks will even do it or not.

MADAM CHAIR PRIDEMORE: I can answer your question, Commissioner. It was not a pilot project, and it was done to encourage EV growth in the state as well as to solve the issue of desert charging.

MR. MARZO: Thank you, Madam Chair.

BY MR. MARZO:

Q One last question on this EV issue, gentlemen.

Mr. Trokey, you just said a moment ago that this issue was not fully litigated in the 2019 rate case. But you agree with me that the language that was ultimately adopted was adopted as part of a settlement that included several -- several parties, including several customers?

A (Witness Trokey) So I am not -- I don't believe this language is in the settlement agreement, if that's what you are asking. I --

Q Is your understanding there is no EV language

in the settlement?

A (Witness Trokey) There is EV language proven to $6 million per year. I don't believe this language that's highlighted in the order is in that settlement agreement.

Q Okay. And the settlement can speak for itself, so in the interest of time, I won't go through that part of it. But let me ask you this: I mean, we -- we are currently in a litigated proceeding with the company's program. And is it your understanding that several parties are supporting various aspects of the company's proposal?

A (Witness Trokey) That's my understanding.

Q Okay. Let me ask you -- I want to ask you a couple of questions about your recommendation as it pertains to stock-based compensation.

Now, gentlemen, are you aware that the company utilizes a total compensation approach that includes a base portion of compensation and a net risk portion of compensation?

A (Witness Smith) Yes.

Q And by that I mean if an employee made $100 in 2022, the base portion of compensation could be $75 and the -- that's the guaranteed to the employee, or for lack of a better word, but the remaining $25 would be at risk and subject to certain goals being met by the company?

Is that your understanding of -- of at-risk compensation?

A (Witness Smith) Generally, there's a number of different tiers in the incentive portion of that. There's the PPP, or performance pay plan. And then there's two stock-based compensation programs. And our panel's testimony, we have removed the expense for the stock-based compensation part.

There is another staff witness, Mr. Mugrace, who is making an adjustment to the PPP portion. But our testimony just adjusts the stock-based compensation portion of the expense.

Q And I understand that. And I am trying not to delve too far into Mr. Mugrace's testimony, but the fact of the matter is that I have got a few questions for you about the history of that, that Mr. Mugrace, I'm guessing, cannot answer because he has not testified here before. So if you will allow me some leeway here, I will ask you a couple questions. You tell me what you are not comfortable asking (sic), and I will know to direct that to Mr. Mugrace.

Now, is it your understanding that the at-risk component of compensation -- and I think to the point you just made, Mr. Smith -- includes both PPP, which is performance pay, and stock base?

A (Witness Smith) Yes, and there are two

particular stock-based programs. We have removed the expense related to the stock-based compensation.

Q Okay. And are you aware that the compensation program of Georgia Power has been developed so that the compensation offered to employees is targeted to the 50th percentile, to be market competitive?

A (Witness Smith) I think there's a target and then there's a range of potential outcomes that vary based on the -- the performance criteria and whether those are achieved or not.

Q And I am not necessarily talking about necessarily the annual function of how a PPP might play out, depending on various goals. What I'm asking you, are you aware that the compensation program itself has been designed with the at-risk component and with the base component such that it's at the 50th percentile for Georgia Power's --

A (Witness Smith) That's my general understanding. That's fairly consistent with other utilities in the industry that compete for the same executive talent and management talent.

Q And do you understand that having market competitive compensation allows the company to ensure that it can attract and retain highly-skilled employees necessary to provide reliable electric service for customers?

A (Witness Smith) We agree with that part, but

what we don't agree with is having ratepayers pay for the stock-based compensation component. There are several other utilities where they have a similar pay structure where they have cash compensation, annual incentive plan, and then another layer on top of that, mainly for executives and top-level managers. And we believe it's good regulatory policy have shareholders bear that level of stock-based compensation.

Q Okay. So what I'm hearing from you, I believe, is that you are not opposed to necessarily the level of compensation as set. You are opposed to it being divided out both at risk, with some components that are financial, versus just a base component. Because, Mr. Smith, isn't the alternative that you could just put 100 percent of compensation as a base component with no at-risk compensation? Isn't that an alternative?

A (Witness Smith) That would be an alternative, but that's not consistent with the utility industry, the way pay is made in the utility industry for executives.

Virtually all the big utility companies have some type of incentive compensation structure, and many of the bigger ones have a stock-based compensation as a component for the very highly paid executives. And in past rate cases, staff has recommended removing that. And in some of the past cases, it has been removed and it is fairly

consistent in the industry to see that removed.

In Florida Power & Light company's last rate case, they removed 47.9 million of executive compensation, including the stock-based compensation component. That's docket 2021-0015.

In Northwestern Energy, which is the largest energy utility in the State of Montana, a vertically-integrated utility --

Q But, Mr. Smith, I appreciate that, but you're not answering my question.

MR. WALSH: Madam Chair, I would ask that the witness be allowed to complete his response.

MADAM CHAIR PRIDEMORE: Is your response complete, Mr. Smith?

MR. SMITH: No, it is not complete.

MADAM CHAIR PRIDEMORE: Okay. Go ahead and be sure that you are answering his question as well.

A (Witness Smith) Yes.

In Northwestern Energy, which is the largest vertically-integrated electric utility operating in the state of Montana, they have removed stock-based compensation in their rate case. That's Docket No. 2022-07-078, direct testimony of Northwest Energy witness Andrew Durkin, page ADD 15. Tucson Electric Power Company, which is the second largest utility operating in the state of Arizona, they are

a vertically-integrated electric company. In their last rate case, E-01933A-19-0028, Decision No. 77856, at pages 84 and 85, the Commission ordered the removal of all stock-based compensation so that wasn't charged to ratepayers.

In Arizona Public Service Company --

MR. MARZO: Madam Chair, I would renew my objection here because my question was around the compensation structure. And what I asked the witness was: There's another way to do this. You can simply -- and we're talking --

BY MR. MARZO:

Q And I should be clear to you, Mr. Smith, we were talking to both about performance pay, which is PPP, and stock-based. And so my question to you was: There's two ways to do this. You can put some compensation at risk and incentivize performance or you could put everything in a base component and pay everything as 100 percent base. And if the company did that in this case, your objection -- the only objection that you've made, which is that there's financial components tied to some of the levels of compensation, those objections go away; correct?

A (Witness Smith) No. Because that's not the way compensation for utility industries are structured. Not for the company, not for any of these big

vertically-integrated electric utilities.

The Arizona Public Service Company, which is the largest utility in the state of Arizona, in their last rate case, Docket No. E-01345A-19-0236, all stock-based compensation was removed from the cost of service in the company's filing.

MADAM CHAIR PRIDEMORE: Mr. Smith, I need you to answer the question. I understand that you have before you a list of different utilities across the country that is interesting to you. That list is not applicable to his -- they are examples.

Answer the gentleman's question for us, please.

A (Witness Smith) Yes. His question is: What if the company structured their compensation differently.

Well, no utility in the entire country, no investor-owned utility in the entire country, to my knowledge, structures their compensation as he's describing in the alternative. The standard structure for utility executive compensation is base pay, an annual performance pay plan, and then another tier for the very highly-paid executives of stock-based compensation. And then a level of perquisites on top of that.

And it's my understanding from doing rate cases across the country that it's fairly common, even for Florida Power & Light, the big utility to the south, to remove that

type of compensation in the rate cases. That's just the point I am trying to make.

VICE CHAIRMAN ECHOLS: Mr. Smith, let me ask you, this trend that you're-- that you say you're seeing, is it -- do you think it's really pandemic related? Economy related? Is it because folks are having a harder time out there and these commissions are asking the utilities to, you know, to take lower compensation? Or what is driving this trend with these four or five that you have mentioned?

MR. SMITH: I think the trend, and it's not a recent trend because in the Florida Power & Light case, we did research what they had done in their last rate case, which was a 2010 rate case, and they did remove those components of executive compensation in that case as well.

I think it's just a recognition by regulatory commissions that shareholders should have some responsibility for this top level of executive compensation, that that's not a legitimate cost that should be borne by utility ratepayers, rather, it should be absorbed by the shareholders. It's placing the executives in the same position as the shareholders are by giving them stock or stock-based forms of compensation.

So I think there's been recognition in Florida and other jurisdictions that this particular tier of compensation should be borne by shareholders and not utility ratepayers

VICE CHAIRMAN ECHOLS: Thank you.

BY MR. MARZO:

Q And, Mr. Smith, let's take those two things in turn. First let me ask you this. If we are going to start using FP&L as an example, doesn't FP&L have a 10.8 ROE and 59 percent equity?

A (Witness Smith) I don't recall.

Q Okay. So you don't recall whether or not that may factor in to what the Commission does and does not do in settlements in that jurisdiction; correct?

A (Witness Smith) I recall that their last rate case was settled and its removal was in their own application.

Q And there's two components to compensation, and I don't want to confuse them because I think you're confused. And I don't suggest you're doing this intentionally. But I think you are confusing the stock-based component, which I will ask you some questions on, with PPP. And if we're going to start talking about what is the history of precedent, hasn't been the precedent of this Commission to allow performance pay into rates in

prior rate cases?

A (Witness Smith) The PPP component it's my understanding has generally been allowed, but the stock-based component was removed in a series of rate cases. Not in the 2019 rate case, but in a series prior to that.

Q Okay. Right now, I am only talking about performance pay. So there's been decades of performance pay being allowed in rates. And in this case, as a dramatic change to that historic position, staff is asking that two-thirds of it be removed; correct?

A (Witness Smith) This panel is only removing stock-based. I think Mr. Mugrace is making a recommendation on the PPP plan.

Q Okay. But, Mr. Trokey, you're the director of electric service here at the Commission -- and I understand Mr. Mugrace may have his opinions -- but I imagine that in discussions with Mr. Mugrace, it was told to him that the historic precedent here at this Commission has been to allow performance pay in the rates. The PPP program. I am not talking about stock-based, because I know Mr. Smith wants to talk about stock-based, but the performance pay program.

A (Witness Trokey) Historically, that's the case and, you know, each case obviously stands on its own. It's going to have different components and priorities. There are a lot of things that have changed over time, you know.

Traditionally, ratepayers have not had to -- or -- there have not been requests to pay for unregulated assets to be owned by the regulated utility either.

So, certainly a lot of changes that will happen from case to case. But the staff believes in this instance, you know, that compensation is more aligned with the interest of shareholders rather than the ratepayers.

Q So is removal of two-thirds of PPAP related to the EV program being included as a proposal in this case?

A (Witness Trokey) That's just an analogy that different things have been requested that weren't previously requested in the past. So I don't think it's a departure, and, you know, the company makes changes as well.

Q And are you aware of any changes to the program that would suggest that there needs to be a different outcome than has been in place with this Commission for the last, as far as I know, several decades that I have been down here?

A (Witness Trokey) That -- I'm not sure. I can't answer that.

Q And just on the stock-based compensation front, Mr. Smith, I understand you want to quote a lot of different jurisdictions, but I'm just going to ask you, I mean, have you done or provided an analysis of the impacts of your recommendation on total compensation?

A (Witness Smith) We've removed the amounts that are identified as stock-based compensation. Again, this is typically compensation that only the most highly-paid executives and management gets. We've removed it from the rate case.

Q And that's not my question. My question is, as we know, in these cases, you've got to put forward evidence to support positions. And I'm asking you: In this case, have you put forward evidence that has evaluated the total compensation packages and determined that the removal of stock-based compensation will not reduce the company's effectiveness and ability to attract the most talented individuals to help provide reliable service to our customers?

A (Witness Smith) Again, we have removed the stock-based compensation portion of expense. We do have, in the proprietary section of our testimony, and in some of the exhibits, some of the features of the plan. I think that shows some of the compensation ranges. I think all of that is in the proprietary stuff. But we did look at that for purposes of our analysis.

Q And I guess my final question on this is: So just to confirm for the record, you have not done any analysis to determine the impacts of less competitive compensation on the company's ability to maintain

reliability, meet customers' evolving energy needs, and provide excellent service?

A (Witness Smith) It would have no impact, because the company would still pay out under its existing compensation package. It's just the ratepayers wouldn't fund the stock-based compensation portion of that program in the rates and the revenue requirement being set in this rate case.

Q So even though it is -- even though, arguably, the company's position is that is a cost of service needed to attract the talent necessary to ensure the utility provide the service that is required by our customers, your position is: Well, it doesn't matter because others can pay for that?

A (Witness Smith) This portion of the compensation package we believe should be absorbed by shareholders and not charged to ratepayers. We are not saying that the company shouldn't pay it. We don't mind if the company pays it. That seems to be consistent with the way compensation in the utility industry is structured. We just don't think that this particular component of it should be borne by ratepayers because it puts the recipients into the same position as shareholders.

Q Okay. And we're talking the stock-base. And we can agree that when we talked throughout this discussion,

so the record is clear, PPP, different than stock-base; correct?

A (Witness Smith) PPP is different than stock-based.

Q Okay.

A It applies it a much broader range of participants. It has different criteria. It is an incentive program. And Mr. Mugrace is addressing that in his testimony.

Q And that's available to all employees, including union employees too; correct?

A (Witness Smith) It is available, I think, to a very broad range of employees, correct.

Q Thank you, gentlemen. I appreciate your time today.

MR. MARZO: Thank you, Madam Chair, for allowing me time to cross.

MADAM CHAIR PRIDEMORE: Redirect?

MR. WALSH: Thank you, Madam Chair. I don't have much on redirect.

REDIRECT EXAMINATION

BY MR. WALSH:

Q You were asked about the band that you were proposing as part of this case.

How did you develop the proposed earnings band?

A (Witness Smith) We started with Mr. Gorman's recommended rate of return and we looked at the history. The history was -- for most of the history was a 200 basis point band. So we selected a range of 100 basis points on either side of Mr. Gorman's recommended band. I know in some prior cases we've tried to narrow the band.

Virginia has a similar earnings test. They have an earnings test. They use 70 basis points around the authorized ROE band. So -- and we would like to see the band reduced, I guess. So currently it is 250 basis points. We thought 200 basis points was reasonable in the context of this rate case. If the Commission wanted to reduce it to plus or minus 70 basis points, you know, we -- I think a narrower band would be helpful to balance the interest of ratepayers and shareholders.

Q You were asked whether the bottom of your proposed earnings band was below the bottom of Mr. Gorman's range. Do you recall that question?

A (Witness Smith) I recall the question, yes.

Q Is the top of the staff's recommended earnings band above the top of Mr. Gorman's 9 to 9.9 range?

A (Witness Smith) The top end of the band would be 10.45, so the top end would be above his -- the top end of his ROE range.

Q So if -- if the Commission were to decide that

it did not want the bottom end of the earnings band to be below the bottom of Mr. Gorman's range or the top of the earnings band to be above the top of Mr. Gorman's range, they would just have to approve a narrower band around the -- his recommended ROE? Is that how it would work?

A (Witness Smith) Well, I think the band serves a different purpose than the return on equity witnesses' range of his ROE estimates. I mean, conceivably, the Commission could look at the ROE witnesses' band and set -- use that for setting the sharing band. But we thought in this particular instance, the 100 basis points below and above his ROE set point would represent a reasonable sharing band.

Q Thank you.

You were asked about the principle of gradualism. Do you recall those questions?

A (Witness Smith) Some of them at least, yes.

Q Do you think that in approving rates in this case, including looking at return on equity, that the Commission should look at what is just and reasonable based on the evidence in this case?

A (Witness Smith) Yes. I think in every rate case, the Commission should look at what is just and reasonable, including the cost of capital.

We usually see gradualism brought up in rate

design, you know, are you going to increase the customer charge by 100 percent or can that be minimized to, you know, some more gradual path of adjusting the rates.

So the concept of gradualism in rate-making, I think, is mainly applied in the area of rate design, to try to mitigate large rate impacts.

Q So let's say that the evidence in this case supported a lower return on equity or let's say this -- the evidence in this case supported a lower return on equity than the company was awarded in the 2019 rate case or a different earnings band than the company was approved for in the 2019 rate case.

Would you consider the Commission basing the decision based on the evidence in this case to be a violation of the principle of gradualism?

A (Witness Smith) No.

Q You were asked questions about the EV Make Ready program. And you were specifically asked a question, Mr. Trokey, about how long the program would be in place for or were certain that the program would be in place for.

Do you recall that question?

A (Witness Trokey) I do.

Q How long has the company proposed the EV Make Ready program?

A (Witness Trokey) So the funding that was

deployed during the last alternative rate plan, you know, those costs will be recovered over, I believe, a 10- or 15-year period of time. And same for this case, the assets that they are requesting to deploy under the Make Ready and Community Charger would also be recovered over that period of time, and it -- you know, I guess there's -- from staff's perspective, there's not necessarily anything -- if this is approved and if this is a new regulatory approach for utility ratepayers to have to fund this type of program going forward, it's staff's expectation that the company would continue to request and expand the program going forward.

MADAM CHAIR PRIDEMORE: Mr. Trokey, that's not the answer to his question.

MR. TROKEY: I'm sorry. I thought it was.

MADAM CHAIR PRIDEMORE: His question was: When did it start? Did it start in the 2016 rate case? The 2019 rate case? Was it an IRP? Do you remember when it started?

MR. TROKEY: Was that the question, when it started?

MR. WALSH: I will ask that question as well.

BY MR. WALSH:

Q Do you recall when the program started?

A (Witness Trokey) Sure.

MADAM CHAIR PRIDEMORE: That wasn't the question?

MR. WALSH: I probably inartfully phrased it, but what I was asking -- what I was addressing were questions about how long the program was going to be in place for going forward. I probably should have phrased that, so I can see where I was ambiguous.

MADAM CHAIR PRIDEMORE: So based upon it was already approved?

MR. WALSH: Right. I was asking for, you know, what's the company requesting for and how long is -- would the program be in place if the company's request was approved.

MADAM CHAIR PRIDEMORE: In this request or in previously-approved requests?

MR. WALSH: I did not specify, but I should have specified, in this request.

MADAM CHAIR PRIDEMORE: Okay.

A (Witness Trokey) So the funding in this request is for 27 million per year for the next three years. However, the costs associated with that, the revenue requirement would be collected from customers over the next decade, I believe.

BY MR. WALSH:

Q Does the company earn a return on its Make

Ready investment?

A (Witness Trokey) It does.

MR. WALSH: Madam Chair, that completes all of the redirect that I had. I would ask that Staff Exhibits 12 through 41 be admitted into evidence.

MADAM CHAIR PRIDEMORE: So moved. So marked.

(Staff Exhibits 12 through 41 were admitted into evidence.)

MADAM CHAIR PRIDEMORE: You may excuse your witnesses.

Next panel. The panel of Baron and Wellborn.

MR. MARZO: Madam Chair, in the interim, can I ask my exhibits be moved in. I don't think I asked for that.

MADAM CHAIR PRIDEMORE: So moved. Georgia Power's exhibits moved into evidence.

(GPC Exhibits 35 and 36 were admitted into evidence.)

MADAM CHAIR PRIDEMORE: Hello, Mr. Ingraham.

MR. INGRAHAM: Good afternoon, Madam Chair.

MADAM CHAIR PRIDEMORE: You're a new face on that table.

MR. INGRAHAM: Yes, I am, and I am happy to provide a new face to these proceedings.

MADAM CHAIR PRIDEMORE: Thank you. Glad you're

here.

MR. INGRAHAM: Glad to be here. Thank you for having me.

Okay. At this time, staff would like to call the panel of Stephen J. Baron and Leah Wellborn on behalf of Commission Public Interest Advocacy Staff.

If you both could remain standing, I will swear you in. Raise your right hand, please.

Thereupon,

STEPHEN J. BARON,
LEAH WELLBORN,
having been duly sworn, testified as follows:

MR. INGRAHAM: Thank you. Please be seated.

DIRECT EXAMINATION

BY MR. INGRAHAM:

Q Mr. Baron, could you please state your full name for the record and by whom you are employed and your position.

A (Witness Baron) Yes. My name is Stephen Baron. I am employed by J. Kennedy and Associates, Inc., and I am the president of the firm.

Q Ms. Wellborn, could you please state your full name and by whom you are employed and your position.

A (Witness Wellborn) Leah Wellborn, Manager of Consulting at J. Kennedy and Associates.

Q Thank you.

Mr. Baron, on October 20th of 2022, did you and Ms. Wellborn prefile or cause to be prefiled 30 pages of public disclosure testimony in question-and-answer form?

A (Witness Baron) Yes.

Q Are there any changes or corrections that you would like to make to that prefiled direct testimony at this time?

A (Witness Baron) None that I am aware of.

Q So if I were to ask you the same questions that are presented in the prefiled testimony, would your answers be the same?

A (Witness Baron) Yes.

MR. INGRAHAM: Madam Chair, I would ask that the public disclosure prefiled direct testimony of Mr. Baron and Ms. Wellborn be copied into the record as if read from the witness stand.

MADAM CHAIR PRIDEMORE: So moved.

MR. INGRAHAM: Thank you.

(Whereupon, the prefiled direct testimonies of Stephen J. Baron and Leah Wellborn follows:)

**PUBLIC DISCLOSURE**

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

| | | |
|---|---|---|
| **GEORGIA POWER COMPANY'S 2022 RATE CASE** | **)** **)** | **DOCKET NO. 44280** |

# DIRECT TESTIMONY AND EXHIBITS

**OF**

**STEPHEN J. BARON**

**LEAH WELLBORN**

**ON BEHALF OF THE**

**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

**OCTOBER 20, 2022**

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## I. BACKGROUND AND QUALIFICATIONS

**Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.**

A. My name is Stephen J. Baron. I am President and a Principal of Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

My name is Leah J. Wellborn. I am Manager of Consulting at Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

**Q. WHAT CONSULTING SERVICES DOES KENNEDY AND ASSOCIATES PROVIDE?**

A. Kennedy and Associates provides consulting services related to electric utility system planning, resource analysis, production cost modeling, ratemaking, finance, accounting, and industry policy issues.

**Q. PLEASE PROVIDE SUMMARIES OF YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A. Summaries of our education, experience, professional certifications, and testimony appearances are provided in Exhibits STF-BW-1 and STF-BW-2 for Mr. Mr. Baron and Ms. Wellborn, respectively.

**Q. HAVE YOU BOTH PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Yes. Mr. Baron and Ms. Wellborn have testified before this Commission on a number of occasions. Most recently, Mr. Baron and Ms. Wellborn testified in the Georgia Power Company's 2022 Integrated Resource Plan proceeding (Docket No. 44160).

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. We are presenting testimony on behalf of the Commission's Public Interest Advocacy Staff ("Staff").

## II. SUMMARY AND RECOMMENDATIONS

**Q. WHAT ARE THE SPECIFIC ISSUES THAT YOU ADDRESS IN YOUR TESTIMONY?**

A. The issues we address are associated with Georgia Power's projected retail revenues, at present rates, for the test year in this case (12 months ending July 31, 2023) and each of the three Plan Years: 2023, 2024 and 2025. For each of these four periods, the Company has developed a detailed revenue forecast that estimates the revenues that the Company will receive at present Commission approved rates. In order to develop the revenue deficiency in this case, projected revenues at present rates are compared to the revenue requirement for each of the four periods. The difference between these two amounts

(revenues at present rates and revenue requirements) produces the amount of the revenue deficiency and rate increase that is necessary to recover the revenue requirement.

The purpose of this testimony is to present our findings and recommend appropriate adjustments to the Company's revenue projections based on the Staff's independent development of alternative revenue forecasts for a number of rate classes.

**Q. PLEASE DESCRIBE THE ANALYSES THAT THE STAFF PERFORMED TO ASSESS THE REASONABLENESS OF THE COMPANY'S REVENUE FORECASTS FOR THE TEST YEAR AND THREE PLAN YEARS.**

A. The Staff reviewed and analyzed approximately 50 Excel spreadsheets/models developed by the Company that ultimately rolled-up into the retail revenue forecasts shown in Exhibit APA-SPA-ADH-MBR-1, Schedule 1 Total Company ("Schedule 1") for the test year and each Plan Year. Schedule 1 provides the revenues used by the Company to determine the revenue deficiency in this case, both on a traditional basis and on a levelized basis.

The initial starting point for the development of the revenue forecast is the projection of base tariff revenues for each of the Company's five rate classes (Residential, Commercial, Industrial, Governmental Lighting, MARTA). These base tariff revenues are the revenues produced from the Company's individual rate schedules. In addition, there are revenues produced by various riders ("Recovery Tariffs"), fuel charges, and a number of adjustments

that will be discussed subsequently in our testimony. Table 1 below shows the components that comprise the Total Company retail revenues included in Schedule 1 for the test year, based on the original filing. Also included are the adjustments made by the Company to Schedule 1 in the Supplemental Filing.

**Table 1: GPC Test Year Projected Revenues ($000)**

| | |
|---|---|
| **Present Revenue by Rate (MFR F-4)** | **6,091,456** |
| NCCR, MFF Adjustments | 8,155 |
| **Retail Revenue Forecast (Appendix Exhibit 1_2)** | **6,099,611** |
| Retail Fuel Revenues, adjustments | 2,004,392 |
| **Total Sales of Electricity (AAHR Schedule 1 Original Filing)** | **8,104,003** |
| Supplement Filing Adjustments | (3,756) |
| **Total Sales of Electricity (AAHR Schedule 1 Supplemental)** | **8,100,247** |

Table 2 summarizes the information for the test year and each Plan Year.

**Redacted Table 2: GPC Projected Revenues ($000) – Test Year and Plan Years**

| | Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| **Tariff Revenue Projected (JKA 1-2 Attach R Update)** | [redacted] | | | |
| Recovery Tariff Revenues, adjustments | | | | |
| **Retail Revenue Forecast (Appendix Exhibit 1_2)** | | | | |
| Retail Fuel Revenues, adjustments | | | | |
| **Total Sales of Electricity (AAHR Schedule 1 Original Filing)** | | | | |
| Supplement Filing Adjustments | | | | |
| **Total Sales of Electricity (AAHR Schedule 1 Supplemental)** | | | | |

As shown in Tables 1 and 2, the revenues produced by base tariffs (rate schedules) form the largest portion of total retail revenues. All of these revenue projections are based on an assumption that current base tariff rates charges remain in effect in the test year and Plan Years without any rate change. What does change, however, are rate class kWh sales,

the number of customers in each rate class and the impact of these changes on the average rate produced by existing rate designs.[1] The Staff's primary analysis focused on these base tariff revenue projections. For the largest rate classes the Company relied on statistical regression models to develop average rate curves. These average rate curves, when combined with the Company's projected MWh sales forecasts developed in the recent IRP case produce projected base tariff revenues for each rate class and sub-class. In its analysis, the Staff analyzed alternative specifications and estimation periods in cases where the staff believed that an alternative model would be more appropriate. Based on this analysis, the staff developed three alternative average rate curve models.

**Q. WHAT ARE THE STAFF'S RECOMMENDED ADJUSTMENTS TO THE COMPANY'S TEST YEAR AND PLAN YEAR RETAIL REVENUES?**

A. Table 3 summarizes the Staff's recommended adjustments to projected test year and Plan Year retail revenues.

[1] For example, if the average kWh usage per customer for the residential class changes, even though the tariff rates do not change, the average revenue produced by each residential kWh will change. Measuring this change is the basis of the revenue forecast.

**Table 3: Staff Projected Revenues Per Schedule 1 - Test Year and Plan Years ($000)**

| | Test Year | CY 2023 | CY 2024 | CY 2025 |
|---|---|---|---|---|
| **Original Filing:** | | | | |
| GPC | 8,104,003 | 7,994,109 | 7,928,981 | 8,002,496 |
| Staff | 8,110,042 | 7,999,854 | 7,933,895 | 8,010,328 |
| Staff Adjustment | 6,039 | 5,745 | 4,914 | 7,831 |
| | | | | |
| **Supplemental Filing:** | | | | |
| GPC | 8,100,247 | 7,987,736 | 7,915,934 | 7,983,007 |
| Staff | 8,106,282 | 7,993,475 | 7,920,837 | 7,990,816 |
| Staff Adjustment | 6,035 | 5,739 | 4,903 | 7,808 |

Table 3 shows the Staff's recommended adjustments based on both the Company's original filing and its Supplemental Filing. The Staff's analysis indicates that retail revenues, based on current rates (i.e., no rate change) would be about $6 to $8 million higher than estimated by the Company. As we will discuss subsequently, the Staff's adjustments are based on the results using alternative statistical models that project average rates/kWh for four of the Company's retail rate classes and sub-classes. These model differences, when projected on a monthly basis for the period August 2022 through December 2025 produce a relatively small change in projected revenues.[2] For example, in the test year ending July 2023, the total retail revenues projected by the Company in its Supplemental filing are shown to be $8,100,247 ($000)[3] (see page 4 of Schedule 1). The Staff's analysis produces a retail revenue amount that is about 0.1% greater [$8,106,282 ($000)].

[2] The Staff's recommended revenues also include the related impacts of the alternative base tariff revenue forecasts on Recovery Tariff revenues and other adjustments.
[3] See page 4 of Company Schedule 1 Supplemental.

**Q. IS THE STAFF RECOMMENDING THAT THE COMMISSION ADOPT ITS ALTERNATIVE REVENUE PROJECTIONS?**

A. Yes. The Staff has incorporated its adjusted revenue projections in the overall recommended revenue deficiency in this case. Staff believes that its alternative average rate curve models are more reasonable than the Company's estimates, and therefore supports its retail revenue adjustments based on those alternative models. As we will explain in later in this testimony, the use of a projected test year or projected plan years requires numerous forecasts of revenues, expenses, investment, and other factors. For the most part, the Staff agrees with the Company's methodology used to project revenues. The Staff's alternative average rate curve statistical models, which rely on the same historic information as used by the Company in its analyses, are simply alternative statistical model specifications, which the Staff believes are more reasonable than the models developed by the Company.

## III. REVIEW OF REVENUE FORECAST METHODOLOGY

### ENERGY FORECAST

**Q. WHAT WAS THE STARTING POINT FOR DEVELOPING THE REVENUE FORECASTS FOR EACH OF THE FOUR PERIODS?**

A. Each of the four revenue forecasts (test year and three Plan Years) were developed using the identical methodology. Separate forecasts were developed for each of the five rate classes (residential, commercial, industrial, governmental lighting and MARTA). The forecasts are driven by the kWh energy sales forecasts presented by the Company in the 2022 IRP case and is designated as the B22 Forecast. This rate class energy forecast was previously evaluated by the Staff in the IRP case. The Staff did not recommend any adjustments to the energy sales forecast in the IRP case and the Company's B22 sale forecast was approved by the Commission in its Order in that case. The Company did not make any adjustments to the approved B22 sales forecast in its revenue forecast in this case.[4]

## REVENUE FORECAST

**Q. HOW DID THE COMPANY DEVELOP ITS REVENUE FORECAST?**

A. For the residential and parts of the commercial and industrial rate classes not associated with a real-time pricing ("RTP") rate,[5] the revenue forecast is based on the product of the B22 energy forecast each month and a projection of the average rate/kWh for the class (e.g., residential) or subclass within a class (e.g., commercial FPA, commercial Non-RTPFPA, commercial RTP CBL, industrial FPA, industrial RTP CBL, where "FPA" stands for fixed pricing alternative). For the residential class and five commercial and

[4] Response to STF-JKA 1-3.
[5] Real-Time Pricing rates are retail tariffs available to customers that price energy at marginal prices. Generally, the energy sold at an RTP price is indicative of a market price with a risk adder.

industrial subclasses, the Company developed statistical regression models to forecast the average rate/kWh as a function of monthly average kWh usage per customer for the class or subclass. For commercial and industrial RTP subclasses, and lighting and MARTA revenues, revenues were projected using a number of different methodologies, which will be discussed later in our testimony. The methodology that the Company employed is much more complex than what was presented in its minimum filing requirements.[6]

In addition to the development of base tariff revenue forecasts described above, the Company also developed separate projections of rider revenues associated with Nuclear Construction Cost Recovery (NCCR), Demand Side Management (DSM), Environmental Compliance Cost Recovery (ECCR), and Municipal Franchise Fee (MFF) tariffs.

**Q. PLEASE EXPLAIN HOW THE REVENUE FORECAST CHANGES BY CLASS OVER THE FORECAST YEARS.**

A. The Company provided estimates of forecasted retail revenues for the test year in this case (12 months ending July 31, 2023) and for three Plan Years (calendar years 2023, 2024 and 2025). For the test year, the retail revenue forecast projects that the Company will receive $6,099,611 ($000) at present rates, excluding fuel adjustment charges. Table 4 provides a breakdown of the Company's overall forecast into 5 rate classes (Residential, Commercial,

[6] Appendix Exhibit 1_2.

Industrial, Government Lighting ("GL", "Light"), and MARTA. All of the Company's revenue projections are based on these 5 rate classes. These revenue forecasts are then allocated to individual rate schedules within each rate class. These amounts estimate the projected revenues for the test year without a rate case and rate increase. It is from this estimate that the rate increase is measured (the amount of the dollar increase).

**Table 4: GPC Projected Test Year Base and Rider Revenues ($000)**

| GPC | Residential | Commercial | Industrial | Light | MARTA | **TOTAL** |
|---|---|---|---|---|---|---|
| Base | 2,330,124 | 1,766,773 | 690,672 | 55,862 | 4,191 | **4,847,622** |
| ECCR | 421,515 | 306,705 | 92,714 | 10,344 | 609 | **831,887** |
| NCCR | 91,690 | 67,746 | 20,270 | 2,253 | 133 | **182,092** |
| DSM | 22,883 | 22,180 | | 748 | | **45,811** |
| MFF | 86,729 | 71,193 | 32,166 | 1,842 | 269 | **192,199** |
| **TOTAL** | **$2,952,941** | **$2,234,598** | **$835,821** | **$71,050** | **$5,201** | **6,099,611** |

It should be noted that this total revenue amount does not include fuel revenues or a number of adjustments to tie to Schedule 1 revenues. These will be discussed later in our testimony.

## FORECAST RECONCILIATION

**Q. THE COMPANY PROVIDED REVENUE FORECASTS ACROSS A NUMBER OF ITS FILED DOCUMENTS. WERE THESE DOCUMENTS CONSISTENT?**

A. No.

**Q. THE COMPANY'S SCHEDULE MFR F-4 SHOWS THAT BASE AND RIDER (RECOVERY TARIFF) REVENUES, EXCLUDING FUEL, FOR THE TEST YEAR ARE $6,091,456,316. THIS IS ALSO THE BASIS FOR THE COMPANY'S TEST YEAR RATE DESIGN. WHAT IS THE DIFFERENCE BETWEEN THE REVENUES SHOWN IN MFR F-4 AND THE $6,099,611,080 SHOWN IN TABLE 4?**

A. The difference ($8,154,764) represents two adjustments that the Company made to projected test year revenues. The first adjustment increases revenues by $[redacted] to reflect higher NCCR revenues in the revenue forecast than what was used for rate design; the second adjustment is a reduction in test year MFF revenues of $[redacted].

**Q. WHAT IS THE TOTAL REVENUE BY RATE CLASS PROJECTED BY THE COMPANY FOR THE TEST YEAR AND EACH OF THE THREE PLAN YEARS?**

A. Table 5 shows the total test year and Plan Year revenue amounts based on the Original Filing and the adjustments made in the Supplemental Filing. Total revenue includes the amounts shown in MFR-4, plus a number of additional items that are included in the calculation of the Company's filed revenue deficiency. Table 5 provides the full reconciliation of the base tariff revenues, Recovery tariff revenues, fuel revenues and each of the adjustments made by the Company to produce the Retail Revenue amounts shown in Schedule 1 in both the Original Filing and the Supplemental Filing.

The first section of Table 5 shows the results of the Company's revenue forecast modeling, including both the average rate curve modeling and the forecasts using other methods (e.g., trend analysis). The second section shows Recovery Tariff revenues and various adjustments that are needed to properly reflect revenues at present rates in the projected periods. One of the large adjustments ($194 million) is needed to reflect the additional revenues produced by the 2019 rate case 3rd step revenue increase that occurred on January 1, 2022. Because all of the Company's revenue forecast modeling only reflected data through August 2021, the January 2022 revenue increase was not included in the model-based forecasts. As such, the Company added an additional $194 million as an after-the-fact adjustment.

The third section of Table 5 removes both the NCCR revenues and the MFF revenues from the forecast, as well as adds in fuel revenues. In addition, a small amount of wholesale revenues are included as a revenue credit in the projection.

**Redacted Table 5: GPC Projected Base and Recovery Tariff Revenues ($000)**
**Test Year and Plan Year Reconciliation with Schedule 1**

| Base Tariff Revenues (per the revenue forecast modeling) | Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| Residential | | | | |
| Commercial | | | | |
| Industrial | | | | |
| Street Light | | | | |
| Marta | | | | |
| **Tariff Revenue Projected (JKA 1-2 Attach R Update)** | | | | |
| Flat Bill Adjustment | | | | |
| 2019 Rate Case 3rd Step Revenue Increase | | | | |
| ECCR | | | | |
| DSM | | | | |
| NCCR | | | | |
| MFF | | | | |
| Incremental (RTP Rev) | | | | |
| **Retail Revenue Forecast (Appendix Exhibit 1_2)** | | | | |
| NCCR Tariff Adjustment (remove NCCR revenues) | | | | |
| DSM Tariff | | | | |
| Municipal Franchise Fees Adjustment (remove MFF revenues) | | | | |
| Normalizaton Items | | | | |
| NCCR/DSM (Over/Under) Recovery | | | | |
| Total Retail Fuel Revenues | | | | |
| Wholesale Revenues | | | | |
| **Total Sales of Electricity (AAHR Schedule 1 Original Filing)** | | | | |
| Traditional Base | | | | |
| ECCR | | | | |
| DSM | | | | |
| Wholesale | | | | |
| **Total Sales of Electricity (AAHR Schedule 1 Supplemental)** | | | | |

**Q. DID THE COMPANY PROVIDE THIS COMPLETE RECONCILIATION IN ITS TESTIMONY, EXHIBITS OR WORKPAPERS THAT IT FILED IN THIS CASE?**

A. No. Through a number of formal and informal data requests, the Company has provided information that permitted the development of a complete reconciliation. As will be discussed later in our testimony, the Staff strongly recommends that in future rate cases, the Company be required to file complete reconciliations so that the Staff and other parties

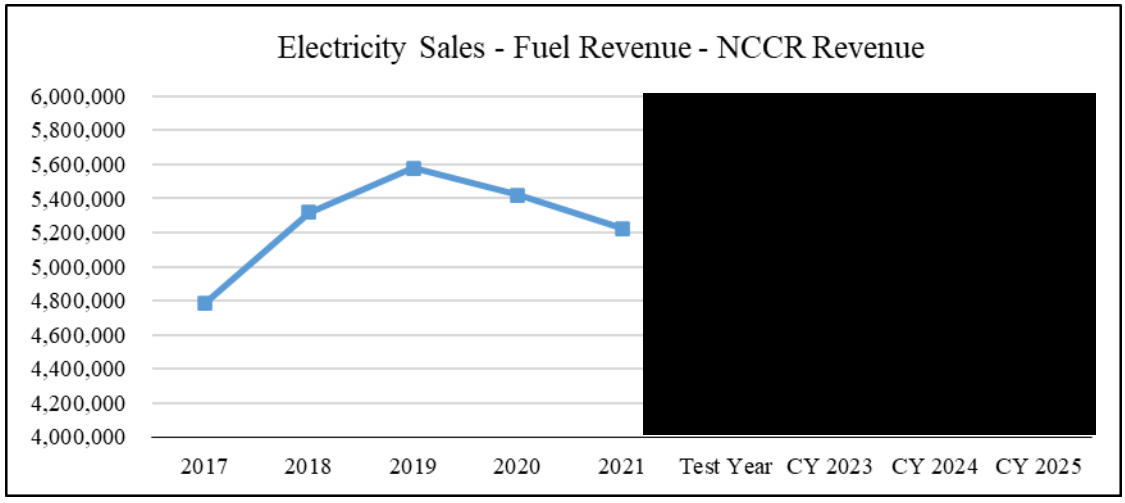
can evaluate the entirety of the Company's analysis. This should also include detailed explanations of the items included in the reconciliation.

## HISTORIC REVENUES AND TREND REVIEW

**Q. HOW DOES THE COMPANY'S FORECAST COMPARE TO HISTORICAL TRENDS?**

A. Figure 1 provides a high-level comparison of the trends.[7] Staff believes the forecast is generally consistent with the historical trend. It is important to recognize that the historical data included base rate increases, while the projected data is based on current rates as of January 2022.

**Redacted Figure 1: Comparison of Forecasted Revenues to Recent History ($000)**




[7] Historic sales Revenue data is from GDS 3-1 from Docket 44160 (Public Disclosure) adjusted for Fuel Cost (PD) and NCCR cash collections (Docket 29849, STF-230-26-b, Public Disclosure). Forecasted data is from JKA 1-2 Attachment R Update 2022-25 TRADESECRET "RECONCILE FOR STAFF" tab.

**FORECAST COMPONENT REVIEW**

**Q. YOU NOTED PREVIOUSLY THAT THE STAFF FOCUSED ITS ANALYSES ON THE BASE TARIFF PROJECTIONS THAT RELIED ON STATISTICAL AVERAGE RATE CURVE MODELING. WOULD YOU DISCUSS THE COMPANY'S AVERAGE RATE CURVE MODELING?**

A. The Company derived its average rate curve models utilizing the EViews statistical software. Each statistical regression model followed the same general specification; average cost per kWh for the rate class or, in the case of the commercial and industrial classes, by sub-class was the dependent variable and the independent variables consisted of various formulations of average kWh usage per customer and indicator variables (binary variables). To produce the monthly revenue forecast, the projected average rate per kWh is multiplied by the kWh energy sales forecast for the rate class (or sub-class) using the B22 energy forecast presented in the recent IRP case.

For certain classes (commercial incremental RTP, industrial incremental RTP, industrial NonRTPFPA, Government Lighting, MARTA), the revenue forecasts are derived using more direct approaches. The forecasts are made up of numerous subparts that are summed together to derive the class forecast. The subparts, or components, have specific short-hand, and generally include an average rate curve component, an "FPA" component which describes the Fixed Pricing Alternative rate design, or a Real Time Pricing ("RTP") incremental rate and an RTP Customer Baseline Load (CBL) component. The total forecast

can be distilled down into approximately 12 individual forecast components, as summarized in Table 6.[8] The Company's forecasting approach breaks the commercial, industrial and MARTA rate classes into these separate groups (components) that reflect similar rate designs. For example, customers taking service under the Commercial RTP rates pay separate charges for their CBL usage and their incremental usage. Since the underlying rates for these two components (CBL, incremental usage) are priced differently, it is reasonable to separately develop revenue forecasts for each component. These are then combined to develop the total Commercial RTP revenue projection. The table describes the components of each forecasted revenue class as well as a note on Staff's review and any proposed adjustment.

[8] In the 2022 rate case, the Company did not include commercial or industrial adjustments in its base tariff forecasts.

**Table 6: Revenue Forecast Components Reviewed**

| Forecasted Class | Forecast Component | Staff Adjustment Summary |
|---|---|---|
| Residential | Residential | **Rate Curve (Staff Adjustment)** |
| Commercial | Com FPA | Rate Curve |
| | Com NonRTPFPA | **Rate Curve (Staff Adjustment)** |
| | Com CBL - RTP | Rate Curve |
| | Com Adj | N/A |
| | Com Incr - RTP | RTP Workpaper |
| Industrial | Ind FPA | Rate Curve |
| | Ind NonRTPFPA | Trend Analysis[1] |
| | Ind CBL - RTP | **Rate Curve (Staff Adjustment)** |
| | Ind Adj | N/A |
| | Ind Incr - RTP | RTP Workpaper |
| Govt Lighting | Govt Lighting | Govt Lighting Trend Analysis[2] |
| MARTA | Marta CBL -RTP | Marta Direct Computation[3] |
| | Marta INCR - RTP | RTP Workpaper |

[1] JKA 1-2 Attach G
[2] JKA 1-2 Attach M
[3] JKA 1-2 Attach N

*RESIDENTIAL*

**Q. HOW DID THE COMPANY ESTIMATE THE RESIDENTIAL CLASS BASE TARIFF REVENUES?**

A. The Company modeled the residential class in total (i.e., no residential sub-class/rate schedule individual modeling) and derived an average rate curve to estimate revenues. As described above, Staff estimated an alternative residential average rate curve model. Based on this alternative model, the Staff determined that the residential class revenues should be increased for the four revenue forecast periods. The Staff's evaluation of the average rate curve models is discussed subsequently in our testimony.

*COMMERCIAL*

**Q. HOW DID THE COMPANY ESTIMATE COMMERCIAL CLASS REVENUES?**

A. The Company developed its commercial class revenue forecast based on three commercial sub-classes: FPA, NonRTPFPA and CBL RTP. The FPA sub-class includes legacy customers who were on the rate beginning in 2011 and customers who have been on an RTP rate for three consecutive years.[9] The RTP revenue forecast is comprised of an RTP incremental component and a CBL component. The CBL component is priced based on a standard tariff. The "Com Incr RTP" component represents the non-fuel portion of the commercial class RTP rate (the fuel portion is included in overall retail fuel revenues). This incremental non-fuel RTP revenue forecast is developed using spreadsheet analysis. These revenues include both non-fuel RTP revenue produced by day ahead and hour ahead tariffs.

For the commercial FPA, non-RTPFPA and CBL forecasts, the Company developed average rate curve models as it did for the residential class. The Staff's evaluation determined that an alternative average rate curve model would be appropriate for the non-RTPFPA average rate curve model, which resulted in an adjustment to forecasted revenues. The Staff's evaluation of the average rate curve models is discussed subsequently in our testimony.

[9] GPC Schedule FPA-11, Fixed Pricing Alternative.

*INDUSTRIAL*

**Q. HOW WERE THE INDUSTRIAL REVENUES DERIVED?**

A. Industrial Class Revenues were forecasted based on modeling of five components:

- **Ind FPA:** Industrial Fixed Pricing Alternative for eligible legacy customers and former RTP customers (average rate curve methodology)
- **Ind NonRTPFPA:** Industrial Fixed Pricing Alternative for non-RTP revenues (trend analysis of average rate per kWh)
- **Ind CBL:** Industrial Customer Baseline Load (average rate curve methodology)
- **Ind Adj:** Industrial Adjustment (No adjustments in this forecast, zero value)
- **Ind Incr:** Industrial Incremental prices (RTP)

As shown in Table 6, only two of the five Industrial sub-class forecasts are based on average rate curve modeling: the Ind FPA forecast and the Ind CBL forecasts. For the Ind. NonFPARTP sub-class, revenues were projected based on a trend analysis of the average rate per kWh.[10] The Company's trend forecast is based on a moving average using monthly data spanning Jan 2015 to Aug 2021 and repeats, by month, exactly for each forecast year.

[10] STF JKA-1-2 Attachment G.

As in the commercial class, the "Ind Incr" component represents the non-fuel portion of the industrial class RTP rate (the fuel portion is included in overall retail fuel revenues). This incremental non-fuel RTP revenue forecast is developed using spreadsheet analysis. This revenue includes both non-fuel RTP revenue produced by day ahead and hour ahead tariffs.

The Staff's evaluation determined that an alternative average rate curve model would be appropriate for the industrial CBL sub-class, which resulted in adjustments to forecasted revenues. The Staff's evaluation of the average rate curve models is discussed subsequently in our testimony.

*RTP*

**Q. HOW DID THE COMPANY DEVELOP ITS FORECASTS OF COMMERCIAL AND INDUSTRIAL INCREMENTAL RTP REVENUE?**

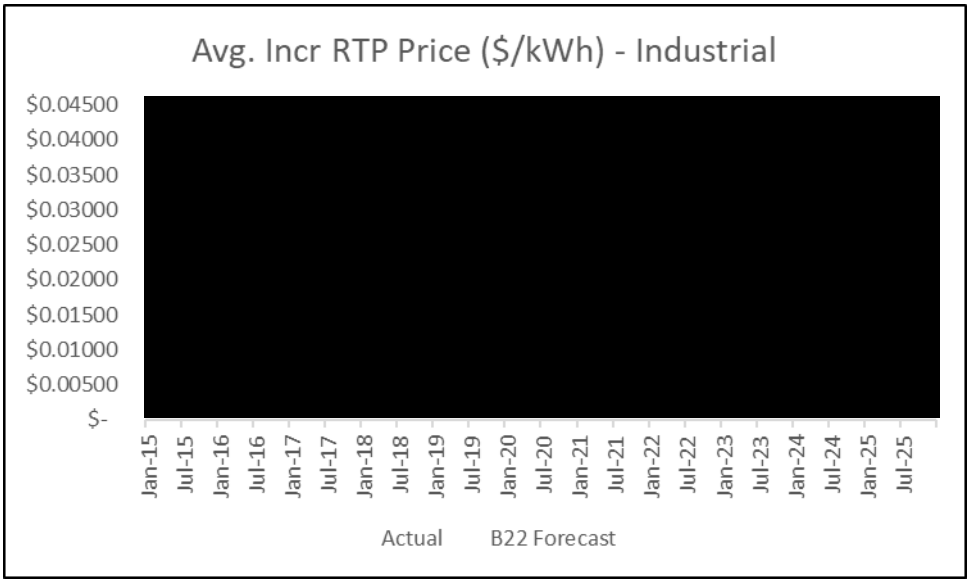
A. Staff in its requests for all workpapers supporting the revenue forecast was finally provided, in an informal response, the derivation of the RTP component forecasts on August 26, 2022. In the Company's informal response, the derivation utilized a monthly day ahead and hour ahead price together with the monthly MWh estimated for both day ahead and hour ahead schedules despite describing an hourly methodology. The Company

further explained in follow up data responses, that the derivation of the monthly values was derived from hourly values.[11]

**Q. HOW DO PROJECTED RTP RATES COMPARE TO HISTORIC RTP RATES?**

A. The following graph (Figure 2) shows the historic RTP price, [redacted] by month trending into the forecasted.[12]

**Redacted Figure 2: RTP Price (excludes RTP fuel cost)**



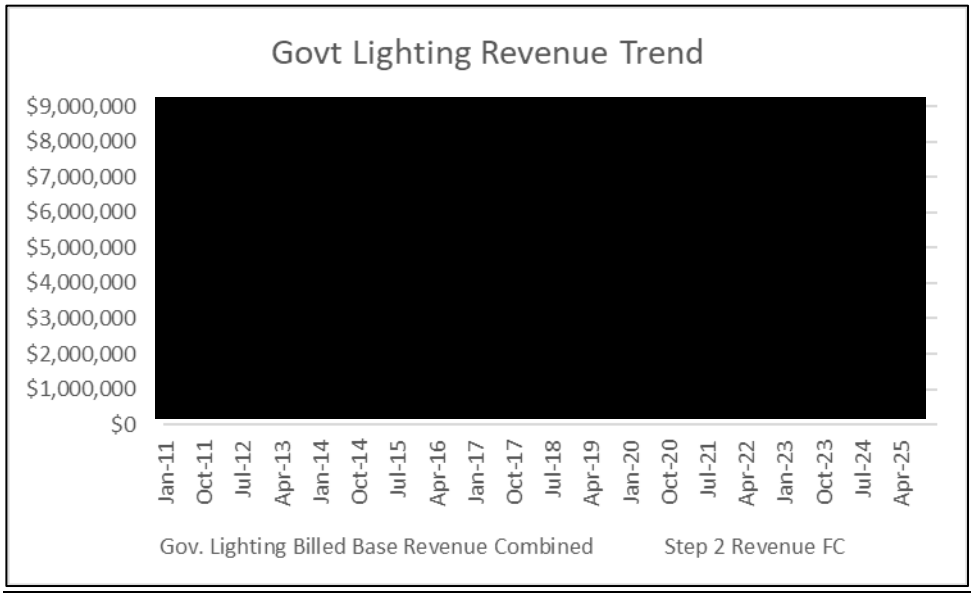

*LIGHTING*

[11] JKA 5-1 and 5-2 describe the methodology and JKA 5-7 the underlying data supporting the monthly figures with hourly data.
[12] Data from: STF-JKA-1-2 Attachment G TRADE SECRET.xlsx.

**Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S GOVERNMENT LIGHTING FORECAST?**

A. The Company describes its modeling as a trend analysis which mainly accounts for the gradual replacement of older lighting with newer more efficient infrastructure.[13] Staff reviewed the trend of historic data used to produce the forecasted revenues and it does appear flat, which would be consistent with any increased load being offset by increasingly efficient fixtures.

**Redacted Figure 3: Government Lighting Revenues**




[13] STF-JKA-1-2 Attachment M TRADE SECRET.xlsx contains the data and STF-JKA-1-2 Attachment L.docx the narrative description.

[redacted]

*MARTA*

**Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S MARTA FORECAST?**

A. The Company models the MARTA revenues following the MARTA tariff rate structure with blocked energy pricing. The Company's estimate was based on 2021 rates, and then adjusted up with a Year 3 adjustment to get the 2022 base rates as baseline for the projection in 2022-2025.[14]

**AVERAGE RATE CURVE AND STATISTICAL ANALYSES**

**Q. WOULD YOU DISCUSS THE COMPANY'S AVERAGE RATE CURVE STATISTICAL MODELING?**

A. As shown in Table 6, the Company develops statistical regression models to forecast the average rate per kWh for six rate classes and sub-classes. These models are all based on a general relationship between a rate schedule's average rate per kWh and the average kWh usage per customer for the rate. The estimated regression models are then used to forecast the average rate per kWh for the class using the Company's B22 energy forecast (kWh per

[14] MARTA revenue forecast provided in STF-JKA-1-2 Attachment N TRADE SECRET.xlsx.

customer) that was presented in the 2022 IRP case. The product of the forecasted average rate per kWh and the B22 forecasted kWh sales for the rate class or sub-class produces the base tariff revenue forecast. The focus of the Staff's review and analyses was on the various average rate curve statistical regression models. The kWh energy sales forecast ("B22") was already addressed by the Staff in the IRP case.

**Q. HOW DID THE COMPANY DEVELOP ITS MODELS?**

A. Georgia Power Company uses a statistical analysis software package called "EViews" to develop its average rate curve models. The Staff obtained EViews and was able to fully evaluate each of the Company's models.

**Q. WHAT WERE THE RESULTS OF THE STAFF'S EVALUATION OF THE COMPANY'S AVERAGE RATE CURVE MODELS?**

A. The Staff found that for three of the Company's models, an alternative specification produced more reasonable statistical results. The Company's models used monthly binary variables for most months that were formed by taking the product of the average kWh usage in the month and a "1" if the observation was for the same month and a "0" if the month was different. For example, if the observation was for January, the January binary variable would be equal to the average kWh use in the month times "1." If the observation was for February, the January binary variable would be equal to "0" (average kWh use in

February times "0" equals "0"). The effect of this modeling specification is that, in general, each month has its own estimated coefficient that relates average usage and the average rate per kWh. While the Staff does not have concerns with this approach, it is somewhat similar to estimating separate average rate curve models for each month. The Staff's alternative models are based on modified specifications and estimation periods that the Staff believes are more appropriate. Staff is recommending alternative rate curves that incorporate a number of adjustments. The adjustments made by the Staff for each of the models are as follows:

**Q. HOW DO THE STATISTICAL RESULTS PRODUCED BY THE STAFF'S ALTERNATIVE MODELS COMPARE TO THE COMPANY'S MODELS?**

A. Staff's proposed alternate models perform about the same as the Company's models, but one of the Staff models has a slightly lower $R^2$ (the "Commercial NonRTPFPA" model).[15] The Staff believes that its revised models are less likely to overfit the data than the

[15] R-squared ($R^2$) is the Coefficient of Determination in a regression model. $R^2$ is a measure of how well the model (independent variables) explain the variation in the dependent variable. Specifically, it measures the percentage of the variation in the dependent variable (average rate/kWh) that is explained by the model (average kWh usage per customer, binary variables).

Company's models.[16] Also, the Staff's models tend to have a better pattern of residuals that the Staff believes support the use of the model adjustments.[17]

**Q. WHAT IS THE IMPACT OF USING THE STAFF'S ALTERNATIVE AVERAGE RATE CURVE MODELS ON THE REVENUE FORECAST FOR THE TEST YEAR AND THE THREE PLAN YEARS?**

A. Using the Staff's alternative average rate curve models produces an additional $6 million to $8 million of revenue at current rates for the four periods.

**Q. DOES THE STAFF BELIEVE THAT THE COMPANY'S AVERAGE RATE CURVE MODELS AND THE RELATED REVENUE FORECASTS ARE UNREASONABLE?**

A. No. As noted earlier in our testimony, the Staff did not identify any specific errors or significant problems with the Company's analyses. Rather, the Staff believes that its alternative models provide a more reasonable measure of projected test year and Plan Year revenues.

[16] A model that overfits the sample data results in independent variables that appear to be significant in explaining the dependent variable, but in fact are just explaining the residuals. This can lead to incorrect conclusions in the analysis and unreliable forecasts.

[17] A requirement of a linear regression model is that the residuals (the difference between the model predicted value and the actual value) follows a normal probability distribution. To the extent that an estimated model produces residuals that are not normally distributed (i.e., deviate from the normality assumption), tests of significance of the estimated coefficients may not be reliable.

## IV. RECOMMENDED REVENUE FORECAST DOCUMENTATION

**Q. DOES STAFF HAVE ANY RECOMMENDATIONS TO ESTABLISH A REQUIREMENT FOR FILING DETAILED REVENUE FORECAST TESTIMONY AND WORKPAPERS IN FUTURE RATE CASES?**

A. Yes. Notwithstanding the Staff's recommended test year and Plan Year revenue forecast adjustments, the Staff did not find specific problems with the Company's overall revenue forecast process in this case. However, in order to make this assessment, the Staff was required to issue multiple data requests for Excel workbooks, narrative explanations, and follow-on data requests in order to fully evaluate and understand the basis for the Company's test year and three Plan Year projections. The Company did not present any testimony on this important issue, nor did the Company file any supporting workpapers with its filing that would facilitate and independent evaluation by the Staff. In the end, following the Staff's formal and informal data requests, the Company provide numerous Excel workbooks containing about 50 individual Excel models that provide the support for its revenue forecasts. The Company also provide a number of narrative descriptions supporting the development of the retail revenue projections for the four test periods (Test Year and Plan Years 2023, 2024 and 2025).

In future Georgia Power Company base rate cases, the Company should be required to file a complete set of workpapers, consistent with all of the Excel workbooks and spreadsheets ultimately provided to the Staff in this case. This should be included in the minimum filing requirements. In addition, the Company should file witness testimony supporting the revenue forecast for each rate class. There should also be a complete set of Excel files that reconcile the various supporting workpapers and resulting rate class revenue forecasts to the retail revenues included in the Company's revenue deficiency analysis.[18]

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

[18] In this 2022 case, this analysis is presented in Abramovitz/Adams/Houston/Robinson Schedule 1.

BY MR. INGRAHAM:

Q Mr. Baron, did you and Ms. Wellborn also prefile or cause to be prefiled two public disclosure exhibits which were marked as Exhibits STF-BW-1 and 2?

A (Witness Baron) Yes.

Q Do you have any changes or corrections to make to those exhibits at this time?

A (Witness Baron) Not that I am aware of, no.

MR. INGRAHAM: Madam Chair, I would ask that the public disclosure exhibits marked as STF-BW-1 and 2 be admitted into the record.

MADAM CHAIR PRIDEMORE: So moved.

(The documents referred to were marked for identification and admitted into evidence as Staff Exhibits STF-BW-1 and STF-BW-2.)

MR. INGRAHAM: Thank you.

BY MR. INGRAHAM:

Q Mr. Baron, did you and Ms. Wellborn also prefiled or cause to be prefiled 30 pages of trade secret testimony in question-and-answer form on October 20th, 2022?

A (Witness Baron) Yes.

Q And are there any changes or corrections that you would like to make to that prefiled trade secret testimony at this time?

A (Witness Baron) No, none that I am aware of.

Q So if I were to ask you the questions that are presented in this prefiled trade secret testimony, the answers that you would give would be the same?

A (Witness Baron) Yes.

MR. INGRAHAM: Madam Chair, I would ask that the prefiled trade secret testimony of Mr. Baron and Ms. Wellborn be marked for identification as Staff Exhibit 42.

MADAM CHAIR PRIDEMORE: So moved, so marked.

(The document referred to was marked for identification as Staff Exhibit 42.)

MR. INGRAHAM: Thank you.

BY MR. INGRAHAM:

Q Mr. Baron, did you and Ms. Wellborn prepare a summary of your testimony?

A (Witness Baron) Yes.

Q Please give it at this time.

A (Witness Baron) Good afternoon, Commissioners.

Our testimony addresses Georgia Power's projected retail revenues, at present rates, for the test year in this case (12 months ending July 31, 2023) and each of the three plan years, 2023, 2024 and 2025. The company has developed a detailed revenue forecast that estimates the revenues that the company will receive at present Commission approved

rates.

Staff developed its own revenue forecast based on present rates for the test year and the three calendar year plan years. Staff's analysis concludes that the company will collect approximately $6 million per year in additional revenues in the test period and in each of the three plan years.

In general, staff has found that the company's revenue forecast methodology is not unreasonable. However, staff has identified adjustments to the company's forecast based on alternative models for the residential rate class and portions of the commercial and industrial rate classes which we believe more accurately reflect revenues that would be collected.

These adjustments result in an increase in projected retail revenues at present tariff rates for each of the forecast -- four forecast periods. Staff's adjustments are shown in our testimony Table 3 and again amount to approximately $6 million per year in the test year and each of the three plan years.

The staff reviewed and analyzed approximately 50 and perhaps, as I understand, maybe many more Excel spreadsheet models developed by the company

that ultimately rolled up into the four retail revenue forecasts and produced the total revenues shown in Georgia Power Company Exhibit APA-SPA-ADH-MBR-1, Schedule 1. Staff's analysis addressed both the company's original filing and the supplemental filing.

The initial starting point for the development of the revenue forecast is the projection of base tariff revenues for each of the company's five rate classes (Residential, Commercial, Industrial, Governmental Lighting, and MARTA). In addition, there are revenues produced by various riders, recovery tariffs such as the environmental compliance cost recovery tariff, the nuclear construction cost recovery tariff, and demand-side management tariff. In addition, there's fuel charges and a number of company adjustments that the staff discusses in our testimony. All of those roll up into the overall revenue calculation.

The starting point for the staff's evaluation of the company's revenue forecast was to review all of the parts of the projections, starting with the company's statistical models that were used to develop the base tariff revenues. Staff analyzed alternative model specifications and estimation

periods for each of the company's models to determine if the models were reasonable or if an alternative model would be more appropriate. Based on this analysis, staff developed three alternative average rate curve models, which is the basis for the calculation of base tariff revenues.

These alternative models were for the residential, the commercial, non-RTP fixed price alternative and the industrial RTP-CBL (customer baseline) classes or subclasses.

Staff believes its alternative average rate curve models are more reasonable than the company's estimates.

Again, the staff estimates that the retail revenues based on current rates would be roughly $6 million higher each year under -- using -- than the company has calculated based on the staff's models.

The Smith-Trokey panel has incorporated our adjusted revenue projections in the overall recommended revenue deficiency in this case.

In order to evaluate the company's revenue projections, the staff was required to issue multiple data requests for Excel workbooks, narrative explanations, and follow-on data requests in order to

fully evaluate and understand the basis for the company's test year and three plan year revenue projections. The company did not present any testimony on this important issue, nor did the company file any supporting workpapers with its filing that would facilitate an independent and complete evaluation by the staff.

In the end, following the staff's numerous formal and informal data requests, the company did provide Excel workbooks that support its revenue forecast.

In future Georgia Power Company base rate cases, the company should be required to file a complete set of workpapers that support its revenue forecast for the test year and plan years when filing their case. This would significantly reduce the time spent by staff and the company on this issue by avoiding multiple data requests and clarifications.

These workpapers should be consistent with all of the Excel workbooks and spreadsheets ultimately provided to the staff in this case. There should also be a complete set of Excel files that reconcile the various supporting work papers and resulting rate class revenue forecasts to the retail revenues, included in the company's overall projections.

This completes our summary.

MADAM CHAIR PRIDEMORE: Questions from commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: All right.

MR. INGRAHAM: Thank you, Mr. Baron and Ms. Wellborn.

Madam Chair, Commissioners, the panel is available for cross.

MADAM CHAIR PRIDEMORE: Very good.

Americans for Affordable Clean Energy?

MR. GALLOWAY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: ChargePoint?

MR. FYKES: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Commercial Group?

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: EVgo Services?

MR. VIJAYKAR: No questions.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers?

MR. CLAY JONES: No questions.

MADAM CHAIR PRIDEMORE: No questions, okay. Georgia Coalition of Local Governments?

MS. BROWN: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Conservation

Voters?

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA?

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch?

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: Interstate Gas Supply?

(No response.)

MADAM CHAIR PRIDEMORE: I believe they have left for the day.

The Kroger Company?

MR. BOEHM: No questions.

MADAM CHAIR PRIDEMORE: MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. DOWDY: No questions, Madam Chair.

MS. PRYOR: Southern Renewable Energy Association?

(No response.)

MADAM CHAIR PRIDEMORE: All right. United States Department of Defense and All Other Federal Executive Agencies?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: Okay. Very good. Georgia Power Company?

MR. HEWITSON: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Mr. Baron, Ms. Wellborn. Good to see you again.

A (Witness Baron) Good to see you.

Q My name is Steve Hewitson. I represent Georgia Power Company.

Just a few questions. Is it fair to say that for the most part you agree with the company's methodology to project revenues used in this case?

A (Witness Baron) Yes, I would say that's correct.

Q Okay. And you didn't -- or you did not, I should say, identify any specific errors or problems with

the company's analysis? Is that fair to say as well?

A (Witness Baron) That is correct. That's correct. I think, as explained in the testimony, that our -- our principal changes were results of alternative statistical analyses.

Q Okay. And the alternative statistical analyses, you believe would be reasonable to implement? Is that the thrust of your recommendation on those issues?

A (Witness Baron) Yes. The staff -- we support and the staff supports the alternative calculations that we developed and provided to the Smith-Trokey panel.

Q Okay. And when I looked at Table 6 of your testimony, it appears that of the 12 individual forecast components, you recommended changes to only three.

Am I reading that right?

A (Witness Baron) That is correct.

Q Okay. And your proposed changes, as you said in your summation, amount to approximately $6 million a year; right?

A (Witness Baron) Yes.

Q And to put that amount into perspective, that's about .1 percent of total projected revenue for the company; right?

A (Witness Baron) That is correct. Of course, it is $6 million, and there are a number of issues in this

case that are less than that.

Q And revenue forecasting is not a static exercise. Would you agree with that?

A (Witness Baron) Yes, I would agree with that.

Q Okay. Would you agree that the variables being reviewed today may not be the variables that we focus on in 2025?

A (Witness Baron) Yes. And -- well, let me just -- I think the answer is yes. But when you say "variables," are you -- are you referring to -- with respect to, say, a statistical model variables, or more broad-based in terms of the elements that go into a forecast, the types of revenue sources that the company might have?

Q More the statistical models.

A (Witness Baron) Yes. I mean, I think traditionally you would expect, based on the historical data, that similar specifications would probably be developed, but certainly with different data, you could have different models.

Q And we said many times in this hearing room reasonable experts can disagree, especially when you are forecasting information; right?

A (Witness Baron) Yes, I think that's fair.

Q Okay. And here, there is only slight disagreement between the experts, with a difference of

approximately $6 million -- and again, not to sneeze at $6 million, but it's only .1 percent of the company's total forecasted revenues; right?

A (Witness Baron) Yes. Yes. And as I said, we believe our analysis and the models we are recommending are more appropriate and reasonable, it amounts to $6 million. And even if you were to put aside that one model might be better than another or different from another, but they are both reasonable -- let's just say you accepted that -- the truth is that the staff's analysis, using reasonable and what we believe more appropriate models, produces an additional $6 million that the company would collect in those forecast periods.

Q Thank you.

MR. HEWITSON: That's all the questions I have for you. I appreciate your time.

A (Witness Baron) Thank you.

MADAM CHAIR PRIDEMORE: Redirect?

MR. INGRAHAM: No redirect.

MADAM CHAIR PRIDEMORE: Thank you. You may excuse your witnesses.

MR. INGRAHAM: Thank you. You are excused.

MADAM CHAIR PRIDEMORE: Next panel, Alvarez, Stephens, and Rana.

MR. WALSH: Madam Chair, at this time the staff

would like to call the panel of Paul Alvarez, Dennis Stephens, and Raj Rana on behalf of Public Interest Advocacy Staff.

If you could please stand, I will swear you in.

Thereupon,

PAUL J. ALVAREZ,
DENNIS STEPHENS,
RAJENDRASINH "RAJ" RANA,

having been duly sworn, testified as follows:

MR. WALSH: Thank you. You may be seated.

DIRECT EXAMINATION

BY MR. WALSH:

Q Gentlemen, starting with Mr. Rana, could you please state your full name for the record and by whom you are employed.

A (Witness Rana) I am employed by my -- Rana Energy Consulting, and I am the president of the company.

Q And could you please state your full name for the record?

A (Witness Rana) I'm sorry?

Q Could you please state your full name for the record?

A (Witness Rana) My name is Rajendrasinh Rana.

Q Thank you.

MADAM CHAIR PRIDEMORE: I would like to remind the witnesses, if you would, straighten the neck of

your mic, get it close to you and speak up into it for us, please.

Thank you.

A (Witness Alvarez) Paul Alvarez. President of The Wire Group.

Q Mr. Stephens, could you please state your full name for the record and by whom you are employed?

A (Witness Stephens) Yes. My name is Dennis Darnell Stephens, and I'm employed by The Wire Group.

Q Thank you.

Mr. Alvarez, I will start with you.

On October 20th, 2022, did you and Mr. Stephens prefile or cause to be prefiled 74 pages of public disclosure testimony in question-and-answer form?

A (Witness Alvarez) We did.

Q Are there any changes or corrections that you would like to make to your prefiled direct testimony at this time?

A (Witness Alvarez) We have none.

Q If I were to ask you the same questions that are presented in the prefiled testimony, would your answers be the same?

A (Witness Alvarez) They would.

MR. WALSH: Madam Chair, I ask that the public disclosure prefiled testimony of Mr. Alvarez and

**Mr. Stephens be copied into the record as if read from the witness stand.**

**MADAM CHAIR PRIDEMORE: So moved.**

**MR. WALSH: Thank you.**

**(Whereupon, the prefiled direct testimonies of Paul J. Alvarez and Dennis Stephens follows:)**

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

| | | |
|---|---|---|
| **GEORGIA POWER COMPANY'S** | **)** | **DOCKET NO. 44280** |
| **2022 RATE CASE** | **)** | |

# DIRECT TESTIMONY

# AND EXHIBITS

# OF

**PAUL J. ALVAREZ**
**AND**
**DENNIS STEPHENS**

**On Behalf of the**

**Georgia Public Service Commission**
**Public Interest Advocacy Staff**

**PUBLIC DISCLOSURE VERSION**

**October 20, 2022**

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## EXHIBIT LIST

| Exhibit | Description |
|---|---|
| PA/DS-1 | Curricula Vitae of Paul J. Alvarez |
| PA/DS-2 | Curricula Vitae of Dennis Stephens |
| PA/DS-3 | Trade Secret Attachment A provided in response to STF-WG-2-8 (”Customer Benefits Study, corrected k-factor”) |
| PA/DS-4 | Attachment S, Appendix B (page 44) provided in response to STF-WG-1-1 (no longer Trade Secret per authorization e-mail from Georgia Power Counsel September 26, 2022 |
| PA/DS-5 | Summary of Grid Investment Plan revenue requirement calculations |
| PA/DS-6 | Summary of Substation Equipment Failures Resulting in Outages calculations |
| PA/DS-7 | Trade Secret Optimization Model screenshots provided informally by Georgia Power in follow-up to discovery conference held October 3, 2022 |
| PA/DS-8 | Trade Secret “Staff Scenario Summary” provided informally by Georgia Power in follow-up to discovery conference held October 3, 2022 |
| PA/DS-9 | Trade Secret Attachment G, Tab “EBA Valuation” provided in response to STF-WG-Informal-1 (Summary projections by year of Georgia Power’s proposed “80 SAIDI” Scenario for the Distribution Investment Plan |
| PA/DS-10 | Sample Annual Performance Report from a utility to the Maryland Public Service Commission |

## I. INTRODUCTIONS AND PREVIEW

**Q. MR. ALVAREZ, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Paul J. Alvarez. My business address is Wired Group, P.O. Box 620756, Littleton, Colorado 80162.

**Q. WHAT IS YOUR OCCUPATION?**

A. I lead the Wired Group, a small consultancy specializing in distribution utility planning, investment, regulation, and performance.

**Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?**

A. Yes. It is presented in Exhibit PA/DS-1. This exhibit summarizes my educational background, professional experience, and appearances before state utility regulators.

**Q. MR. STEPHENS, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Dennis Stephens. My business address is 1153 Bergen Parkway, Suite 130, Evergreen, CO 80439.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am an independent consultant specializing in utility distribution planning, investment, operations, asset management, reliability, and safety. I frequently work for the Wired Group in support of the firm's clients.

**Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?**

A. Yes. It is presented in Exhibit PA/DS-2. This exhibit summarizes my educational background, professional experience, and appearances before state utility regulators.

**Q. ON WHOSE BEHALF ARE YOU APPEARING?**

A. We are testifying in the public interest on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff (Staff).

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of our testimony is to provide recommendations for Commission consideration regarding Georgia Power Company's (Georgia Power or Company) proposed continuation of the Grid Investment Plan (GIP). With the exception of transmission lines, we have completed detailed reviews of, and discovery into, all aspects of the GIP. (Transmission lines are addressed in the testimony of Staff Witness Mr. Raj Rana, though many of the themes of our testimony are repeated in Mr. Rana's testimony, and many observations made by Mr. Rana are relevant to the portions of the GIP we examined.)

**Q. PLEASE PREVIEW YOUR TESTIMONY**

A. Our testimony begins in Section II with context regarding transmission and distribution investments related to reliability improvements, as well as perspectives on the associated timing and rate increases. (The Company claims the GIP is needed to maintain and improve service reliability.)[1] Later, our testimony presents analyses indicating that the largest components of GIP spending will not deliver reliability improvements sufficient to outweigh costs. But in this Section we observe 1) that electric rates are already poised to rise substantially in Georgia over the next few years; 2) that there is no pending reliability emergency or customer demand for the reliability improvements Georgia Power proposes to pursue; and 3) that the results of various GIP investments to date will not be known for at least a few more years. These observations strongly suggest a need to complete formal

[1] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson On Behalf of Georgia Power Company ("APA-SPA-ADH-MBR Direct"), p. 15 at 7-13

and rigorous (independent) study of the results of Georgia Power's GIP spending so far before more such spending is authorized.

In Section III, we explain why the GIP investments the Company plans for its transmission grid will not deliver reliability benefits of sufficient value to outweigh associated rate increases. Proposed at $1.0 billion from 2023-2025, and representing a 278% increase over annual transmission spending in years prior to the GIP, the transmission investment plan (TIP) benefits shareholders far more than it will customers or Georgia's economy. Specifically, we challenge the Company's practice, new to the GIP, of replacing substation (and transmission line) equipment that has passed periodic, objective tests and inspections that all utilities, including Georgia Power, conduct routinely. The practice, which we call premature equipment replacement, relies on the estimated useful lives – typically employed only to inform accounting depreciation periods -- rather than objective test and inspection results, to determine when equipment should be replaced. We will explain why premature equipment replacement is inappropriate, and recommend all proposed investments from this practice be rejected. We favor the objective approaches Georgia Power has successfully employed in the past, and continues to employ in this rate case, to identify equipment for replacement.

In Section IV, we explain why some distribution investment packages in the Company's GIP will not deliver reliability benefits of sufficient value to outweigh associated rate increases. Proposed at $1.3 billion from 2023-2025, and part of a total distribution capital spending request amounting to a 131% increase (more than double) over annual distribution spending prior to the GIP (2009-2019), the distribution investment plan (DIP) is rendered cost-ineffective by circuit hardening and undergrounding investment packages. Not only are these packages cost-ineffective due to their extremely high cost per premise, the DIP ignores vastly less expensive practices almost all utilities employ to improve reliability, namely, more aggressive vegetation management and a more formal worst-

performing circuit program. In this section we will also describe multiple flaws with the Optimization Model the Company uses to select circuits to treat and investment packages to deploy, and which the Company uses to justify its distribution investment plan. Finally, we summarize what the Maryland Commission has done to cost-effectively improve reliability, and recommend that proposed spending on circuit hardening and undergrounding be eliminated while preserving a 55% increase in overall distribution capital spending over the average levels prior to the GIP.

In Section V, we address the Company's plan to invest $100 million in a distributed energy resource management system, or DERMS. The level of distributed energy resources needed to justify such a system is high, and will not be reached by the time the proposed DERMS is fully depreciated in 2030, let alone by the end of the upcoming rate planning period in 2025. Further, Georgia Power already maintains systems and processes to manage distributed energy resources. We recommend this proposed spending be postponed until a future rate case, when the level of distributed energy resources on Georgia Power's grid provides sufficient justification for such a system.

**Q. PLEASE SUMMARIZE THE SPENDING ADJUSTMENTS RECOMMENDED IN YOUR TESTIMONY**

A. Table 1 below summarizes our recommended spending and cost recovery adjustments. These adjustments are translated into revenue requirement reductions in the testimony and exhibits of Staff Witnesses Mr. Ralph Smith and Mr. Robert Trokey (Smith-Trokey). It should be noted that the annual amount of transmission and distribution capital investment Staff does not recommend be rejected is still double the annual average for 2009 – 2021. This large increase that still remains is in contrast to the much smaller growth in number of customers, energy sales (MWhs), and peak demand (MW).

Table 1: Summary of Recommended T&D Capital Investment Reductions

| ($ in millions) | 2009-2021 Average Actual | 2023 | 2024 | 2025 | '23-'25 Average |
|---|---|---|---|---|---|
| T&D Capital Requested | | 2,310 | 2,207 | 2,316 | 2,278 |
| Transmission Investment Plan | | (328) | (314) | (359) | (334) |
| Circuit Hardening | | [redacted] | [redacted] | [redacted] | [redacted] |
| Undergrounding | | [redacted] | [redacted] | [redacted] | [redacted] |
| T&D Capital Remaining | 769 | 1,654 | 1503 | 1588 | 1,581 |
| DERMS (Corporate) | | (10) | (40) | (50) | (33) |

**Q. HAVE YOU ATTACHED ANY EXHIBITS TO YOUR TESTIMONY?**

A. Yes. In addition to our qualifications, which are in Exhibit PA/DS-1 and PA/DS-2, we have attached Exhibits PA/DS-3 through PA/DS-10. These exhibits contain some of the more critical materials (or sub-sections) secured in discovery, as well as a few workpaper summaries and sample materials relevant to this testimony. We did not include all responses to data requests cited in our testimony, as these are collectively, and in many cases individually, too voluminous to include as exhibits. For these data request responses, we trust the administrative record will serve as an accurate and accessible repository.

## II. TRANSMISSION AND DISTRIBUTION RATE INCREASES ARE BAD FOR GEORGIA'S BUSINESSES, CONSUMERS, AND ECONOMY UNLESS ACCOMPANIED BY RELIABILITY IMPROVEMENT VALUE SUFFICIENT TO OUTWEIGH THEM

**Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY.**

A. This section of testimony will begin with a review of Georgia Power's Grid Investment Plan (GIP). It will provide context on transmission and distribution (T&D) rate increases for reliability improvements generally; present Georgia Power's recent reliability performance in the context of its peers; discuss the lack of customer demand for, or willingness to pay for, better reliability; present imminent rate increases heading toward Georgia's economy outside of the Company's or the Commission's control; and note that the results of over a billion dollars in GIP spending to date are not yet known. All of these call the timing of continued GIP spending in the upcoming rate case period into question.

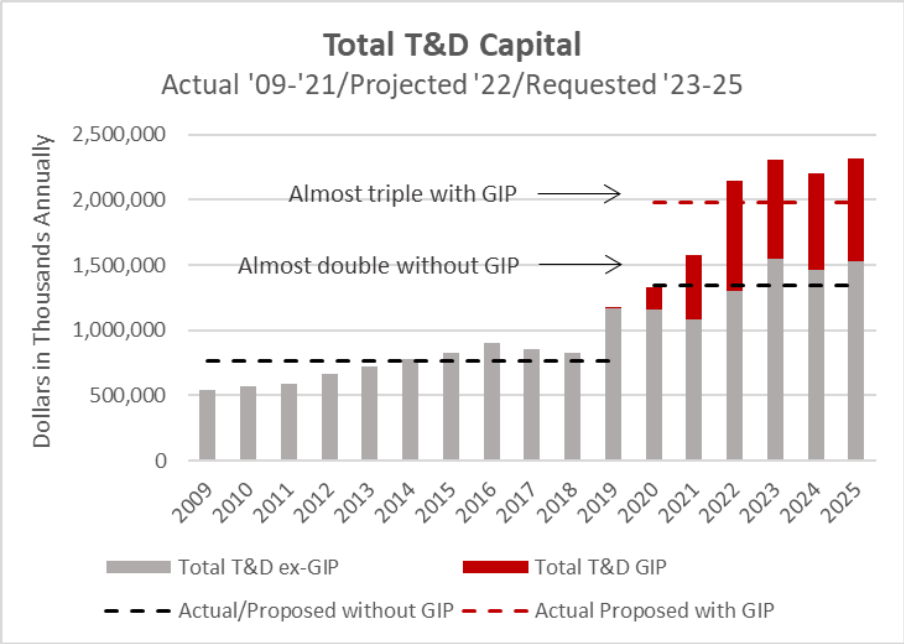
**Q. PLEASE SUMMARIZE GEORGIA POWER'S GRID INVESTMENT PLAN.**

A. In its 2019 rate case Georgia Power proposed a $7.5 billion Grid Investment Plan (GIP) to be completed over eleven years, from 2020 to 2031. The GIP consisted of $2.6 billion in transmission grid reliability investments (the Transmission Investment Plan, or TIP) and $4.9 billion in distribution grid reliability investments (the Distribution Investment Plan, or DIP).[2] The GIP, combined with requested increases in more typical T&D capital spending, delivers extreme increases in T&D investments relative to historic investment levels. Figure 1 below indicates that the Company's proposed T&D capital spending 2023-2025 is almost three times (296%) the historical levels of investment before the GIP. *Even without the GIP, proposed T&D capital spending increase is almost two times (197%) the*

[2] Georgia PSC Docket No. 42516. DIP Capital from the Attachment provided in response to STF-L&A-5-38, "(Initial) Customer Benefits Study", page (i). TIP capital from "2019 Base Rate Case Overview" Presentation to Staff dated June 27, 2019, p. 7. ($7.5 billion for GIP less $4.9 billion for DIP.)

*historical levels of investment before 2020.*[3]

Figure 1: Total T&D Capital Spending Actual '09-'21/Projected '22/Requested '23-'25.




**Q. WHAT BENEFITS DID GEORGIA POWER PROJECT FROM THE GIP IN 2019 RATE CASE DOCKET 42516?**

A. Georgia Power projected no reliability improvements at all from the TIP, and states that the TIP is designed only to maintain current transmission reliability levels.[4] At the time the DIP was initially proposed, Georgia Power projected the DIP would deliver a 50% reduction in system average interruption duration (SAIDI), from approximately 130 minutes on average at the time to 65 minutes on average by 2031. The Commission approved the Company's proposed GIP spending. By the end of this year, the Company anticipates completing $[redacted] in TIP investments and $[redacted] in DIP

[3] Actual spending per attachment provided in response to STF-WG-2-1(a); projected and requested spending per Trade Secret attachment provided in response to STF-PIA-4-4.

[4] Attachment provided in response to STF-WG-1-3 (d).

investments.[5]

**Q. IS GEORGIA POWER PROPOSING TO CONTINUE GIP SPENDING IN THIS RATE CASE?**

A. Yes, the Company proposes to continue its GIP in the amount of $2.3 billion from 2023 to 2025, including $1.0 billion in TIP spending and $1.3 billion in DIP spending.[6] The Company is making some adjustments to the DIP from its initial 2019 proposal. Based on the Company's experience implementing the DIP 2020-2022, it is discontinuing some spending programs. The total DIP capital requirement has thus fallen from $4.9 billion originally to about $4.6 billion in the current DIP,[7] a reduction of 7.7%. It has also reduced expectations for DIP-related reliability improvements. Originally projected at a system SAIDI of 65 minutes by 2031, the revised system SAIDI target is 80 minutes by 2031,[8] a 23.1% deterioration. This significant revision in target system SAIDI after only three years calls into question the Company's projection of the actual performance improvement customers will receive for very large capital investment made by Georgia Power. The TIP appears to be unmodified from its original proposal.

**Q. DO GEORGIA POWER'S RELIABILITY IMPROVEMENT ESTIMATES AND CHANGES CAUSE YOU CONCERN?**

A. Yes. We are concerned that the Company attributes no reliability improvements at all to its TIP spending. But our biggest concern relates to the lack of performance accountability, a subject we will return to in Section IV, which is dedicated to the DIP.

[5] Georgia PSC Docket No. 42516. "2019 Base Rate Case Overview" Presentation to Staff dated June 27, 2019, p. 7

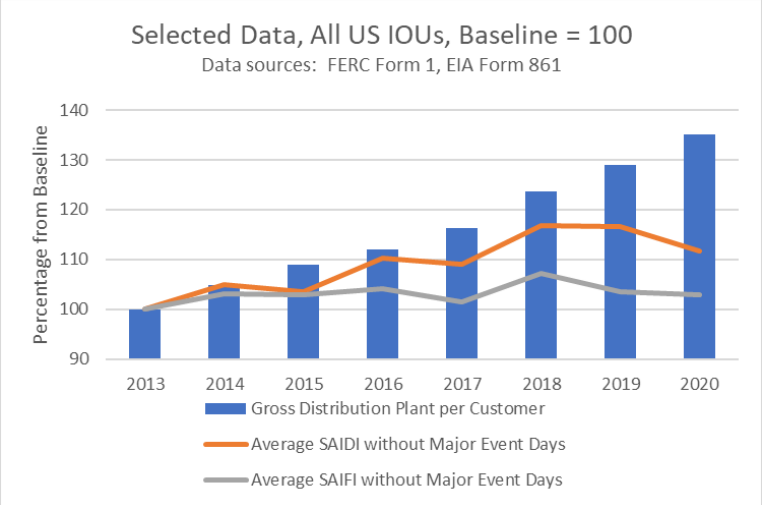
[6] Trade Secret attachment provided in response to STF-PIA-4-4.

[7] $3.4 billion to be spent over the remaining eight GIP years plus $[redacted] to be spent through December 31, 2022.

[8] Trade Secret Attachment A provided in response to STF-WG-2-8 ("Customer Benefits Study, corrected k-factor"), p. i.

We also note the 23.1% deterioration in the SAIDI target from the 2020-2022 DIP to the current DIP. Such a significant change in just three years is consistent with our experience that reliability improvements from increased grid investment are not a given, and that reliability-related investment performance varies dramatically from utility to utility, and among various types of spending packages. As indicated in Figure 2, reliability performance by U.S. Investor-Owned Utilities (IOUs) over the last ten years has not improved, and in fact has deteriorated, despite dramatic increases in grid investment per customer.[9] The lack of correlation between grid investment and grid performance has also been noted by other researchers.[10]

Figure 2: U.S. investor-owned utility reliability performance relative to distribution investment, 2013-2020.



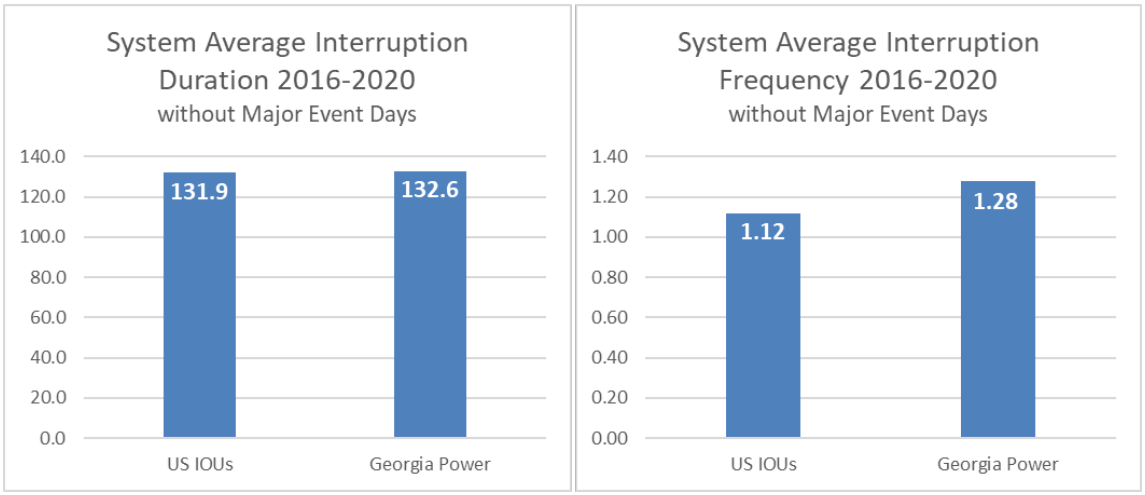

**Q. HOW DOES GEORGIA POWER'S RELIABILITY PERFORMANCE COMPARE WITH OTHER INVESTOR-OWNED UTILITIES?**

[9] Reliability data without major event days submitted by U.S. investor-owned utilities to the U.S. Energy Information Administration on Form 861; Gross Distribution Plant data submitted by U.S. investor-owned utilities to the FERC on Form 1 for FERC Accounts 360-374. SAIDI is system average interruption duration (in minutes); SAIFI is system average interruption frequency (per customer, per year).

[10] Larsen P et al. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Ernest Orlando Lawrence Berkeley National Laboratory. Pages 37-38. August 2015.

A. As indicated in Figure 3, Georgia Power service interruption duration and frequency are about average for U.S. IOU peers over the last 5 years.[11] There does not appear to be any grid reliability emergency at Georgia Power that must be addressed immediately, or that would justify the massive increase in the transmission and distribution capital investment proposed by the Company.

Figure 3: 5-Year Reliability Performance Averages, Georgia Power vs. US IOUs




**Q. WHAT ABOUT CUSTOMER DEMANDS? ARE CUSTOMERS DEMANDING RELIABILITY IMPROVEMENTS FROM GEORGIA POWER?**

A. No. With but one exception, customer satisfaction surveys filed by the Company with the Commission in 2019, 2020, and 2021 indicate that both residential and business customers rate their satisfaction with Georgia Power reliability higher than they rate their satisfaction with Georgia Power overall.[12] (The lone exception is the residential customer class in 2021; this cohort reported reliability satisfaction slightly lower than overall satisfaction.)

[11] Reliability data without major event days submitted by U.S. investor-owned utilities, including Georgia Power, to the U.S. Energy Information Administration on Form 861, 2016-2020. System Average Interruption Duration is SAIDI (in minutes). System Average Interruption Frequency is SAIFI (per customer, per year).

[12] Trade Secret Attachment A provided in response to STF-WG-1-42.

Further, the Company's most recent "willingness to pay" research on reliability indicates that customers in all classes are willing to pay less than a 1.7% rate increase on average for significant (50%) improvements in reliability.[13] We estimate that the revenue requirement increase for the $7.5 billion GIP at the time Georgia Power first presented it in 2019 will be 10%,[14] or almost six times greater than what customers reported they were willing to spend, and for a reliability improvement which is projected to be much less than the 50% customers indicated they would be willing to pay a 1.7% rate increase to secure.

**Q. YOU MENTIONED THAT RATE INCREASES FOR REASONS OTHER THAN THE GIP ARE IMMINENT. WHAT ARE THE SOURCES OF THESE RATE INCREASES AND HOW LARGE WILL THEY BE?**

A. Multiple sources of large electric rate increases will be hitting Georgia businesses and consumers simultaneously in the next few years. We believe the Commission should consider the impact of these rate increases on Georgia's economy as it reviews Georgia Power's request to continue GIP spending. At least two sources of significant rate increases are imminent beyond the Company's request in this rate case, including 1) The full impact of Plant Vogtle has yet to hit rates; and 2) higher fuel rates to recover higher fuel cost and unpaid fuel balance. Staff estimates the combined impact of these factors with the rate increase Georgia Power requests in this rate case to be in excess of 40%.[15]

**Q. WHAT IS THE RELEVANCE OF THESE RATE INCREASE PRESSURES?**

A. These rate increase pressures are relevant because some of them, particularly fuel, are outside of the Commission's control. When likely rate increases outside the Commission's

[13] Trade Secret Attachment S provided in response to STF-WG-1-2, page 44. (Please note that the Company agreed to remove the Trade Secret designation for Attachment S via e-mail dated September 26, 2022 in response to Staff's request.)

[14] See Exhibit PA/DS-5 for a summary of calculations.

[15] See Opening Testimony of Staff Witnesses Mr. Ralph Smith and Mr. Robert Trokey dated October 20, 2022.

control are clearly apparent, it becomes more critical to scrutinize closely capital investment and expenses that are discretionary. GIP spending is clearly a source of rate increase under the Commission's control. Given that there is no reliability emergency, and that customer demand for, and willingness to pay for, reliability improvements is almost zero, we consider GIP capital spending to be discretionary. Further, the results of GIP spending to date are not yet known, and our analysis of the two largest DIP programs, circuit hardening and undergrounding, indicate that rate increases exceed benefits by a wide margin. We note that other researchers examining circuit hardening and undergrounding come to the same conclusions, and we will provide details in Section IV.

Rate increases negatively impact Georgia's businesses and economy. Research indicates that employment falls as energy costs rise.[16] We consider rate increases to be a precious resource; a tool to be drawn upon only when necessary. Accommodating all types of Georgia Power spending requests simultaneously leaves less gas in the Georgia economy's tank for unexpected emergencies outside of Commission or Georgia Power control (like rising costs for capital or natural gas).

**Q. YOU MENTIONED THAT THE RESULTS OF GIP SPENDING TO DATE ARE NOT YET KNOWN. PLEASE EXPLAIN.**

A. All we have so far are the Company's projected reliability improvements from DIP spending "packages". As noted above, Georgia Power provides no projected reliability improvements from TIP spending; there is little evidence that increasing grid investment delivers improved grid performance nationally; and we have significant concerns regarding DIP performance improvement accountability. Further, circuit-specific reliability is inherently variable year-to-year, with weather being the largest of many sources of

[16] Metcalf GE. *The Relationship Between Electricity Prices and Jobs in Missouri*. Tufts University. February 27, 2013. Exhibit 1.

variation. Finally, despite the massive amount of money spent to date, the numbers of circuits rebuilt (hardened) to date, and the number of customers undergrounded to date, are extremely small. Further, and significantly, vegetation management the Company completed on circuits that were hardened or partially undergrounded makes it impossible to isolate the level of improvement secured by new investment from the level of improvement secured by vegetation management, a dramatically lower-cost option. (We will return to these subjects in Section IV.) In short, it is impossible to reach any conclusions regarding the reliability improvements if any from Georgia Power's DIP spending so far.

We recommend a minimum of three years' post-deployment experience be used to determine actual reliability improvement delivered relative to cost for each of the Company's reliability improvement initiatives, including premature transmission equipment replacement (more on that in the transmission section of this testimony) and each of the distribution investment plan "packages". Further, controls for various performance impacts are needed. For example, vegetation management is typically conducted on circuits as they are rebuilt (circuit hardening in the Company's parlance); we ask, to what degree was any performance improvement the result of vegetation management and not circuit hardening? All of this increases the need to complete formal and rigorous (independent) study of the results of Georgia Power's GIP spending so far before more such spending is authorized. Given the lack of a reliability emergency, and the impending perfect storm of rate increases, the prudent thing to do now is to measure results to date before doubling down on the GIP.

**Q. YOU SEEM TO BE QUESTIONING GEORGIA POWER'S INTEREST IN IMPROVING RELIABILITY. WHY WOULDN'T GEORGIA POWER WANT TO IMPROVE SERVICE RELIABILITY?**

A. We are not questioning Georgia Power's interest in improving reliability. Certainly,

Georgia Power wants to provide reliable service to its customers. What we do question are the Company's methods. As the Commission is well-aware, the Company has a fiduciary responsibility to uphold and advance shareholder interests. Shareholder interests are advanced when share prices grow. Share prices grow when earnings grow, and earnings grow when the rate base grows (all else being equal). Thus, as illustrated by the Company's GIP, capital bias looms large in IOU reliability improvement initiatives. Any utility can spend billions on its grid and improve reliability. The goal should be to improve reliability to as great an extent possible for the least possible cost to customers. As the rest of this testimony will indicate, Georgia Power's GIP is not only intended to improve reliability; it is intended to improve reliability while massively and unnecessarily growing the rate base.

Further, we are concerned that advance approval of the GIP virtually eliminates the risk of penalties (cost disallowances) associated with excess grid investment. Before multi-year rate plans, Georgia Power would make the grid investments it considered necessary for safe and reliable service, and bore the responsibility for proving that its spending was prudent after the fact. The cost-disallowance risk presented a potential price shareholders might pay if the Company over-invested. However, if a grid investment plan is approved with unnecessary investments, the potential penalty for overspending is significantly lessened, as the regulator is unlikely to reverse a previous decision. This creates a moral hazard situation in which there is little to discourage a utility from proposing extreme or even cost-ineffective investments.[17] (In 1996 this Commission was only the second state utility regulator in the U.S., after the California Public Utilities Commission, to authorize the use of multi-year rate plans in ratemaking.)[18] It is certainly plausible that Georgia Power considered capital bias and moral hazard as it developed its GIP.

[17] Alvarez P. et al. *Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers?* Electricity Journal Vol. 35, Issue 8 (October 2022).

[18] Georgia PSC Docket No. 6292-U. Order dated February 16, 1996.

## III. THE TRANSMISSION INVESTMENT PLAN (TIP) WILL NOT DELIVER RELIABILITY IMPROVEMENTS SUFFICIENT TO OUTWEIGH ASSOCIATED RATE INCREASES

**Q. PLEASE PREVIEW THIS SECTION OF TESTIMONY.**

A. This section of testimony examines Georgia Power's $2.6 billion Transmission Investment Plan (TIP) over the period 2020 -2031. The Company describes its TIP as the replacement of aging transmission infrastructure,[19] which laypersons are likely to perceive as reasonable and necessary. However experts like Mr. Stephens, who have held the responsibility for maximizing reliability performance for the least amount of capital spending at a utility, would not describe the replacement of transmission assets based primarily on age as a cost-effective way to improve reliability, nor would such experts describe replacements based primarily on age as reasonable or necessary. We will describe why the practice of replacing transmission assets based primarily on age, which we call premature equipment replacement, is vastly more costly for customers than the value of the tiny reliability improvements it will deliver to customers, and why premature equipment replacement is both unreasonable and unnecessary.

**Q. WHAT IS PREMATURE EQUIPMENT REPLACEMENT?**

A. Georgia Power defines aging transmission assets as those that have exceeded their "expected life".[20] The Company's TIP selects transmission line and T&D substation equipment for replacement based on asset age[21] relative to expected life. It is inappropriate to use expected life and asset age as the basis for transmission line and T&D substation equipment replacement.[22] The actual operating condition of T&D equipment as measured

[19] APA-SPA-ADH-MBR Direct, p. 50 at 3.

[20] Georgia PSC Docket No. 42516. Direct Testimony of David P. Poroch, Sarah P. Adams, and Michael B. Robinson On Behalf of Georgia Power Company ("DPP-SPA-MBR 2019 Rate Case Direct"). Page 59 at 28.

[21] Ibid, p. 60 at 13.

[22] Alvarez P, Ericson S, and Stephens P. *"Asset Replacement Based on Risk Modeling – Emergency Best Practice?*

by periodic, objective testing and inspection programs should be the primary drivers of replacement, not age.

**Q. WHY IS IT INAPPROPRIATE TO USE THE AGE OF A PIECE OF EQUIPMENT, RELATIVE TO THE EXPECTED LIFE FOR EQUIPMENT OF THAT TYPE, AS THE BASIS FOR REPLACING THAT PIECE OF EQUIPMENT?**

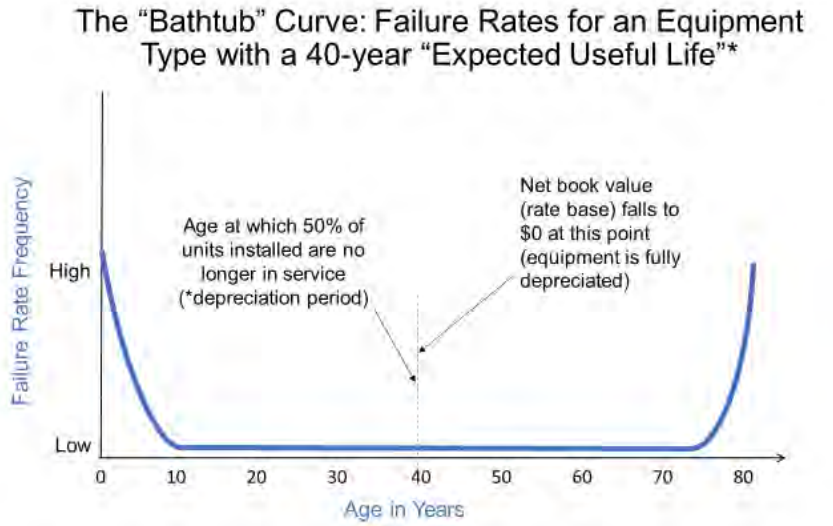
A. As the reader might imagine, there is significant variation between any individual piece of equipment's actual age at failure and the expected life for that type on average. If the expected life for a particular equipment type is 40 years on average, it means a few units of that type are likely to fail immediately, a few units of that type will likely still be operating safely and reliably after 80 years, and all the other units of that type will fail at some age between zero years and 80 years. For illustrative purposes, a representative chart depicting failure rates for a hypothetical equipment type with an expected life of 40 years is presented in Figure 4 below.[23] Most units of a particular equipment type will either fail very early in their lives ("infant mortality", due to manufacturing defects, design errors, or unobserved damage caused during installation, as examples) or very late in their lives. This failure rate characteristic gives a failure rate chart a "bathtub curve" shape (because it resembles the cross-section of a bathtub). Hearing attendees may recall Georgia Power Witness Mr. Robinson mentioning the bathtub curve.[24]

*(Challenging Utility Grid Hardening Proposals). Part 1*. Public Utilities Fortnightly. August 2020. P. 58.

[23] This is an illustrative chart. It is not based on any actual Iowa Curve used for any particular equipment type.

[24] Hearing Transcript September 27, 2022. Page 333 at 23; page 347 at 1.

Figure 4: Illustrative "Bathtub" Curve for a hypothetical equipment type with an average expected or estimated life of 40 years.



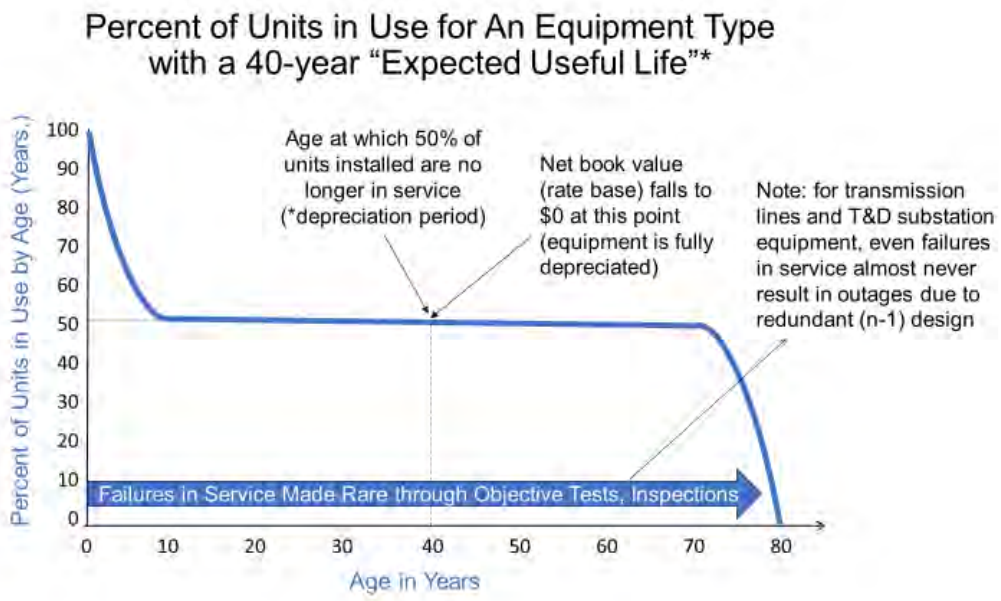

The illustrative bathtub failure rate curve can be plotted by percent of units of a particular equipment type in service by age, as depicted in Figure 5 below. As Figure 5 indicates, replacing a piece of equipment simply because it has reached its expected useful life is inappropriate because it deprives customers of decades of useful life from transmission equipment that has passed its tests or inspections, that has therefore been deemed capable of providing safe and reliable service, and for which customers have already paid in rates.[25] Premature equipment replacement thus increases rate base by "churning" assets unnecessarily, a practice which violates established regulatory precedent.[26] Investor-owned utilities are motivated to replace assets once they are fully depreciated, as fully

[25] Alvarez P, Ericson S, and Stephens P. *"Asset Replacement Based on Risk Modeling – Emergency Best Practice? (Challenging Utility Grid Hardening Proposals). Part 1*. Public Utilities Fortnightly. August 2020. P. 58.

[26] According to Averch and Johnson, "The firm has an incentive to acquire additional capital if the allowable rate of return exceeds the cost of capital." Like all other state utility regulators, the Commission provides Georgia Power with an allowable rate of return that exceeds the Company's cost of capital as an incentive to invest in its grid. All the Company needs is a reason to raise capital, and replacing assets before it is economically rational to do so represents one of those reasons. Averch and Johnson continues, "The firm has an incentive to (operate) in an uneconomic fashion that is difficult for the regulatory agency to detect." Averch H and Johnson L. *The Behavior of the Firm Under Regulatory Constraint.* The American Economic Review, December 1962, Vol. 52, No. 5, pp. 1052-1069

depreciated assets have no book value and earn no rate of return.

Figure 5: Application of illustrative Bathtub failure rate curve to percent of units in use by age.




**Q. DOES PREMATURE REPLACEMENT IMPROVE RELIABILITY?**

A. By the tiniest of amounts, yes, but almost imperceptibly. The degree of improvement is certainly not enough to justify the massive cost increases premature equipment replacements incur, for two reasons. First, all utilities, including Georgia Power, perform objective tests and inspections of transmission lines and critical T&D substation equipment on a routine, periodic basis. Any equipment which does not pass its tests or inspections is scheduled for repair or replacement, typically within a few months or a year. These objective tests are much more accurate predictors of equipment failure than age, which is precisely why utilities, including Georgia Power, have been using them for decades. Second, transmission systems are designed and operated based on the "N-1" criterion, explained in detail below. As a result of the N-1 criterion, in the already rare instance of a transmission line or T&D substation equipment failure, it is extremely unlikely such a failure will cause a service interruption for customers. Objective testing and inspection

practices combined with the inherent redundancy in the transmission grid results in excellent transmission system reliability *without* premature equipment replacement. The opportunity to improve transmission line and T&D substation reliability through premature equipment replacement is therefore almost zero to begin with, as will be demonstrated with the Company's own data later in this Section.

**Q. PLEASE DESCRIBE THESE OBJECTIVE TESTS AND INSPECTIONS.**

A. Unlike distribution circuit equipment, for which any one asset may only serve a handful of customers, transmission lines and T&D substations can serve thousands of customers. The increased consequences of failure for transmission line and T&D substation equipment have motivated utilities to establish comprehensive testing and inspection programs for various pieces of equipment and lines. For example, utilities test T&D substation power transformers every three years or so through "dissolved gas analysis", or DGA. Increases in certain types of gasses in transformer oil indicate deterioration that should be monitored closely and addressed. Utilities thus use DGA test results to indicate when a substation power transformer needs to be replaced. Construction planning to replace a power transformer that fails its DGA tests typically begins immediately and is scheduled and completed on a reasonably prompt basis. With an objective test like DGA available, there is no need to replace assets prematurely based on age relative to an estimated or expected useful life.

Similarly, T&D substation circuit breakers, switches, relays, and load tap changers are the subject of routine, periodic (typically every three to five years) functional testing programs at all utilities. In these programs, devices are taken out of service (power is temporarily rerouted to nearby equipment during testing) and forced to operate under simulated severe disturbance scenarios. Equipment that does not respond in an expected manner within parameters specified by the manufacturer are scheduled for prompt repair or replacement. Transmission lines, equipment, and towers are the subject of formal inspections conducted

periodically, complete with checklists and objective scoring mechanisms. Conductor, equipment, or towers that fail inspections are immediately scheduled for repairs or replacements in a controlled manner. Further, there is nothing prohibiting Georgia Power from increasing the frequency of testing and inspections for older equipment if it chooses.

To summarize, transmission line and substation equipment testing and inspection programs make the likelihood of equipment failures in service extremely rare. Moreover, the practice of prematurely replacing equipment based on age means that Georgia Power is replacing equipment that has passed its most recent tests and inspections, and was therefore operating safely and reliably at the time it was replaced. On this measure alone, premature equipment replacement is unreasonable and unnecessary, and a strong case could be made that the practice is imprudent. Furthermore, utilities maintain spare stocks of critical substation equipment, as well as power line structures and conductors, which helps to reduce repair/replacement time.

**Q. PLEASE EXPLAIN N-1 CRITERION AND ASSOCIATED REDUNDANCY**

A. Electric utilities are required to plan and operate their power systems using the N-1 criterion to comply with the NERC reliability standards. This means that the power system will operate safely and reliably following an outage of a single critical facility without causing thermal overloads or voltage problems on the facilities that remain in service. This also means that there is inherent redundancy in the system available to accommodate failures of critical network elements and equipment with no service interruptions for customers. Furthermore, the power system can operate reliably even with two network elements out due to options available to system operators such as temporary generation redispatch or network reconfiguration. Known as N-1-1 criteria, these additional options means that the power system can operate reliably in the event a critical network element fails and is followed by a second critical element failure. Once repairs/replacements are completed, the system is restored to a normal state of operation. Such built-in redundancy

further reduces the likelihood that an equipment failure – already made rare through equipment testing and inspection practices – results in a service interruption for customers or causes any reliability problems.

Based on transmission outage and equipment failure data provided by the Company in discovery from 2012 to 2021 (10 years), we have calculated the likelihood that various types of T&D substation equipment will both fail in service *and* result in a service interruption for customers. Further, we have applied the cost of premature equipment replacements to these likelihoods, arriving at the system-wide investment required to avoid one service interruption per year over the expected life of the new equipment by equipment type. Table 2 presents these results of these calculations, and is an accurate representation of the size (tiny) of the reliability improvement opportunity available from premature equipment replacement, as well as its extremely high cost. (See Exhibit PA/DS-6 for more calculation details.) As Table 2 indicates, the opportunity to improve reliability through premature equipment replacement is incredibly small to begin with, and certainly not worth the $2.6 billion cost of the Transmission Investment Plan. (Staff Witness Mr. Rana completes a similar analysis for premature Transmission Line replacements.)

Table 2: Annual likelihoods of a failure in service resulting in a service interruption for various T&D substation equipment types Georgia Power is replacing prematurely as part of its GIP, and associated capital costs required to avoid one such service interruption per year.[27]

| A | B | C | D | E |
|---|---|---|---|---|
| Substation Equipment Type | Annual Likelihood of a Failure Resulting in a Service Interruption[28] | Average Number of Customers per Interruption[29] | Equipment Replacements Required to Avoid One Service Interruption per Year | Capital Required to Replace the Counts of Equipment Identified in D (per Georgia Power Cost Data)[30] |
| Power Transformers | 0.0045 (45 in 10,000) | 690 | 224 | $[redacted] |
| Circuit Breakers | 0.0047 (47 in 10,000) | 219 | 212 | $[redacted] |
| Load Tap Changers | 0.0002 (2 in 10,000) | 9,503 | 4,510 | $[redacted] |

**Q. BUT WHAT ABOUT INCREMENTAL REPLACEMENT COSTS? GEORGIA POWER CLAIMS THAT EMERGENCY REPLACEMENT COSTS ARE TWO TO THIRTEEN TIMES HIGHER THAN PLANNED REPLACEMENT COSTS.[31]**

A. It is true that the costs to replace equipment in an emergency are higher than planned equipment replacements. But in our experience, replacements of equipment identified through equipment testing and inspection practices are planned, and do not constitute

[27] The values in column E represent capital investment. The present value of the revenue requirement (collections from customers) would be [redacted] higher per the Company's "k-factor".

[28] Service interruption data per Trade Secret attachment provided in response to STF-WG-2-26; System-wide equipment counts by type from response to STF-WG-1-33.

[29] Average Customer Counts per service interruption data per Trade Secret attachment provided in response to STF-WG-2-26.

[30] Georgia Power cost data by equipment type per Trade Secret response to STF-WG-1-34.

[31] Response to STF-WG-2-25 (b).

emergencies. These planned replacements are typically completed within reasonable timeframes of six to eighteen months, and do not incur incremental costs. Only replacements of equipment that fails in service *and* causes a service interruption constitute replacements so emergent as to incur such large incremental cost multiples. As Table 2 Column B indicates, such failures are incredibly rare. Thus while some amount of incremental emergency replacement cost can be avoided through premature replacement, the infrequency of emergency replacements makes these incremental replacement costs very low relative to the extreme incremental cost of premature replacement.

As an example, the rate of failure resulting in a service outage for substation circuit breakers is about five in one thousand per year, and Georgia Power reports having 1,868 circuit breakers. Thus, in an average year, about nine circuit breakers will need to be replaced on an emergency basis across the Company's entire system.[32] The incremental emergency replacement cost associated with replacing nine circuit breakers annually, even when combined with the reliability benefits of avoiding nine outages annually for 219 customers each outage, simply does not justify the $[redacted] capital cost of prematurely replacing 1,868 circuit breakers before a test indicates such replacements are necessary.[33]

Further, like most large utilities, Georgia Power maintains an inventory of T&D substation equipment of various types and sizes, and this significantly reduces the cost of emergency replacement in many instances.[34] The Edison Electric Institute, of which Georgia Power is a member, also maintains and/or participates in multiple T&D substation and transmission equipment access programs to reduce transmission and substation equipment procurement times and costs, including the Spare Transformer Equipment Program, SpareConnect, Grid

[32] 1868 circuit breakers multiplied by 0.005.

[33] 1,868 circuit breakers multiplied by an average replacement cost of [redacted].

[34] Response to STF-WG-4-2 (d).

Assurance, and RESTORE.[35]

**Q. HOW DO YOU KNOW THAT PREMATURE REPLACEMENT OF TRANSMISSION LINE AND T&D SUBSTATION EQUIPMENT DOES NOT DELIVER BENEFITS TO CUSTOMERS IN EXCESS OF COSTS TO CUSTOMERS?**

A. Georgia Power bears the burden to prove that premature equipment replacement is cost-effective for customers. Georgia Power has not prepared any cost-benefit analyses of its TIP,[36] or its premature equipment replacement program,[37] or its distribution investment plan packages (a subject to which we will return in Section IV). Indeed, Georgia Power Witness Mr. Robinson claimed that it is not possible to complete such cost-benefit analyses.[38] We do not agree, and Table 2 indicates the extreme costs of premature replacement relative to benefits, as informed by historical outage data. Further, neither we nor Georgia Power are aware of any industry studies or research indicating that premature equipment replacement is cost-effective.[39] Furthermore, there is no industry standard that transmission equipment should be replaced when it reaches its expected useful life, nor any industry standards for the expected useful lives (in years) of various types of transmission equipment.[40,41]

**Q. HOW DO YOUR RESPOND TO MR. ROBINSON'S TESTIMONY THAT GEORGIA POWER WOULD NOT WAIT FOR EQUIPMENT FAILURE?**

[35] *Spare Equipment and Grid Resilience Programs*. Edison Electric Institute document. June, 2021.

[36] Georgia PSC Docket No. 42516. Response to STF-PIA-3-7.

[37] Response to STF-WG-2-25 (b).

[38] Hearing Transcript September 27, 2022. Page 348 at 1.

[39] Ibid, subpart (c).

[40] Response to STF-WG-4-5.

[41] Response to STF-WG-4-6.

A. Mr. Robinson stated that "We don't want to be the utility to wait to failure. We have seen what happens across the United States when companies wait to failure, whether it is transmission lines or substation assets."[42] "Waiting for failure," is not an accurate description of Georgia Power's historical approach to transmission reliability. Georgia Power has never simply waited for assets to fail. Through its equipment testing and inspections programs, Georgia Power has historically followed, and continues to follow, utility best practices for identifying equipment in need of repair or replacement in advance of failure. Through redundant design, Georgia Power has historically followed, and continues to follow, utility best practices for eliminating the consequences (service interruptions) associated with rare instances of transmission equipment failures in service. In our estimation, Georgia Power should continue to rely on the best practices it has followed in the past to continue to provide customers with exceptional transmission system reliability in the future.

Finally, we are not sure to which utilities Mr. Robinson was referring when he discussed what Georgia Power has seen "across the United States," but we have a few observations to share. If Mr. Robinson was referring to the wildfires caused by Pacific Gas and Electric equipment failures, subsequent investigations blame those wildfires on a lack of inspections and maintenance (most commonly, vegetation management), not a lack of equipment replacement.[43] If he is referring to the lengthy service interruptions in Louisiana following Hurricane IDA, damage to transmission lines serving New Orleans was caused by a hurricane, not by a lack of Entergy equipment replacement or transmission investment.

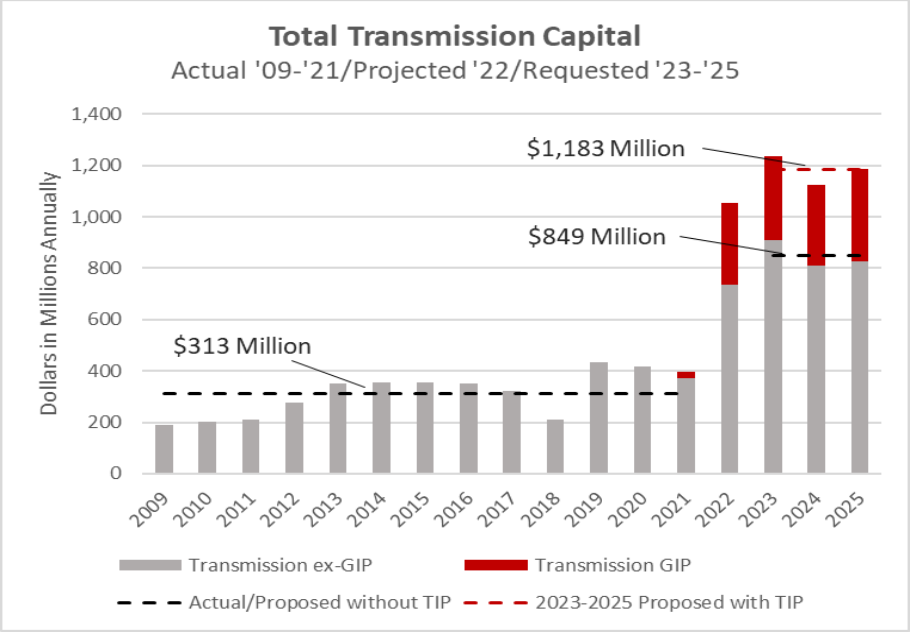
Georgia Power's attempt to support its request through a vague reference to the experiences

[42] Hearing Transcript September 27. 2022. Page 346 at 9.

[43] 1) *The Camp Fire Public Report*. A summary of the Camp Fire investigation by the Butte County (California) District Attorney. June 16, 2020. Pages 82-87. 2) *October 2017 Fire Siege*. Report by the Safety and Enforcement Division of the California Public Utilities Commission. June 13, 2019. Pages 2-3.

of other utilities is misplaced given how Georgia Power's proposed increases compare to the transmission investments of other utilities. *Even if the Commission rejects the Company's entire $1 billion proposal to continue TIP spending 2023-2025, the remaining transmission investments proposed still represent a 171% increase (almost triple, from $313 million per year to $849 million per year) over average annual transmission investment from 2009 to 2021 (before the TIP commenced in earnest).* Thus, the Commission should rest assured that such a rejection would not deprive the Company of an ample increase in capital spending to improve transmission reliability, assuming the Company operates in an efficient and economic manner. Figure 6 illustrates the situation clearly.[44] Given that energy sales (MWhs), peak demand (MW), and number of customers are expected to grow less than 2%, a 171% increase in capital spending should be more than enough to maintain and improve reliability under efficient and economic management.

Figure 6: Total Transmission Capital Spending, Actual 2009-2021/Projected 2022/Requested 2023-2025




[44] Actual spending per attachment provided in response to STF-WG-2-1(a); projected and requested spending per Trade Secret attachment provided in response to STF-PIA-4-4.

**Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING GEORGIA POWER'S REQUEST TO CONTINUE TIP IMPLEMENTATION?**

A. We recommend the Commission reject Georgia Power's $1.0 billion request to continue TIP implementation in its entirety, as summarized in the table below. The 171% increase over historical spending levels that remains after such a rejection (almost triple) will be more than sufficient to allow Georgia Power to make the investments required to maintain and improve transmission reliability. The amounts rejected are reflected in the revenue requirement adjustments found in the Smith-Trokey testimony and exhibits, and the rejection of TIP capital related to transmission lines (as distinguished from the T&D substation investments we discuss here) are addressed in the testimony of Staff Witness Mr. Rana.

Table 3: Summary of transmission capital request and recommended rejections.

| ($ in millions) | '09-'21 Average Actual | 2023 | 2024 | 2025 | '23-'25 Average |
|---|---|---|---|---|---|
| Transmission Capital Requested | | 1,236.7 | 1,125.5 | 1,186.8 | 1,183.0 |
| Transmission Investment Plan | | (327.8) | (314.1) | (358.7) | (333.5) |
| Transmission Capital Remaining | 313.0 | 909.0 | 811.4 | 828.0 | 849.5 |

## IV. GEORGIA POWER'S DISTRIBUTION INVESTMENT PLAN (DIP) WILL NOT DELIVER RELIABILITY IMPROVEMENTS SUFFICIENT TO OUTWEIGH RATE INCREASES

**Q. PLEASE SUMMARIZE THIS SECTION OF TESTIMONY.**

A. This section of testimony is organized as follows, as further introduced immediately below.

1. Summary of Georgia Power's Distribution Investment Plan
2. Circuit hardening is not a cost-effective way to improve reliability
3. Undergrounding is not a cost-effective way to improve reliability
4. The DIP applies costly DIP investment packages to too many circuits which do not need them
5. The DIP ignores dramatically more cost-effective approaches to improving reliability
6. The DIP is prompting premature retirement of reliable assets for which customers are paying
7. Why the Commission should afford little to no weight to the Company's Customer Benefits Study
8. The DIP offers no performance accountability
9. Summary of the Maryland Commission's efforts to improve reliability in a cost-effective manner
10. DIP Recommendations for Commission Consideration.

This section of testimony begins with a summary of Georgia Power's Distribution Investment Plan (DIP). We then critique the DIP, focusing on four problems: 1) The largest DIP investment packages by far, circuit hardening and undergrounding of overhead lines, are not remotely cost-effective approaches to improving reliability; 2) The Company

applies costly DIP investment packages to too many circuits which already demonstrate reasonably good reliability performance, further damaging the cost-effectiveness of the DIP; 3) The DIP ignores dramatically more cost-effective approaches to improving reliability, including vegetation management and worst-performing circuit programs; and 4) The DIP appears to be causing premature retirement of reliable equipment customers continue to pay for in rates, as evidenced by $[redacted] in projected write-offs of equipment with book value remaining 2023-2025. (This is not only wasteful, but violates established legal and regulatory precedents).[45]

This Section also explains why the Commission should assign little or no weight to the Company's Customer Benefit Study. (The Customer Benefit Study is not a cost-effectiveness test or cost-benefit analysis, but rather an optimization of capital-intensive options and constraints designed specifically to justify large capital investments.) We will also describe our concerns regarding Georgia Power's accountability for securing DIP-related reliability improvements, and summarize the Maryland Public Service Commission's efforts to secure reliability improvements from utilities in a cost-effective manner, along with associated results. We will conclude with recommendations for Commission consideration, including a recommendation that the Commission reject Georgia Power's requests for the circuit hardening and undergrounding capital components of the DIP in their entirety. We note that if the Commission follows this recommendation, the remaining distribution capital budgets still represent an increase of 131% of historical distribution capital spending 2009-2019 (more than double). This increase should be more than enough to help Georgia Power improve the reliability of its distribution grid in a cost effective manner for customers.

[45] Averch and Johnson describe how cost-of-service regulation encourages regulated, for-profit utilities to raise and spend more capital than necessary for safe and reliable service (see footnote 27). Large-scale retirement of equipment with book value remaining is one indication that a utility is over-investing in its grid, resulting in premature removal of equipment operating safely and reliably.

*1. Summary of Georgia Power's Distribution Investment Plan (DIP)*

**Q. PLEASE SUMMARIZE THE COMPANY'S DIP**

A. Georgia Power's DIP consists of six investment "packages" the Company has defined to be applied to circuits to improve their performance. (Note that the packages do not include low-cost options, or options involving operations and maintenance spending, a subject we revisit later in this Section.) The Company uses an Optimization Model to determine which of the packages to apply to circuits in the third and fourth reliability performance quartiles (meaning, the circuits performing below the median circuit's performance), and in what priority. (Note that "median" is a much different measure than "average", and that the calculation and use of the median value determines the universe of circuits to which packages can be applied;[46] we will return to both observations later in this Section.) Of circuits performing below the median, additional criteria are applied to develop package lists per circuit. The packages are then implemented by a dedicated GIP project implementation department[47] over time (meaning, the twelve years and four rate cases from 2020 through 2031).

The Company defined each investment "package" to include a discrete set of actions and investments, along with implementation costs, resulting in both rate increases and reliability improvements for customers. These are the same definitions used in the Optimization Model. In that Model, "Rate Increases" reflect changes in O&M expenses and revenue requirements from capital investment, while reliability improvements are valued as customers might value them (meaning, as a reduction in the costs customers incur from service interruptions). The Optimization Model varies all of these as investment levels change; discrete investment levels, described as "scenarios", are associated with projected reliability improvements (system average interruption duration in minutes) by

[46] Customer Benefit Study, corrected k-factor, page (i).

[47] Discovery conference October 13, 2022.

the end of the DIP period (2032) for each investment level. The cost of service outages to customers falls as the count of package applications increases (up to a point, called the point of diminishing returns, at which the incremental implementation costs become higher than the fall in customer service outage costs). The Company's DIP capital requests thus represent the cost to implement the count of packages the Optimization Model determines to be optimum *given the packages and their attributes as the Company has defined them*. (We note this is not the same as the lowest-cost way to improve reliability, a subject to which we return later in this Section.)

Using its Optimization Model, the Company employed its 2017 reliability performance to place circuits into quartiles, thereby qualifying certain circuits (those below the performance of the median circuit in 2017) to receive DIP packages. These placements of circuits into quartiles, thus qualifying them to receive DIP packages, using 2017 data, remain static through to today.[48]

Brief descriptions of the six packages the Company has defined and proposed for 2023-2025 spending are presented in Table 4 below.[49] As indicated earlier, Georgia Power spent $[redacted] implementing DIP packages 2020-2022, and proposes $1.3 billion 2023-2025. As the chart indicates, packages "circuit hardening" and "undergrounding" are by far the largest categories of spending in the DIP, representing 85% of total DIP spending from 2020-2025 (39% and 46% respectively).

[48] Trade Secret response to STF-WG-1-42 (c); Trade Secret Optimization Model screenshots provided informally in follow-up to the Optimization Model discovery conference held October 3, 2022.

[49] Trade Secret attachment provided in response to STF-WG-1-18.

Table 4: Summary of DIP packages, spending, applications, and cost per circuit.

| Package | Description | Capital Request 2023-2025 | Actual & Projected 2020-2022 | Circuits Applied 2020-2022 | Cost per Circuit 2020-2022 |
|---|---|---|---|---|---|
| 1. Add sections & distribution automation | Dividing circuits up into smaller sections increases fault isolation granularity so that fewer customers experience an outage. | [redacted] | [redacted] | [redacted] | $1.3 million |
| 2. Add & Strengthen Ties | Adding ties increase flexibility for routing power to all but isolated customers. "Strengthening" means increasing tie capacity to ensure re-routing is possible during peak. | [redacted] | [redacted] | [redacted] | $7.8 million |
| 3. Circuit Hardening | Replacing poles and/or crossarms; replacing fuses with TripSavers®; and add wildlife protection devices to reduce outage frequency. | [redacted] | [redacted] | [redacted] | $8.7 million |
| 4. Break Feeder | Split an existing circuit into two smaller circuits (similar to #1) | [redacted] | [redacted] | [redacted] | $11.6 million |
| 5. Bring Feeder to Road | To improve access (faster repair), relocate feeder from back lots with difficult access to front lots/streets. | [redacted] | [redacted] | [redacted] | $29.5 million |
| 6. Underground Overhead Lines | Move lines, equipment, and services currently overhead to underground to reduce outage frequency. | [redacted] | [redacted] | [redacted] | $49.1 million |
| | Totals | $1.3 billion | [redacted] | [redacted] | $16.2 million |

**Q. WHAT RESULTS DOES THE COMPANY EXPECT FROM ITS DIP?**

A. In its initial DIP in the 2019 rate case, the Company projected that a system-wide improvement in average interruption duration (SAIDI), currently 132.6 minutes on average over the last five years as reported in Figure 3 earlier, to 65 minutes by 2031.[50] (We note that the Company's five-year average SAIDI is within 1% of the five-year average for U.S. investor-owned utilities.) In the current DIP, as noted earlier, the Company revises its projection to a SAIDI target of 80 minutes. In just three years, the Company's projected reliability improvement has already deteriorated 23.1% from initial projections. In a discovery conference, the Company specified that Staff should not consider an 80-minute SAIDI as a goal (or as we prefer to say, an expectation), but rather as nothing more than a projection from its Optimization Model.[51] The low likelihood that the Company can be held responsible for securing projected reliability improvements is a significant DIP deficiency, and is yet another subject we will revisit later in this Section.

**Q. WHAT RESULTS HAS THE COMPANY SECURED TO DATE FROM DIP INVESTMENTS?**

A. As indicated in Section II of this testimony, it is far too early to determine results from DIP investments. Not only have relatively few of the most questionable packages implemented on circuits to date been completed (meaning, circuit hardening and undergrounding), there are insufficient years of experience (we recommend three years minimum) to make any conclusions. Significantly, packages have been deployed together, often in conjunction with vegetation management, making it impossible to determine if an investment package, or if simple and inexpensive vegetation management, was responsible for any improvements secured. We will return to this topic later in this Section.

[50] Georgia PSC Docket No. 42516. Attachment provided in response to STF-L&A-5-38.

[51] Optimization Model discovery conference held October 3, 2022.

*2. Circuit Hardening Is Not a Cost-Effective Way to Improve Reliability*

**Q. WHAT IS CIRCUIT HARDENING?**

A. The Company uses circuit hardening to describe a number of investments intended to reduce the frequency of service interruptions. Primary activities including replacing poles, replacing pole crossarms, installing animal guards, and replacing fuses with TripSaver® devices. The Company also claims circuit hardening investments will reduce operations and maintenance costs.

**Q. PLEASE EXPLAIN WHY CIRCUIT HARDENING IS NOT A COST-EFFECTIVE WAY TO IMPROVE RELIABILITY.**

A. Examining the cost-effectiveness of any grid investment involves comparing the benefits to customers from the investment (in this case, the value of reliability improvements) to the costs to customers of those investments (rate increases/revenue requirements). As the circuit hardening package includes multiple activities, it is difficult to parse these out individually. However, the analysis described below indicates that even if the Company secures the reliability improvements it projects from circuit hardening, the program is so costly on a per premises basis that it cannot deliver benefits to customers in excess of costs to customers.

**Q. HOW EXPENSIVE IS CIRCUIT HARDENING?**

A. Georgia Power reports that it will harden [redacted] circuits[52] at a cost of $[redacted] between 2020 and 2025, for an average cost per circuit of $6.45 million. Including carrying charges (costs of capital, taxes on Company income, sales and property taxes, etc.) the cost per circuit to customers grows to $[redacted] (the present value of the revenue requirement

[52] Trade Secret attachment provided in response to STF-WG-1-18.

on $6.45 million assuming the Company's "k-factor" of [redacted]).[53] Given that the average Georgia Power circuit serves 1,109 customers,[54] this works out to $[redacted] in present value of revenue requirements *per average customer served by a hardened circuit*. We consider this to be quite expensive relative to the potential benefits available.

**Q. HOW EFFECTIVE IS CIRCUIT HARDENING?**

A. It is difficult to say. The Company projects a reduction in outage duration of [redacted] from circuit hardening. In discovery, the Company provided reliability data on 30 circuit hardening projects completed from 2012 to 2016. For these circuits, outage duration fell an average of 25% from pre-hardening performance,[55] which seems to validate the Company's projections. Unfortunately, vegetation management was completed concurrently on 50% of these circuits.[56] While concurrent completion of vegetation management on circuits being hardened is common and appropriate (to make room for the work being done), concurrent vegetation management makes it impossible to determine how much of the reliability improvement realized on hardened circuits is due to vegetation management, and how much is due to hardening investment.

**Q. GIVEN THESE COSTS AND THE COMPANY'S EFFECTIVENESS PROJECTIONS, HOW DOES THE CUSTOMER VALUE OF RELIABILITY IMPROVEMENTS COMPARE TO CUSTOMER COSTS?**

A. Unfortunately, not favorably. Our analysis finds that customers receive only $0.46 in reliability improvement value per dollar of rate increase. An explanation of our analysis follows.

[53] Customer Benefits Study, corrected k-factor, page 12. $6.45 million multiplied by the corrected k-factor is $[redacted]

[54] 2.6 million customers divided by 2,344 circuits; $[redacted] divided by 1,109 customers is $[redacted] each.

[55] Trade Secret attachment provided in response to STF-WG-1-8.

[56] Trade Secret Attachment B provided in response to STF-WG-2-16.

We applied the Company's current reliability improvement assumptions for the circuit hardening package to the average reliability 2017-2021 of the 25 circuits the Company selected for this package 2020-2022.[57] (Remember, according to the Company's Optimization Model, these first circuits prioritized for hardening should represent the worst circuits in the Company's distribution system.) From a starting average SAIDI of 261.4 minutes on these circuits, the Company's projected average improvement of [redacted] results in a reduction to [redacted] minutes. From a starting SAIFI on these circuits of 2.33 interruptions per year, the Company's projected average improvement of [redacted] results in a reduction to [redacted] interruptions per year. As an initial observation, we note that the customer "willingness to pay" research cited earlier indicates customers would be unwilling to incur costs amounting to $[redacted] each for such reliability improvement levels. But we continued our analysis through an additional step: utilizing the US Department of Energy's Interruption Cost Estimator (ICE) tool to quantify the dollar value to customers of reliability improvements from circuit hardening projected by Georgia Power. We can then compare this value to the average customer cost of $[redacted] million per circuit to determine the cost-effectiveness of circuit hardening (or lack thereof).

**Q. WHAT IS THE DEPARTMENT OF ENERGY'S ICE TOOL?**

A. The ICE tool is an internet-based software application designed specifically by the Department of Energy to help utilities estimate the value to customers of reliability improvements.[58] Georgia Power employed the ICE tool to estimate the cost of outages to customers as a reality check against its Customer Benefits Study results using the Company's own "cost of outage" estimates, secured from customer research conducted in 2011. (Customer Benefits Study results using the ICE tool estimates and using the

[57] Trade Secret attachment provided in response to STF-WG-1-18.

[58] The Interruption Cost Estimator for anyone to use at https://icecalculator.com/build-model?model=reliability

Company's own estimates were very similar.)[59] A different option the ICE tool offers, based on the same underlying "cost of outages to customers" research data, estimates the value to customers of reliability improvements.

**Q. HOW DID YOU USE THE ICE TOOL TO ESTIMATE THE PRESENT VALUE OF RELIABILITY IMPROVEMENTS FROM CIRCUIT HARDENING?**

A. We used the ICE tool's "value of reliability improvements" option to estimate the value to customers of the reliability improvements the Company projects from the circuit hardening package. We input the starting and improved SAIDI and SAIFI levels for the first 25 circuits described above into the ICE tool, as well as all other inputs the tool required specific to Georgia Power (customer counts by class for these circuits; inflation rate = [redacted]; discount rate = [redacted]; expected lifetime of benefits in years = 40; etc.). Using all this Company-specific and circuit-specific data, the ICE tool calculates the present value of projected reliability improvements from hardening the first 25 circuits to be $94.9 million, or $3.8 million per circuit. Compared to the present value of the average cost to customers to harden a circuit ($[redacted] per circuit, per above), the ICE tool valuation of reliability improvements indicates that circuit hardening delivers just $0.46 in reliability improvement value for every $1 in customer rate increase.[60]

Thus, the circuit hardening package is cost-ineffective by a wide margin, and not in the interest of customers or the public. Recall that our analysis employed Georgia Power's own projections for costs and reliability improvements from circuit hardening; *it is entirely possible Georgia Power will not be able to deliver the reliability improvements it projects within the costs it estimates*. (Further, our finding is consistent with one of the most thorough studies of circuit hardening ever completed, on behalf of the Public Utilities

[59] Customer Benefits Study, corrected k-factor, p. 31-32.

[60] $3.8 million in benefit per circuit divided by $[redacted] in customer costs (PVRR) per circuit = $0.46

Commission of Texas. The study, which focused on hardening for hurricanes, determined that cost-effectiveness for circuit hardening was only indicated for about 1% of distribution structures, including only those within 50 miles of the Gulf of Mexico.[61]

*3. Undergrounding of Overhead Lines Is Not a Cost-Effective Way to Improve Reliability*

**Q. PLEASE EXPLAIN WHY UNDERGROUNDING IS NOT A COST-EFFECTIVE WAY TO IMPROVE RELIABILITY.**

A. As with circuit hardening, we cite undergrounding's extreme cost as the primary reason why undergrounding cannot possibly deliver reliability improvements sufficient to deliver value to customers in excess of rate increases. While our circuit hardening analysis identified a cost per circuit of $[redacted], and a cost per customer served by a hardened circuit of $0,000, the customer cost to underground overhead lines (present value of the revenue requirement) is 3.6 times more costly than circuit hardening on a per circuit basis ($[redacted]),[62] and more than twice as costly as circuit hardening on a customer-specific basis, at $15,241.[63] This customer-specific amount is far less than we have seen in the industry, at about $1 million in utility cost per overhead mile undergrounded, divided by the U.S. average of customers per distribution line mile of 40 ($25,000 per customer), which indicates that our customer-specific cost estimate (based on Georgia Power data) is likely understated by a significant amount. Recently, Pacific Gas & Electric Company reported an undergrounding cost of over $4 million per overhead line mile,[64] though

[61] Brown R. *Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs*. Prepared by Quanta Technology on behalf of PUC Texas in Docket No. 36375. March 4, 2009.

[62] Trade Secret attachment provided in response to STF-WG-1-18. $[redacted] 2020-2025 divided by [redacted] circuits, multiplied by the corrected k-factor of [redacted] = $[redacted].

[63] Trade Secret attachment provided in response to STF-WG-1-18. Upon dividing, [redacted] customers to be undergrounded 2020-2025 (six years) at a cost of $[redacted] yields $[redacted] in utility costs per undergrounded customer. Multiplied by the corrected k-factor of [redacted] (for costs of capital, taxes, etc.) yields a cost to customers of $15,241 per undergrounded customer.

[64] California PUC Docket No. A.21-06-021. *2022 Wildfire Mitigation Plan and 2023 General Rate Case Updates*.

admittedly through rough terrain (steep, rocky, and heavily forested). In a discovery conference, Georgia Power admitted that one of the lessons learned from DIP implementation so far is that undergrounding costs more than original estimates due to the rocky nature of Georgia soil.[65]

**Q. HOW EFFECTIVE IS UNDERGROUNDING AT IMPROVING RELIABILITY?**

A. Undergrounding is quite effective at improving reliability. But high cost, not the level of effectiveness, is the problem. The Company reports using the reliability of circuits that are already undergrounded as the basis for its undergrounding reliability improvement projections (though it admits it has never implemented a massive undergrounding program in the past).[66] While this is a reasonable approach in the absence of actual undergrounding program data, the cost of undergrounding is so high as to render the undergrounding effectiveness question meaningless.

We know this because we applied a 100% SAIDI and SAIFI reduction to the eight circuits for which undergrounding was the only package the Company applied 2020-2022. In our analysis, using ICE tool values by customer class for the cost to customers of service interruptions, and the Company's cost projections[67] and other Company-specific assumptions, we found that the Company's costs (not even including profits and taxes customers must pay) exceeded the customer value of reliability improvements for every single one of the eight circuits, and for most of them, by a very wide margin. *This finding bears repeating: even at a 100% reliability improvement assumption (perfect reliability),*

Stakeholder presentation dated February 24, 2022. Slide 5.

[65] Discovery conference October 3; Customer Benefit Study, corrected k-factor, page (i).

[66] Response to STF-WG-2-7.

[67] Trade Secret Attachment A to STF-WG-1-49.

*the customer value of reliability improvements from undergrounding did not exceed the Company's undergrounding costs.*

Our contention that the extremely high cost of undergrounding overhead lines makes the practice a cost-ineffective way to improve reliability is well-supported by extensive amounts of research and state regulator evaluation. A study completed in follow-up to the aforementioned PUC Texas study (on circuit hardening) that focused exclusively on undergrounding found only $0.30 in benefits for every $1 spent to underground overhead lines.[68] Multiple other state utility regulators have studied the undergrounding question, including Florida, Maine, Maryland, North Carolina, and Virginia. In every instance but one, no state utility regulator has endorsed undergrounding of its own accord.[69] In the lone exception, the Virginia State Corporation Commission severely limited a utility's undergrounding application, though that Commission fully rejected two other undergrounding applications by the same utility.[70]

**Q. WHAT OTHER EVIDENCE DO YOU HAVE THAT UNDERGROUNDING IS NOT A COST-EFFECTIVE WAY TO IMPROVE RELIABILITY?**

A. As with Georgia Power's circuit hardening package, we used the ICE tool to estimate the reliability improvement value of the undergrounding package. We employed the same method for undergrounding as we did for circuit hardening, using the average SAIDI (270 minutes) and SAIFI (2.4 interruptions) 2017-2021 of the 16 circuits the Company selected

[68] Larsen P. A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution lines. Lawrence Berkeley National Laboratory report 1006394. Preprint page 42. Published in Energy Economics, Vol. 60, p. 47-61. November 2016.

[69] Brown R. *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion*. Florida PSC Docket No. 06-0351-PAAEI. Feb. 2007. Page 9.

[70] Virginia SCC Case Nos. PUE 2014-00089, Order dated July 30, 2015; PUE 2015-00114, Order dated August 22, 2016; PUR 2018-00100, Order dated January 17, 2019. Note that subsequent legislation in Virginia (S 1473 in 2017) and Florida (HB 797/SB796 in 2019) instructed regulators to permit recovery of undergrounding costs. We consider such legislation ill-informed, and a legislative overreach into state utility regulator authority.

for undergrounding 2020-2022 as the ICE tool starting point. We then input the reliability improvements the Company's Optimization Model assumes for the undergrounding package, along with all other variables specific to Georgia Power and these 16 circuits, just as we did for circuit hardening. Using the Company's own reliability improvement projections (SAIDI down to [redacted] and SAIFI down to [redacted]) and all other circuit-specific and Company-specific inputs, the ICE tool calculated a reliability improvement value of $170 million, or $10.6 million per circuit. Compared to the average cost per circuit of $[redacted], our analysis indicates that customers will receive only $0.36 in value per $1 of undergrounding rate increase[71] – not significantly different than the $0.30 per $1 found by the Texas undergrounding study cited above.

**Q. HAVE YOU INCLUDED THE OPERATIONS AND MAINTENANCE (O&M) SAVINGS ASSOCIATED WITH CIRCUIT HARDENING OR UNDERGROUNDING IN YOUR COST-EFFECTIVENESS CALCULATIONS?**

A. No. But as the Company's Customer Benefits Study indicates, avoided customer outage costs represent the greatest single value proposition of the Company's DIP by far.[72] Based on our finding that customer reliability value is dramatically insufficient to justify the cost of circuit hardening or undergrounding, it is not possible for the relatively small reduction in O&M costs associated with undergrounding (stemming largely from reductions in vegetation management) or circuit hardening to remotely make up the shortfall in customer reliability value relative to customer costs.

[71] $10.6 million in benefits per circuit divided by $29.5 million in customer costs per circuit is 0.36.

[72] Customer Benefits Study, corrected k-factor, p. v, Figure 2, "Present Value of Total Costs (to customers)"

*4. The DIP applies costly DIP investment packages to too many circuits which do not need them.*

**Q. IN THE INTRODUCTION TO THIS DIP INVESTMENT SECTION YOU STATED "The Company applies costly DIP investment packages to too many circuits which already demonstrate reasonably good reliability performance, further damaging the cost-effectiveness of the DIP." PLEASE EXPLAIN THIS.**

A. In our summary of the Company's DIP we related that the Company's DIP Optimization Model applies investment packages to circuits performing below the median (meaning, circuits performing in the third or fourth quartile) as measured in 2017. This criteria identifies half of all circuits as the best candidates for capital investment rather just the very worst performers. As the reader can imagine, one-half of the Company's circuits exhibit a very wide range of reliability performance, with many circuits performance close to the system average performance. Indeed, our examination of circuits with "below the median" reliability 2017 to 2021 identifies circuits with SAIDI as low as 99 minutes (the circuit ranked immediately below the median circuit) in the third quartile.[73] *Given that the Company's 5-year average SAIDI 2017-2021 is 131, this means that the Company's DIP will eventually apply investment packages to circuits with above-average reliability*.

Clearly, the application of costly investment packages to circuits with above-average reliability does not make sense. To be sure, focusing investment packages on the worst-performing circuits, and not those above the average, nor even those near the average, makes the most sense. Figure 7 below illustrates the problem with applying investment packages to circuits "below the median": it does not sufficiently focus DIP attention and investment on the worst-performing circuits.

[73] Georgia PSC Docket No. 44160. Trade Secret Attachment 1(b) provided in response to STF-WG-1-1.

Figure 7: Circuit Counts and SAIDI performance by quartile using the most-recent 5-year averages.

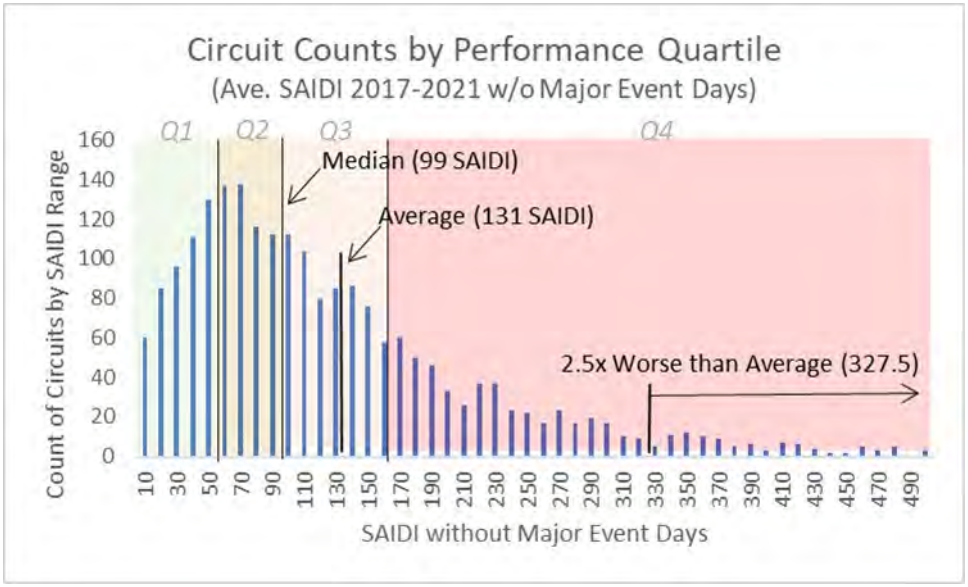



Figure 7 indicates that investing in so many circuits does not sufficiently concentrate spending to optimize package assignments. Unconcentrated spending increases the cost of the DIP and reduces the average reliability improvement per DIP capital dollar. This is because the very worst-performing circuits present a much larger performance improvement opportunity than circuits performing at, near, or above the average. For example, attention focused on circuits with SAIDI 2.5 times higher than average would address just 126 circuits at Georgia Power, not the 800 or so circuits that the Company's DIP targets for package deployment.[74]

**Q. WHY DOES A FOCUS ON FEWER CIRCUITS DELIVER A BIGGER BANG FOR THE BUCK?**

A. As the reader can appreciate, the starting point reliability for a circuit makes a big difference in the percentage of reliability improvement that might be expected from the

[74] Customer Benefit Study, corrected k-factor, page (i).

application of a package. For the sake of argument, assume that the average circuit's SAIDI after hardening will average about 99 (the median circuit at Georgia Power in 2017). For a circuit with a SAIDI of 131 before hardening, the resulting SAIDI improvement would be 24% (131 to 99). For circuit with a SAIDI of 400 before hardening, the resulting SAIDI improvement would be three times greater, at 75% (400 to 99). This illustrates why the performance improvement opportunity for a circuit with a SAIDI of 400 is much larger than the performance improvement opportunity for a circuit with a SAIDI of 131, and why a focus on 126 circuits with really poor reliability delivers much better "bang for the buck" than a focus on 800 circuits.

Neither the Company's DIP nor its Optimization Model account for this difference in performance reliability opportunity. For all packages but undergrounding, the reliability improvement percentages the Optimization Model applies for a given package remain the same for all circuits receiving that package regardless of reliability starting point.[75] This Optimization Model flaw guarantees that the DIP applies packages to circuits that do not need them, resulting in more capital investment than necessary to achieve a given reliability performance target.

**Q. BUT EARLIER YOU SAID THAT THE COMPANY'S OPTIMIZATION MODEL DOES PRIORITIZE CIRCUITS BASED ON RELIAIBILITY.**

A. Yes, this is true. But focusing on circuits with reliability in the third quartile does not sufficiently focus attention and investment on the very worst circuits where the most benefit could be achieved for each dollar of capital investment. Indeed, we know of no utility that focuses reliability improvement attention on circuits even in the fourth quartile, or the bottom 25% of circuits. Instead, our experience is that most utilities operate "worst performing circuit" programs focused on circuits with reliability that is three times worse

[75] Response to STF-WG-6-1.

than the average circuit. The most aggressive of such programs focus on circuits with reliability that is 2.5 times worse than the average circuit. Such programs focus reliability improvement attention on far fewer than 25% or 50% of a utility's circuits, as Georgia Power's DIP does.

In Georgia Power's case, using 2017-2021 reliability data, a circuit with reliability performance 2.5 times worse than the 2017-2021 average of 131 minutes would be circuits with a SAIDI worse than 327.5 minutes. According to that definition, only 126 of Georgia Power's circuits, or 5.8% of the 2,162 circuits on which the Company provided 5-year SAIDI data,[76] merit attention. Attention and investment in the 5.8% of circuits with the worst performance is much more targeted than attention and investments in the bottom 50% of circuits (third quartile and below, about 1080 circuits), and more targeted even than investments in the bottom 25% of circuits (fourth quartile, about 540 circuits). Focusing attention and investment on the bottom 5.8% of circuits would provide much greater reliability improvement per dollar than focusing on circuits in the third or fourth quartiles (50% of the Company's circuits). This explains how the Company's DIP applies too many packages to circuits which do not need them, constituting a significant problem with the Company's DIP.

**Q. EARLIER, YOU SAID THAT THE COMPANY USED 2017 RELIABILITY PERFORMANCE TO PLACE CIRCUITS INTO QUARTILES, AND THAT THE PLACEMENT OF CIRCUITS INTO QUARTILES USING 2017 DATA REMAINS STATIC THROUGH TO TODAY. IS THIS SIGNIFICANT? IF SO, HOW?**

A. The static use of 2017 reliability performance to place circuits into quartiles is extremely significant, and extremely problematic. Georgia Power's reliability performance in 2017 was strong. In fact, reliability performance in 2017 was the best of any year from 2015 to

[76] Georgia PSC 44160. Trade Secret Attachment 1(b) provided in response to STF-WG-1-1.

2021. The Company reports that a SAIDI of [redacted] was the median in 2017, and that this value was used to qualify circuits for receipt of DIP packages.[77] *Applying such a SAIDI to actual reliability data 2017-2021, we found that a SAIDI of* [redacted] *is low enough to qualify about 75% of the Company's circuits for investment packages*. If the Commission allows the Company's DIP to continue as is, the reliability investment packages will eventually be applied to all but 25% of the Company's circuits. Applying packages and investments to 75% of circuits is the exact opposite of "focused" spending. Figure 8 indicates the severely unfocused and inappropriate nature of DIP spending permitted through the use of a SAIDI of 00.00 to qualify a circuit for costly DIP packages.

Figure 8: Counts of circuits qualifying for DIP packages using 2017 median performance as criteria

As we see it, the DIP Optimization Model and the Company's application of it are designed specifically to justify the greatest possible amount of rate base growth that also happens to improve reliability by some amount. It succeeds in this by including only high-cost, capital-

[77] Trade Secret response to STF-WG-1-42.

intensive package options in its Optimization Model, and by employing parameters which result in the application of those packages to far too many circuits. It is not difficult to improve reliability with capital; any utility can throw billions of dollars at its distribution grid and improve reliability. The real challenge is to identify the actions that improve reliability at a cost which is less than the value to customer of those reliability improvements. But as we shall explain, this is not what the Company's DIP or Optimization Model set out to do, because the DIP and Model ignore two extremely common and cost-effective approaches to improving reliability: more aggressive vegetation management and a more formalized approach to addressing worst-performing circuits.

*5. The DIP ignores dramatically more cost-effective approaches to improving reliability.*

**Q. WHAT ARE THE DRAMATICALLY MORE COST-EFFECTIVE APPROACHES TO IMPROVING RELIABILITY THAT THE COMPANY'S DIP IGNORES?**

A. The two dramatically more cost-effective approaches to improving reliability that almost all utilities employ are more aggressive vegetation management programs and more rigorous worst-performing circuit programs. The Company's Optimization Model and its resulting DIP do not consider such programs.

**Q. DOESN'T GEORGIA POWER ALREADY HAVE SUCH PROGRAMS?**

A. Yes, but our discovery indicates these programs are less formal and rigorous than we would have expected from a utility of Georgia Power's size and sophistication. Critically, we note that neither more aggressive vegetation management nor a more rigorous worst-performing circuit program have been evaluated as alternatives to DIP packages.

**Q. WHY DO YOU DESCRIBE THE COMPANY'S VEGETATION MANAGEMENT PROGRAM AS LESS FORMAL AND RIGOROUS THAN YOU WOULD HAVE**

**EXPECTED?**

A. Early in discovery, Georgia Power reported that its program completes vegetation management on circuits at a frequency of between every 24 and 60 months, with an average of 42 months (3.5 years).[78] Our examination of detailed historical "line miles cleared" data obtained through subsequent discovery[79] revealed a different picture. From 2012 through 2021, assuming 55,188 overhead distribution line miles,[80] Georgia Power actually completed vegetation management on circuits at a frequency of between two years and nine years, with an average of 4.4 years. We also noted that budgets for vegetation management varied widely from year to year, with a low of $44 million reported in 2017 to a high of $124 million reported in the twelve months ending May 31, 2022.[81]

Given Georgia's extended growing season, a more aggressive, formal, and consistent vegetation management program is the first place we would concentrate to secure cost-effective improvements in reliability. Indeed, an examination of outage cause data 2017-2021 indicates that vegetation contact was one of the most common causes of service interruptions, amounting to one-fifth of all service interruptions 2017-2021.[82] This is consistent with our experience across utilities.

**Q. HOW INEXPENSIVE IS VEGETATION MANAGEMENT RELATIVE TO UNDERGROUNDING?**

A. Georgia Power's vegetation management (O&M) costs averaged $[redacted] per line mile from 2016-2021.[83] As noted earlier, an industry rule of thumb for undergrounding is $1 million

[78] Response to STF-WG-1-27 (b).

[79] Trade Secret Attachment B provided in response to STF-WG-2-16 (c).

[80] Response to STF-WG-1-36 (a) + (c) + (e).

[81] Response to STF-LA-2-65.

[82] Trade Secret Attachments F through J provided in response to STF-WG-1-30. Includes all vegetation contact.

[83] Response to STF-LA-2-65 (vegetation management $ 2016-2021); Trade Secret Attachment B provided in response

capital cost per line mile. Granted, vegetation management costs must be incurred every four years or so. But at these price differentials, over the 40-year depreciation period typically applied to underground cable, no sophisticated analysis needs to be completed to recognize that vegetation management is tens of multiples less costly than undergrounding.[84]

**Q. WHAT CHANGES TO GEORGIA POWER'S VEGETATION MANAGEMENT PROGRAM WOULD YOU RECOMMEND?**

A. At a minimum, we would recommend strict compliance with a four-year vegetation management cycle. By "strict compliance", we mean that no section of any circuit should go more than four years without vegetation management. Further, reductions in vegetation management cycles to 3.5 years or even 3.0 years should not be ruled out. Indeed, we note the Company plans to increase its average annual vegetation management budget by more than 58% over recent years, from $63 million (2016-2020) to $100 million, in this rate case test period.[85] An increase of this magnitude could be expected to enable a reduction in the average vegetation management cycle from 4.5 years to 3.5 or even 3.0 years. We also recommend the Commission order an annual vegetation management report detailing miles cleared relative to the level required to maintain the Commission-approved vegetation management cycle, and to track resulting reliability improvements.

If the Commission wishes to focus on improving reliability in a cost-effective manner, more innovative vegetation management ideas can be considered. For example, California

to STF-WG-2-16 (c) (vegetation management miles 2016-2021).

[84] Looking at just one mile, over 40 years, vegetation management would likely be completed 10 times at a cost of $[redacted] each time ($[redacted]). Compared to a $1 million capital cost to underground that same mile of overhead lines, a rough estimate is that undergrounding is about [redacted] times more costly than vegetation management ($1 million divided by $[redacted]).

[85] Attachment provided in response to STF-LA-2-65.

recently increased utility rights-of-way radii from 18 inches to as much as four feet.[86] A legislated expansion of utility rights-of-way in Georgia certainly represents one potential approach to improving reliability in a cost-effective manner. In Washington, Avista Utilities is developing a program to pay rebates to customers to trim (and possibly to remove) trees outside the right-of-way that pose a threat to distribution lines in windy conditions.[87] Indeed, the Company agrees that purchasing additional rights-of-way is an option.[88] But none of these approaches appear to have been evaluated on an economic or effectiveness basis as alternatives to capital-intensive circuit hardening or undergrounding packages the Company has defined.[89]

**Q. MOVING ON TO WORST-PERFORMING CIRCUIT PROGRAMS, CAN YOU PROVIDE A DESCRIPTION OF A TYPICAL UTILITY PROGRAM?**

A. A typical worst-performing circuit program consists of several steps. The first step, completed annually, is to compute one or more reliability metrics for each circuit to enable the identification of poor performers. While SAIDI and SAIFI (interruption duration and frequency) are the most common reliability metrics employed for this purpose, we have seen others used. Another popular metric is the count or percentage of customers on a circuit experiencing over a certain number of interruptions (for example five, six, or seven) in a year.[90] Other metrics we have seen include identifying circuits that have appeared on the worst-performing circuit list (however defined, see next) for two or more years in a row, or to use two-year averages to measure circuit reliability. (Year-to-year variation can cause too many "false positive" worst-performing circuit identifications when a single

[86] Accessed at https://www.pge.com/en_US/safety/yard-safety/powerlines-and-trees/laws-and-regulations.page

[87] Washington Utilities and Telecommunications Commission Docket No. UE-200900. Exhibit DRH-2 filed October 30, 2020 (Avista Utilities Wildfire Resilience Plan). Page 42.

[88] Response to STF-WG-2-18.

[89] Response to STF-WG-2-16.

[90] This statistic, commonly known as "customers experiencing multiple interruptions", or "CEMI" is typically expressed as "$CEMI_{(x)}$", where "x" is the number of interruptions used as the threshold for the metric.

year's reliability is measured. Georgia Power's program appropriately uses two-year averages to measure circuit reliability.)[91]

Once the reliability of all circuits is calculated, the next step is to identify those that warrant additional investigation as "worst-performing". As indicated earlier, most utilities establish an annual list of circuits performing at worse than three times the average circuit's interruption duration or frequency, though we have seen definitions using 2.5 times worse than the average circuit at some utilities. As indicated earlier, about 6% of Georgia Power's circuits would currently qualify for attention using a 2.5x definition.

For circuits identified as worst-performers, the next step is to complete root-cause analyses. Typically, the engineer responsible for the circuit's performance will examine outage cause data as the first step towards identifying any recurring outage root causes. The inability to identify a root cause of poor reliability is common; random variability due to weather or accidents often encourage root cause analysts to recommend no remediation, or to simply put such circuits on a watch list for future consideration. In summary, the challenge with identifying circuits in such programs is to avoid excluding circuits from the list that merit attention, nor to include on the list circuits that do not merit attention. To optimize spending, the ideal process for circuit identification/list creation is fairly sophisticated.[92] Georgia Power's approach – to identify every circuit below the median for potential application of packages – is not sophisticated at all and results in unnecessary capital investment.

When a recurring root cause is found, the next step is to develop and schedule remediation actions. In our experience the most common remediation activity is spot vegetation

[91] Response to STF-WG-1-27(c).

[92] Brown, R. *Identifying Worst Performing Feeders.* Eighth International Conference on Probabilistic Methods Applied to Power Systems, Iowa State University, Ames, Iowa. September 12-16, 2004. Available from IEEE.

management, though sometimes a problematic piece of equipment is identified for replacement. Other common, and inexpensive, remediation actions include the installation of animal guards, or adjusting the settings of protective devices (such as reclosers) on a circuit. Root causes and associated remediation plans rarely involve large capital expenditures, though installation of additional reclosers, sectionalizing devices (to reduce the number of customers who are impacted by a fault), and distribution automation schemes are called for on occasion. (All of these latter options require capital spending.)

**Q. WHY DO YOU DESCRIBE THE COMPANY'S WORST-PERFORMING CIRCUIT PROGRAM AS LESS FORMAL AND RIGOROUS THAN YOU WOULD HAVE EXPECTED?**

A. First, the Company has no standard criteria for identifying circuits as "worst," thereby qualifying for additional attention. Instead, the Company seems to take actions commensurate with the level of spare capital budgets that might be available from year-to-year.[93] The Company seems to have no written policies to formalize its worst-performing circuit program,[94] nor do any dedicated capital or O&M budgets appear to exist for the program. Indeed, program spending has varied widely from year to year over the past 12 years, from a low of $[redacted] in 2010 to a high of over $[redacted] in 2018.[95]

**Q. ARE WORST-PERFORMING CIRCUIT PROGRAMS COST-EFFECTIVE?**

A. Judging by their popularity among utilities, we believe so. Anecdotal data from Georgia Power's program also appears to indicate that they might be, particularly relative to extremely costly DIP investment packages such as circuit hardening and undergrounding. Table 5 below provides the pre- and post-investment results for worst-performing circuit

[93] Response to STF-WG-2-19(a).

[94] Response to STF-WG-1-27(c).

[95] Trade Secret Attachment provided in response to STF-WG-2-37.

projects completed in 2017 and 2018, along with average project costs per circuit.[96] Note the dramatically lower capital costs per circuit of this program compared to the radical capital spending per circuit associated with Georgia Power's circuit hardening package.

Table 5: Average Costs and Effectiveness of Georgia Power's WPC Program, projects completed in 2017 and 2018.

| Year projects completed | Count of Circuits w/projects completed | Ave. Capital Cost per Circuit | Ave. SAIDI 3 yrs. prior | Ave. SAIDI 3 yrs. post | Percent Improved | Ave SAIFI 3 yrs. prior | Ave. SAIFI 3 yrs. post | Percent Improved |
|---|---|---|---|---|---|---|---|---|
| 2017 | [redacted] | | | | | | | |
| 2018 | | | | | | | | |

**Q. WHAT CHANGES TO GEORGIA POWER'S WORST-PERFORMING CIRCUIT PROGRAM WOULD YOU RECOMMEND?**

A. We would recommend that the Company develop written policies to formalize its program, including clear criteria for identifying circuits for additional attention annually; standards for completing root-cause analyses; standards for developing remediation plans; and standards for reviewing plans and authorizing spending, as well as standards for tracking spending, projects, and results. We would also recommend that specific budgets for the program be established, and that personnel/organizational accountabilities for program administration, root cause analyses, and remediation plan development and implementation be established. The Commission may also wish to consider establishing annual reporting requirements for the program. The Maryland PSC has established a strong reliability performance improvement program, including both vegetation management and worst-performing circuit reporting features, that merits the Commission's attention. We will describe this program in more detail later in this Section.

[96] Ibid.

*6. The DIP is prompting premature retirement of reliable assets for which customers are paying.*

**Q. DOES THE DIP PRESENT OTHER PROBLEMS FOR CUSTOMERS?**

A. Yes. It appears that the DIP consists in large part of wholesale and indiscriminate equipment replacement, essentially constituting rebuilding or undergrounding entire circuits or sections of circuits, as examples. We believe the new equipment installed via the DIP is inadvertently displacing a great deal of existing equipment that is perfectly sound and is operating safely and reliably (in the same way that the transmission investment plan's premature replacement practice does). Replacing poles and cross-arms that have passed their most recent inspections, whether through circuit hardening or undergrounding packages, deprives customers of many years, or even decades, of useful life from equipment for which they have paid, or for which they continue to pay, in rates. This obviously represents a significant opportunity cost that should also be included in the Commission's evaluation of the Company's proposed DIP.

**Q. WHAT IS YOUR EVIDENCE THAT THIS IS HAPPENING?**

A. We can see from accounting details provided in discovery that the Company is retiring distribution assets with book value remaining at an alarming rate. A piece of equipment with book value means that it is still being depreciated. If a piece of equipment is still being depreciated, that means it has not yet reached the end of its estimated life, let alone the end of its operating life (meaning, fully depreciated but passing its inspections). To summarize, the opportunity costs to customers of the DIP makes the already negative cost-benefit ratio of packages like circuit hardening or undergrounding even more negative.

**Q. WHY DO YOU CHARACTERIZE THE RETIREMENT OF DISTRIBUTION ASSETS WITH BOOK VALUE REMAINING AS "ALARMING"?**

A. From 2023 to 2025, the Company projects that it will retire distribution equipment with a net book value of $[redacted].[97] Given that Company's entire distribution capital request 2023-2025 (including the DIP) is $[redacted],[98] our interpretation is that almost one quarter of the distribution capital the Company is requesting replaces assets that have not reached their estimated life. The replacement of equipment that is operating safely and reliably despite being fully depreciated comes on top of this amount. While a small amount of retirement is unavoidable (for example, government-requested facility relocations or accidents or storms that destroy equipment), we believe the DIP, and particularly its application to too many circuits not performing poorly enough to justify investment, is to blame for the extremely high level of equipment retirements Georgia Power projects.

The significant retirement of equipment with book value remaining is evidence of asset churn, or replacing assets with low (or no) book value simply to increase rate base and profits. There is legal and regulatory precedent against this practice,[99] and we encourage the Commission to consider the waste and opportunity cost caused by circuit hardening and undergrounding as just one more reason to reject capital requests for these DIP packages.

*7. Why the Commission should afford little to no weight to the Company's Customer Benefits Study.*

**Q. YOU HAVE MADE SOME COMPELLING POINTS, BUT THE COMPANY'S CUSTOMER BENEFITS STUDY INDICATES ITS DIP IS COST-EFFECTIVE. HOW COULD THE COMPANY'S STUDY RESULTS BE SO DIFFERENT FROM YOUR FINDINGS?**

[97] Trade Secret attachment provided in response to STF-LA-10-1.

[98] Trade Secret attachment provided in response to STF-PIA-4-4.

[99] See footnotes 27 and 45 for brief discussions of the Averch-Johnson effect and our application of it.

A. Actually, the Company's Customer Benefits Study provides no indication that the DIP is cost-effective (meaning, that it delivers economic benefits to customers in excess of associated rate increases). The Customer Benefits Study is not a cost-effectiveness test, nor is it a cost-benefit analysis, though the Company undoubtedly wants the Commission to consider it as such. Instead, the optimization modeling the Company presents in its DIP is a hypothetical exercise to optimize outcomes within a set of constraints self-imposed and designed by the Company. Neither the DIP nor the Optimization Model is designed to answer the question, "What are the most cost-effective ways to improve reliability?" Instead, the DIP consists of the following components:

1. A set of capital-intensive grid investment packages;
2. A set of implementation cost and customer cost reduction assumptions (from reliability improvements) for each package;
3. The application of constrained optimization modeling techniques to identify the mix and level of package implementation that results in the lowest total cost to customers *given the limited set of capital-intensive grid investment packages specified.*

The DIP provides the optimum results or plan given a limited set of solutions which exclude more cost-effective solutions such as more aggressive vegetation management, a more formalized worst performing circuit program, and a focus on fewer circuits with the most abject reliability performance. This is absolutely not the way to develop a cost-effective plan to improve reliability.

**Q. HOW DO YOU BELIEVE A UTILITY SHOULD DEVELOP A COST-EFFECTIVE PLAN TO IMPROVE GRID RELIABLITY?**

A. Instead of modeling a constrained set of options designed and limited by Georgia Power, the Company should have identified all commonly-employed approaches to improve reliability, including approaches that are not capital-intensive, such as more aggressive vegetation management and a more formalized worst-performing circuit program. For each

approach identified – including vegetation management and worst-performing circuit approaches – the Company should have used historical cost and results data from previous applications to project the costs and benefits (a cost-benefit analysis) for each approach. Armed with a cost-benefit analysis for each approach, the Company could have selected those delivering the biggest reliability improvements per dollar, and applied them only to the circuits with the most dramatically poor reliability performance (rather than up to 75% of circuits, as the use of 2017 median circuit performance enables). The Company did not complete a cost-benefit analysis for any of the capital-intensive packages it defined,[100] let alone for any of the myriad, lower-cost alternatives to the six capital-intensive packages that exist. Nor did the Company consider limiting spending to a smaller number of circuits.

The Commission should give little or no weight to the Company's Customer Benefits Study because it answers an irrelevant question. The irrelevant question the Study answers is "Of the capital-intensive packages we have defined, what mix delivers the lowest total cost to customers?" The relevant question the DIP should answer is "What are the most cost-effective ways to improve reliability?" Until and unless the Company provides cost-benefit analyses for all commonly-employed approaches to improving reliability, thus enabling an answer to this relevant question, we recommend the Commission afford no weight to the Company's Customer Benefits Study and reject the Company's requests for capital to continue the most outrageously expensive and cost-ineffective DIP packages: circuit hardening and undergrounding.

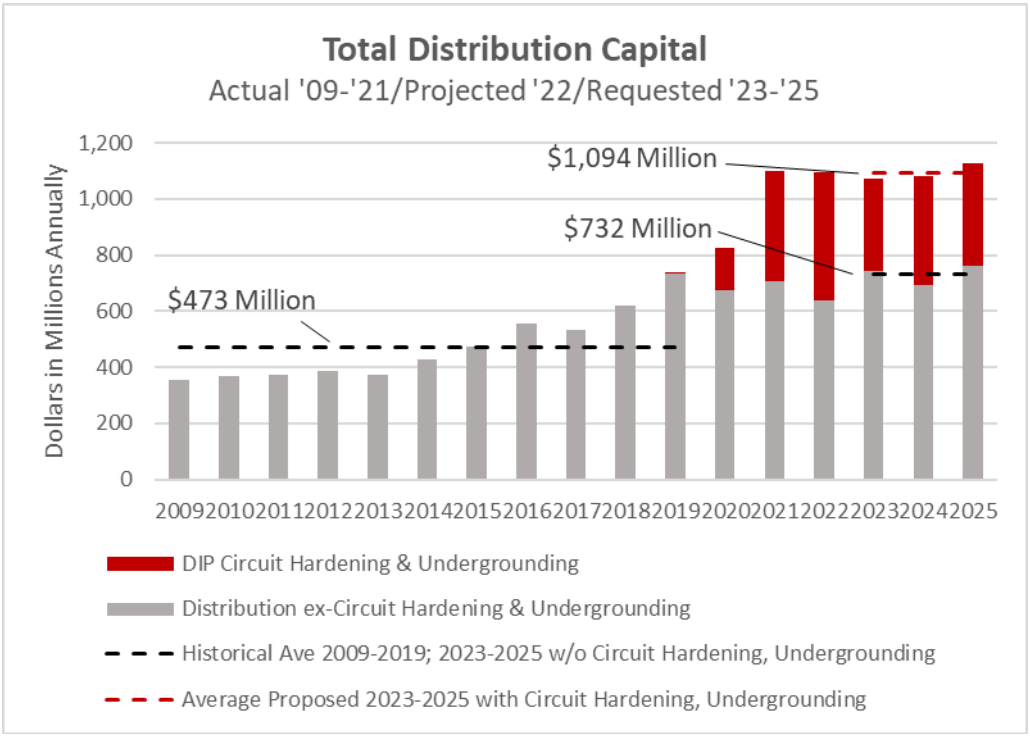
**Q. BUT SHOULDN'T THE COMMISSION ENCOURAGE GEORGIA POWER TO IMPROVE ITS SERVICE RELIAIBLITY?**

A. Of course it should, but not at any cost. There are many more cost-effective ways to improve reliability than those the Company chose for its DIP that can be, and should have

[100] Response to STF-WG-1-8(f).

been, considered. Figure 9 indicates that if the Commission follows our recommendation to reject continued investments in the circuit hardening and undergrounding packages 2023-2025 entirely, the remaining distribution investments proposed still represent a 55% increase (from $473 million per year to $732 million per year) over average annual distribution investment from 2009 to 2019 (before the DIP commenced). If the Commission follows our recommendations there is little to no risk that an authorized 55% increase could be perceived as disdainful of reliability improvement goals. Given such an increase, and assuming efficient and economic management, the Company should be able to maintain and improve service reliability without the circuit hardening and undergrounding components of the DIP.

Figure 9: Total Distribution Capital Actual '09-'21/Projected '22/Requested '23'-25



*8. The DIP offers no performance accountability.*

**Q. DO YOU HAVE OTHER CONCERNS ABOUT GEORGIA POWER'S DIP?**

A. Yes. Packages other than circuit hardening and undergrounding may also fail to deliver benefits to customers in excess of associated rate increases. The Company's spending on moving distribution lines from back lots to front lots falls in this category. As with circuit hardening and undergrounding, this package entails an extremely high cost per premise. The "add circuit ties" package becomes cost-ineffective when applied to increasingly rural circuits. While circuit ties in urban and suburban areas are relatively short, circuit ties in rural areas, where circuits are far apart, are much longer, and therefore much more costly to build. At the same time, low customer density on rural circuits means that dramatically fewer customers will benefit per dollar spent adding ties. Thus, at some point, adding more circuit ties will cross into the point of diminishing returns. (Though of course, less costly ways to improve rural circuit reliability are available, and those should be pursued as appropriate.) Even distribution automation and sectionalization, an approach to improving reliability we generally favor, has its limits. At some point, the cost to add more sections and distribution automation schemes exceeds the resulting reliability improvements. None of these packages should be approved without cost-benefit tests to determine cost-effectiveness and the point of diminishing returns.

But the period for discovery is limited, and the Company's permitted response times are long.[101] We simply did not have sufficient opportunity to investigate all DIP packages to the extent we would have preferred. Regarding other DIP concerns, the largest by far is our concern that the DIP offers no opportunities for holding Georgia Power accountable for

[101] In our experience, data request response time in all cases in which we have served our clients has never been longer than 14 calendar days or 10 business days, approximately half of what Georgia Power is allowed. This extended response time severely limited the number of follow-up rounds of discovery we could complete within procedural schedule limits. Given the complexity of distribution grids and investment plans, the ability to complete multiple rounds of discovery is critical to completing full investigations of distribution grid investments proposed by utilities.

securing the reliability improvements the Company projects from DIP spending.

**Q. WHY IS ACCOUNTABILITY A CONCERN? THE COMPANY'S CUSTOMER BENEFITS STUDY CLEARLY INDICATES AN EXPECTATION THAT ITS DIP WILL ACHIEVE A SYSTEM-WIDE SAIDI GOAL OF 80 MINUTES.**

A. An expectation does not constitute actual performance by the Company, nor an actual benefit from capital investment. Georgia Power's Customer Benefits Study states "The revised plan . . . is expected to invest ~$3.4B over the remaining 8 years and achieve an end-state overall company SAIDI of ~80 by 2031."[102] However in a discovery conference to review the Optimization Model the Company used to develop the DIP, the Company corrected our characterization of the system wide SAIDI of 80 minutes as a "target". The Company explained that the 80-minute SAIDI cited was nothing more than the Optimization Model's projected improvement from the level of spending the Company proposes in its DIP, and should not be considered a target. The Company also rejected any notion that its cost recovery vary with the actual reliability performance delivered.[103] (There is an emerging trend in the US towards performance-based ratemaking, particularly in jurisdictions employing a forward-looking/multi-year rate plan approach to ratemaking, which Georgia Power has enjoyed since the mid-1990s).

We also note that if reliability fails to improve by 2032, or improves only modestly, the Company's shareholders will win, while the Company's customers will lose. Shareholders will benefit from earnings and share price growth associated with billions of dollars in rate base growth. Customers will lose, saddled with decades of rate increases with little or no reliability improvement to show for it. Customers, not shareholders, bear the risk that GIP rate increases will not be offset by reliability improvements. This is what we mean when

[102] Customer Benefits Study with corrected k-factor, p. (i).

[103] Response to STF-WG-1-4(d).

we say the DIP includes no performance accountability for Georgia Power.

Finally, we assume the Commission relied heavily on the reliability projection the Company provided with its first DIP, in 2019, which indicated a system-wide SAIDI of 65 minutes. We imagine the Commission is interested to know that the Company has not only relaxed its original SAIDI projection to 80 minutes, but also corrected our characterization of the SAIDI projection as a reliability performance target. These are not encouraging signs that the Company can deliver the reliability improvements it projects from its DIP.

**Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE COMMISSION'S ABILITY TO HOLD THE COMPANY ACCOUNTABLE FOR DIP RELIABILITY IMPROVEMENTS?**

A. Yes. We note that all the DIP packages but one (package #5, "Bring Feeder to Road", which is designed primarily to reduce outage duration by speeding repairs) are designed primarily to reduce the frequency of service interruptions (defined as those lasting longer than five minutes). Yet the Customer Benefits Study only publicly identifies a system-wide SAIDI (interruption duration) projection, and no system-wide SAIFI projection (interruption frequency). While a system-wide SAIFI projection for 2032 can be found in a trade secret response to an informal data request ([redacted]),[104] the Company's hesitation to publicly provide a system-wide interruption frequency projection is concerning.

Interruption frequency and interruption duration are two vastly different measures of reliability, and both are important. We are concerned that the discrepancy between investment intentions (to reduce interruption frequency) and investment performance measurement (interruption duration) will make it difficult if not impossible for future Commissions to hold the Company accountable for delivering actual reliability

[104] Trade Secret Attachment G provided in response to WG-Informal-1. Tab "EBA Evaluation", cell N11.

improvements from the DIP.

*9. Summary of the Maryland Commission's efforts to cost-effectively improve reliability, and associated results.*

**Q. HAVE YOU SEEN OTHER STATE UTILITY COMMISSIONS SUCCESSFULLY SECURE RELIABILITY IMPROVEMENTS IN A COST-EFFECTIVE MANNER?**

A. Yes. We have become particularly familiar with the Maryland Commission's efforts to improve distribution reliability in a cost-effective manner through our work on behalf of the Maryland Office of People's Counsel. We are encouraged by the results of the Commission's efforts, which are focused largely on annual performance reporting requirements.

**Q. PLEASE SUMMARIZE THE MARYLAND COMMISSION'S EFFORTS.**

A. After a series of storms in 2010 and 2011 involving prolonged (1-2 week) service interruptions for many thousands of customers, the Maryland legislature tasked the Public Service Commission with implementing service quality and reliability standards for electric distribution utilities.[105] After a series of stakeholder working groups led by the Maryland Staff, the Commission approved the addition of Chapter 20.50.12 to the utility section of the Code of Maryland Regulations, "Service Quality and Reliability Standards". The Chapter specified minimum annual performance reporting requirements as well as the minimum reliability statistics (SAIDI and SAIFI, along with multiple variations) the utilities must measure. The initial Chapter included minimum SAIDI and SAIFI values the regulated utilities were required to achieve by year for the first few years.

Subsequent workshops refined the reporting requirements, and periodic updates to the

[105] Maryland General Assembly, 2011 General Session. HB 391/SB 692. Signed into law May 10, 2011.

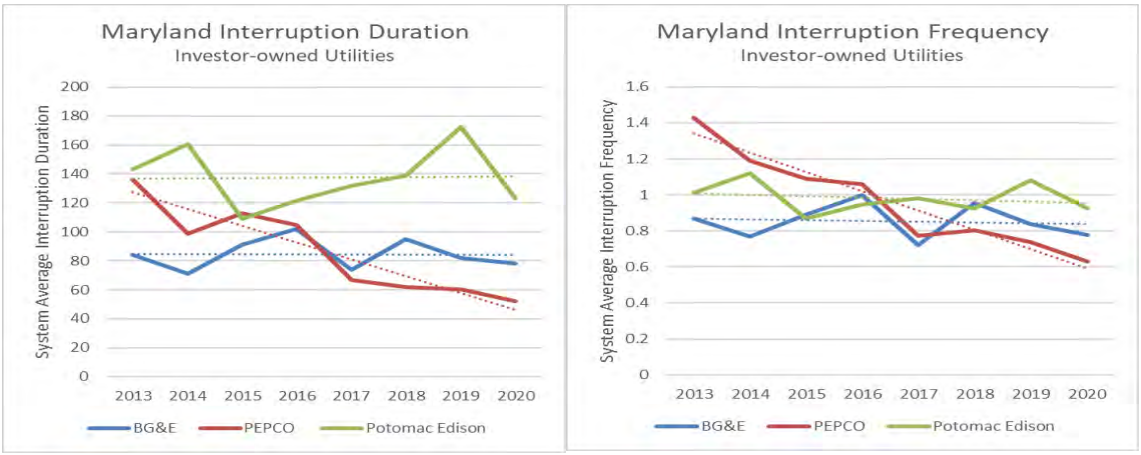
minimum SAIDI and SAIFI values have slowly required more stringent performance expectations over the years. An example of an annual performance report from a Maryland utility is provided as Exhibit PA/DS-10. As the reader can observe, there is a significant focus on vegetation management and worst-performing circuit programs, along with a focus on documented remediation action plans for failures to meet various performance expectations. In summary, the old adage "what gets measured, gets managed" applies.

**Q. HOW HAVE THE MARYLAND UTILITIES' RELIABILITY PERFORMANCE LEVELS IMPROVED?**

A. Maryland utility reliability has held constant or improved since the standards and reporting requirements were implemented,[106] as presented in Figure 10. Maryland utility reliability has bucked the trend of deteriorating reliability exhibited by U.S. investor-owned utilities in recent years (See Figure 2), *and at a reasonable cost*. (No significant reliability improvement investment plans were implemented by Maryland utilities from 2013 to 2020.) If the Georgia Commission wishes to focus on improving reliability in a cost-effective manner, it might want to consider a similar type of effort. However, such efforts will not reduce the requirement to complete cost-benefit analyses on any reliability-related investments Georgia Power might propose.

[106] Data submitted by Maryland investor-owned utilities to the Energy Information Administration on Form 861.

Figure 10: Maryland reliability performance of investor-owned utilities 2013-2020.




*10. DIP recommendations for the Commission's consideration.*

**Q. PLEASE SUMMARIZE YOUR DIP RECOMMENDATIONS FOR THE COMMISSION.**

A. Our primary recommendation is for the Commission to reject the circuit hardening and undergrounding components of Georgia Power's distribution investment plan. The rejected amounts are presented below, and reflected in the revenue requirement adjustments detailed in the Smith/Trokey testimony and exhibits.

Table 6: Summary of distribution capital request and recommended rejections.

| ($ in millions) | 2009-2019 Actual Average | 2023 | 2024 | 2025 | 2023-2025 Average |
|---|---|---|---|---|---|
| Distribution Capital Requested | | 1,072.9 | 1,081.4 | 1,129.2 | 1094.5 |
| Circuit Hardening | | [redacted] | [redacted] | [redacted] | [redacted] |
| Undergrounding | | [redacted] | [redacted] | [redacted] | [redacted] |
| Distribution Capital Remaining | 473.3 | 744.6 | 691.6 | 759.4 | 731.9 |

In addition, we recommend the Commission secure at least three years' data on the reliability improvements delivered by DIP packages implemented to date before drawing any conclusions on package effectiveness. The Commission must take care to isolate the beneficial impacts of individual DIP packages from other packages implemented, and from vegetation management actions taken on the same circuits, as these will undoubtedly improve the results of any individual package.

For any remaining DIP program components the Commission does not reject, we strongly recommend that the Commission document Company projections for SAIDI and SAIFI in 2032, and that the Commission hold the Company accountable for securing those projected reliability improvements. We believe the Commission would be within its rights to disallow recovery of any costs that ultimately do not deliver the reliability improvements the Company projects it will secure from the remaining DIP. Commission approval of the Company's investment plans in advance minimizes risks to the Company of disallowances and removes incentives to cost-effectively improve reliability.

Finally, we recommend the Commission require formal policies, budgets, and annual performance reporting for the Company's vegetation management and worst performing circuit programs. The Commission may also wish to consider implementing a long-term effort dedicated to cost-effective reliability improvement, using the Maryland Commission's efforts as an example.

## VI. THE LEVEL OF DISTRIBUTED ENERGY RESOURCES GEORGIA POWER MUST MANAGE DOES NOT WARRANT A $100 MILLION DERMS

**Q. WHAT IS A DISTRIBUTED ENERGY RESOURCE MANAGMENT SYSTEM?**

A. A distributed energy resource management system (DERMS) is a software package which can, when combined with data from and remote control of customer and field equipment, help a utility meet the challenges of increasing levels of distributed energy resources on its grid. Distributed energy resources (DERs) can consist of synchronous generators (meaning a spinning turbine, such as an industrial customer might own), or inverter-based generators and energy storage devices (PV solar panels and batteries, also known as asynchronous).

**Q. WHAT "CHALLENGES" DO SYNCHRONOUS AND INVERTER-BASED DERS PRESENT TO UTILITIES?**

A. Utilities typically describe four challenges DERs may present to grid operations. First, they are concerned that DER generation can "confuse" circuit breakers and other protective equipment, causing them not to operate when they should (leading to equipment damage), or causing them to operate when they should not (leading to service interruptions). Second, they are concerned that DERs will continue to put power onto the grid during a power outage (unintentional islanding), presenting a safety issue. Third, they are concerned that DERs can increase grid voltage levels above prescribed limits in localized areas. Fourth, they are concerned that DERs "mask" loads that utilities must be prepared to serve if the DERs on a circuit discontinue power delivery unexpectedly.

**Q. ARE THESE CONCERNS WARRANTED?**

A. To some extent, but every situation is different, and we believe utility concerns regarding DERs to be overblown generally. For example, synchronous (spinning turbine) DER are known to confuse circuit breakers and other protective equipment. However, inverter-based (asynchronous, meaning PV solar and battery) DER are not known to cause such

confusion. Further, Georgia Power's interconnection standards require all DERs to follow IEEE 1547. IEEE 1547 requires all interconnected DERs be installed with a switch which disconnects the DER from the grid within seconds of a loss of grid power. This helps address unintentional islanding concerns. Switches also disconnect DER when voltage rises above prescribed limits, and switch "ride through" settings (which permit DER to remain connected until prescribed ranges of voltage or frequency disturbance are exceeded) can help ensure DERs do not disconnect unexpectedly. Finally, simply tracking the types and capacities of DER installed on a circuit can help a utility understand masked load levels.

One study modeled various combinations of PV Solar locations and penetration levels (the peak DER capacity on a circuit relative to the circuit's peak load) to determine PV Solar "tolerance" on 16 representative circuits. The model indicated that in more than two-thirds of cases, circuits tolerated PV Solar penetration of 90% or more relative to peak loads. The same study indicated that only 16% of circuits could not tolerate PV Solar penetration levels of 15% (a limit commonly applied to DER penetration by utilities with little DER accommodation experience).[107] All of these observations indicate that utility concerns over DER penetration generally, and PV Solar/battery penetration specifically, are overblown.

**Q. DOES GEORGIA POWER HAVE SYSTEMS IN PLACE TODAY TO MANAGE DER ON ITS TRANSMISSION AND DISTRIBUTION GRIDS?**

A. Yes. Georgia Power reports that it uses SCADA systems (supervisory control and data acquisition) to manage DER connected to its transmission and distribution grids today.[108]

[107] A. Hoke et al. *"Steady-State Analysis of Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders."* IEEE Transactions on Sustainable Energy, vol. 4, no. 2, pp. 350-357, April 2013.

[108] Response to STF-WG-2-1 (a), (b), and (c).

**Q. HAVE OTHER UTILITIES INSTALLED DERMS TO MANAGE DERS?**

A. Very few utilities have installed DERMS, due largely to the low penetration of DER on most utilities' grids. Southern California Edison has installed a DERMS,[109] but its overall DER penetration is somewhat high at over 17% of system peak load.[110] Of note, Hawaiian Electric Company has not yet installed a DERMS[111] despite overall DER penetration on Oahu Island of almost 50% of system peak load.[112]

**Q. WHAT IS THE DER PENETRATION AT GEORGIA POWER?**

The Company reports having [redacted] MW of peak DER relative to 15,831 MW of system peak load,[113] for a system-wide DER penetration of [redacted]%. In addition, the 2022 Integrated Resource Plan approved by the Commission calls for as much as 200 MW of DER to be procured and up to 250 MW of DER to be installed under the Company's new DER Customer Program.[114] Even if these efforts are 100% subscribed, and even if all of this DER capacity is connected to the distribution grid (much will likely be connected to the transmission grid), it is highly unlikely DER capacity will exceed [redacted] MW, for a DER penetration of only [redacted]% at most, by 2025.

**Q. WHAT INCREMENTAL CAPABILITIES WILL DERMS OFFER THAT**

[109] Response to STF-WG-2-5.

[110] *Southern California Edison's Grid Modernization Plan*. Stakeholder workshop presentation June 10, 2019, slide 9 (installed DER capacity forecast at 4,000 MW in 2020). System peak of 23,328 MW from Southern California Edison's 2020 Form 861 submission to the U.S. Energy Information Administration.

[111] Hawaii Public Service Commission Docket No. 2019-0327. *Application of Hawaiian Electric Company Inc*. September 30, 2019. Figure 2, Page 12.

[112] Hawaii Public Service Commission Docket No. 2019-0327. Hawaiian Electric Company response to CA-SIR-i(i). Forecast DER capacity, Oahu, 2021 = 532.1 MW. System Peak of 1,087 MW from Hawaiian Electric Company's 2020 Form 861 submission to the U.S. Energy Information Administration.

[113] Georgia PSC Docket No. 44160. Trade Secret response to STF-WG-1-1(b). Columns T and V. System peak of 15,831 MW from Georgia Power's 2020 Form 861 submission to the U.S. Energy Information Administration.

[114] Georgia PSC Docket No. 44160. Stipulation dated June 10, 2022. Page 6, paragraph 22 and page 9, paragraph 33.

**GEORGIA POWER DOES NOT HAVE TODAY?**

A. The principal value propositions of a DERMS are 1) Tracking types and capacities of (large) DER installed on each circuit; and 2) Monitoring and controlling large customer DERs and relevant field equipment settings remotely.

**Q. ARE THESE CAPABILITIES REQUIRED DURING THE RATE CASE PERIOD?**

A. No. First, tracking the types and capacities of (large) DERs on each circuit is not a demanding task, particularly given the relatively small number of (large) DERs connected to the Company's distribution grid. Hawaiian Electric Company tracks these DER attributes through the use of an inexpensive Demand Response Management System.[115] Second, the SCADA systems the Company currently uses to manage DERs on the Company's transmission and distribution grids already offer the ability to monitor customer DERs and to disconnect them in an emergency.[116] (Emergency situations are the only ones in which we believe the Company should be able to exert control over customer DER absent written customer permission. Please see the testimony of Staff Witness Ms. Barber for more on Company control over customer-owned DER.) Third, while there is some merit to a capability to control field equipment settings remotely, we believe few field devices with remote communication and control capabilities have been installed, and note that linemen can be dispatched to modify equipment settings in any event. In short, the small incremental benefits and the low DER penetration likely during the rate case period simply do not justify the extremely high DERMS price tag.

**Q. HOW MUCH CAPITAL INVESTMENT IS THE COMPANY REQUESTING TO INSTALL DERMS IN THIS RATE CASE?**

[115] Hawaii Public Service Commission Docket No. 2019-0327. Application of Hawaiian Electric Company Inc. September 30, 2019. Figure 2, Page 12.

[116] Response to STF-WG-2-3.

A. Georgia Power is requesting $100 million to install DERMS in this rate case.[117] This amounts to at least $120,000 per MW of installed DER capacity ([redacted] at most) we expect will be installed on the Company's distribution grid by the end of the rate case period. Given that the cost to install DER capacity is likely around $1.8 million per MW,[118] the cost to implement DERMS is roughly equivalent to a minimum 6.7% cost premium on top of the costs the Company or its customers incur to install DERs. This represents a high level of overhead for very little benefit.

**Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S PROPOSAL TO INSTALL DERMS?**

A. Yes. If approved by the Commission, the Company proposes to depreciate its DERMS investment over five years.[119] For such an extensive system with significant capabilities, we believe DERMS constitutes a major software package. Any DERMS spending the Commission authorizes should be depreciated over 10 years, not five, consistent with a major software classification.

**Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S $100 MILLION REQUEST TO INSTALL A DERMS?**

A. We recommend the Commission reject the Company's capital request to install DERMS in its entirety due to the small incremental benefits and relatively low DER penetration the Company expects on its grids by the end of the rate case period. The fact that the Company is successfully managing large DERs connected to the Company's grids today figures prominently into this recommendation. The Commission can always reconsider any capital requests to install DERMS the Company might make in the future as the number and

[117] Response to STF-WG-1-1

[118] U.S. Energy Information Administration. "*Average U.S. Construction Costs for Solar Generation Continued to Fall in 2019*." Available via internet at https://www.eia.gov/todayinenergy/detail.php?id=48736. July 16, 2021.

[119] Trade Secret response to STF-WG-2-3.

capacity of large DERs on Company's grid increases. This recommendation is reflected in the revenue requirement reductions addressed in the Smith-Trokey testimony.

## VII. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

**Q. PLEASE SUMMARIZE YOUR TESTMONY PROVIDING PERSPECTIVES ON T&D RATE INCREASES, RELIABILITY, AND INVESTMENTS/TIMING.**

A. In the perspectives section we relayed that rate increases are bad for Georgia's businesses, consumers, and economy unless accompanied by reliability improvements of sufficient value to outweigh them. We characterized Georgia Power's Grid Investment Plan (GIP) as discretionary, citing as evidence 1) Georgia Power's reliability is about average relative to other investor-owned utilities; 2) customers are satisfied with current levels of reliability; and 3) customers are unwilling to pay much for reliability improvements. We described the exceptional electricity bill increases (estimated by Staff at over 40%) that are heading toward Georgia in the next rate case period, stemming largely from sources outside of Commission control. We also noted that the results of over $1 billion in GIP spending to date will not be known or measurable for a few more years. Finally, we observe that even if the Commission rejects the Company's proposed continuation of the GIP in its entirety (which we do not recommend), the proposed transmission and distribution capital spending that remains still constitutes a doubling of Georgia Power's average annual investment from 2009 to 2019 (pre-GIP). We conclude this section of testimony by calling into question the timing, necessity, and wisdom of continued GIP spending in the upcoming rate case period.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS REGARDING GEORGIA POWER'S TRANSMISSION INVESTMENT PLAN.**

**A.** The transmission portion of the Company's GIP (which we call the Transmission Investment Plan, or TIP) consists entirely of premature equipment replacement, or what the Company calls "the replacement of aging transmission infrastructure". While

laypersons are likely to perceive aging equipment replacement as reasonable and necessary, we exposed the replacement of equipment based on age as the wasteful and cost-ineffective practice that it is. We described the objective testing and inspection practices all utilities use to determine the appropriate times for equipment replacement, and how these practices plus "N-1" criterion (redundant design and operation) make service interruptions resulting from transmission equipment failure exceedingly rare. For example, using Georgia Power's own data, we calculated the likelihood that a substation power transformer will both fail *and* result in a service interruption at 45 in 10,000 per year. To summarize, the opportunity to improve reliability through preemptive equipment replacement is almost zero to begin with, making the extremely costly and wasteful practice unnecessary and unreasonable. We recommend the Commission reject the transmission portion of the GIP in its entirety as a result, which still leaves a 171% increase over historical spending levels in place.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS REGARDING GEORGIA POWER'S PROPOSED DISTRIBUTION INVESTMENT PLAN.**

A. We began with a summary of the distribution portion of Georgia Power's GIP, which we refer to as the Distribution Investment Plan (DIP). We then critiqued the DIP, focusing on three problems: 1) The largest DIP investment packages by far, circuit hardening and undergrounding of overhead lines, are not cost-effective approaches to improving reliability; 2) The Company applies costly DIP investment packages to too many circuits which already demonstrate reasonably good reliability performance, further damaging the cost-effectiveness of the DIP; 3) The DIP ignores dramatically more cost-effective approaches to improving reliability, including vegetation management and worst-performing circuit programs; and 4) The DIP is causing premature retirements of distribution equipment operating safely and reliably, incurring large customer opportunity costs not otherwise being considered or accounted for.

We also explained that the Commission should ignore the Company's Customer Benefit Study, because that study is not a cost-benefit analysis of DIP packages, and therefore irrelevant to the task at hand (identifying the most cost-effective ways to improve reliability). We described our concern that the DIP is leading to premature equipment retirement, and our concerns regarding Georgia Power accountability for securing DIP-related reliability improvements. Finally, we summarized the Maryland Public Service Commission's efforts to secure reliability improvements from utilities in a cost-effective manner, and concluded with a recommendation that the Commission reject Georgia Power's requests for the circuit hardening and undergrounding capital components of the GIP in their entirety. We noted that the distribution capital budgets that remain still represent an increase of 55% over historical distribution capital spending pre-GIP, which should be more than enough to maintain and improve distribution reliability.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS REGARDING GEORGIA POWER'S $100 MILLION PROPOSAL TO IMPLEMENT A DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM.**

In this section of testimony we described the challenges of managing high levels of distributed energy resources. But we also explained why utility claims that these challenges are imminent are generally overblown. We described how utilities with high levels of DER are managing the challenges, in at least one case (Hawaiian Electric Co., with extremely high levels of DER) with no DERMS at all. We identify the systems Georgia Power has been using to manage DER to date, and can continue to use in the future. Finally, we supported our belief that even under the most aggressive growth scenarios, Georgia Power DER levels will remain relatively low through 2025 as compared to other utilities. We recommend this proposed spending be postponed until some future rate case, when the

level of distributed energy resources on Georgia Power's grid provides sufficient justification for such a system.

**Q. DO YOU HAVE ANY CONCLUDING REMARKS FOR COMMISSION CONSIDERATION?**

A. Yes. As indicated in our perspectives Section of testimony, the Company's GIP spending is discretionary. However, the electric bill increases heading toward Georgia are unavoidable. Given our testimony on the cost-ineffectiveness of the transmission, circuit hardening, and undergrounding portions of the GIP, we are convinced these investments are not in the public interest. What's more, there is no reliability emergency, and no harm in measuring the results of $1 billion in GIP spending to date, before approving more of the same.

Finally, we believe the Commission should consider the positives of limiting T&D capital spending to "only" a doubling of pre-GIP levels. All businesses in Georgia other than regulated monopolies are required by market forces to restrain capital spending. The managers of these business face a constant challenge: how to deliver products and services the market wants for the least possible amount of capital. This forces them to restrict capital spending to only the most critical and immediate needs, and as a result, these businesses are putting their limited capital to its highest and best possible use. By rejecting some of the Company's proposed capital spending through the recommendations we suggest, the Commission will simply be requiring the same type of discipline from the Company's managers as other Georgia businesses must maintain. That is a very good thing. After all, utility regulation evolved as a way to replace the market forces lacking in authorized monopoly businesses.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

# Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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## Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

## Appearances and Research Projects in Regulatory Proceedings

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor. Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Evaluate Dominion's Grid Transformation Plan. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

## Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

## Noteworthy Publications

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34 (October, 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South

Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

## Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators*. Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

## Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

## Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

## Certifications

New Product Development Professional. Product Development and Management Association. 2007.

# Curriculum Vitae – Dennis Stephens

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## Profile

Mr. Stephens has over 40 years' experience in electric and gas distribution grid planning, design, operations management, and asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy and its subsidiary Public Service Company of Colorado, a distribution utility serving 1.5 million electric customers and 1.4 million gas customers. After a series of electrical and gas engineering and management roles of increasing responsibility, Mr. Stephens retired as the Director of Innovation and Smart Grid Investments for all of Xcel Energy's electric and gas distribution businesses in 2011. He now works for the Wired Group and its clients on a part-time basis.

## Career History (all positions with Public Service Company of Colorado or its parent, Xcel Energy)

**1976 -- Planning Engineer**. Performed electric distribution system planning for Southeast Denver, Boulder, Front Range and Cheyenne divisions, including system protection, voltage support and distribution system design.

**1983 – Senior Engineer, Electric Distribution Planning.** Provided direction and guidance for junior engineers. Led special projects relating to electric distribution system reliability and design. Promoted to Supervisor of Electric Distribution Planning with a staff of 12 electrical engineers with responsibility for capacity and reliability planning.

**1988 -- Manager of Operations, Colorado Front Range Division**. Responsible for all electric and gas distribution operations, including a high-pressure gas system (engineering, operations, and construction).

**1994 -- Manager of Operations & Maintenance Engineering, Southeast Denver.** Managed the design of gas and electric distribution system replacements.

**1997 -- Manager, Distribution Reliability Assessment, Xcel Energy South (CO, WY, TX, OK)**. Led an engineering team focused on electric distribution grid reliability and capacity.

**1998 -- Director of Electric and Gas Operations, Southwest Denver Division**. Responsible for all aspects of electric and gas engineering, operations, and construction in the Southwest Denver Division.

**1999 -- Director of Operations, City and County of Denver Division**. Responsible for all aspects of electric and gas engineering, operations, and construction for Division, including downtown Denver. Promoted to Director, New Construction of electric and gas systems for the entire metro area.

**2001 -- Director Electric Distribution Asset Strategy, Xcel Energy**. Developed and implemented asset management strategies for all electric distribution assets in Xcel Energy's 8-state service area.

**2005 -- Director of Utility Innovations and Smart Grid Investments**. Led Xcel Energy's Utility Innovations department, developing and implementing new technologies and business processes in multiple electric and gas distribution functional areas. Advanced the concept of an Intelligent Network at Xcel Energy, and led several aspects of the SmartGridCity® demonstration project in Boulder, Colorado. Department secured a national Edison Award for Innovation in 2006. Retired in 2011.

**2016 – Senior Technical Consultant, Wired Group**.

**Noteworthy Projects**

**Smart Grid Solutions Development, 2010.** Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens**.**

**DER Integration Strategy and Roadmap Development, 2009.** Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.

**SmartGridCity™ Project Development, 2008.** Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).

**Distribution Automation Design, 2007.** Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).

**Utility Innovations Program Development, 2006.** Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.

**Distribution Asset Optimization Process, 2005.** Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.

**Distribution Asset Optimization Software Development, 2004**. Worked with Itron on the development of a Distribution Asset Optimization software program.

**Fixed AMI Communications Network Development, 2003**. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.

**Electric Asset Management Strategy Development, 2002**. Developed Xcel Energy's Electric Distribution Asset Management Strategy

**Automated Switching System Deployment, 2001**. Worked with S&C Electric Corporation to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.

**High Pressure Gas Pipe Replacement Program, 1988**. Initiated and managed the renewal and replacement of 26 miles of high pressure gas pipe, over a 5 year period, reducing the likelihood of seam failures as outlined in an "Alert Notice" issued by the Department of Transportation's Office of Pipeline Safety. Project roles included community engagement, government and regulator relations (PUC, DOT, EPA), and contractor management. Project completed 1 year ahead of schedule and 14% under budget.

**Regulatory Appearances**

**Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan.** Panel testimony with Paul Alvarez on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

**Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan.** Panel testimony with Paul J. Alvarez on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

**Evaluate Oklahoma Gas & Electric Company Grid Modernization Spending and Plans.** Testimony on behalf of the Office of Attorney General in PUD 202100164. April 27, 2022.

**Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities.** Panel testimonies with Paul J. Alvarez on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

**Dominion Grid Modernization Plan Review.** Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. PUR-2021-00127. September 13, 2021.

**Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes.** Panel testimony with Paul J. Alvarez on behalf of Public Counsel. WUTC 200900, 200901, and 200894. April 29, 2021.

**Pepco's 2021-2023 Grid Investment and Plan.** Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MDPSC 9655. March 3, 2021

**Baltimore Gas & Electric Company's 2021-2023 Grid Investment and Operations Plan.** Panel testimony with Paul J. Alvarez on behalf of the Maryland Office of People's Counsel. MD PSC 9645. Aug 14, 2020.

**Review of Maryland Utilities' 2019 Annual Performance Reports**. Comments of the Office of People's Counsel. MD PSC 9353. June 8, 2020

**Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan.** Testimony before the North Carolina Utilities Commission critiquing Duke Energy's Plan on behalf of a group of environmental and consumer advocates. NCUC E-7, Sub 1214 Feb 18, 2020 & E-2, Sub 1219 Mar 25, 2020.

**Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan.** Testimony before the Indiana Utility Regulatory Commission on behalf of the City of Indianapolis critiquing Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Cause 45264. October 7, 2019.

**Investigation into Distribution Planning Processes.** Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

**New Hampshire Public Utilities Commission Distribution Planning/Grid Modernization Proceeding.** Comments in IR 15-296 describing a transparent, stakeholder-engaged distribution planning process.

**Pacific Gas and Electric 2019 General Rate Case.** Testimony in A.18-12-009 on behalf of TURN related to $270 million in proposed "Integrated Grid Platform" investments.

**Southern California Edison 2017 General Rate Case.** Testimony in A.16-09-001 on behalf of TURN related to $2.3 billion in proposed grid modernization investments.

**Pacific Gas and Electric 2016 General Rate Case**. Testimony in A.15-09-001 on behalf of related to $100 million in proposed grid modernization investments.

**Notable Publications and Presentations**

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**Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities.** With Paul Alvarez and Sean Ericson. Electricity Journal. Volume 34 (October, 2021).

**Florida Storm Protection Plans: A Bonanza for Utilities, A Bust for Consumers and the State.** Whitepaper co-authored with Paul J. Alvarez for AARP-Florida. October 5, 2020.

**Challenging Utility Grid Modernization Proposals.** With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 to be published September, 2020.

**The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement.** With Paul Alvarez & Sean Ericson. Accepted for publication by Public Utilities Fortnightly. Anticipated publication June, 2019.

**Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers.** Whitepaper co-authored with Paul Alvarez for GridLab. January 31, 2019

**Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders.** Whitepaper co-authored with Paul Alvarez for GridLab. October 5, 2018.

**DistribuTECH 2010, Tampa, Florida**. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"

**OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California.** "Smart Grid City: A blueprint for a connected, intelligent grid community"

**ABB 2007 World Conference, Jacksonville, Florida**. "Use of Distribution Automation Systems to identify Underground Cable Failure"

**North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida**. "Xcel Energy Utility Innovations and Distribution Asset Optimization"

**DistribuTECH 2005, San Diego, California**. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

## Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

## Awards

Led Xcel Energy team that received a National Edison Award for Utility Innovations, 2006.

**TRADE SECRET** **STF-WG-2-8 Attachment A**

# A Customer Benefit Study of Distribution Investment for the Georgia Power Company System

**August 2022**

Georgia Power

# EXECUTIVE SUMMARY

Electric utility customers expect and depend on high levels of service reliability at a reasonable cost. As such, when developing a reliability improvement plan, a diligent utility must carefully evaluate the costs and benefits that accrue to customers under such a plan. The purpose of this Distribution Investment Study for the Georgia Power Company ("GPC") system is to determine the range of investment in GPC's distribution system that is optimal from a customer perspective.

This study is an updated version of the Economic Benefit Analysis completed in 2019 and reviews a revised Distribution Investment Plan that reflects lessons learned over the last 3 years. This study analyzes the best set of investments to be made under the Grid Investment Plan starting in 2023. This study concludes that the revised 8-year investment plan in the amount of ~$3.4B is within the optimal range of investment.

As background, GPC conducted an Economic Benefit Analysis on its original Distribution Investment Plan in 2019 to ensure that the plan was within the optimal range of investment from a customer perspective. The original plan was a ~$4.9B, 11-year plan that sought to improve approximately 800 of GPC's worst-performing distribution feeder circuits (also referred to as "circuits") with a target end-state SAIDI of ~65 by 2031 (also referred to as "Original Plan").

GPC has updated the Original Plan based on lessons learned through the execution of the plan over the last 3 years. Changes from the Original Plan are primarily driven by:

(1) Revised investment criteria, which select circuits with sustained poor performance.

(2) Increased capital requirements by investment package due to increases in the scope and cost of work required to achieve expected reliability improvements.

(3) A refined optimization methodology which relaxes the investment package hierarchy used in 2019 and allows for a larger set of possible investments to be evaluated when determining the optimal set of investments for a given scenario.

The revised plan (also referred to as "Distribution Investment Plan" or "the Plan") is expected to invest ~$3.4B over the remaining 8 years and achieve an end-state overall company SAIDI of ~80

by 2031. By targeting GPC's worst-performing circuits, the plan strives to equalize the customer experience and improve overall company reliability.

To create the Distribution Investment Plan, 15 alternate investment plans were constructed targeting end-state system reliability scores ranging from ~155 SAIDI to ~30 SAIDI. The plan that resulted in the lowest total cost to the customer under the most sensible set of assumptions was selected as the go-forward Distribution Investment Plan (also referred to as the "Base Case").

Plans targeting end-state SAIDIs lower than ~80 represent higher levels of investment than the Base Case. Plans targeting end-state SAIDIs higher than ~80 represent lower levels of investment than the Base Case. The "No Incremental-Investment" plan represents a scenario in which GPC does not invest any incremental capital in its distribution system above historical levels, leading to a forecasted decline in GPC reliability and an end-state SAIDI of ~155 by 2031. See III.A for further discussion of investment scenarios.

Consistent with findings from the Original Plan, the Base Case shows that higher levels of investment result in diminishing reliability improvement (see Figure 1). This is because circuits with the poorest reliability that represent the highest improvement opportunities are invested in first. Increasing capital investment means investing in circuits with relatively better reliability that represent lower improvement opportunities.

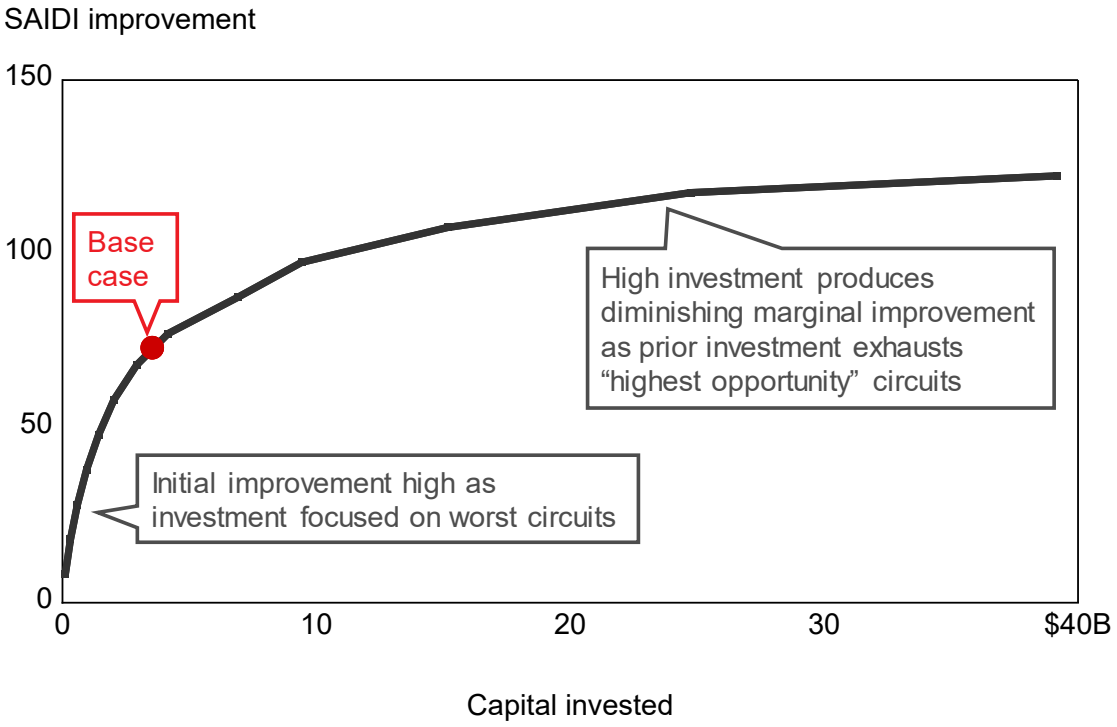


**Figure 1. Diminishing Reliability Improvement**

As illustrated in Figure 1, incremental customer benefit from distribution investment levels off after a certain amount of spending. The Base Case plan corresponds to the level of investment that includes the highest opportunity investments but excludes investments that produce diminishing returns. See III.B for further discussion of diminishing reliability improvement.

To evaluate the Distribution Investment Plan from the customers' perspective, the present values of three types of costs were evaluated for each scenario. These include:

- **Capital Revenue Requirement:** Capital revenue requirement refers to the direct monetary cost customers incur as a result of GPC's capital investment. On a present value basis this is equal to the amount of capital GPC is required to spend under each scenario multiplied by GPC's distribution capital k-factor of [redacted][120]. See I.N for further discussion of capital revenue requirement assumptions and calculations.

[120] GPC's k-factor is used to convert GPC's capital investment into a present value of revenue requirements to customers.

- **Economic Cost:** Economic cost refers to the implicit costs customers incur as a result of outages. For the purposes of this study, economic cost strictly refers to the costs customers incur as a result of distribution outages in each scenario. See I.O for further discussion of economic cost assumptions and calculations.
- **Operations and Maintenance Expense ("O&M"):** In this study, O&M refers to outage repair-related and vegetation management O&M. Only these pieces of O&M are included, as investment in GPC's distribution system will not impact other components of O&M. See I.P for further discussion of O&M assumptions and calculations.

Because all of these costs are explicitly or implicitly borne by customers, an investment plan that minimizes the sum of these costs is considered to be within the optimal range of investment.

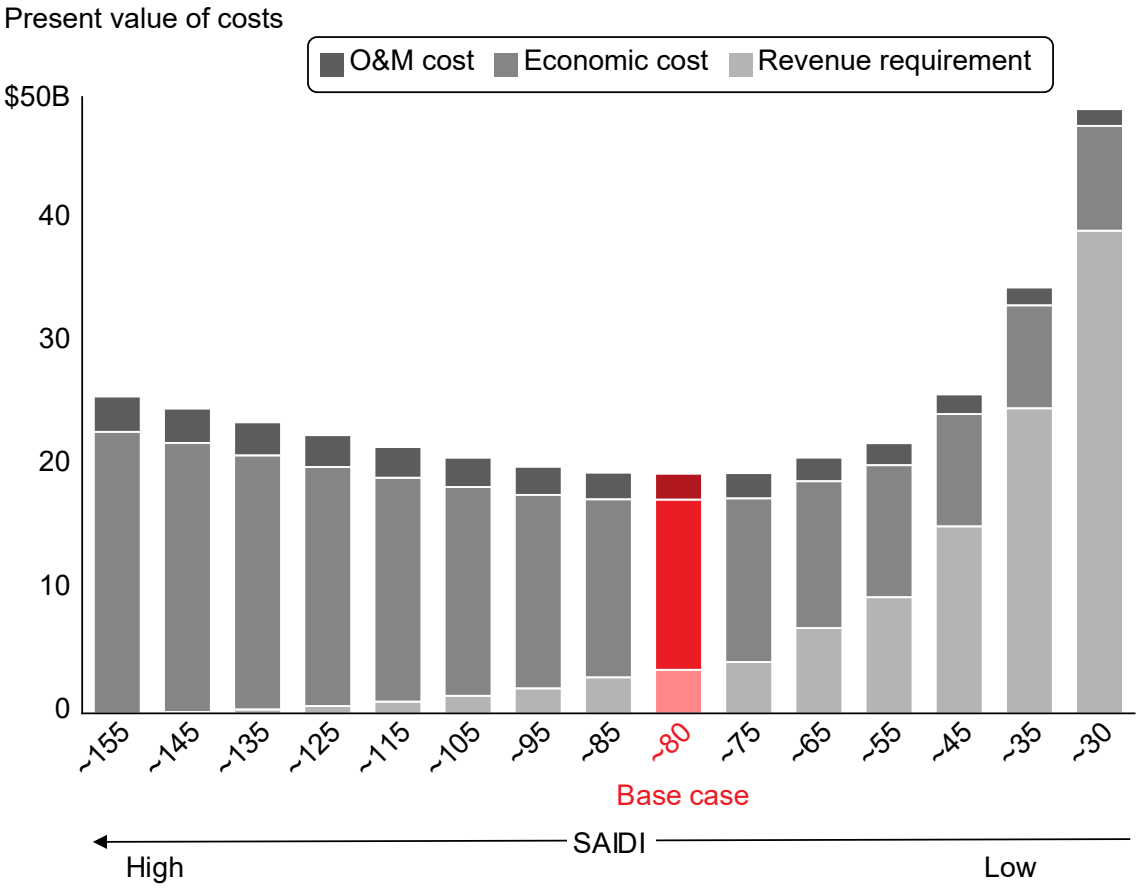


**Figure 2. Present Value of Total Cost**

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Figure 2 demonstrates the total of these three costs (capital revenue requirement, economic cost, O&M) for each scenario. Moving from left to right along the chart's x-axis, capital revenue requirements increase as more aggressive reliability targets are achieved, while both economic costs and O&M costs decrease. Of the 15 scenarios evaluated, the Base Case scenario results in the minimum present value of costs and should thus be seen as the preferred option for customers.

Minimizing the present value of total customer cost is equivalent to maximizing the net present value of investment.

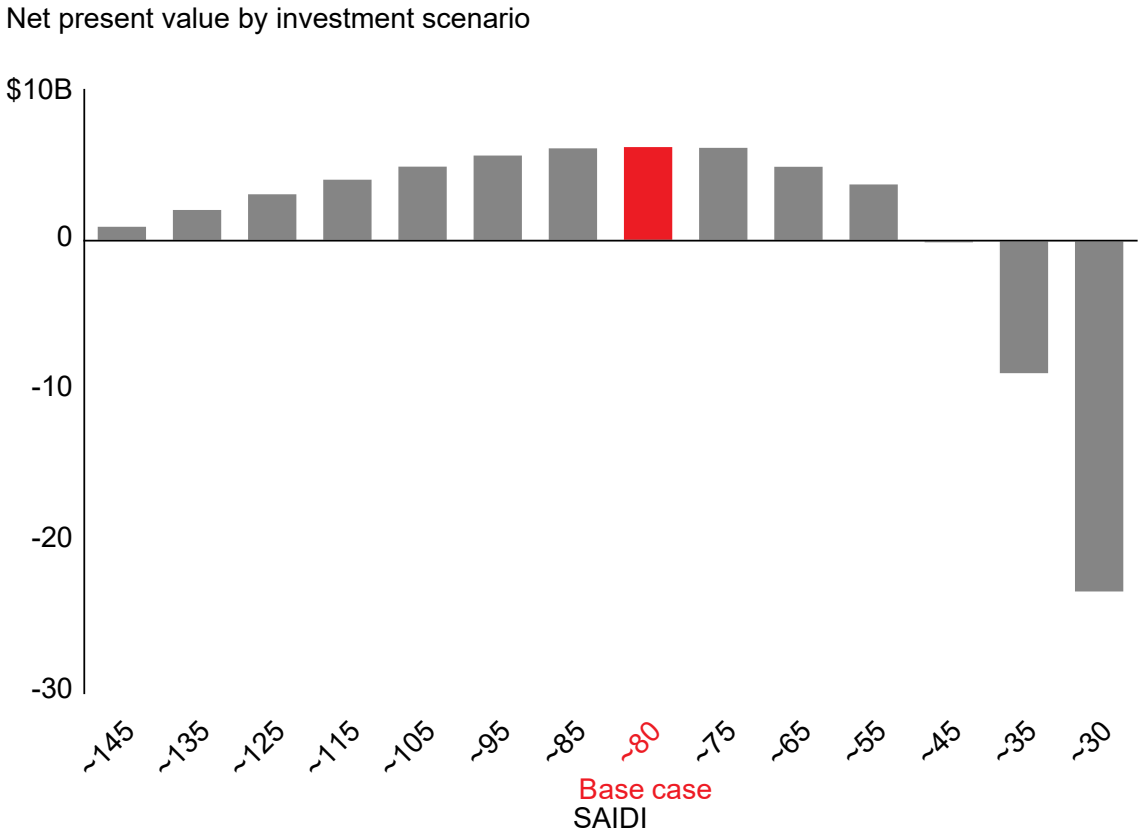


**Figure 3. Net Present Value**

Figure 3 shows the net present value ("NPV") of customer costs for each scenario. The NPV for any given scenario (for example, scenario "S") is calculated by taking the difference between the

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No Incremental-Investment scenario's present value of costs and scenario S's present value of costs. The Base Case scenario has the highest associated NPV of all scenarios and therefore creates more customer value than any other scenario analyzed. See Section III for a further discussion of scenario cost calculation.

In addition, seven sensitivity analyses on key inputs to the model were conducted. While these sensitivities result in increases or decreases to the overall costs incurred by customers under each scenario, the Base Case plan remains in the optimal range of investment across all sensitivities. As an example, Figure 4 shows a sensitivity on this study's capital investment cost assumptions. To capture potential deviations from current investment cost estimates, cost assumptions were flexed up and down 10% to determine the impact on the optimal investment range. As shown in figure 4, the Base Case has the lowest total cost using both the 90% and 110% assumptions and therefore remains in the optimal range of investment under both assumptions. See Section IV for a further discussion of sensitivity analyses.

Present value of costs (Investment sensitivity)

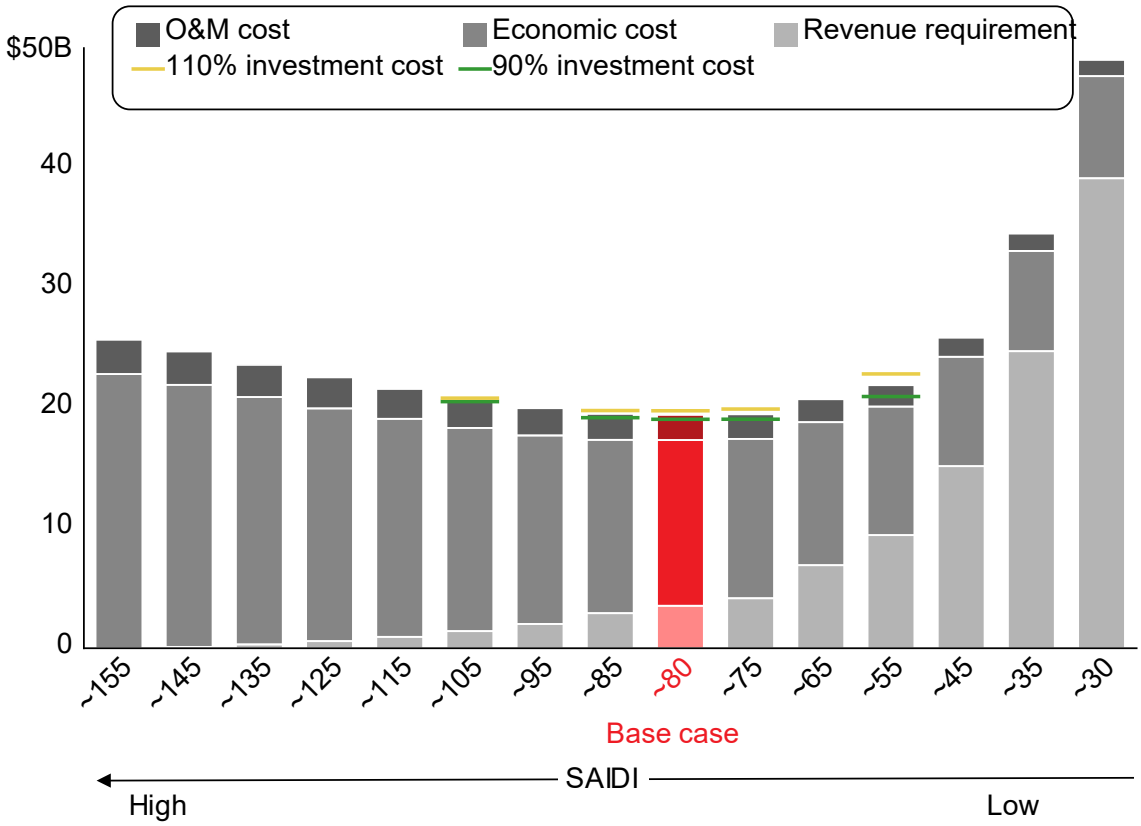

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**Figure 4. Investment Cost Sensitivity**

Because the Distribution Investment Plan remains in the optimal range across all sensitivities, the Base Case investment plan should be considered the preferred option for GPC customers.

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# I. ASSUMPTIONS

The following sections of this report provide detailed discussions related to the input assumptions associated with the 2022 Distribution Investment Plan.

## Explanation of Investment Packages

The Distribution Investment Plan assumes that GPC distribution circuits can receive any one (or multiple) of 6 different "investment packages." The menu of circuit investment packages was developed by GPC distribution engineers based on prior investments that GPC has successfully implemented in its distribution system. Packages are listed in Table I.1 below:

**Table I. 1. Description of Investment Packages**

| Number | Name | Description |
|---|---|---|
| **1** | Add sectionalizing, DA devices | • Install additional intelligent line devices on overhead line to achieve segmentation |
| **2** | Add / strengthen ties | For circuits without a tie:<br>• Add new tie(s) to other circuit(s)<br>For circuits with existing tie(s):<br>• Increase capacity of tie points that offer increased ability to restore load<br>• In some cases, create a new tie on a radial branch of the circuit |
| **3** | Circuit hardening (BIL) | • Replace wooden and steel pole arms with fiberglass brackets<br>• Add wildlife protective equipment |
| **4** | Break feeder | • Introduce a new source (e.g., new breaker at existing substation) to split an existing circuit into two smaller circuits while applying segmentation |

| | | |
|---|---|---|
| **5** | Relocate feeder; bring to road | • Identify inaccessible lines and rebuild on private property along accessible roadway |
| **6** | Underground the feeder | • Underground 100% of multiphase overhead lines |

## Criteria for Package Investment

To determine which (if any) investment package(s) should be applied to each circuit, specific criteria are set for each package. Criteria for each package are chosen to tailor package choice to each circuit based on that circuit's specific characteristics. A circuit must meet ALL criteria thresholds in order to qualify for an investment package. The criteria thresholds used in the Base Case scenario are listed below in Table I.2:

**Table I. 2. List of Package Investment Criteria**

| Number | Name | Criteria for Investment |
|---|---|---|
| **1** | Add sectionalizing, DA devices | [redacted] |
| **2** | Add / strengthen ties | [redacted] |

| | | |
|---|---|---|
| **3** | Circuit hardening (BIL) | [redacted] |
| **4** | Break feeder | [redacted] |
| **5** | Relocate feeder; bring to road | [redacted] |
| **6** | Underground the feeder | [redacted] |

| | | |
|---|---|---|
| | | |

The criteria above were determined in collaboration with GPC distribution engineers and subject matter experts to isolate circuits with "systemic issues" that are in most need of investment and most likely to experience further reliability decline in the absence of investment. For the purposes of this study, circuits with "systemic issues" are those with poor reliability stemming from topographical conditions (e.g., vegetation growth), unaddressed customer or load growth, or legacy design specifications. The criteria above have been updated slightly from 2019 based on lessons learned over the last 3 years. A key difference from the Original Plan is the transition to utilizing 5 years of reliability data to determine which circuits qualify for investment. Utilizing the average reliability performance across 5 years allows GPC to better identify circuits with consistently poor reliability.

Data from ~2300 distribution circuits were analyzed against these criteria to determine if circuits were 'qualified' for each investment package. In many cases, circuits qualify for just a single investment package. In cases where a circuit qualifies for multiple packages, the following logic is applied to determine the set of investments the model can select from:

[redacted]

[redacted]

[redacted]

After all qualified investment packages are identified, the model evaluates combinations of potential investments to determine the optimal subset of investments to achieve the lowest total cost to the customer for a given SAIDI (details on the selection approach are described in section I.F below).

Each subset of investments selected represents a single scenario and each scenario is identified by the end-state SAIDI achieved. As part of this study, 15 scenarios were ultimately created for SAIDIs ranging from ~155 to ~30.

To create investment scenarios with SAIDIs below 60, certain of the above criteria are flexed to be more permissive, allowing more circuits to qualify for, and receive, investment. This change in criteria is necessary to reach the lowest SAIDIs.

## Package Investment Cost Drivers

Estimated capital required for each circuit investment is determined based on the cost driver(s) of the package(s) the circuit receives. Cost drivers and unit costs for each package were determined by GPC engineers based on analysis of test projects and were then updated based on the first 3 years of implementation experience. In addition, over the last three years, the Company has determined that additional work is required to complete certain investments. Therefore, a scope multiplier has been added to the sectionalizing, circuit hardening, and undergrounding investments. See Table I.3 for the list of drivers, scope multipliers, and unit costs.

**Table I. 3. List of Package Cost Drivers and Unit Costs**

| Number | Name | Driver | Unit Cost |
|---|---|---|---|
| **1** | Add sectionalizing, DA devices | [redacted] | |
| **2** | Add / strengthen ties | | |
| **3** | Circuit hardening (BIL) | | |
| **4** | Break feeder | | |
| **5** | Relocate feeder; bring to road | | |
| **6** | Underground the feeder | | |

## Expected Investment Package Reliability Benefit

Expected SAIDI and SAIFI improvement for each circuit receiving an investment is determined based on the package(s) it receives. Expected SAIDI and SAIFI improvements for each package are based on past GPC projects.[121] While initial investments from the first 3 years of the Grid Investment Plan have resulted in positive reliability benefits, GPC has not updated the expected benefits due to the small sample size of investments that have been completed for a full calendar year and desire to remain conservative in estimating potential benefits.

The scope of the Distribution Investment Study only extends to forecasting SAIDI and SAIFI values scrubbed of major weather events for each circuit. See Table I.4 for a list of expected package reliability improvements.

**Table I. 4. Estimated Reliability Improvements for Package Investment**

| Number | Name | SAIDI Reduction | SAIFI Reduction |
|---|---|---|---|
| **1** | Add sectionalizing, DA devices | [redacted] | |
| **2** | Add / strengthen ties | | |
| **3** | Circuit hardening (BIL) | | |
| **4** | Break feeder | | |
| **5** | Relocate feeder; bring to road | | |
| **6** | Underground the feeder | | |

121 [redacted]

### Expected Package Investment Benefit Length

All package benefits are forecasted to last 25 years past the investment period of 2020 to 2030 (i.e., to 2055). This reflects a conservative estimate of the average useful life of package improvements[122] and is in line with historical GPC experience.

### Investment Selection

Once it is determined which package(s) a circuit qualifies for, a projection for the cost and benefit of each possible investment occurring in each possible year is made in the optimization model. An optimization model then evaluates possible combinations of investments to determine which subset of investments generates the greatest benefits for the customer (in terms of reduced O&M and reduced economic cost of outages) for each invested dollar. The optimal subset of investments selected produces the lowest total cost to the customer for a given SAIDI score.

Using this approach, 15 different scenarios were created, each targeting an end-state system reliability score ranging from ~155 SAIDI to ~30 SAIDI. The 15 scenarios were compared to determine which scenario produced the lowest overall total cost to the customer. This overall lowest total cost to the customer scenario corresponds to the Base Case and go-forward Distribution Investment Plan.

### Investment Sequencing

Circuit investments are sequenced for execution over the remaining 8-year investment horizon (2023-2030). Exact investment sequencing is determined based on several factors:

- **Annual spend:** Fluctuation in annual overhead and underground investment cost is minimized from year to year as spikes in either overhead or underground spend and labor requirements would be difficult to manage from an operational and supply chain perspective.
- **Region-by-region approach:** The region by region sequencing established in 2019 was maintained with 2 exceptions: The South region was shifted forward 1 position to start in advance of the West region and the Northeast region was shifted forward 1 position to start in advance of the Metro North region. These switches were made in order to balance the amount of overhead and underground spend and labor required from year

[122] Brown (2009) states underground and overhead T&D infrastructure have 40 and 60 year lifespans, respectively. See section IV.E for a sensitivity analysis on this assumption.

to year given the new set of investments selected for the revised Distribution Plan. In keeping with the 2019 plan, all circuits selected for investment in a particular region are addressed in sequence, such that once investment in a region begins, that region is invested in every year until investment in that region is completed.

- **Annual regional spend:** Year over year fluctuation in total investment per region is minimized to ensure that no one region is oversaturated with investment in one particular year, as concentrated construction may pose operational difficulties and negatively impact customer experience.
- **Circuit ordering:** Within the constraints described above, circuits in each region which present the worst reliability are prioritized for investment. In order to minimize travel, disruption, and switching costs, investments within a single substation were grouped where possible.

### Reliability Decline

Without continued maintenance or investment, certain circuits are expected to experience reliability decline over the long term[123]. To reflect this, the roughly 1000 circuits identified as having systemic issues (as discussed in I.B) and hence qualifying for investment are projected to experience a modest yearly reliability decline across the investment period[124] or until invested in.

[123] Because of the multitude of factors impacting circuit reliability in a given year (e.g., weather, traffic incidents, wildlife incidents) reliability cannot be forecasted accurately on a yearly basis. That said, over a longer period (e.g., 10 years) reliability can be expected to follow a forecasted trend.

[124] Note that reliability decline is capped after the investment benefit period.

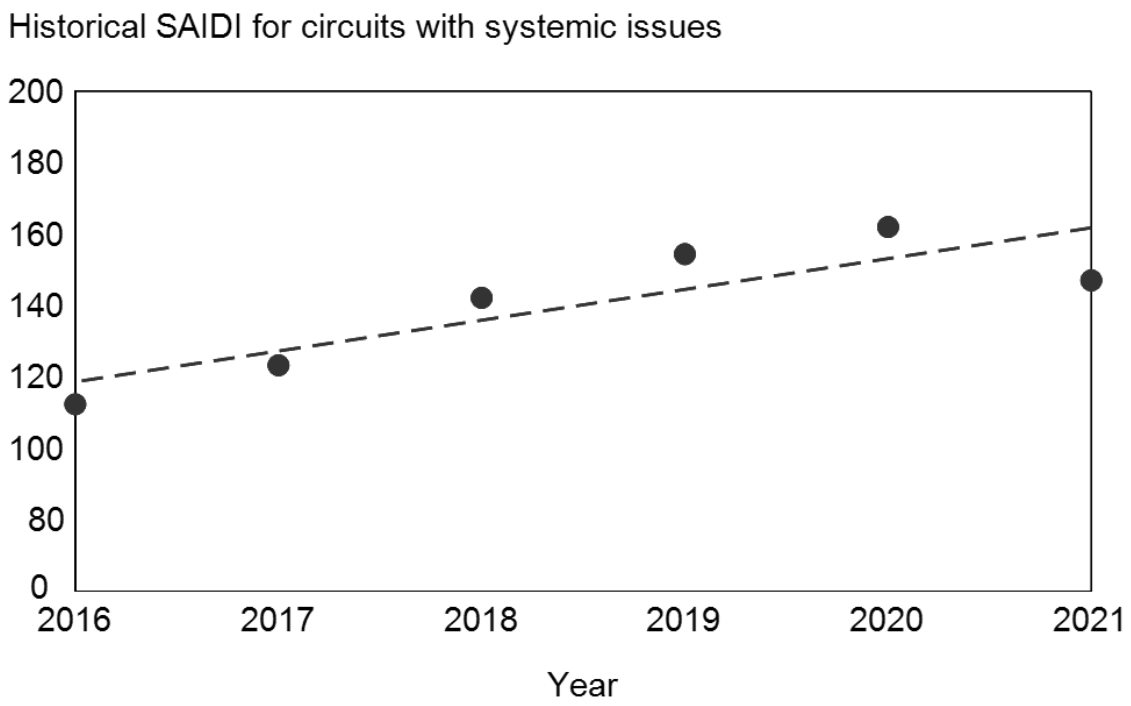


**Figure I. 1. Historical SAIDI of Circuits with Systemic Issues**

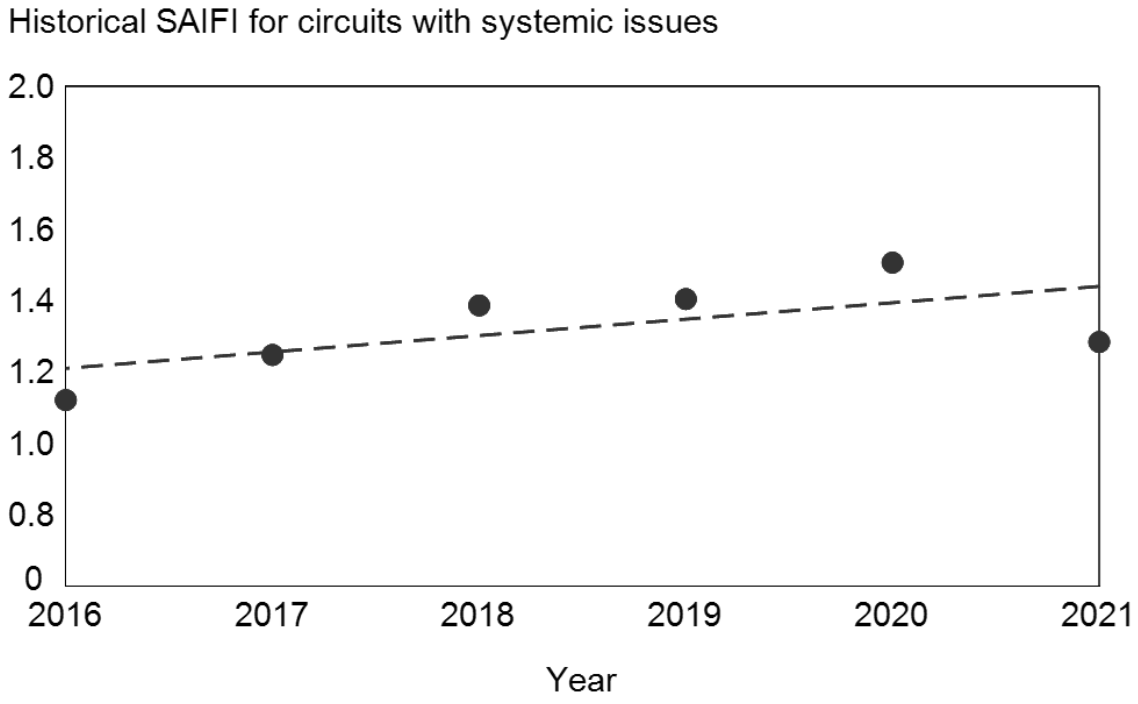


**Figure I. 2. Historical SAIFI of Circuits with Systemic Issues**

Figures I. 1 and I. 2 show the historical SAIDI and SAIFI, respectively, of roughly 1000 circuits identified as having systemic issues. Within the last six years, these circuits have experienced an average of ~6% SAIDI and ~3% SAIFI increase per year. To be conservative, SAIDI is projected to decline 4% for these circuits. SAIFI is projected to decline at 3%, in line with historical trends and the previous study.

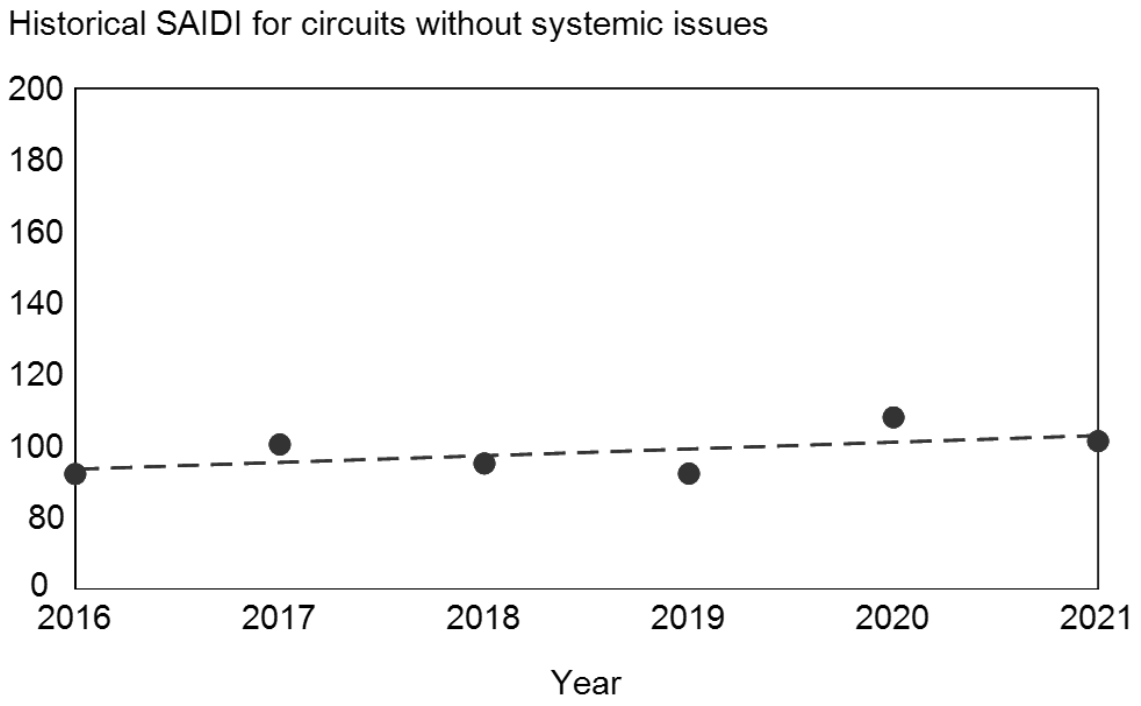


**Figure I. 3. Historical SAIDI of Circuits without Systemic Issues**

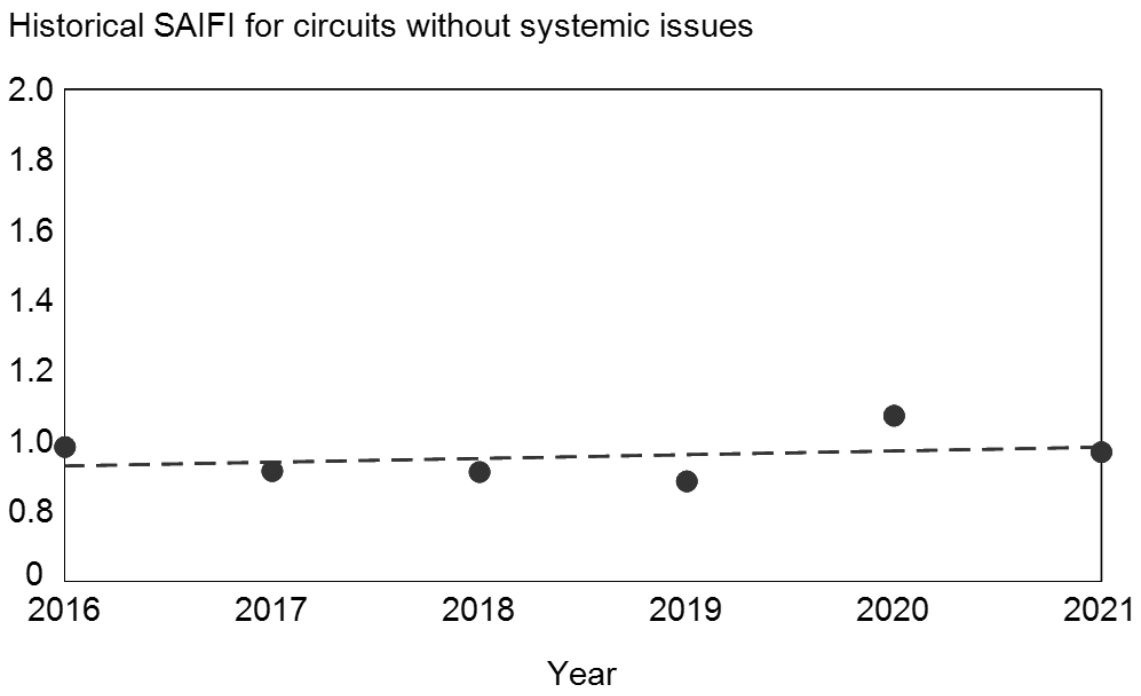


**Figure I. 4. Historical SAIFI of Circuits without Systemic Issues**

Figures I. 3 and I. 4 show the historical SAIDI and SAIFI trends, respectively, of the remaining ~1300 GPC circuits that were not identified as having systemic issues. In the last six years, reliability for these circuits has been flat to improving. As such, this study assumes each of these circuits will experience no reliability increases or decreases over the course of the investment period and these circuits do not qualify for investment as part of the GIP.

## Package Investment Benefit Timing

To reflect variations in the timing of circuit investment completions, for packages 1-5, only 1/3 of expected reliability benefit is realized during investment. The remaining 2/3 of benefit is realized in the year following completion.

For package 6 specifically, as no benefit can be realized until investment is complete and customers transitioned to the new line, no benefit is realized during investment. Instead, 100% of the reliability benefit is achieved in the year following completion.

## Population Growth

GPC's customer base is assumed to grow at an annual rate of [redacted]% between 2023 and 2055, based on GPC subject matter expert projections.

## System Load Growth

Customer power usage (measured in MWh) is assumed to decline at an annual rate of [redacted]% between 2023 and the end of the investment period, based on GPC subject matter expert projections.

## Weighted Average Cost of Capital

GPC's corporate WACC (Weighted Average Cost of Capital) of [redacted]% is used for all discounting.

## Historical Inflation Rate

An inflation rate of [redacted]% is used to correct historical dollar figures to 2022 values, to discount projected costs, and to estimate expected investment cost increases over time. This figure is used for consistency with other GPC studies and reports[125].

## Capital Revenue Requirement

Capital revenue requirement refers to the direct monetary cost customers incur as a result of GPC's capital investment on a present value basis. This is equal to the amount of capital GPC is required to spend under each scenario multiplied by GPC's distribution capital k-factor of [redacted][126].

Investment values in each year are multiplied by GPC's distribution capital k-factor of [redacted] to achieve a revenue requirement number for each year. Revenue requirement numbers for each year's expenditures are then discounted back to 2022 values to achieve the present value of capital revenue requirement for a given investment plan.

[redacted]

[126] GPC's k-factor is used to convert GPC's capital investment into a present value of revenue requirement to customers.

## Economic Cost

Economic cost refers to the implicit costs customers incur as a result of outages. Economic costs in the utility setting are often measured in terms of willingness to pay to avoid an outage or lost production as a result of an outage. For the purposes of this study, economic cost strictly refers to the costs customers incur as a result of distribution outages[127] in each scenario.

To facilitate estimating the economic cost of outages, Freeman, Sullivan & Company conducted a Cost of Expected Unserved Energy (EUE) survey of GPC and Mississippi Power Company (MPC) in 2011. This survey was conducted among the following four customer classes:

- Residential
- Commercial (below 1 MW average demand)
- Industrial (below 1 MW average demand)
- Large Business (commercial and industrial customers above 1 MW average demand)

The cost of EUE (in 2022 dollars) for these four customer classes is shown in Table I. 5.

**Table I. 5. Cost of Expected Unserved Energy by Customer Class[128]**

| Customer Class | Cost per Unserved KWh (2022) |
|---|---|
| **Residential** | [redacted] |
| **Commercial** | [redacted] |
| **Industrial** | [redacted] |
| **Large Business** | [redacted] |

[127] A "distribution outage" is defined as an outage that originates on a distribution circuit (as opposed to originating from, for example, a transmission substation).

[128] Values are an average of summer and winter dollar amounts from the survey. Values are adjusted to 2022 dollars.

The yearly economic cost of distribution-related outages on a system level is calculated using the following formula:

*Economic cost for system = SAIDI * Average KWh Usage per Minute * Cost per Unserved KWh*

Where:
Economic cost for system = Nominal economic cost of unserved power for customers on the system;
SAIDI = System Average Interruption Duration Index in minutes;
Average KWh Usage per Minute = Amount of energy used in the average minute for customers on the system; and
Cost per Unserved KWh = weighted average EUE cost survey value for customers across the system

System nominal economic costs for each year are discounted back to 2022 dollars and summed together to calculate the present value of economic cost.

Implicit in these formulas is that system economic cost (a) declines as reliability of the system improves and (b) declines as system load decreases. Since package investment is sequenced across the investment period of 2023-2030 and full reliability benefit for each circuit is only realized after investments are completed, an investment plan targeting an end-state reliability figure will see a gradual improvement of economic cost until end-state reliability is reached in 2031.

## Operations and Maintenance Expense Impacted by Investment

In this study, Operations and Maintenance Expense ("O&M") refers only to portions of GPC O&M that could be impacted by the circuit investments analyzed in this study. Specifically, this study forecasts two pieces of O&M:

- **Outage Repair-Related O&M:** Costs that are related to the restoration of power when outages occur. When reliability improves and the frequency and duration of outages decreases, these O&M costs are expected to decline.
- **Vegetation Management O&M:** Costs associated with the trimming of plant foliage and removal of trees adjacent to distribution lines and within GPC's right-of-way. Vegetation

management costs are incurred to ensure that plant foliage and trees do not interfere with overhead distribution circuits. For distribution circuits receiving package 6 (undergrounding) vegetation management is expected to decline.

These two pieces of O&M are assumed to grow or decline with the following:

- **Outage Repair-Related O&M:** Increases or decreases with SAIFI
- **Vegetation Management O&M:** Increases at historical CAGR of ~2.2%, decreases with proportion of overhead 2&3-phase line miles undergrounded

As such, outage repair-related O&M decreases with investment as system reliability improves. Vegetation management O&M also decreases to a lesser degree with investment as 2&3-phase line miles are undergrounded.

Outage repair-related O&M is projected using the prior year's system outage O&M spend, disaggregated to the circuit level based on a circuit's contribution to system level SAIFI. Vegetation management O&M is projected using a historical 3-year average[129] of system total vegetation spend, disaggregated to the circuit level based on a circuit's proportion of 2 and 3 phase overhead line miles.

As with capital revenue requirement and economic cost, O&M is forecasted out for each year in the investment period in nominal terms and then discounted back to 2022 dollars to obtain a present value of O&M.

### Optimal Investment Range Determination

Customers directly or indirectly incur capital revenue requirement costs, O&M costs, and economic costs. As such, customers prefer investment plans that offer a lower present value of capital revenue requirement, O&M, and economic costs over plans that offer a higher present value of these costs. Thus, an investment plan that minimizes the present value of the sum of these three costs is considered optimal from the customer's perspective. Because only a finite number of investment plans can be tested, for the purposes of this study, the investment plan that minimizes the present value of costs is assumed to be in the optimal investment *range* (as opposed to the exact optimal investment plan).

[129] GPC uses a three-year vegetation management cycle for most circuits.

# II. SIMULATION PROCEDURE

The following sections of this report provide detailed discussions related to the steps taken to generate each investment scenario and arrive at total costs (including capital revenue requirement costs, economic costs, and O&M costs) for that scenario.

## A. Application of Investment Criteria and Selection of Investments

Circuit data are evaluated against investment criteria for each investment package (see Table I. 2 for a list of criteria and baseline values) to determine which investment package(s) each circuit qualifies for.

As described in I.F above, a projection is then created to determine the cost and benefit of undertaking every qualified investment using the cost drivers and benefit estimates described in I.C and I.D respectively. An optimization model then evaluates possible combinations of these investments to determine which subset produces the lowest total cost to the customer for a given SAIDI.

## Sequencing of Investments

After investments are selected, circuits are sequenced according to the procedure outlined in I.G. This places each circuit investment into a specific investment year within the 2023-2030 investment window.

## Forecasting Circuit Reliability

GPC circuit reliability scores are then projected out for each year in the investment horizon. The projection takes the following variables as inputs:

- 5-year average (2017-2021) SAIDI and SAIFI for each circuit
- For circuits that are part of the investment plan for the scenario in question: Selected package(s), timing of investment, and expected reliability improvement
- For circuits with systemic issues: Assumed reliability decline in the absence of, or until, investment

### Forecasting Circuit CMI and Customer Interruptions[130]

By using the circuit-level forecasted reliability figures from II.C, customer counts for each circuit, and the GPC compound annual growth rate to forecast customer counts for each circuit for each year in the investment horizon, we forecast each circuit's CMI and customer interruptions for each year in the investment horizon.

### Calculating Aggregate Reliability Scores

System-wide SAIDI is calculated by summing together each circuit's forecasted CMI and dividing by the projected number of GPC customers in each year. System-wide SAIFI is calculated by summing together each circuit's forecasted customer interruptions and dividing by the projected number of GPC customers in each year.

### Forecasting Capital Revenue Requirement

Capital revenue requirement for each year is calculated by summing the investment costs of circuits that will be invested in a given year and multiplying by the k-factor of [redacted], as discussed in I.N.

### Forecasting Economic Cost

The economic cost of outages across GPC for each year is determined by summing up the economic costs (calculated using methods described in I.O) of all distribution circuits.

### Forecasting Operations and Maintenance Expense

Outage repair-related O&M is forecasted on an aggregate level for 2020-2031 in proportion to system SAIFI projections (see I.P).

Vegetation management O&M is forecasted at a circuit level using the 3-year average of spend. As mentioned (see I.P), vegetation management O&M increases at historical rates and decreases with the proportion of overhead 3-phase line miles undergrounded.

[130] Annual "customer interruptions" for a circuit is the sum of the number of customers impacted by an outage across each of a circuit's outages in a given year. Customer Interruptions = SAIFI * Total Number of Customers.

### Discounting Projected Costs

Using GPC's WACC (see I.L) and the assumed inflation rate (see I.M), projected capital revenue requirement, economic cost of outages, and O&M for each year in the investment horizon are discounted back to 2022 dollars.

### Calculating Terminal Value of Costs

Since benefits of investment are expected to last well beyond 2031 (see I.E), the present value of costs beyond the investment horizon is calculated using a bounded terminal value. Economic and O&M costs are estimated to continue to grow at a terminal growth rate equal to the estimated population growth (see I.J). Since traditional terminal value calculation assumes an infinite time horizon, a bounded terminal value is calculated using the following formula:

$$TV_{2033\text{-}2055} = TV_{2033} - TV_{2056}$$

Where:

$TV_{2033\text{-}2055}$ = Present value of costs from 2033 to 2055;

$TV_{2033}$ = Present value of costs from 2033 onward; and

$TV_{2056}$ = Present value of costs from 2056 onward

This figure is discounted back to 2022 dollars to calculate the present value of 2033-2055 economic and O&M costs.

### Calculating Present Value of Costs

Summing the present value of 2023-2032 costs and 2033-2055 costs yields a total present value of costs for a given investment plan.

## III. SCENARIO RESULTS

### A. Summary of Scenarios and Selection of Base Case

For this analysis, 15 alternative investment scenarios were evaluated. Each scenario was created by determining the optimal subset of potential investments that delivers the lowest total cost to the customer for a given SAIDI score ranging from ~155 to ~30. The results of these scenarios were then compared to determine which of the scenarios produced the overall lowest total cost to the customer. This scenario was then selected as the 'Base Case'.

Under the Base Case, roughly 870 circuits are marked for investment for the remainder of the plan. The set of circuits and associated investment packages in the Base Case scenario make up GPC's proposed Distribution Investment Plan[131]. The Base Case set of investments is projected to cost ~$3.4B over the remaining 8 years (using the cost estimates discussed in I.C). Under the Base Case scenario, GPC reliability is projected to reach ~80 SAIDI by 2031 (using reliability improvement estimates outlined in I.D).

As noted in section I.B, to achieve end-state SAIDI below 60 requires significant undergrounding and so the undergrounding investment criteria were relaxed to allow more circuits to qualify for undergrounding investments in all scenarios with SAIDIs below 60.

The worst reliability scenario (the "No Incremental-Investment" scenario) results in an end state of ~155 SAIDI, based on the assumption that GPC does not invest any incremental capital in its distribution system between 2023 and 2030 and that circuits with systemic issues continue to decline during this period. The best reliability scenario targets an end state of ~30 SAIDI, which is the lowest feasible end-state SAIDI target under current input assumptions. To reach this scenario's end-state would require a very large increase in total capital spend (roughly 11x as much capital as required in the Base Case) and number of circuits invested in (roughly 2x as many circuits as are included in the Base Case). In addition, reaching an end state of ~30 SAIDI would require undergrounding far more circuits than are undergrounded in the Base Case[132] (roughly 35x).

### Diminishing Reliability Improvements with Investment

Moving from the worst reliability scenario, in which no incremental investments are made, to each successive reliability scenario, which target better customer reliability experience and lower end-state SAIDI, requires adding circuits to the investment plan. As more circuits receive investment, a better end-state SAIDI is expected.

[131] Exact set of circuits and investment timing in Base Case scenario will closely mirror final proposed Distribution Investment Plan; however, slight updates to the Distribution Investment Plan may be made after this study is published. As such, the Base Case scenario in this study may differ slightly from GPC's final Distribution Investment Plan.

[132] This is due to the fact that the undergrounding package generally results in the lowest reliability end-state compared to any other investment package.

The circuits with the worst reliability tend to be the circuits that, when invested in, are expected to produce the largest reliability improvement. As a result, higher investments (i.e. investment scenarios targeting more circuits and better end-state reliability) result in diminishing reliability improvements. This is because the worst circuits presenting the highest reliability improvement opportunity have already been added to the investment plan and incremental circuits added to the plan present lower reliability improvement opportunity. As a result, reliability benefit per invested dollar diminishes as investment scope increases. In Figure III. 1 one can see a visualization of this process.

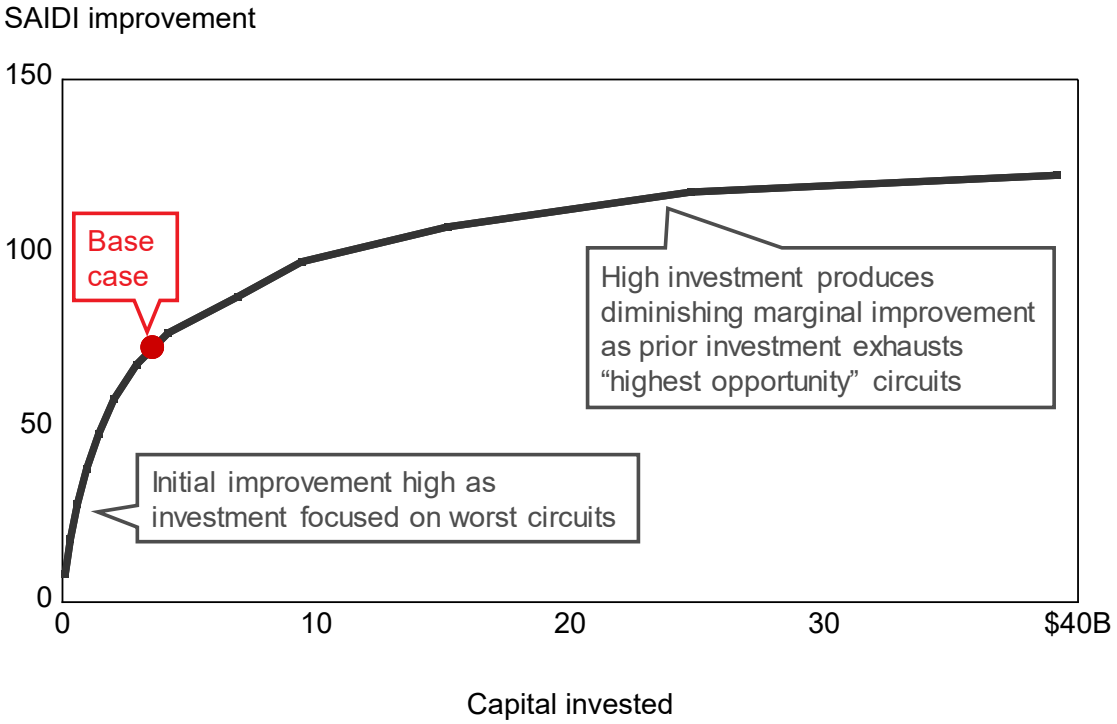


**Figure III. 1. Diminishing Reliability Improvement**[133]

The slope of the curve is initially high as investment focuses on the worst circuits. As successive incremental investment is restricted to better and better circuits, however, reliability improvement per dollar falls and the slope tapers off. Investment past the Base Case (i.e. targeting end-state GPC SAIDI values lower than ~80) requires investing in circuits with relatively better reliability and shows a pronounced decline in reliability improvement per dollar invested.

[133] "SAIDI improvement" is the difference between a scenario's end-state SAIDI and the No Incremental-Investment end-state SAIDI; each point represents a scenario.

## Introduction and Discussion of U-Curve

As discussed in I.Q, the optimal range of investment from a customer perspective is that which minimizes the summed present values of capital revenue requirement, economic cost, and O&M. Taking the identified scenarios as the domain of investment plans, the optimal range of investment can be identified by calculating the present value of each of these costs for each investment plan.

### i. Present value of capital revenue requirement

The present value of capital revenue requirement for each scenario is shown below in Figure III. 2:

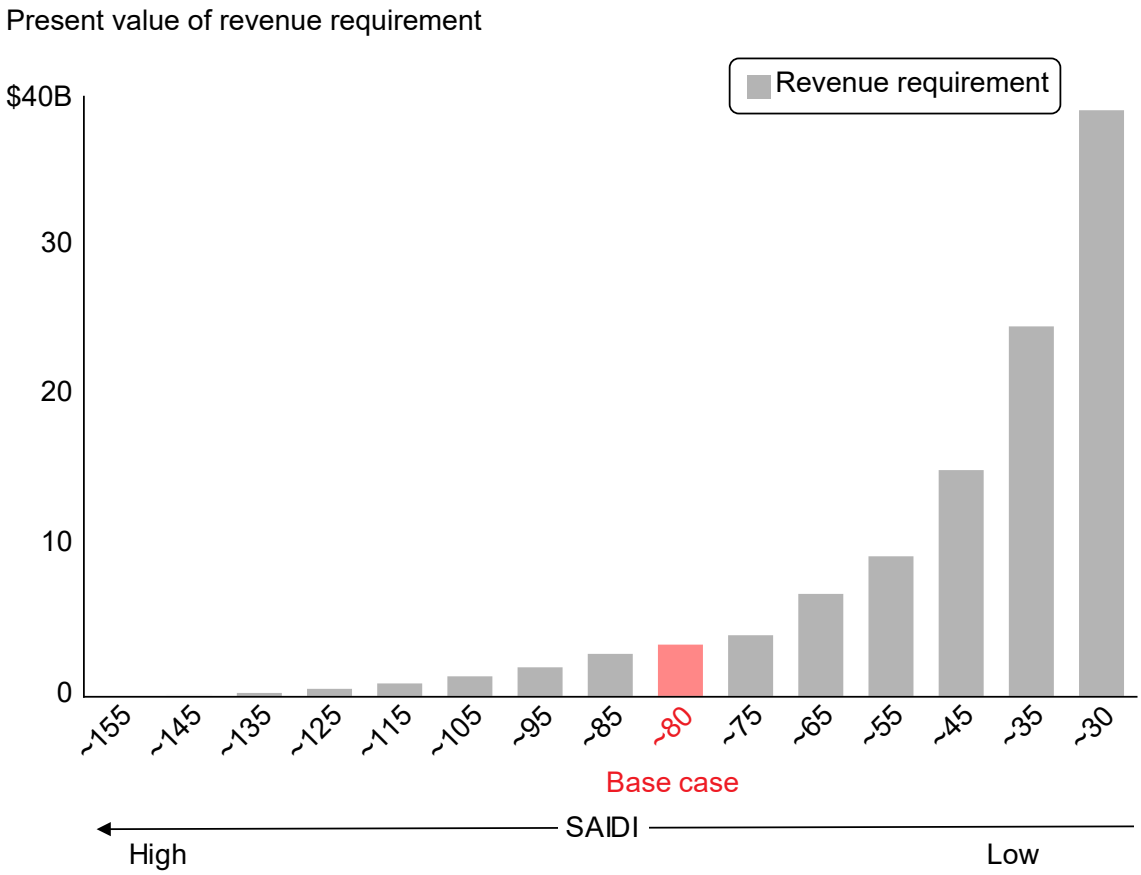


**Figure III. 2. Present Value of Capital Revenue Requirement**

As mentioned above, the worst reliability scenario with end state ~155 SAIDI assumes that no incremental investment is made in the distribution system during the investment period and thus

has a present value of capital revenue requirement equal to $0. Moving right along the axis, the slope of the curve increases as equal reliability improvements can only be attained via higher and higher levels of capital investment in the distribution system which results in higher and higher revenue requirements. This is due to diminishing reliability improvement, as discussed in Section III.B. The right most scenarios targeting the most aggressive end-state reliability scores require increasingly large investment amounts as incremental investment is restricted to relatively better circuits with lower reliability improvement opportunity.

### ii. Present value of outage economic cost

The present value of outage economic cost for each scenario is shown below in Figure III. 3:

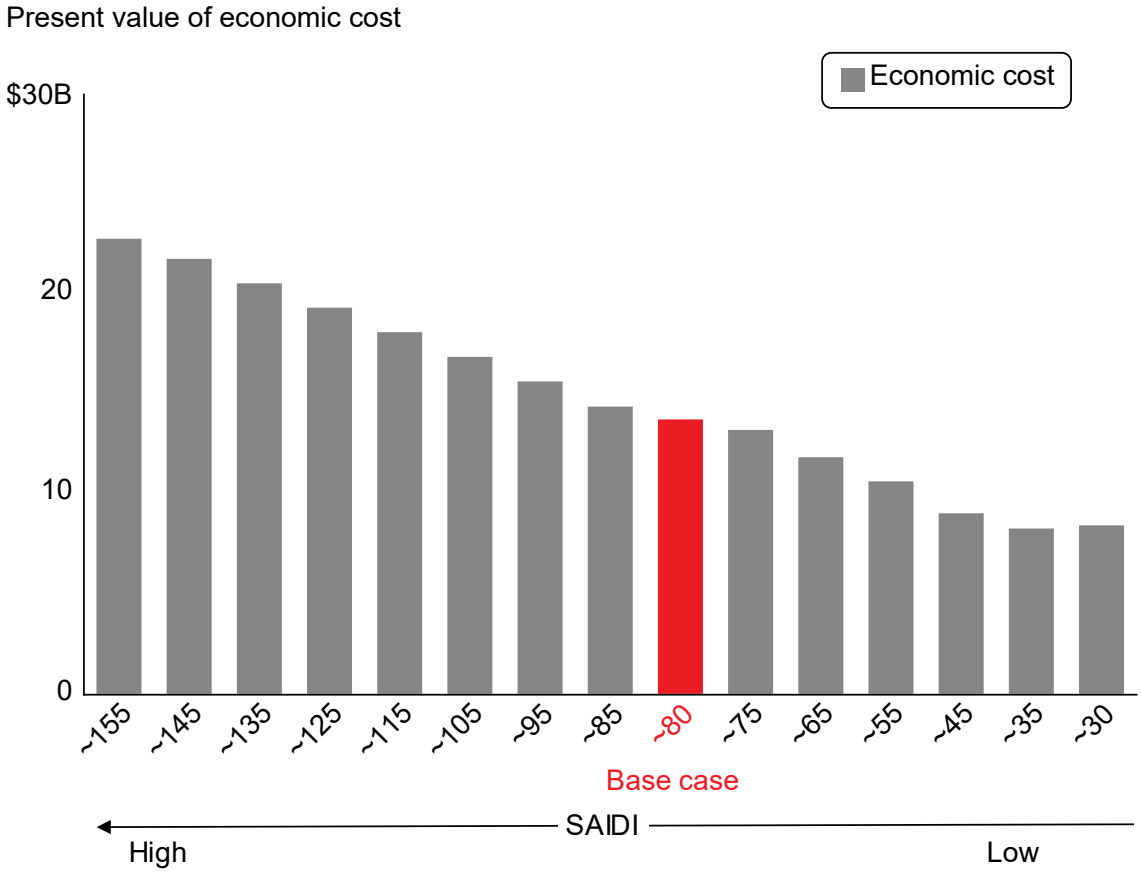


**Figure III. 3. Present Value of Economic Cost from Outages**

The present value of economic cost decreases moving from left to right along the x-axis. As end-state reliability improves, customers face less outage time and incur less economic cost as a result.

The concave nature of the curve pictured is due to two factors:

- **Gradual reliability improvement:** As discussed in Section I.O, end-state reliability for a given investment plan is only reached in 2031. Between 2023 and 2031, reliability benefit accrues gradually as GPC invests in more circuits. As such, the differences between scenarios is less pronounced in earlier years.
- **Discounting:** Due to the compounded discounting of economic costs, the economic costs of the investment period's early years (when scenarios' reliability differences are less pronounced) are given more weight than later years (when scenarios' reliability differences are more pronounced).

### iii. Present value of O&M

The present value of O&M cost for each scenario is shown below in Figure III. 4:

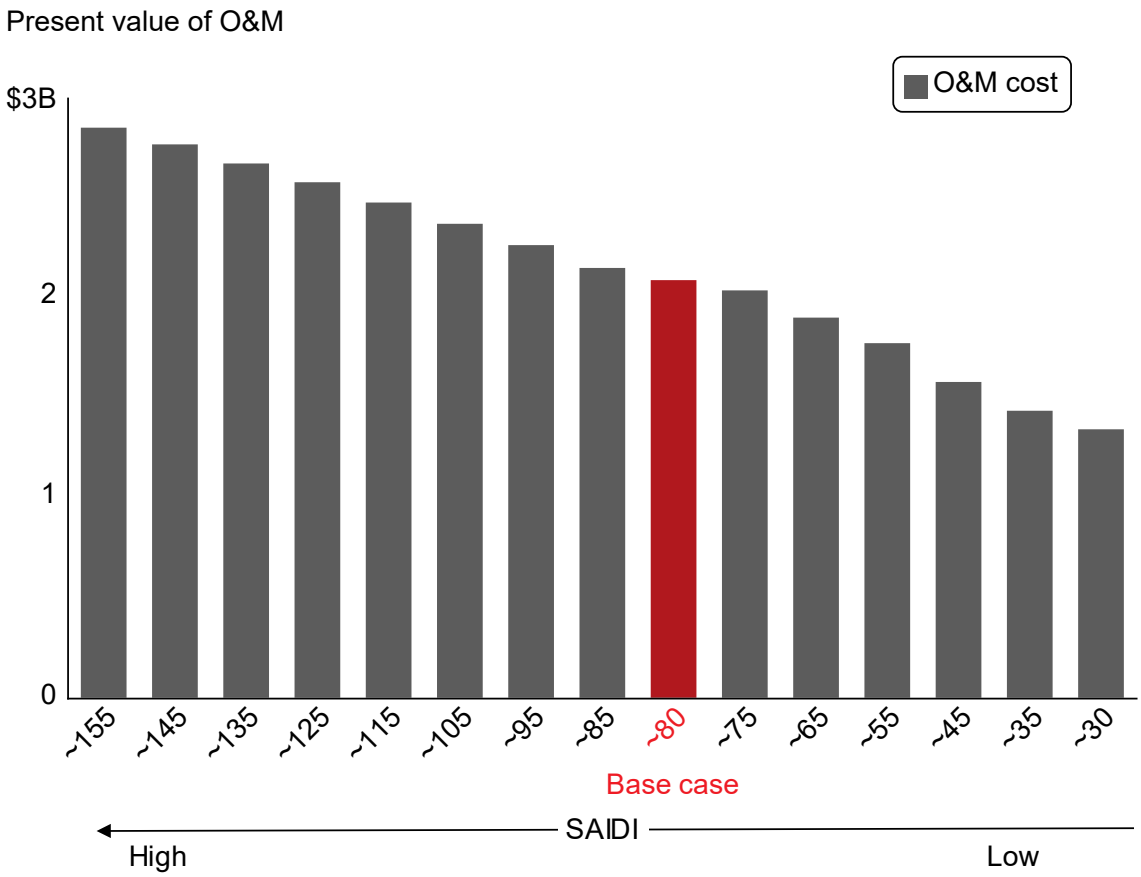


**Figure III. 4. Present Value of O&M**

The present value of O&M steadily decreases as lower SAIDI end-states are targeted. This is due to declining system SAIFI (resulting in lower outage restoration costs) and increased undergrounding (resulting in lower vegetation management costs). Notably, O&M represents a much smaller portion of total cost than economic costs and capital costs. Again, the concave nature of the pictured function is due to gradual reliability improvement and discounting, similar to economic cost.

### iv. Present value of total cost

The present value of all costs for each scenario is shown below in Figure III. 5:

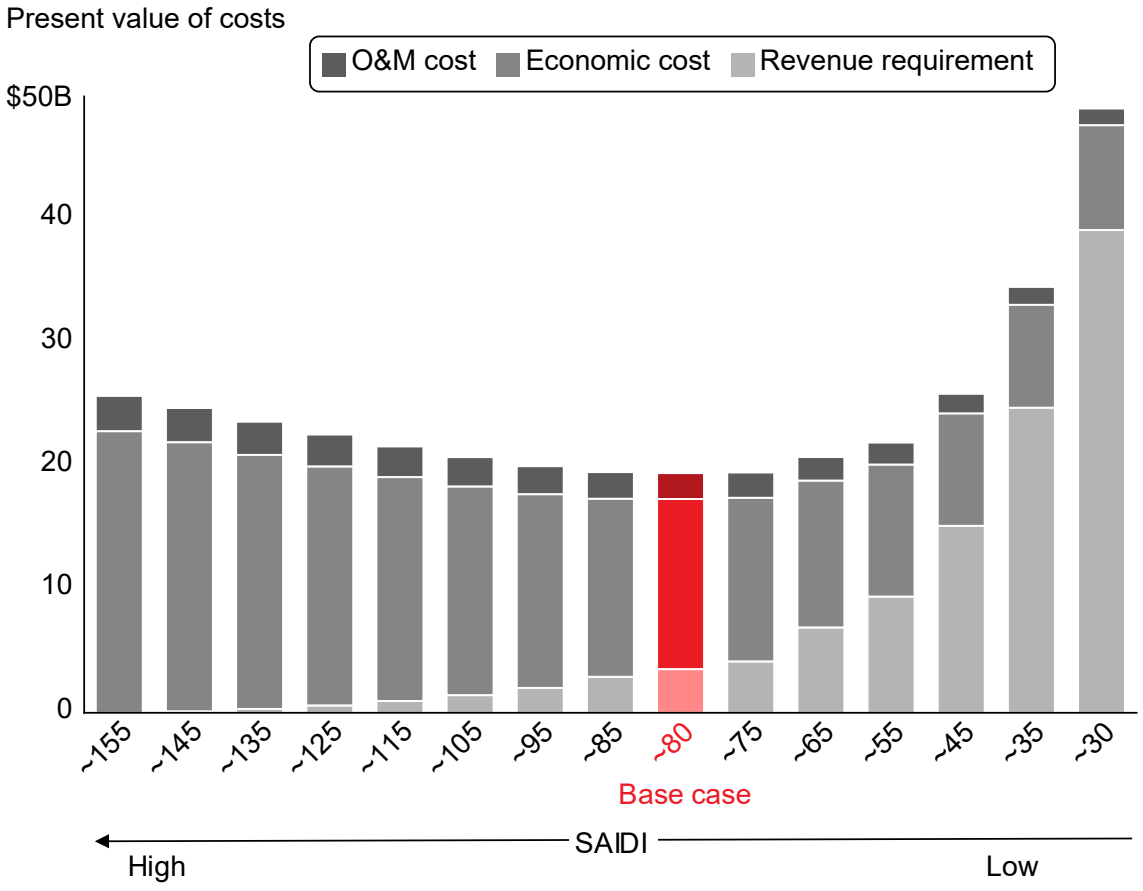


**Figure III. 5. Present Value of Total Cost**

Moving from left to right along the x-axis, capital revenue requirement increases for each successive scenario while O&M and economic cost decrease. The Base Case scenario lies at the minimum of the U-curve and is therefore the plan that minimizes customer costs under default assumptions.

## Net Present Value of Investment Scenarios

The net present value (NPV) of an investment scenario S is the measure of its benefit compared to investing $0 incrementally and is calculated using the following formula:

$$NPV_S = PVC_{NI} - PVC_S$$

Where:
$NPV_S$ = Net present value of scenario S;
$PVC_{NI}$ = Present value of costs for the No Incremental-Investment scenario; and
$PVC_S$ = Present value of costs for scenario S

When the NPV of a scenario is positive, that scenario's investment plan represents a net benefit for customers, with a present value equal to the NPV. When the NPV of a scenario is negative, that scenario's investment plan represents a net loss for customers, with a present value equal to the NPV. If scenario S' has a higher NPV than scenario S, S' represents a higher benefit for customers and should be preferred for investment. The "optimal range" is represented by the scenario with the highest NPV.

The net present value for each scenario is shown below in Figure III. 6:

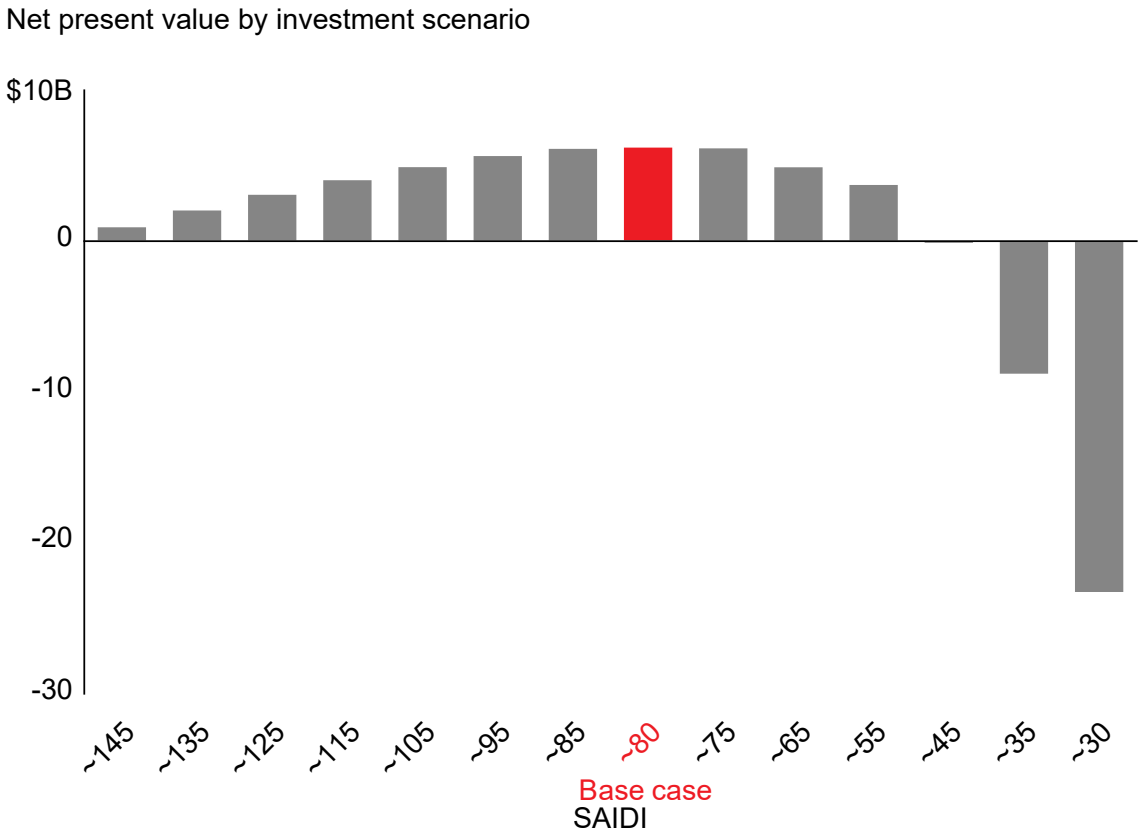


**Figure III. 6. Net Present Value**

Of note is that Figure III. 6 is a derivative of Figure III. 5's present value U-curve. The NPV for each scenario (for example, scenario "S") is calculated by taking the *difference* between the No Incremental-Investment scenario's present value of costs (the left-most bar) and scenario S's present value of costs. Hence, the NPV of the No Incremental-Investment scenario is $0 and is therefore not pictured in this figure.

As shown in Figure III. 6, the Base Case scenario represents the optimal investment plan with an NPV of ~$6.3B. Each investment scenario, with the exception of the 3 scenarios targeting ~45, ~35, and ~30 SAIDI end-state, is NPV positive, indicating that investment is strictly more beneficial to customers than non-investment. Moving from left to right along the x-axis, NPV begins falling after reaching the Base Case scenario. This is because incremental investment is restricted to the highest performing circuits. Reaching ~45 or below SAIDI as an end-state would result in a net

detriment to customers as increased capital revenue requirement would outweigh any reduction in economic costs and O&M.

## Marginal Benefit of Grid Investment

As mentioned in III.B, reliability improvement per invested dollar declines as investment increases. This relationship can also be analyzed by calculating *marginal benefit per invested dollar* (MBID)[134], where marginal benefit is calculated using the following formula:

$$MBID = -1 * \Delta \text{ Benefit} / \Delta \text{ Capital Revenue Requirement}$$

Where:
MBID = Customer value gained per dollar of investment, moving from S to S', where S and S' are adjacent scenarios
Δ Benefit = $PV_{S'}$(Economic cost) – $PV_S$(Economic cost) + $PV_{S'}$(O&M) – $PV_S$(O&M)
Δ Revenue Requirement = $PV_{S'}$(Capital revenue requirement) – $PV_S$(Capital revenue requirement)

When MBID is greater than $1, additional investment benefits customers more than it costs customers. This is because the additional reliability improvement grants customers greater savings in economic cost and O&M than it costs them in capital revenue requirement. When MBID is less than $1, additional investment costs customers more than it benefits them. This is because the additional reliability improvement costs customers more in capital revenue requirement than it saves them in economic cost and O&M. Thus, an MBID of $1 represents an "efficiency cutoff" for investment.

The MBID for each reliability end-state is shown below in Figure III. 7:

[134] Denominator is expressed in terms of capital revenue requirement because this is the cost of investment from the customer's perspective.

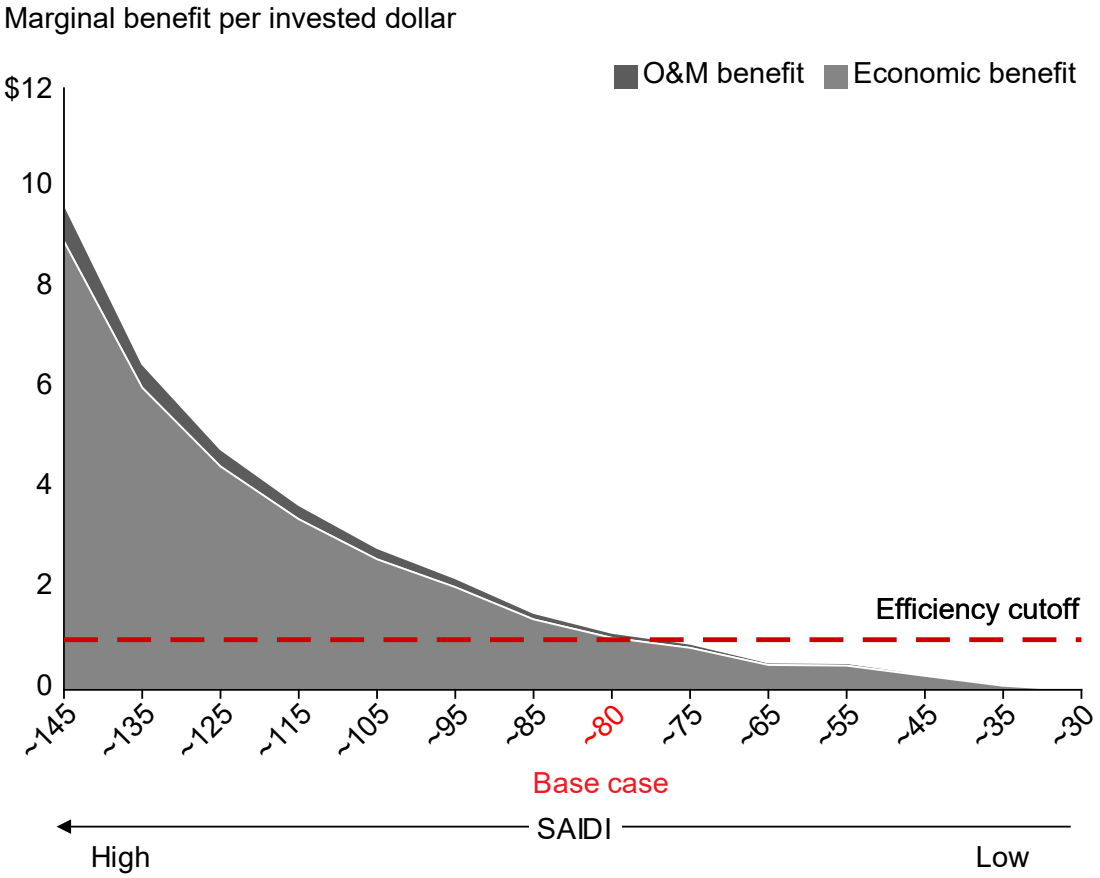


**Figure III. 7. Marginal Benefit per Invested Dollar**[135]

MBID is initially high as investment focuses on the worst circuits but declines as target SAIDI end-states get lower. Continued investment is above the efficiency cutoff, and therefore beneficial to customers, until reliability end-state passes ~80 SAIDI, after which point continued investment is no longer sensible.

## IV. SENSITIVITY ANALYSES

The following sensitivities were run to determine the optimal ranges of investment under varying model conditions, and whether optimality shifts when assumptions are adjusted. For each sensitivity, excluding IV.A, two sets of analysis were run for each sensitivity, one in which the

[135] Curve represents the best-fitting exponential line.

assumptions were flexed up above the baseline assumption and one in which the assumptions were flexed down below the baseline assumption. Note that all sensitivities were conducted on only a subset of investment scenarios above and below the Base Case. This approach was taken to balance thoroughness and efficiency.

### A. Publicly Available Cost of EUE

The first sensitivity run uses publicly available EUE data to replace internal EUE survey data. Specifically, this sensitivity uses the Interruption Cost Estimate Calculator[136], developed by Nexant and funded by Lawrence Berkeley National Laboratory and the Department of Energy, to estimate the present value of the economic cost of outages for each scenario.

The ICE calculator differs from this study's default economic cost methodology in several ways:

- EUE values are estimated based off proprietary Nexant surveys
- Economic cost calculation incorporates SAIFI in addition to SAIDI
- ICE incorporates household income, the distribution of outages over the course of the day, industry breakdown among business customers, and prevalence of backup generation as additional factors

The present value of costs U-curve using the ICE calculator to estimate the economic cost of outages is below in Figure IV. 1:

[136] The ICE calculator is available for use at http://icecalculator.com

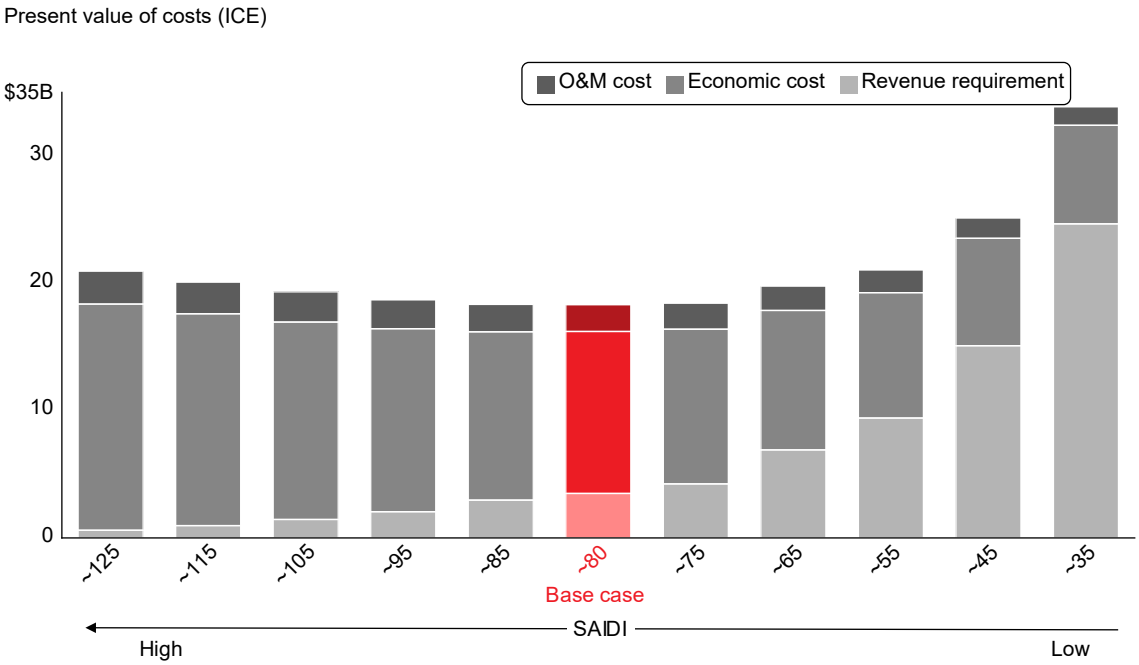


**Figure IV. 1. Present Value of U-Curve with ICE Economic Costs**

Compared to the Base Case EUE calculation in Figure III. 5, the economic cost of outages is slightly lower for each scenario. This has the effect of flattening the curve and therefore compressing the gap between scenarios. O&M and capital revenue requirement remain the same for each scenario. This is because the calculation of economic cost has no influence on either. The Base Case remains in the optimal investment range, targeting an end-state of ~80 SAIDI.

## Internal EUE Estimates

Since customer electricity reliability expectations may change during the investment period, EUE cost estimates were flexed up and down by 10% to determine the impact on economic cost calculations and the optimal investment range. Flexing EUE cost estimates impacts the economic cost bar only, as capital revenue requirement and O&M cost bars are not affected by this variable. Figure IV. 2 shows the sensitivity calculations for the Base Case and four points around the Base Case. The Base Case remains in the optimal investment range under both 90% and 110% of default EUE cost assumptions.

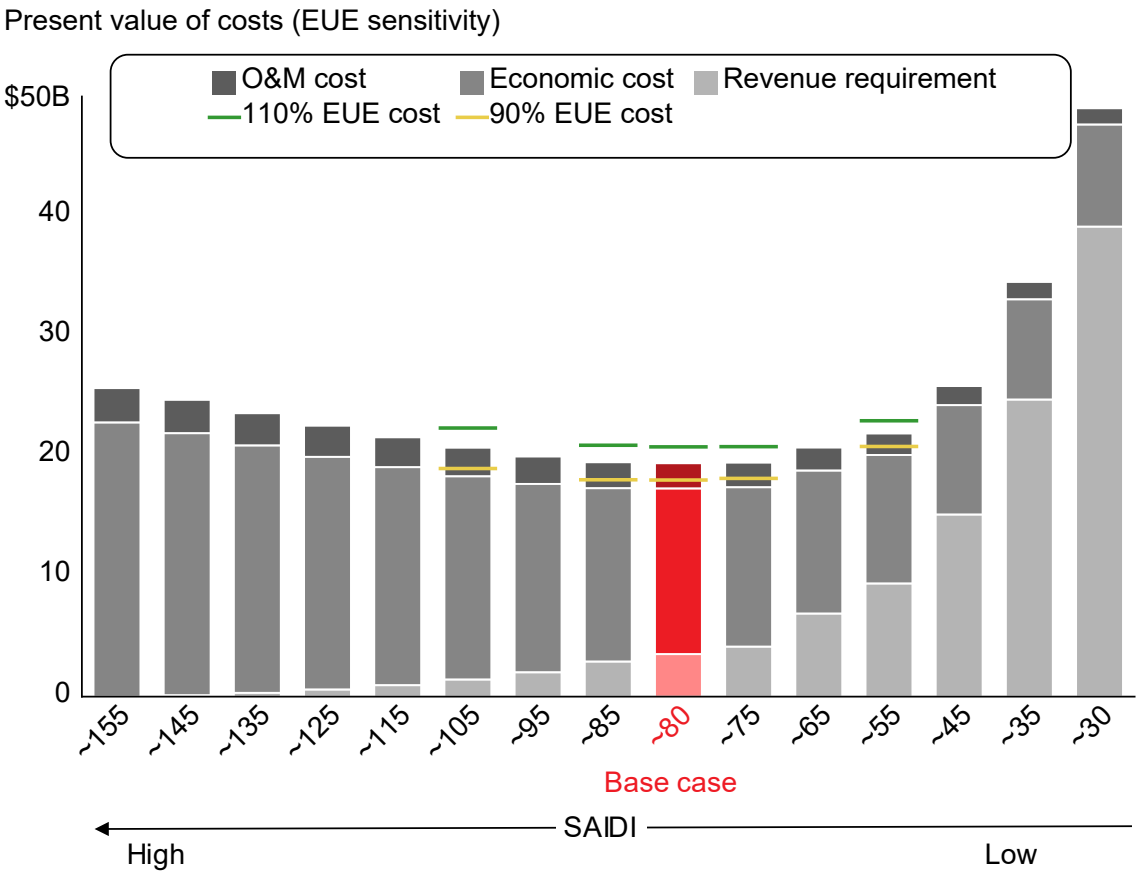


**Figure IV. 2. Internal EUE Estimate Sensitivity**

## Investment Cost

To capture potential deviations from current investment cost estimates, investment cost assumptions were flexed up and down 10% to determine the impact on capital revenue requirement and the optimal investment range. Flexing investment cost assumptions only affects the capital revenue requirement cost bar as economic cost and O&M are unaffected by investment cost. Figure IV. 3 shows the sensitivity calculations for the Base Case and four points about the Base Case. The Base Case remains in the optimal investment range under both 90% and 110% of default investment cost assumptions.

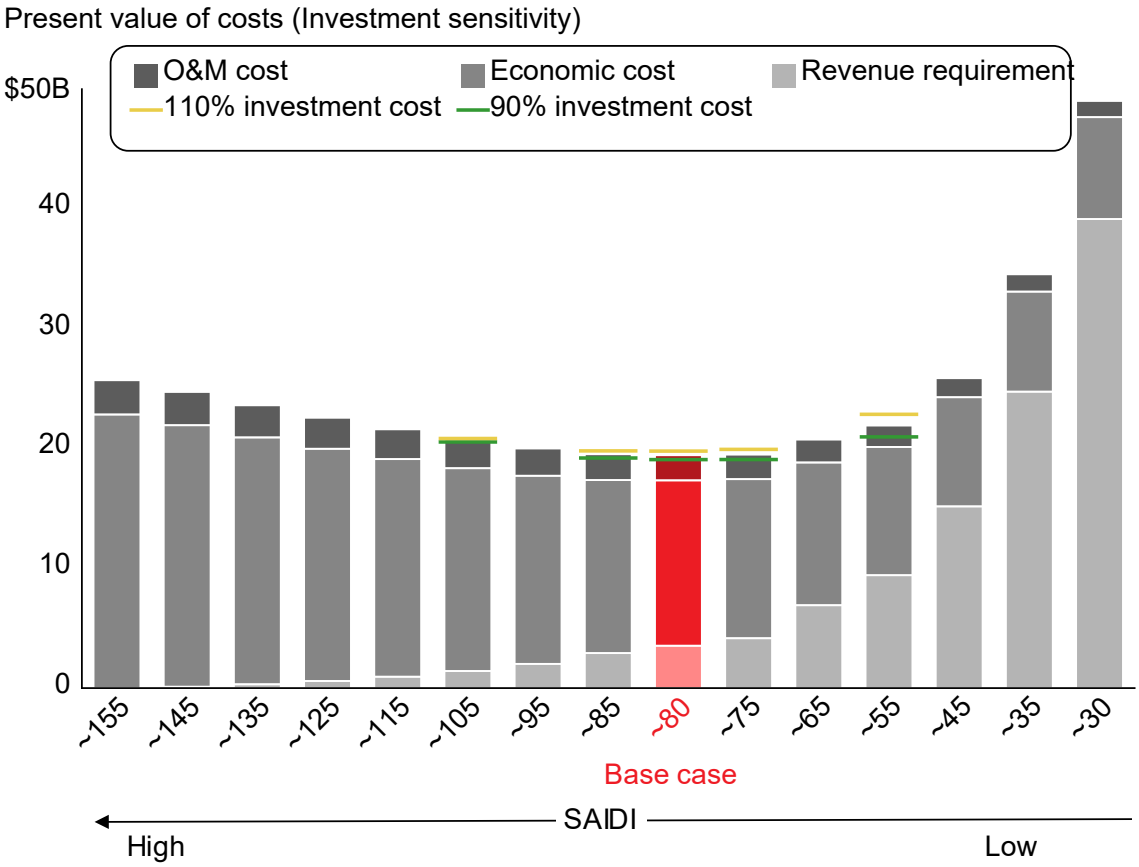


**Figure IV. 3. Investment Cost Sensitivity**

## Load Growth

As discussed in I.K, default assumptions, electricity demand per customer is projected to decline [redacted]% annually over the course of the investment period. To capture possible load growth changes, estimated load growth was flexed up and down by 1 percentage point to determine the impact on economic cost and the optimal investment range. Flexing load growth assumptions affects the economic cost bar by changing the volume of unused energy during loss of service. Capital revenue requirement and O&M are unaffected by flexing load growth assumptions. Figure IV. 4 shows the sensitivity calculations for the Base Case and four points about the Base Case.

The Base Case remains in the optimal investment range under both [redacted]% and [redacted]% load growth assumptions.

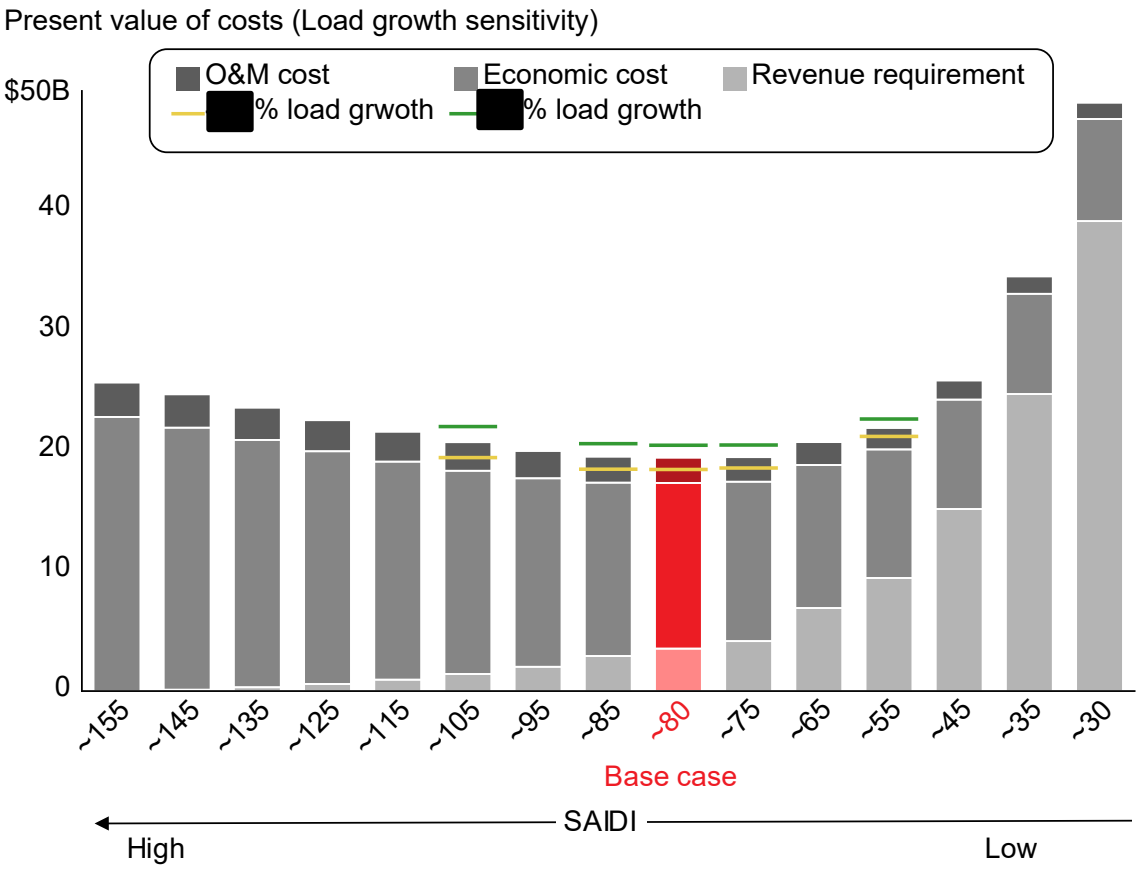


**Figure IV. 4. Load Growth Sensitivity**

## Benefit Length

As discussed in I.E, under default assumptions package investment benefit is expected to last until 2055, 25 years past the end of the investment period of 2023-2030. To capture variation in realized benefit length, estimated benefit length was flexed up and down by 10 years on a system level to determine the impact on economic cost and the optimal investment range. Flexing benefit length assumptions affects both the economic cost and O&M bars by extending the valuation horizon. Capital revenue requirement is unaffected by changes to the assumed benefit length. Figure IV. 5 shows the sensitivity calculations for the Base Case and four points about the Base Case.

Under a 15-year benefit assumption, the optimal point shifts to the ~85 SAIDI scenario and using the 35-year benefit assumption, the optimal point decreases to ~75 SAIDI. However, in both scenarios, the Base Case SAIDI remains in the optimal investment range.

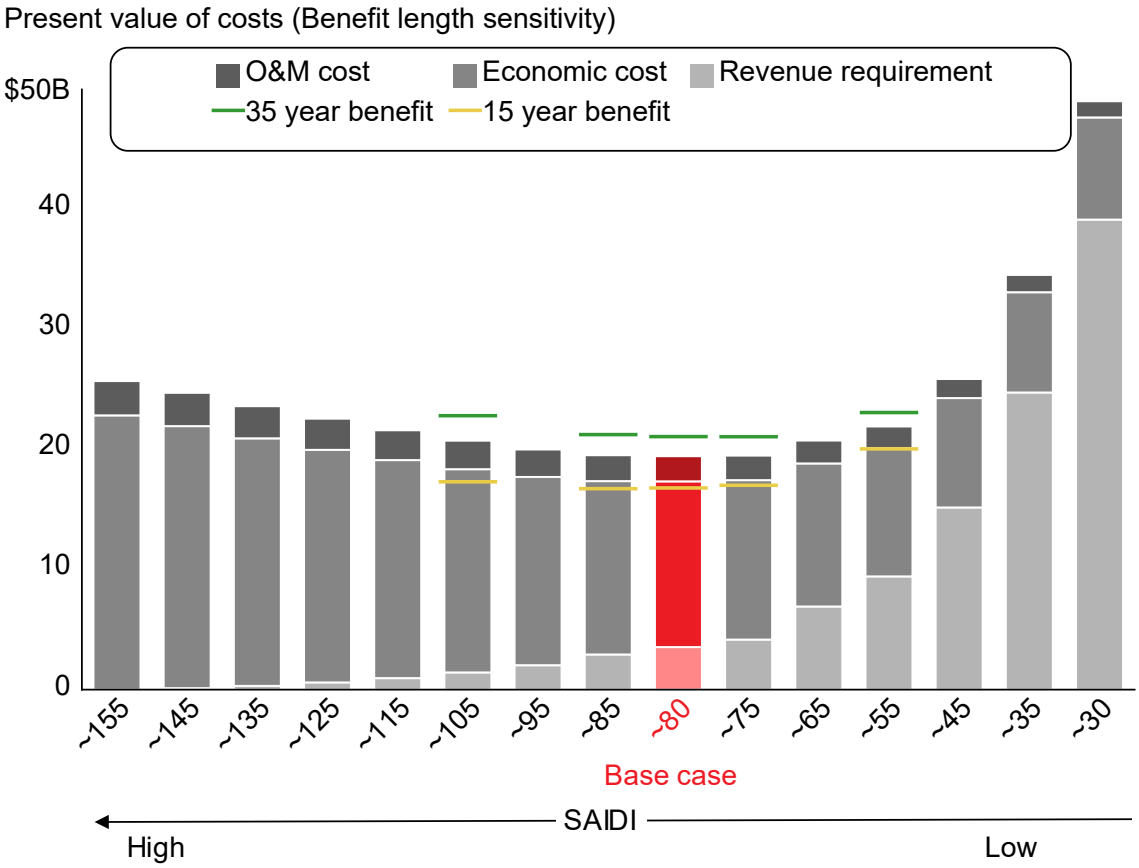


**Figure IV. 5. Benefit Length Sensitivity**

## Load Growth / Benefit Length Interaction

Load growth and benefit length are unique among the study's assumptions in that they interact with one another. High load growth can strain circuit infrastructure, decreasing the expected benefit length of circuit investment. Low load growth can increase benefit length by extending circuit infrastructure useful life. To capture this variation, two separate model variants were run: (1) [redacted]% load growth and 35 year benefit, and (2[redacted]% load growth and 15 year benefit. Both variants affect the economic cost and O&M bars, while capital revenue requirement remains unchanged. Figure IV. 6 shows the sensitivity calculations for the Base Case and four points about the Base Case. The Base Case remains in the optimal investment range under the [redacted]% load growth and 35-year benefit assumption. Under the 15-year benefit and [redacted]% load growth assumption, the optimal point shifts to the ~85 SAIDI scenario.

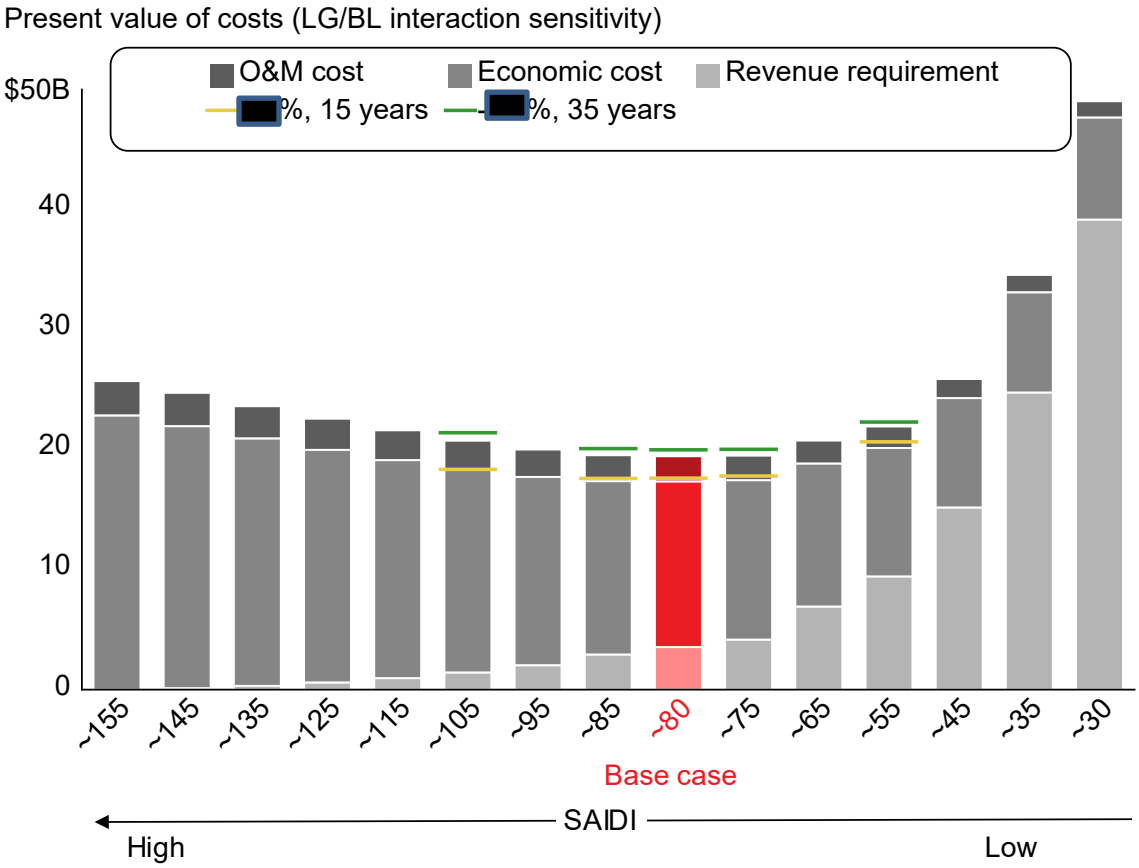


**Figure IV. 6. Load Growth / Benefit Length Interaction Sensitivity**

## Rate of Reliability Decline

As discussed in I.H, the roughly 1000 circuits identified as having systemic reliability issues are projected to continue to experience reliability decline at conservative annual SAIDI and SAIFI rates of ~4% and ~3%, respectively, for each year in the investment horizon or until invested in. Given that reliability can vary year-by-year due to factors such as weather patterns, traffic, and wildlife events, possible reliability decline differences were captured by varying SAIDI and SAIFI decline rates up or down by 2 percentage points. Figure IV. 7 shows the sensitivity calculations for the Base Case and four points about the Base case. The Base Case remains in the optimal investment range under both high-decline and low-decline assumptions.

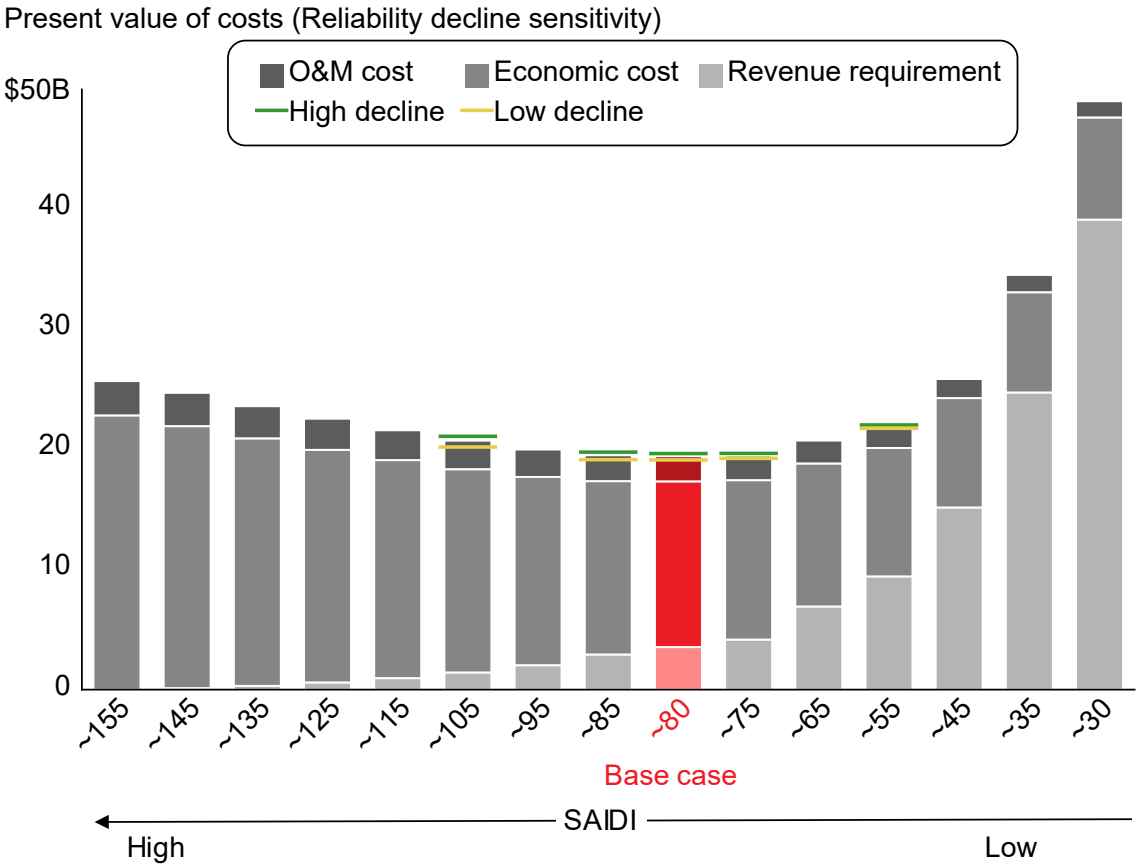


**Figure IV. 7. Reliability Decline Sensitivity**

## V. CONCLUSION

The 2022 Distribution Investment Study is aimed at determining the optimal investment range for GPC's proposed Distribution Investment Plan by comparing the costs and benefits across various investment scenarios. As shown in Figure III. 1 (reproduced below) investment scenarios targeting more circuits and better end-state reliability result in diminishing reliability improvements. As noted, this is because the "highest opportunity circuits" are the first to be invested in. The Base Case plan corresponds to the level of investment that includes the highest opportunity investments but excludes investments that produce diminishing returns.

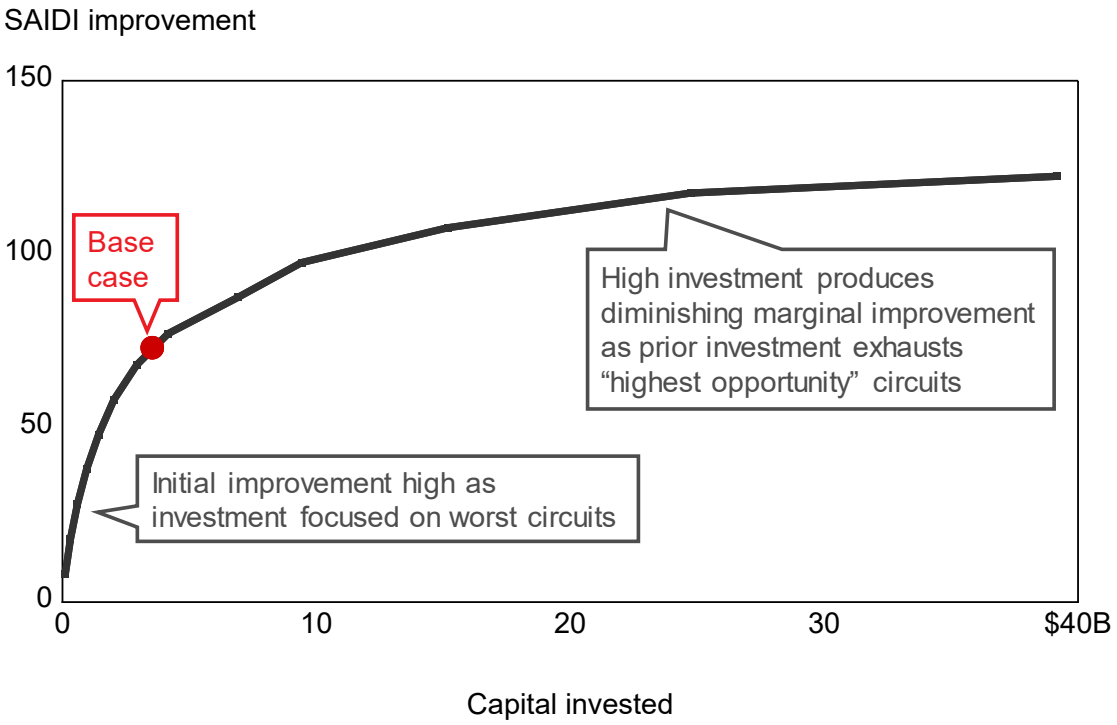


**Figure III. 1. Diminishing Reliability Improvement**

As discussed above in I.Q, the investment scenario that minimizes capital revenue requirements, economic costs, and O&M can be seen as optimal from the customer's perspective. This is because all of these costs are either directly or indirectly borne by customers. As shown in Figure III. 5 (reproduced below), of the 15 scenarios run, the Base Case scenario results in the minimum cost and should therefore be seen as the preferred option for customers.

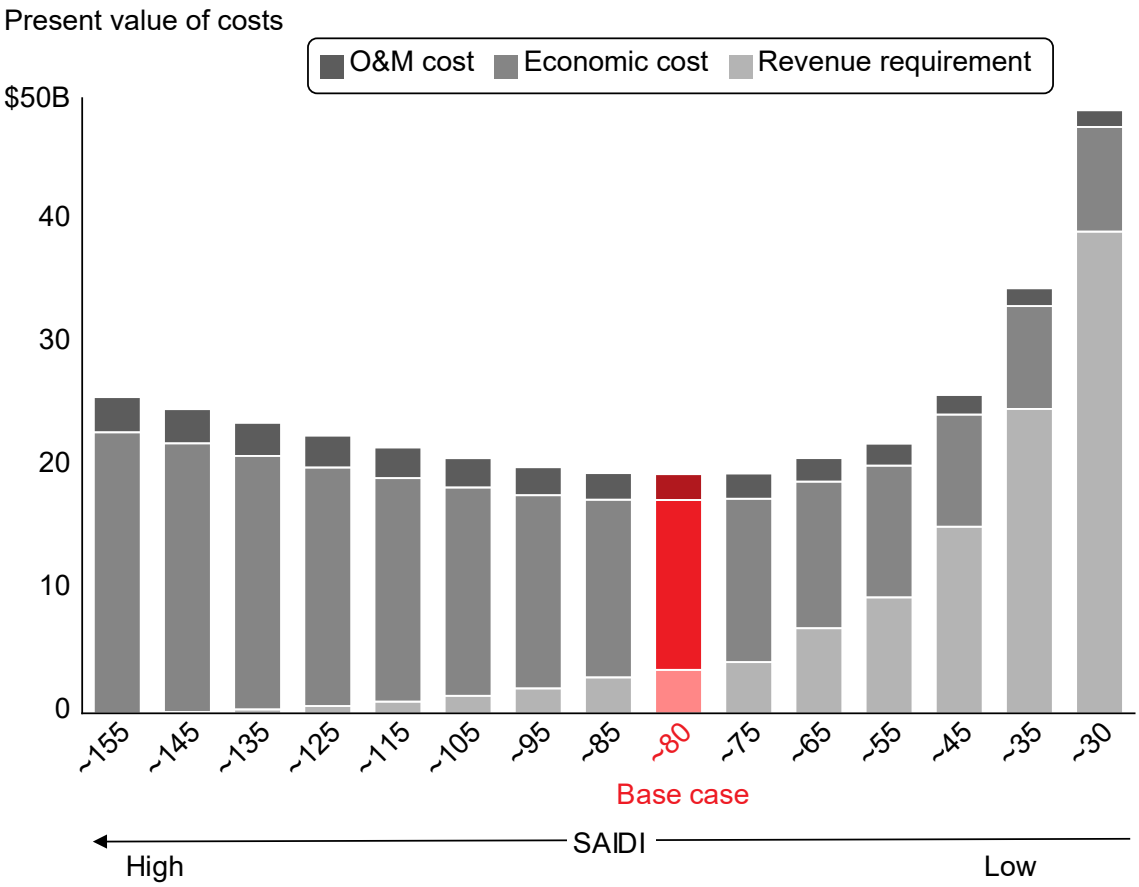


**Figure III. 5. Present Value of Total Cost**

Minimizing total customer cost is equivalent to maximizing the net present value of investment.

Figure III. 6, reproduced below, shows NPV of each scenario.

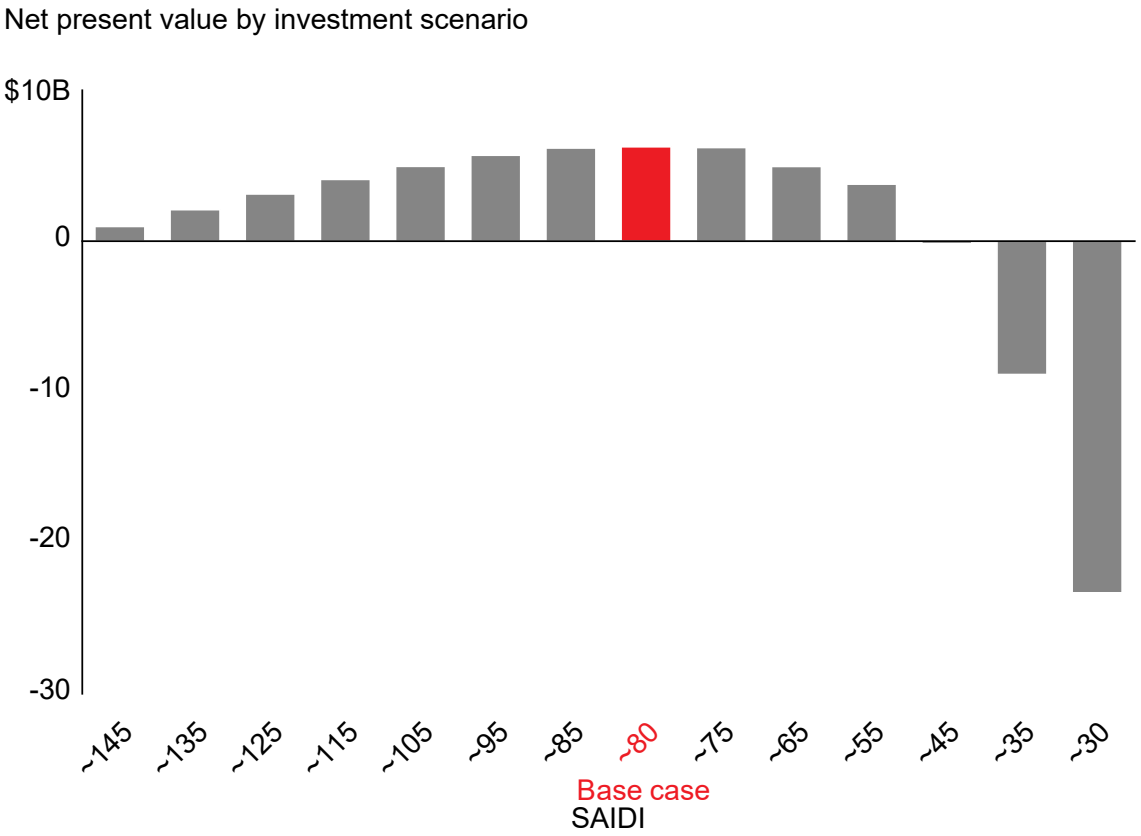


**Figure III. 6. Net Present Value**

Lastly, seven sensitivity analyses on key inputs to the Distribution Plan have been conducted. While these sensitivities result in increases or decreases to the overall cost bars, the Base Case investment plan remains in the *optimal range* of investment across all sensitivities. It is thus the conclusion of this report that the Base Case investment plan (the "Distribution Investment Plan") should be the preferred solution from the customer's perspective.

## Appendix B. Alternative Valuation of Service Reliability

The survey instruments included two additional questions related to the value of service reliability. These two questions were presented to respondents after all of the outage scenario questions were completed. The questions were worded as follows:

- Suppose your utility provided an option to experience half as many outages as you currently receive. If you were charged more for this option, what would be the highest acceptable rate increase?
- Suppose your utility provided an option to experience twice as many outages as you currently receive. If you received a discount for this option, what would be the lowest acceptable rate discount?

Both questions were designed to link the change in reliability to the customer's electricity bill. Although framing the questions in this manner may have made them more relevant to the respondent, these questions had many of the same drawbacks that the willingness-to-pay (WTP) questions did for residential. As explained in Section 4.1.1, some respondents are confused by WTP questions or end up answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their ability to pay, their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such redefining of the question is probably even more likely when the question involves the customer's electricity bill, as it does in these two additional questions.

Table B-1 provides the average response by customer class for the first question, which relates to the highest acceptable rate increase in exchange for experiencing half as many outages. Outliers were not dropped from this analysis because the responses were naturally constrained between 0% and 100%. The average response is similar for residential, commercial and industrial customers. If there was a rate option for which they would experience half as many outages, the average residential, commercial and industrial customer would be willing to pay up to around 1.7% more for electricity. Large business customers did not value the 50% reduction in outage frequency as highly. Large business customers were only willing to accept a 1.2% increase in electricity cost for this improvement in reliability. Among non-residential customers, this finding is consistent with the EUE cost estimates for which large business customers placed the lowest value on electricity on a per kWh basis.

**Table B-1:**
**Highest Acceptable Rate Increase**
**for Half as Many Outages – by Customer Class**

| Customer Class | N | Average Response | 95% Confidence Interval | |
|---|---|---|---|---|
| | | | Lower Bound | Upper Bound |
| Residential | 1,232 | 1.75% | 1.55% | 1.96% |
| Commercial | 1,348 | 1.68% | 1.41% | 1.95% |
| Industrial | 662 | 1.69% | 1.34% | 2.05% |
| Large Business | 92 | 1.21% | 0.54% | 1.88% |

Wired Group Estimate of GIP Revenue Requirements (in $000s) and Percentage Increases Over 2019 Baseline Revenue Requirements ("Rates")

| Invest | Revenue Requirements for Investment Year ___ Recovered in: | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
| 2020 | 20,401 | 19,817 | 19,233 | 18,649 | 18,065 | 17,482 | 16,898 | 16,314 | 15,730 | 15,146 | 14,562 | 13,978 |
| 2021 | | 56,973 | 55,342 | 53,711 | 52,081 | 50,450 | 48,820 | 47,189 | 45,559 | 43,928 | 42,298 | 40,667 |
| 2022 | | | 101,459 | 98,555 | 95,652 | 92,748 | 89,844 | 86,940 | 84,037 | 81,133 | 78,229 | 75,326 |
| 2023 | | | | 90,025 | 87,449 | 84,872 | 82,296 | 79,719 | 77,143 | 74,566 | 71,990 | 69,414 |
| 2024 | | | | | 88,355 | 85,826 | 83,297 | 80,769 | 78,240 | 75,711 | 73,183 | 70,654 |
| 2025 | | | | | | 93,713 | 91,031 | 88,349 | 85,667 | 82,985 | 80,303 | 77,621 |
| 2026 | | | | | | | 73,346 | 71,247 | 69,148 | 67,048 | 64,949 | 62,850 |
| 2027 | | | | | | | | 73,346 | 71,247 | 69,148 | 67,048 | 64,949 |
| 2028 | | | | | | | | | 73,346 | 71,247 | 69,148 | 67,048 |
| 2029 | | | | | | | | | | 73,346 | 71,247 | 69,148 |
| 2030 | | | | | | | | | | | 73,346 | 71,247 |
| 2031 | | | | | | | | | | | | 73,346 |
| GIP RR by Yr | 20 | 77 | 176 | 261 | 342 | 425 | 486 | 544 | 600 | 654 | 706 | 756 |
| 2019 RR (baseline RR) | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 | 7,577 |
| GIP RR Percent Increase | 0.27% | 1.01% | 2.32% | 3.44% | 4.51% | 5.61% | 6.41% | 7.18% | 7.92% | 8.63% | 9.32% | 9.98% |

| Georgia Transmission Equipment Analysis | Using TODB DATA from 2012 to 2021 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Georgia Equpment outage classification | Source # | Total number of Units/miles on the system | Failure unit count | Period of measure Years | Failure Rate/yr | Annual probability of Failure rate/unit | # of units or miles to Rpl to eliminate 1 failure | Cost to to eliminate 1 failure |
| *Source: TODB = Transmission Outage Data base* | | | *DR to Utility* | *ODB/utility* | *TODB* | *Calc* | *Calc* | *Calc* | *Calc* |
| Equipment | | | | | | | | | |
| Substation Transformers (TODB) | | 1 | 2,264 | 101 | 10 | 10 | 0.00446 | 224.16 | $1,120,792,079 |
| Circuit Breakers (TODB) | | 1 | 1,868 | 88 | 10 | 9 | 0.00471 | 212.27 | $161,964,091 |
| Low side Breakers | Low side Breakers | 1 | 1,705 | | | | | | |
| High side breakers | High side breakers | 1 | 163 | | | | | | |
| Load Tap Changers (TODB) | Voltage Regulation | 1 | 451 | 1 | 10 | 0.100 | 0.00022 | 4,510 | $9,922,000,000 |
| Outlined cells are those presented in Table 2. | | | | | | | | | |
| | Source # | | | | | | | | |
| Transmission outage Data base STF-WG-2-26-Attachment | | TODB | ("TODB" is an acronym for transmission outage database) | | | | | | |
| Equipment counts STF-WG-1-33 | | 1 | | | | | | | |
| Transmissin Equipment replacment cost cost STF-WG-1-34 TRADE SECR | | 2 | | | | | | | |

(TRADE SECRET Optimization Model Inputs, Circuit Hardening Package)

REDACTED

(TRADE SECRET) Optimization Model Inputs, Undergrounding Package)

REDACTED

(Staff e-mail to Company requesting an alternative Scenario to be run through the Optimization Model, October 5)

Cheryl,

In follow-up to the demonstration of the Optimization Model provided by the Company on October 3, Staff requests the Company run a scenario specified by Staff. In this scenario, Staff requests no changes be made to the model except for the thresholds for 3rd and 4th Quartile SAIDI and SAIFI the Company uses to qualify circuits to receive various Distribution Investment Plan packages in various timeframes. Staff specifies the following thresholds:

| | 3rd Quartile | 4th Quartile |
|---|---|---|
| SAIDI | 98.96 | 165.87 |
| SAIFI | 0.9332 | 1.4446 |

Staff requests all the same outputs from the Staff-specified scenario that the Company typically secures from the model, including components of the Company's Economic Benefits Analysis (Present value of revenue requirements, Costs to customers of remaining service interruptions, and O&M costs); resulting SAIDI; resulting SAIFI; and the Model's output list of circuits, the packages they would receive, and the timing of those upgrades (in a manner similar to that provided by the Company in response to STF-WG- 2-7 Attachment TS). Please also provide the capital cost detail by year which resulted in the present value of revenue requirements.

Thank you, and please reach out with questions.

Rob Trokey
Director, Electric Unit
Georgia Public Service Commission
Office: (404) 656-4549
Mobile: (404) 825-1284

(TRADE SECRET Georgia Power Summary of Optimization Model Results from the Staff Scenario)

REDACTED

(TRADE SECRET Summary of Optimization Model projections by year of Georgia Power's proposed "80 SAIDI" Scenario for the Distribution Investment Plan)

REDACTED

PotomacEdison
A FirstEnergy Company

10802 Bower Avenue
Williamsport, MD 21795

Jeffrey P. Trout

Telephone: 301.790.6116
Fax: 330.436.8124
jtrout2@firstenergycorp.com

March 24, 2021

**VIA E-FILE**

Andrew S. Johnston, Executive Secretary
Maryland Public Service Commission
6 St. Paul Street
Baltimore, MD
21202

**Re:** **Annual Reliability Report of The Potomac Edison Company**

Dear Secretary Johnston:

Pursuant to COMAR 20.50.12.11, enclosed please find the Annual Reliability Report prepared by The Potomac Edison Company ("Potomac Edison") pursuant to COMAR 20.50.12.11.

If you have any questions about this matter, please do not hesitate to contact me.

Very truly yours,

Jeffrey P. Trout
Senior Corporate Counsel

JP/dml

Enclosure

cc: Michael Dean, PSC Staff; Jacob Ouslander, OPC

**The annual performance report is submitted to the State of Maryland Public Service Commission on behalf of The Potomac Edison Company ("Potomac Edison" or the "Company"). Potomac Edison is a wholly owned subsidiary of FirstEnergy Corp. and a public utility in the state of Maryland. This annual performance report is filed pursuant to Code of the Maryland Regulations 20.50.12.11 for the calendar year 2020.**

***20.50.12.11(A)(1) The reliability index information and results required in this chapter, including a table showing the actual values of the reliability indices required in this chapter for each of the preceding 3 calendar years;***
***20.50.12.11(A)(2) Annual year-end and 3-year average performance results as required under Public Utilities Article, § 7-213(g)(2)(i) and (ii), Annotated Code of Maryland, including a table showing the actual values for each of the preceding 3 calendar years.***
***20.50.12.05 Additional Reliability Indices Reporting***
***A. CAIDI, SAIDI and SAIFI excluding major event days. A utility shall calculate and report the following information for its Maryland service territory:***

1. ***CAIDI, SAIDI and SAIFI excluding major event days;***
2. ***All IEEE major event days; and***
3. ***The reliability indices, including and excluding planned outages.***

The table below provides the required reliability index results for system average interruption frequency index ("SAIFI"), system average interruption duration index ("SAIDI") and customer average interruption duration index ("CAIDI") for the Potomac Edison ("PE") system. PE's annual SAIFI and SAIDI results were lower than the calendar year 2020 reliability standard identified in COMAR 20.50.12.02(D)(1)(d). Therefore, PE is not required to provide a corrective action plan as the standards were satisfied.

| | Outage | Index | 2018 | 2019 | 2020 | 3-Year Avg | 2020 COMAR |
|---|---|---|---|---|---|---|---|
| Including Planned Outages | All Interruption Data | SAIFI[1] | 1.12 | 1.42 | 0.95 | 1.16 | N/A |
| | | SAIDI[2] (Min) | 264.5 | 392.3 | 133.8 | 263.5 | N/A |
| | | CAIDI[3] (Min) | 236.9 | 276.6 | 140.7 | 218.1 | N/A |
| | All Interruption Data Minus Major Outage Event Interruption Data | SAIFI | 0.89 | 1.42 | 0.95 | 1.09 | N/A |
| | | SAIDI (Min) | 145.4 | 392.3 | 133.8 | 223.8 | N/A |
| | | CAIDI (Min) | 162.7 | 276.6 | 140.7 | 193.3 | N/A |
| | All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occuring on Another Utility's Electric System | SAIFI | N/A | N/A | N/A | N/A | N/A |
| | | SAIDI (Min) | N/A | N/A | N/A | N/A | N/A |
| | | CAIDI (Min) | N/A | N/A | N/A | N/A | N/A |
| | All Interruption Data Minus IEEE Major Event Day Interruption Data | SAIFI | 0.92 | 1.08 | 0.90 | 0.97 | 1.06 |
| | | SAIDI (Min) | 138.8 | 172.4 | 117.8 | 143.0 | 142.0 |
| | | CAIDI (Min) | 150.1 | 159.8 | 131.4 | 147.1 | N/A |
| Excluding Planned Outages | All Interruption Data | SAIFI | 1.07 | 1.36 | 0.92 | 1.12 | N/A |
| | | SAIDI (Min) | 259.9 | 385.4 | 129.3 | 258.2 | N/A |
| | | CAIDI (Min) | 242.8 | 282.9 | 140.5 | 222.1 | N/A |
| | All Interruption Data Minus Major Outage Event Interruption Data | SAIFI | 0.85 | 1.36 | 0.92 | 1.04 | N/A |
| | | SAIDI (Min) | 141.2 | 385.4 | 129.3 | 218.6 | N/A |
| | | CAIDI (Min) | 166.1 | 282.9 | 140.5 | 196.5 | N/A |
| | All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occuring on Another Utility's Electric System | SAIFI | N/A | N/A | N/A | N/A | N/A |
| | | SAIDI (Min) | N/A | N/A | N/A | N/A | N/A |
| | | CAIDI (Min) | N/A | N/A | N/A | N/A | N/A |
| | All Interruption Data Minus IEEE Major Event Day Interruption Data | SAIFI | 0.88 | 1.02 | 0.87 | 0.92 | N/A |
| | | SAIDI (Min) | 134.2 | 165.7 | 113.3 | 137.7 | N/A |
| | | CAIDI (Min) | 152.8 | 161.9 | 130.9 | 148.5 | N/A |

[1] SAIFI represents system average interruption frequency index, a reliability indicator to measure the average number of interruptions that a customer would experience. It is in units of interruptions.

[2] SAIDI represents system average interruption duration index, a reliability indicator which measures the average outage duration for each customer served in utility service territory and can be in hours or minutes. COMAR uses minutes for SAIDI. Each utility shall report SAIDI in minutes.

[3] CAIDI represents customer average interruption duration, a reliability indicator to measure average outage duration that any given customer would experience and is reported in minutes.

***20.50.12.11(B)(8) Any corrective action plans required under Public Utilities Article, §7-213(e)(1)(iii), Annotated Code of Maryland, or this chapter.***

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required. However, as reported in the 2019 Annual Reliability Report of the Potomac Edison Company, the annual SAIFI and SAIDI results were identified as being higher than the calendar year 2019 reliability standard identified in COMAR 20.50.12.02(D)(1)(d). Therefore, a Corrective Action Plan was implemented and beginning on January 1, 2021 PE transitioned its vegetation management trimming cycle from five years to four years.

***20.50.12.05(B) A utility shall report an annual $CEMI_n$ [1] for customers experiencing three or more ($CEMI_2$), five or more ($CEMI_4$), seven or more ($CEMI_6$) and nine or more ($CEMI_8$) sustained interruptions.***

| | $CEMI_2$ | $CEMI_4$ | $CEMI_6$ | $CEMI_8$ |
|---|---|---|---|---|
| All Interruption Data | 11.42% | 2.74% | 0.66% | 0.21% |
| All Interruption Data Minus Major Event Data | 11.42% | 2.74% | 0.66% | 0.21% |

***20.50.12.05(C). A utility shall calculate and report in its supplemental annual performance report an annual ($MAIFI_E$) for its Maryland service territory unless it does not have the means to make the calculation, in which case it shall provide an explanation of the reason, and an estimate of the cost to provide the information going forward.***

| | $MAIFI_E$[2] |
|---|---|
| All Interruption Data | 12.3 |
| All Interruption Data Minus Major Event Data | N/A[3] |

***20.50.12.11(A)(3) The time periods during which major outage event interruption data was excluded from CAIDI, SAIDI and SAIFI indices, including a brief description of the interruption causes during each time period.***

Potomac Edison did not experience any major outage events in 2020 but did experience two Major Event Days.

[1] CEMI is defined as customers experiencing multiple interruptions.
[2] Please note that PE is able to report MAIFI, but not $MAIFI_E$. PE does not have smart meters and must rely on gathering data by manually reading counters from line reclosers annually. Reclosers are set to reclose as many as three times before locking out on the fourth operation. Adjacent reclosers can operate in succession for the same fault. There can be as many as five counter readings for each fault on the overhead system.
[3] PE is unable to calculate MAIFI excluding major event data. The data is gathered by manually reading counters from line reclosers annually. Operations during major events cannot be differentiated. The ability to calculate this excluding major event data would require a multimillion-dollar investment in smart meters.

***20.50.12.11(A)(4) A description of the utility's reliability objectives, planned actions and projects, and programs for providing reliable electric service.***

***20.50.12.11(A)(5) An assessment of the results and effectiveness of the utility's reliability objectives, planned actions and projects, programs and load studies in achieving an acceptable reliability level.***

PE strives to provide safe, affordable and reliable electric service to its customers and, as such, supports several programs to maintain reliability of the system. The operation and maintenance ("O&M") programs impose schedules for regular inspection of distribution facilities, which in turn, reduces the potential of distribution line and equipment caused outages.

PE's O&M programs and practices balance cost and benefit while identifying and repairing unsafe conditions or areas that may adversely affect service reliability or system performance. Within these practices, schedules are established for regular inspection of distribution facilities. Specifically, PE conducts:

- A visual inspection of distribution circuits and equipment from the substation to the first protective device every two years, as well as a total circuit line and equipment inspection every six years;
- A visual inspection, and when necessary, a physical inspection of wood poles every ten years;
- A visual inspection of above-ground pad-mounted transformers and distribution underground equipment every five years;
- A visual inspection of distribution line capacitors annually; and
- A visual inspection of distribution substation equipment and a distribution substation safety and security inspection every two months.

These inspections provide an important basis for information in determining the need for, and prioritizing, the repair, improvement or replacement of PE's distribution facilities.

In addition to O&M, the Company utilizes other routine programs to ensure the reliability of its distribution system. First, the Company has maintained a 5-year cycle vegetation management program to support continued and safe operation of its distribution and subtransmission system. A more vigorous 4-year cycle program has been implemented beginning in 2021. Second, the Multiple Device Activation and CEMI programs both focus on clusters of devices and customers that experience frequent or repeated outages or other issues, such as momentary outages. These programs target enhanced system performance and establish a method to reduce the frequency of outages at the customer level. Third, PE continues to focus on remediation activities of the poorest performing feeders ("PPFs"), in efforts to improve reliability. Fourth, the Company engages in a reactive program for underground cable and targets those cables that have exhibited a history of failures. Within this program, projects are identified and ranked based on the number of customers affected, the number of failures and the impact on customer satisfaction. The program identifies underground cable in need of replacement and improves reliability and customer satisfaction. This program was increased significantly in 2020 as part of the Company's Electric Distribution Infrastructure Surcharge ("EDIS") program.

In addition to PE's 2021 projects related to its PPFs,[4] the Company also has several planned reliability projects to be implemented across its service territory. These include:

- Install a 230-34.5 kV substation and associated equipment west of Jefferson, MD. Since 2012, Potomac Edison has experienced nineteen source outages to Brunswick and Jefferson substations totaling 29.6 minutes of SAIDI. This averages 3.3 minutes per year. Adding the West Jefferson substation will help strengthen the subtransmission line feeding these substations. This will allow automatic restoration to each substation during all times of the year. This project will improve service to approximately 5,500 customers.

- Install two distribution automation (DA) schemes. A five-recloser DA scheme will tie together the Carroll – CW12 and Unionville – Route 31 circuits. This project is expected to save 276 customer interruptions and 30,647 customer minutes interrupted each year. Also, a five-recloser scheme will be installed that will tie together the Garrett – Hoyes Run Road and Thayerville – Mayhew Inn Road circuits. This project is expected to save 2,242 customer interruptions and 575,000 customer minutes interrupted each year. Additional details of these projects are provided in the company's 2020 Annual EDIS report.[5]

- Replace thirteen substation reclosers with single-pole tripping devices. The new reclosers are designed to only interrupt the faulted circuit phase(s) in the event of a fault that does not impact all three circuit phases. Existing substation circuit reclosers are usually three-phase devices that operate all three phases even when a fault occurs only on a single circuit phase. During momentary faults, the new reclosers analyze real-time data in order to minimize the number of customers interrupted. They also have remote-operation capabilities that allow system operators in the Distribution Control Center to operate the reclosers remotely and assist line workers in the field during restoration activities. Additional details and reliability savings of each installation are provided in the company's 2020 Annual EDIS report.[6]

***20.50.12.11(A)(6) Current year expenditures, an estimate or budget amount for the following 2 calendar years, if available, current year labor resources hours, and progress measures for each capital and maintenance program designed to support the maintenance of reliable electric service.***

***20.50.12.11(B)(1) The actual operation and maintenance and capital expenditures for the past 3 calendar years for each utility's reliability programs, including, but not limited to underground and overhead distribution plant inspection, maintenance and replacement programs, vegetation management, subtransmission inspection and maintenance programs, and distribution substation plant inspection and maintenance programs.***

[4] See section 20.50.12.03(C) of this report for PE's PFF remedial actions.
[5] Reference Maillog #232729 dated November 25, 2020
[6] Ibid

The tables below provide the 2020, 2021 and 2022 forecasted capital budgets, the 2018, 2019 and 2020 actual capital expenditures, plus operation and maintenance reliability- specific expenditures for the same periods, broken down by investment reason.

Note that the hours worked in 2019 and 2020 do not include contractor hours.

## Capital Expenditures[7]
## (Designed to Support Maintenance of Reliable Electric Service)

| Program | Actual ($) | | Budget ($) | Actual ($) | Labor Hours | | Forecasted Budget ($) | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2020 | 2019 | 2020 | 2021 | 2022 |
| **Distribution** | | | | | | | | |
| Condition | 9,763,816 | 5,138,888 | 7,385,211 | 6,369,100 | 17,363 | 24,288 | 7,228,546 | 17,558,112 |
| Forced | 25,860,387 | 48,843,028 | 44,644,753 | 42,220,281 | 166,664 | 130,325 | 39,881,167 | 38,079,236 |
| Miscellaneous | 3,093,446 | 3,658,335 | 2,895,986 | 4,175,304 | 21,078 | 22,240 | 3,015,147 | 2,980,930 |
| System Reinforcement | 972,205 | 651,278 | 2,143,865 | 3,669,795 | 2,070 | 10,910 | 4,018,861 | 1,139,752 |
| Vegetation Management | 3,241,788 | 4,308,956 | 4,809,080 | 3,719,946 | 4,172 | 3,425 | 5,771,469 | 5,934,634 |
| **Sub-Total** | 42,931,643 | 62,600,484 | 61,878,894 | 60,154,426 | 211,348 | 191,188 | 59,915,190 | 65,692,663 |
| **Transmission** | | | | | | | | |
| Condition | 6,962,106 | 12,383,915 | 9,348,624 | 3,594,833 | 13,995 | 4,351 | 7,870,302 | 9,977,912 |
| Forced | 3,318,813 | 980,244 | 251,730 | 461,090 | - | 184 | 2,498,823 | 109,603 |
| Miscellaneous | 113,750 | 619,824 | 272,568 | 99,571 | 10,882 | 11,566 | 0 | - |
| System Reinforcement | 2,127,679 | 1,827,273 | 9,875,799 | 4,631,571 | 12,476 | 4,883 | 10,368,063 | 65,437,601 |
| Vegetation Management | 465,925 | 593,481 | 1,558,209 | 973,743 | 1,790 | 1,837 | 1,369,353 | 1,097,316 |
| **Sub-Total** | 12,988,274 | 16,404,737 | 21,306,930 | 9,760,808 | 39,143 | 22,821 | 22,106,542 | 76,622,433 |
| **TOTAL** | 55,919,917 | 79,005,221 | 83,185,824 | 69,915,234 | 250,491 | 214,008 | 82,021,732 | 142,315,097 |

| **Distribution Variances** | |
|---|---|
| **2020 Budget vs. Actual** | |
| Condition | Under budget due to internal labor, contractor, material, and overhead costs being lower than planned. |
| Forced | Not applicable |
| Miscellaneous | Over budget due to internal labor, contractor, material, and overhead costs being greater than planned. |
| System Reinforcement | Over budget due to internal labor, contractor, material, and overhead costs being greater than planned. |
| Vegetation Management | Under budget due to the second cycle trim work required to achieve specification was slightly less than anticipated and the quantity of off corridor removals (capital) were not as high as projected. |

| **Transmission Variances** | |
|---|---|
| **2020 Budget vs. Actual** | |
| Condition | Under budget due to contractor, labor, material costs and related overheads being lower than planned. |
| Forced | Over budget due to contractor costs and related overheads being higher than planned. |
| Miscellaneous | Under budget due to contractor costs and related overheads being lower than planned. |
| System Reinforcement | Under budget due to labor, material costs and related overheads being lower than planned. |
| Vegetation Management | Under budget due to related overheads being lower than planned. |

**Definitions:**
Condition – costs associated with replacement of outdated and/or poor performing equipment and reliability related costs Forced – costs associated with storm outage restoration, failed substation or line equipment and devices, regulatory required and relocations of facilities associated with roadways and bridge projects.
Miscellaneous – costs associated with corrective maintenance, operations, lighting and meter System
Reinforcement – costs associated with system reinforcement
Vegetation Management – costs associated with planned and unplanned tree trimming and vegetation management programs.

[7] Transmission expenditures have been updated from the 2019 Annual Reliability Report to include costs inadvertently excluded.

## Operating & Maintenance Expenditures[8]
## (Designed to Support Maintenance of Reliable Electric Service)

| Program | Actual ($) | | Budget ($) | Actual ($) | Labor Hours | | Forecasted Budget ($) | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2020 | 2019 | 2020 | 2021 | 2022 |
| **Distribution** | | | | | | | | |
| Scheduled Maintenance | 20,948 | 22,208 | 43,664 | 26,346 | 0 | 0 | 47,524 | 41,992 |
| Corrective Maintenance | 2,565,181 | 2,539,074 | 2,291,271 | 3,045,615 | 17,615 | 20,521 | 743,219 | 674,150 |
| Vegetation Management | 4,633,262 | 5,770,597 | 5,041,890 | 6,336,762 | 4,412 | 3,942 | 7,735,589 | 7,821,116 |
| Other: Condition | 1,952,741 | 2,033,169 | 2,605,333 | 2,380,514 | 23,114 | 23,985 | 1,775,463 | 3,933,081 |
| Other: Forced | 3,659,535 | 7,244,516 | 6,122,289 | 3,772,959 | 45,474 | 23,781 | 13,365,414 | 10,121,093 |
| Other: Miscellaneous | 1,461,945 | 1,536,546 | 1,146,833 | 1,653,155 | 17,004 | 18,213 | 957,884 | 1,024,281 |
| **Sub-Total** | 14,293,612 | 19,146,111 | 17,251,280 | 17,215,351 | 107,619 | 90,442 | 24,625,094 | 23,615,712 |
| **Transmission** | | | | | | | | |
| Scheduled Maintenance | 113,707 | 124,877 | 881,265 | 284,367 | 12,405 | 1,931 | 1,448,596 | 1,457,785 |
| Corrective Maintenance | 1,285,183 | 1,531,100 | 868,322 | 1,335,436 | 14,331 | 13,596 | 952,720 | 976,921 |
| Vegetation Management | 919,070 | 729,537 | 1,298,232 | 1,139,129 | 3,182 | 2,075 | 2,278,873 | 2,154,655 |
| Other: Condition | 146,131 | 504,530 | 410,455 | 397,317 | 220 | 1,576 | 1,365,106 | 1,396,999 |
| Other: Forced | 543,776 | 546,873 | - | 157,798 | - | 1,050 | 13,340 | 13,323 |
| Other: Miscellaneous | 428,072 | 413,862 | 799,972 | 632,702 | 1,971 | 1,903 | 603,516 | 693,451 |
| **Sub-Total** | 3,435,939 | 3,850,779 | 4,258,246 | 3,946,749 | 32,109 | 22,130 | 6,662,151 | 6,693,135 |
| Total | 17,729,550 | 22,996,890 | 21,509,526 | 21,162,101 | 139,728 | 112,572 | 31,287,245 | 30,308,847 |

| **Distribution Variances** | |
|---|---|
| **2020 Budget vs. Actual** | |
| Scheduled Maintenance | Under budget due to internal labor, contractor, material, and overhead costs being lower than planned. |
| Corrective Maintenance | Over budget due to internal labor, contractor, material, and overhead costs being greater than planned. |
| Vegetation Management | Over budget due to internal labor, contractor, material, and overhead costs being greater than planned. |
| Other: Condition | Not applicable |
| Other: Forced | Under budget due to internal labor, contractor, material, and overhead costs being lower than planned. |
| Other: Miscellaneous | Over budget due to internal labor, contractor, material, and overhead costs being greater than planned. |

| **Transmission Variances** | |
|---|---|
| **2020 Budget vs. Actual** | |
| Scheduled Maintenance | Under budget due to labor costs being lower than planned. |
| Corrective Maintenance | Over budget due to labor and transportation costs being higher than planned. |
| Vegetation Management | Under budget due to labor and Vegetation Management contractor costs being lower than planned. |
| Other: Condition | Not applicable |
| Other: Forced | Over budget due to labor and contractor costs being higher than planned. |
| Other: Miscellaneous | Under budget due to labor costs being lower than planned. |

**Definitions:**
Condition – costs associated with obsolete equipment, fix-it-now, and reliability
Corrective Maintenance – costs associated with corrective maintenance, operations and preventative maintenance Forced – costs associated with failures, IPP/Municipal connect, relocations, storms and substation failures Miscellaneous – costs associated with system reinforcement, lighting and meter
Scheduled Maintenance – costs associated with scheduled maintenance
Vegetation Management – costs associated with planned and unplanned vegetation management activities

[8] Transmission expenditures have been updated from the 2019 Annual Reliability Report to include costs inadvertently excluded.

***20.50.12.11(A)(8) The number of outages by outage type including planned outage, non- planned outage minus major outage event, and major outage event.***

***20.50.12.11(A)(9) The number of outages by outage cause including, but not limited to, animals, overhead equipment failure and underground equipment failure.***

***20.50.12.11(A)(10)(11) The total number of customers that experienced an outage and the total number of customer minutes of outage time***

| Outage Category | Number of Outages | Customers Affected | Customer Outage Minutes |
|---|---|---|---|
| Planned | 786 | 8,334 | 1,221,016 |
| Non-Planned Minus Major Outage Events | 4,705 | 251,687 | 35,371,777 |
| Major Outage Events | 0 | 0 | 0 |
| Total | 5,491 | 260,021 | 36,592,793 |

The table below represents a breakdown of the above table into specific outage causes, excluding the major outage events.

| Outage Cause | Number of Outages | Customers Affected | Customer Outage Minutes |
|---|---|---|---|
| Vegetation | 1,222 | 88,398 | 16,957,628 |
| Overhead ("OH") Equipment Failure | 686 | 54,327 | 6,101,452 |
| Underground ("UG") Equipment Failure | 715 | 19,135 | 3,078,855 |
| Weather (not lightning) | 55 | 12,251 | 2,142,366 |
| Lightning Strike | 53 | 2,982 | 350,674 |
| Equipment Hit | 94 | 9,609 | 1,210,378 |
| Animals | 966 | 20,987 | 2,038,586 |
| Overload | 5 | 572 | 49,641 |
| Other[9] | 384 | 22,202 | 1,529,192 |
| Planned Outages | 786 | 8,334 | 1,221,016 |
| Unplanned Planned Outages[10] | 0 | 0 | 0 |
| Unknown | 525 | 21,224 | 1,913,005 |
| Total | 5,491 | 260,021 | 36,592,793 |

[9] Other: Human Error Company, Forced Outage, UG Dig-up, Fire, Object Contact with Line, Customer Equipment, Vandalism, Human Error Non-Company, Other Utility-Non Electric

[10] PE does not record unplanned planned outages in the manner defined by Maryland PSC Staff and is, therefore, reporting zero in this category.

***20.50.12.11(A)(12) To the extent practicable, a breakdown, by the number of days each customer was without electric service, of the number of customers that experienced an outage.***

The following chart provides a breakdown of the number of customers that were associated with outages lasting less than one day, between one day and two days, and so on. The sum of these values is equal to the total number of customers interrupted by a sustained outage during reporting year 2020 (i.e. 642 customers were impacted by an outage event lasting longer than one day but less than two days).

| | ≤1 day | >1 & ≤2 Days | >2 & ≤3 days | >3 & ≤4 days | >4 & ≤ 5 days | >5 & ≤6 days | >6 & ≤7 days | >7 & ≤8 days | >8 days |
|---|---|---|---|---|---|---|---|---|---|
| All Interruptions | 259,379 | 642 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| All Interruptions Minus Major Outages | 259,379 | 642 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

***20.50.12.11(A)(13) Poorest performing feeder information and results.***

***20.50.12.03(A)(1) A utility shall report CAIDI, SAIDI and SAIFI indices of all feeders assigned to Maryland that are identified by the utility as having the poorest feeder reliability.***

***20.50.12.03(A)(2) Each index shall be calculated and reported in the annual performance report using all interruption data minus the following exclusions:***

***(a) Source loss, including any outage that occurs on the feeder by an event occurring external to the feeder;***
***(b) Major outage events; and***
***(c) Planned outages.***

***20.50.12.03(D)(2)(a) The feeders used in determining the utility's system-wide SAIDI and SAIFI performance results as reported to the Commission by the utility's 2010 annual reliability report shall be assigned to Maryland unless otherwise directed by the Commission.***

***20.50.12.03(A)(3) For each utility, the feeders with poorest reliability shall be all feeders having circuit reliability performance 250 percent or more above the utility's System-Wide SAIFI and SAIDI, which shall be calculated in accordance with the exclusions identified in §A(2) of this regulation.***

PE has 353[11] distribution circuits serving at least one customer in the state of Maryland. Of these 353 circuits, PE submits five distribution circuits that have the poorest reliability based on the ranking method described in COMAR 20.50.12.03.

[11] PE notes that the 353-circuit count includes 339 circuits which are assigned to Maryland and are used to calculate PE's reliability statistics. The 353-circuit count also includes 14 circuits which are not assigned to Maryland and are therefore not used to calculate PE's reliability statistics, but which serve at least one Maryland customer, and are therefore included in order to evaluate PE's PPFs.

| Feeder Name | Substation | No. of Customers on Feeder | All Interruptions | | | All Interruptions Minus Major Outage Events | | | Special Medical Needs Facilites Served | Repeat PPF from 2019? (Y/N) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | SAIFI | SAIDI (Min) | CAIDI (Min) | SAIFI | SAIDI (Min) | CAIDI (Min) | | |
| Little Orleans | Great Cacapon | 335 | 4.50 | 3,300.19 | 734.1 | 4.50 | 3,300.19 | 734.1 | 0 | Y |
| Mayhew Inn Road | Thayerville | 1,497 | 4.33 | 1,574.95 | 364.1 | 4.33 | 1,574.95 | 364.1 | 0 | N |
| Bartholows | Mt. Airy | 455 | 3.70 | 813.14 | 219.8 | 3.70 | 813.14 | 219.8 | 0 | N |
| Lynn Burke | New Market | 951 | 3.42 | 1,401.01 | 410.1 | 3.42 | 1,401.01 | 410.1 | 0 | N |
| Pysell Crosscut | Oakpark | 1,735 | 3.40 | 2,240.42 | 659.3 | 3.40 | 2,240.42 | 659.3 | 0 | N |

***20.50.12.03(A)(4) No feeder shall appear in a utility's list of poorest performing feeders during three consecutive 12-month reporting periods, unless the utility has undertaken reasonable remediation measures to improve the performance of the feeder.***

Poorest Performing Feeders 2018

| Feeder Name | Substation | Rank History | | |
|---|---|---|---|---|
| | | 2018 | 2019 | 2020 |
| Little Orleans | Great Cacapon | 1 | 1 | 1 |
| Catoctin Furnace | Catoctin | 2 | N/A | N/A |
| Williams Road | Messick Road | 3 | N/A | N/A |
| South | Lonaconing | 4 | N/A | N/A |
| Hampshire Mine | Mt. Zion | 5 | N/A | N/A |

Poorest Performing Feeders 2019

| Feeder Name | Substation | Rank History | |
|---|---|---|---|
| | | 2019 | 2020 |
| Little Orleans | Great Cacapon | 1 | 1 |
| Green Ridge | Flintstone | 2 | N/A |
| Bittinger | Jennings | 3 | N/A |
| Route 144 | Ridgeville | 4 | N/A |
| Town Hill | Hancock | 5 | N/A |

Poorest Performing Feeders 2020

| Feeder Name | Substation | Rank History |
|---|---|---|
| | | 2020 |
| Little Orleans | Great Cacapon | 1 |
| Pysell Crosscut | Oakpark | 2 |
| Mayhew Inn Road | Thayerville | 3 |
| Lynn Burke | New Market | 4 |
| Bartholows | Mt. Airy | 5 |

Despite remediation work that was completed on the Little Orleans circuit in years 2019 and 2020, its performance ranked it as a repeating Poorest Performing Feeder (PPF) in the 2020 reporting period. An overview of the circuit and its historical performance is provided in the tables below.

| Little Orleans Circuit Description | | |
|---|---|---|
| Length (miles) | Cust. Served | Description |
| 23.7 | 335 | Rural, heavily treed circuit area which serves load primarily in the Hancock and Little Orleans, Maryland areas |

| Little Orleans Reliability Performance | | | | | |
|---|---|---|---|---|---|
| Period | Incidents | CMI | SAIDI | SAIFI | CAIDI |
| 2018 | 21 | 1,038,270 | 3,099 | 6.62 | 468 |
| 2019 | 18 | 1,248,007 | 3,725 | 7.32 | 509 |
| 2020 | 8 | 1,105,562 | 3,300 | 4.50 | 734 |

| Little Orleans Top Outage Causes | |
|---|---|
| Period | Description |
| 2018 | Trees |
| 2019 | Trees |
| 2020 | Trees, Vehicle/Helicopter |

Little Orleans circuit was originally ranked as a PPF in the 2018 reporting period with twenty-one outage incidents and a total of 1,038,270 customer minutes interrupted (CMI). Little Orleans appeared as a 2018 PPF primarily due to four large incidents that accounted for 811,567 or 78% of the total CMI. These four incidents were caused by off ROW trees involving more than 300 customers and more than 130,000 CMI each. Of the twenty-one incidents, seventeen were caused by trees which accounted for more than 99% of the total CMI on the circuit.

During 2019, Potomac Edison completed a scheduled full circuit tree trim, which included the removal of danger trees, and completed the scheduled overhead circuit inspection. The Company also completed follow-up construction for issues identified during the inspection as needing repaired or replaced.

Despite the remediation work that was completed on the Little Orleans circuit during 2019, its performance resulted in a PPF ranking again in the 2019 reporting period with eighteen outage incidents and a total of 1,248,007 CMI. Little Orleans appeared as a 2019 PPF primarily due to seven large incidents caused by off-ROW trees involving more than 300 customers and more than 65,000 CMI each. Those seven incidents totaled 1,018,401 CMI for 82.6% of the total. Four of the seven incidents occurred during storms with the largest occurring on February 25, 2019 with 474,118 CMI.

In 2020, a danger tree patrol was completed, and identified trees were removed from a 4,500 foot section of the circuit that has been susceptible to incidents caused by off- ROW trees.

Potomac Edison also attempted to install SCADA-controlled reclosers at strategic locations along the circuit to more efficiently route the line crews to the problem area. However, due to poor signal strength throughout the rural area of this circuit, communications (microwave and cellular) needed for SCADA indication and control were not able to be established and the project was discontinued.

A Distribution Automation scheme was also considered as a solution to the Little Orleans reliability issue. However, due to its rural location with no adjacent circuit ties, extensive construction work would be required to implement this solution. The Little Orleans circuit was then proposed as an Energy Storage Device candidate under the MD Energy Storage Pilot Program for completion in 2022. A battery-storage system would have provided the second source to Little Orleans during outages by strategically placing it on the circuit away from the areas where most of the off-ROW tree incidents occurred. This would have allowed an automation scheme to be established to automatically isolate the faulted section of the circuit and automatically restore power to the remaining portion of the circuit serving the most customers. The battery system would have been sized to provide ride-through for the typical outage durations until repairs could be made and the normal source re-established to serve the load. This project was outsourced to a consultant for engineering and design where it ultimately was discovered that the battery-storage system could not properly be applied to the Little Orleans circuit since it is a single-phase circuit for most of its length. The Energy Storage project for Little Orleans circuit was abandoned due to this finding.

Despite the remediation work that was completed on the Little Orleans circuit in years 2019 and 2020, its performance ranked it as a repeating PPF in the 2020 reporting period with eight outage incidents and a total of 1,105,562 CMI. Little Orleans appeared on the PPF list in the 2020 reporting period primarily due to one very large incident, caused by an off-ROW tree, which occurred during a storm on November 2, 2019 and accounted for 64% of the total CMI of 708,794. A second large incident caused by an off-ROW tree resulted in 140,140 CMI and a third large incident caused by a helicopter clipping the conductors on a 1,300-foot span across the Potomac River resulted in 158,543 CMI.

A full overhead circuit inspection was completed on the Little Orleans circuit on May 11, 2020 from which repair work has been identified and scheduled for construction in 2021.

Despite implementing all traditional remediation measures, Little Orleans continues to experience incidents caused by off-ROW trees placing it on the PPF list. Potomac Edison has therefore focused on a more robust solution to this reliability issue. Several overhead sections of the Little Orleans circuit most prone to off-ROW tree outages have been evaluated and two portions have been identified to be relocated and placed underground. Potomac Edison does not normally propose placing existing overhead facilities to underground for reliability improvement, but in this case, it appears to be a viable option. To immediately address the Little Orleans repeater PPF in 2021, Potomac Edison designed the following two projects to place existing overhead facilities underground:

1. Approximately 3,000 feet of an existing overhead portion of circuit in Washington County, Maryland

2. Approximately 2,000 feet of an existing overhead portion of circuit in Allegany County, Maryland.

Potomac Edison is planning to complete these two projects by December 31, 2021.

***20.50.12.03(C) Evaluation of Remedial Actions. For the feeders identified as having the poorest performing performance, the utility shall provide the following information:***
***(1) In the annual performance report in which the feeders are identified as requiring reasonable remediation measures, a brief description of the actions taken or proposed, if any, to improve reliability and the actual or expected completion date of the action***

Below are PE's remedial actions to the performance based poorest performing feeders, including a brief description of any actions taken or proposed, to improve reliability and expected completion date.

| Feeder Name | Substation | Remedial Action Description | Actual/Expected Completion Date |
|---|---|---|---|
| Little Orleans | Great Cacapon | 1) Convert an overhead portion of circuit to underground in Washington County, Maryland | 12/31/2021 |
| | | 2) Convert an overhead portion of circuit to underground in Allegheny County, Maryland | 12/31/2021 |
| Pysell Crosscut | Oakpark | 1) Complete fuse coordination on portion of circuit | 9/30/2021 |
| Mayhew Inn Road | Thayerville | 1) Complete EDIS Distributon Automation (DA) Scheme with Hoyes Run Road circuit | 12/31/2021 |
| Lynn Burke | New Market | 1) Completed 11/18/2020: Installed electronic line recloser for additional sectionalizing. | 11/18/2020 |
| | | 2) Install additional sectionalizing devices, install fault indicators, externally fuse and animal guard | 9/30/2021 |
| Bartholows | Mt. Airy | 1) Forestry completed full circuit trim on regular cycle in 2020 | 5/23/2020 |
| | | 2) Install additional sectionalizing devices, complete fuse coordination on portions of circuit, externally fuse | 9/30/2021 |

***20.50.12.03(B) Poorest Performing Feeder Standard for Feeders Not Assigned to Maryland.***
***(1) Report the feeder's CAIDI, SAIDI, and SAIFI indices; if the feeder would have been included on the poorest performing feeder list but for the fact that the feeder is not assigned to Maryland.***
***(2) Report the number of customers located in Maryland and the number of customers located in a bordering jurisdiction***
***(3) Implement reasonable remediation measures to improve the performance of the feeder portion serving Maryland customers.***

PE does not have any PPFs to report in this section.

***20.50.12.11(A)(14) Multiple device activation information and results***

***20.50.12.04(A) Report the number of devices that activated five or more times during the prior 12-month reporting period causing sustained interruptions in electric service, including during major outage events, to more than ten Maryland customers.***

***20.50.12.04(B) For each device referenced in § A, evaluate and report the cause of the multiple activations.***

***20.50.12.04(C) For each device referenced in §A, implement reasonable remediation measures to reduce the number of activations and describe the measures***

The table below provides a list of the protective devices that activated five or more times during the reporting period causing sustained interruptions in electric service, including during major events, to more than ten Maryland customers. Protective devices are defined as substation breakers and reclosers, line reclosers, line sectionalizing equipment and line fuses.

| Protective Device ID | Device Description/ Type | Outage Cause(s) | No. of times activated | No. of Customers Affected | Remediation Measures | Repeat from 2017 (Y/N) | Repeat from 2018 (Y/N) | Repeat from 2019 (Y/N) | Special Medical Needs Facilities Served (Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| G13845-PE18 | Fuse | Trees, Ice | 5 | 13 | 1. Complete fuse coordination on portion of circuit | N | N | N | N |
| A1517-PE11 | Recloser | Trees, Line failure, Forced outage | 5 | 126 | 1. Complete fuse coordination on portion of circuit | N | N | N | N |
| G11459-PE11 | Fuse | Trees, Unknown, Ice | 6 | 10 | 1. Complete fuse coordination on portion of circuit | N | N | N | N |
| G9431-PE18 | Recloser | Trees, Vehicle | 5 | 46 | 1. Complete fuse coordination on portion of circuit | N | N | N | N |
| G3126-PE11 | Fuse | Unknown, Trees, Line failure | 7 | 84 | 1. Complete fuse coordination on portion of circuit | N | N | N | N |
| F21920-PE12 | Fuse | Trees, Wind | 5 | 13 | 1. Completed 2/13/2021 - Forestry completed full circuit trim.<br>2. Install additional sectionalizing devices, install animal guards on OH transformers. | N | N | N | N |
| F41328-PE12 | Recloser | Trees, Wind | 5 | 67 | 1. Install additional sectionalizing devices.<br>2. Forestry to complete danger tree patrol on portion of tap. | N | N | Y | N |
| F54675-PE12 | Fuse | Line failure (UG Cable), Planned | 6 | 33 | 1. Completed 2/21/2020 - replaced several failed spans of primary UG cable.<br>2. Replace UG cable 2021: Replace remaining spans of UG cable on this tap. | N | N | N | N |
| MD2387A-PE19 | Fuse | Unknown, Trees, Line failure | 6 | 12 | 1. Completed 2/13/21 - Forestry completed full circuit trim.<br>2. Install additional sectionalizing devices, install animal guards on OH transformers. | N | N | N | N |
| U3529-PE19 | Fuse | Trees, Unknown, Line failure | 5 | 43 | 1. Forestry to complete full circuit trim.<br>2. Install additional sectionalizing devices, install animal guards on OH transformers. | N | N | N | N |
| F27408-PE15 | Fuse | Trees, Forced, Planned | 5 | 33 | 1. Install additional sectionalizing devices, complete fuse coordination on portion of circuit, install animal guards on OH transformers. | N | N | N | N |

***20.50.12.11(B)(2) Service restoration requirement information and results.***

***20.50.12.06(A) A utility shall restore service within 8 hours, measured from when the utility knew or should have known of the outage, to at least 92 percent of its customers experiencing sustained interruptions during normal conditions.***

***20.50.12.06(B) A utility shall restore service within 50 hours, measured from when the utility knew or should have known of the outage, to at least 95 percent of its customers experiencing sustained interruptions during major outage events where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers, whichever is less.***

| Normal Conditions | | Major Outage Events | |
|---|---|---|---|
| % of Interruptions Restored within 8 Hours | | % of Interruptions Restored within 50 Hours | |
| Actual | COMAR Standard | Actual | COMAR Standard |
| 96.44% | 92% | N/A | 95% |

***20.50.12.06(E) If a utility fails to satisfy the standard during the previous calendar year, it shall provide a corrective action plan.***

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required.

***20.50.12.11(B)(3) Downed wire response performance information and results.***

Considering data for normal and major event conditions, PE responded to a government agency responder guarded downed electric utility wire within three hours or less after notification 99.06% of the time during the 2020 reporting period.

| Government Emergency Responder Guarded Downed Wires | |
|---|---|
| % of Gov't Emergency Responder Guarded Downed Wires Responded to Within 3 Hours After Notification by a Fire Department, Police Department or 911 emergency dispatcher | COMAR Standard |
| 99.06% | 90.0% |

***20.50.12.07(B) If a utility fails to satisfy the standard during the previous calendar year, it shall provide a corrective action plan.***

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required.

***20.50.12.11(B)(7) For the immediately preceding calendar year, and considering normal conditions only:***

***(a) The number of downed electric utility wires to which the utility responded in:***
***(i) 4 hours or less;***
***(ii) More than 4 hours but less than 8 hours;***
***(iii) 8 hours or more; and***
***(b) The total number of downed electric utility wires reported to the utility***

During the reporting period, PE received 1,126 reports of downed electric wires during normal conditions. The tables below show the number of downed electric utility wires in which PE responded.

| | Total Reported Downed Wires | Total Utility Responsible Wires | 3 Hours or Less | More than 3 Hours but Less than 8 Hours | 8 Hours or More |
|---|---|---|---|---|---|
| Normal Condition Downed Wires | 1,126 | 747 | 572 | 121 | 54 |

***20.50.12.11(B)(4) Customer communications performance information and results.***

***20.50.12.08(A) Customer Telephone Call Answer Time Standard. Each utility shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes.***

***20.50.12.08(B) Abandoned Call Rate Standard. Each utility shall achieve an annual average abandoned call percentage rate of 5 percent or less, calculated by dividing the total number of abandoned calls by the total number of calls offered to the utility for customer service or outage reporting purposes.***

| % of Calls Answered within 30 seconds | COMAR Standard | % Annual Abandoned Calls | COMAR Standard |
|---|---|---|---|
| 87% | ≥75% | 2.36% | ≤5% |

Customer telephone call answer time rate and abandoned call rate includes calls offered to a customer service representative, interactive voice response system ("IVR") or an overflow system. The abandoned call rate is calculated by dividing the total number of abandoned calls by the total number of calls offered to the utility for customer service or outage reporting purposes.

***20.50.12.08(H) Corrective Action Plan. If a utility fails to satisfy the standard in § A, B or C, of this regulation, it shall provide a corrective action plan in its annual performance report.***

PE satisfied the standards of this regulation in 2020, therefore, a corrective action plan is not required.

***20.50.12.08(D) Other Customer Communications Information. Each utility shall state in its supplemental annual performance report:***

***(1) Based solely upon those calls offered to its customer service representatives:***
***(a) The percentage of calls that are answered within 30 seconds; and***
***(b) The abandoned call percentage rate; and***

***(2) The average speed of answer, which shall be calculated by dividing the total amount of time callers spend in queue after requesting to speak to a customer service representative through the automated voice response system by the total number of calls handled, including calls handled by the automated voice response system.***

| % of Calls Answered Within 30 Seconds | % Abandoned Calls | Average Speed of Answer (Seconds) |
|---|---|---|
| 62% | 7.11% | 35 |

***20.50.12.09(C)(3) Each utility shall include a summary of the information required under §C(2) of this regulation about its vegetation management during the preceding calendar year, and shall describe vegetation management planned for the current calendar year, as part of the annual performance report.***

See Appendix A for a summary of the vegetation management work completed in 2020. When performing vegetation management, PE physically performs the following methods: brush removal by cutting or mowing, brush control utilizing hydraulic foliage, low volume basal, and cut surface herbicide application techniques, off and on corridor tree removal, including off corridor hazard trees, property owner notification, and the pruning of trees which can originate either from off or on the corridor. All vegetation activities are performed with oversight by a Maryland Licensed Tree Expert, and all vegetation management activities are documented for each circuit in the Company's inspection records.

***20.50.12.09(C)(3)(a)(b) Expenditures for vegetation management in the preceding calendar year and vegetation management budget for the current calendar year.***

See the charts in section 20.50.12.11(A)(6) on pages six and seven of this report for the distribution and subtransmission expenditures for 2020, as well as the budget for 2021 and 2022.

***20.50.12.09(C)(3)(c) Circuits or substations, completion dates, and the estimated number of***

***overhead circuit miles trimmed in the preceding calendar year in compliance with the cyclical vegetation management requirements.***

See Appendix A for a summary of the 1,264 circuit miles that PE completed vegetation management on in 2020. This summary identifies feeders where vegetation management is 100% complete.

Six feeders that were originally scheduled for 2020 were not started but will be 100% completed in 2021. These feeders are:

Potomac Park – 20.8 miles (to be completed first quarter 2021)
Bidle Hill – 14.9 miles (completed first quarter 2021)
Cone Branch Road – 3.0 miles (completed first quarter 2021)
Town – 14.8 miles (to be completed first quarter 2021)
AB3 – 3.9 miles (to be completed second quarter 2021)
FA3 – 3.6 miles (completed first quarter 2021)

Six feeders that were originally scheduled in 2020 were only partially completed but will be 100% completed in 2021. These feeders are:

#3 North Branch (MD Portion) – 1.2 miles (to be completed third quarter 2021)
North – 48.6 miles (completed first quarter 2021)
Woodville – 29.3 miles (completed first quarter 2021)
Marsh Pike - 24.4 miles (completed first quarter 2021)
Tall Oaks – 8.9 miles (completed first quarter 2021)
WB1 – 6.6 miles (completed first quarter 2021)

Twelve feeders were added to the schedule and completed in 2020. The additional feeders are:

Rosemont - 0.9 miles
Largent (MD Portion) - 0.3 miles
Rock Creek – 23.9 miles
Nolans Ferry - 0.8 miles
RA 2 - 3.5 miles
WT2 - 0.8 miles
WD3 - 5.3 miles
SM2 - 3.3 miles
WH0 - 0.8 miles
PR - 0.6 miles
RG1 - 0.4 miles
RA1 - 2.6 miles

***20.50.12.09(C)(3)(d) Circuits or substations and the estimated number of overhead miles scheduled for the current calendar year in compliance with the cyclical vegetation management requirements.***

See Appendix B for a list of the circuits which represent the 1,494 overhead circuit miles of vegetation management scheduled to be completed in 2021.

***20.50.12.09(C)(3)(e) Total overhead circuit miles for the system.***

PE currently has 6,059 miles of overhead circuit miles on its system.

***20.50.12.09(C)(3)(f) If applicable, a corrective action plan.***

COMAR 20.50.12.09(F)(2) states that in the third year of a five-year trim cycle a utility shall perform vegetation management on not less than fifty-six percent of its total distribution miles. PE performed vegetation management in 2020 for a combined total of fifty-six percent of its overhead circuit miles therefore a corrective action plan is not required.

***20.50.12.11(B)(6) Periodic equipment inspection information and results***

PE has adopted written procedures for the inspection of its equipment in order to maintain safe and reliable service. On March 31, 2020, these programs were filed with the Commission. The O&M filing included programs for wood poles, overhead circuits and equipment, pad-mounted transformers and underground equipment, line capacitors and substation patrols.

PEs compliance with its 2020 planned inspection program is demonstrated in the chart below:

| Potomac Edison | | | | |
|---|---|---|---|---|
| | | **Frequency** | **Planned** | **Completed** |
| **Distribution** | Wood Poles | 10 years | 20,680 | 23,593 |
| | Overhead Circuits and Equipment from Substation to First Protective Device | 2 years | 157 | 157 |
| | Overhead Circuits and Equipment | 6 years | 62 | 62 |
| | Total Circuits Inspected | | 219 | 219 |
| | Pad-mounted Transformers & Underground Equipment | 5 years | 15,183 | 15,183 |
| | Line Capacitors | Annual | 449 | 449 |
| **Substation** | Patrol Inspections[12] | 2 months | 320 | 320 |

[12] In addition to the patrol inspections that are completed, twice a year PE also conducts an open cabinet inspection to obtain equipment readings and perform seasonal preventative maintenance.

# APPENDIX

# APPENDIX A

| Substation Name | Feeder/Circuit | Overhead Mileage | Date Complete |
|---|---|---|---|
| Bedford Road | Lake Gordon (MD Portion) | 14.8 | 5/13/2020 |
| Bedford Road | Rt 220 North (MD Portion) | 0.1 | 1/23/2020 |
| Bedford Road | Rt 220 South | 27.3 | 5/12/2020 |
| Braddock Heights | Boulevard | 16.5 | 7/22/2020 |
| Braddock Heights | Hollow Road | 7.0 | 5/20/2020 |
| Braddock Heights | Route 40 A | 7.3 | 7/9/2020 |
| Brunswick | Sandy Hook | 40.5 | 1/2/2020 |
| Brunswick | Rosemont | 0.9 | 1/9/2020 |
| Catoctin | Catoctin Furnace | 48.6 | 3/18/2020 |
| Coverwood | Bishop Walsh Drive | 7.8 | 5/20/2020 |
| Coverwood | Searstown | 3.5 | 5/11/2020 |
| Cresaptown | Bel-Aire | 4.1 | 11/5/2020 |
| Cresaptown | McMullen Hwy | 19.0 | 12/26/2020 |
| Damascus | Purdum | 37.3 | 4/2/2020 |
| Damascus | Howard Chapel | 9.2 | 3/18/2020 |
| Eaglehead | Mt. Pleasant | 37.0 | 1/24/2020 |
| Eaglehead | Summerfield | 2.1 | 1/2/2020 |
| East Hagerstown | Fairway Meadows | 9.9 | 8/13/2020 |
| East Hagerstown | Fox Deceived | 8.5 | 7/2/2020 |
| East Hagerstown | Hospital No 1 | 1.1 | 5/6/2020 |
| East Hagerstown | Hospital No 2 | 1.0 | 6/4/2020 |
| East Hagerstown | Mount Aetna | 17.2 | 7/30/2020 |
| East Hagerstown | Robinwood | 1.6 | 5/7/2020 |
| East Hagerstown | Youngstoun | 1.6 | 6/18/2020 |
| Frederick A | Carroll Street | 3.9 | 3/27/2020 |
| Frederick A | Frederick Iron & Steel | 1.9 | 3/5/2020 |
| Frederick A | Highs | 4.4 | 3/26/2020 |
| Frederick A | Hospital | 1.8 | 3/19/2020 |
| Frederick A | Northwest | 2.7 | 3/27/2020 |
| Frederick A | Southwest | 4.5 | 2/5/2020 |
| Frederick A | Wisner St | 2.0 | 4/30/2020 |
| Garrett | Hoyes Run Road | 52.7 | 9/3/2020 |
| Garrett | Marsh Hill Road | 3.8 | 9/16/2020 |
| Garrett | Rt 219 South | 19.9 | 1/13/2020 |
| General Office | Homewood | 4.8 | 2/20/2020 |
| General Office | Storeroom | 12.4 | 7/9/2020 |
| General Office | Downsville | 52.4 | 9/24/2020 |
| Halfway | Cedar Lawn | 3.0 | 7/22/2020 |
| Halfway | Elliott Parkway | 0.8 | 7/9/2020 |
| Halfway | Hopewell | 1.6 | 8/13/2020 |
| Halfway | Hunt Ridge | 3.2 | 10/15/2020 |
| Halfway | Kemps Mill | 22.7 | 9/17/2020 |
| Halfway | K-Mart | 0.2 | 7/2/2020 |
| Halfway | Lakeside | 0.7 | 7/2/2020 |
| Halfway | Newgate | 0.1 | 6/17/2020 |
| Halfway | Tandy | 2.4 | 7/2/2020 |
| Hazelton | Prison (MD Portion) | 1.3 | 12/24/2020 |
| Huyetts | South | 0.03 | 12/31/2020 |
| Key Mall | Grove Road | 4.3 | 4/8/2020 |
| Key Mall | Monocacy Battlefield | 21.2 | 6/29/2020 |
| Larkin | Largent (MD Portion) | 0.3 | 12/31/2020 |
| Lavale | Rt 40 East | 14.6 | 7/7/2020 |
| Lavale | Rt 40 West | 5.3 | 9/17/2020 |
| Lavale | Sunset View | 5.1 | 9/22/2020 |
| Mccain | Ballenger Creek | 1.5 | 6/24/2020 |
| Mccain | Brigadoon | 7.0 | 7/9/2020 |

| Substation Name | Feeder/Circuit | Overhead Mileage | Date Complete |
|---|---|---|---|
| Mccain | Center Park | 1.3 | 6/25/2020 |
| Mccain | Crestwood Village | 3.1 | 7/14/2020 |
| Mccain | Emerald Farm | 0.6 | 7/22/2020 |
| Mccain | Jefferson Street | 5.2 | 7/29/2020 |
| Mccain | Keys Stadium | 3.3 | 7/9/2020 |
| Mccain | Mccain Drive | 0.1 | 7/21/2020 |
| Mccain | Schaffer Drive | 0.3 | 7/20/2020 |
| Milnor | Mason Dixon (MD Portion) | 1.8 | 9/11/2020 |
| Monocacy | Community College | 1.5 | 7/1/2020 |
| Monocacy | Gov Johnson | 8.9 | 7/21/2020 |
| Monocacy | Mill Island | 4.8 | 5/18/2020 |
| Monocacy | North Crossing | 1.5 | 5/21/2020 |
| Monocacy | Opossumtown Pike | 3.7 | 5/28/2020 |
| Monocacy | Progress Hvd | 0.04 | 6/18/2020 |
| Monocacy | Riverside Hvd | 0.01 | 6/18/2020 |
| Monocacy | Wormans Mill | 1.7 | 5/27/2020 |
| Mt Airy | Long Corner | 6.0 | 3/26/2020 |
| Mt Airy | Village Gate | 4.7 | 5/13/2020 |
| Mt Airy | Twin Arch | 9.1 | 6/18/2020 |
| Mt Airy | Watersville Road | 22.8 | 6/10/2020 |
| Mt Airy | Bartholows | 14.5 | 5/21/2020 |
| Mt Airy | Main Street | 6.3 | 3/26/2020 |
| Myersville | Wolfsville | 77.8 | 2/6/2020 |
| Old Farm | Rock Creek | 23.9 | 12/31/2020 |
| Paramount No 1 | West Longmeadow | 12.3 | 6/4/2020 |
| Petersville | Burkittsville | 41.9 | 5/7/2020 |
| Petersville | Landers | 32.3 | 3/10/2020 |
| Plaza | Braddock Run | 10.5 | 5/7/2020 |
| Plaza | Shopping Center | 0.2 | 4/11/2020 |
| PPG | Industrial Park | 0.9 | 9/24/2020 |
| PPG | Prison | 0.5 | 9/24/2020 |
| PPG | Super Fos | 0.5 | 9/24/2020 |
| Ridgeley | Main Street (MD Portion) | 0.1 | 5/11/2020 |
| Ridgeville | Rt 144 | 25.4 | 8/20/2020 |
| Ridgeville | St Michaels Road | 34.3 | 12/31/2020 |
| Showalter | Maugansville | 12.6 | 10/15/2020 |
| Showalter | Orchard Hills | 3.4 | 10/15/2020 |
| Showalter | State Line | 4.4 | 9/24/2020 |
| South Frederick | Evergreen Point | 3.0 | 10/21/2020 |
| South Frederick | Linganore | 14.2 | 9/17/2020 |
| Thayerville | Mayhew Inn | 41.7 | 12/9/2020 |
| Thayerville | Turkeyneck | 61.5 | 11/14/2020 |
| Thomas Street | Shades Lane | 15.3 | 3/11/2020 |
| Thomas Street | Rt. 28 (MD Portion) | 6.3 | 1/3/2020 |
| Thomas Street | The Moose | 1.5 | 1/3/2020 |
| Tuscarora | Nolans Ferry | 0.8 | 12/12/2020 |
| West Frederick | 7th Street | 5.5 | 10/15/2020 |
| West Frederick | Hillcrest | 1.1 | 9/24/2020 |
| West Frederick | Rosemont | 6.0 | 11/5/2020 |
| West Frederick | State Farm | 0.6 | 9/22/2020 |
| West Frederick | Westridge | 1.3 | 9/24/2020 |
| AT1 Tap-LK1-LK2 Tap (Hyattstown) | AD3 | 11.5 | 12/10/2020 |
| B&O Shops-Canal Jct | BO1 | 0.3 | 9/10/2020 |
| Boonsboro-Skycroft | O1 | 2.1 | 4/17/2020 |
| Canal Jct-Thomas Street | BO2 | 1.0 | 9/10/2020 |
| Carlos Jct-Chambers Landfill | CC | 2.2 | 10/15/2020 |
| Carlos Jct-Lonaconing | LW1 | 4.1 | 12/23/2020 |

| Substation Name | Feeder/Circuit | Overhead Mileage | Date Complete |
|---|---|---|---|
| Catoctin-Thurmont & Raven Rock (MD Portion) | WT4 | 7.3 | 4/2/2020 |
| Chambers Landfill-Cresaptown | CC1 | 4.3 | 12/17/2020 |
| Coverwood-Plaza | CF3 | 1.2 | 4/23/2020 |
| Cumberland - Lavale | CV | 3.5 | 1/30/2020 |
| Cumberland-Ridgeley (MD Portion) | RX | 0.1 | 9/5/2020 |
| Cumberland-Thomas Street (MD Portion) | CT | 0.9 | 1/23/2020 |
| Cumberland-Wills Mtn Jct | RN | 3.9 | 10/1/2020 |
| Fairchild Plant - Showalter | RA2 | 3.5 | 12/31/2020 |
| Fort Detrick-Old Farm | DF2 | 2.1 | 7/2/2020 |
| Fountain Head-Paramount | FR1 | 1.9 | 2/5/2020 |
| Frederick A-Fort Detrick | DF1 | 2.6 | 7/2/2020 |
| Frederick A-Frederick B | M1 | 0.8 | 3/26/2020 |
| Frederick A-South Frederick | FK | 0.7 | 2/5/2020 |
| Ft Richie Tap-Blue Ridge Summit | WT2 | 0.8 | 12/31/2020 |
| Garrett-Cablentertainment & Thayerville | GT | 5.6 | 12/9/2020 |
| Huyetts - Milnor (MD Portion) | WD3 | 5.3 | 12/10/2020 |
| IP Tap-General | SM2 | 3.3 | 12/19/2020 |
| Jefferson - Petersville | BF2 | 5.0 | 1/8/2020 |
| Key Mall-Balleger Sewage | AL3 | 1.5 | 4/1/2020 |
| Legore-Carroll | TL2 | 7.5 | 3/24/2020 |
| Lonaconing-Westernport | LW2 | 6.1 | 12/3/2020 |
| Marlowe-Ip Tap (MD Portion) | SM1 | 1.7 | 4/15/2020 |
| Marlowe-Williamsport | WH0 | 0.8 | 12/24/2020 |
| Mt Airy-Ridgeville | AD1 | 4.3 | 8/13/2020 |
| Oldtown-Donaldson (MD Portion) | GR0/GR1 | 0.1 | 5/11/2020 |
| Paramount-Reid | FR2 | 1.9 | 12/26/2020 |
| Penna Glass & Sand-Hancock | H4 | 0.7 | 11/14/2020 |
| Petersville - Brunswick | BF3 | 2.4 | 1/9/2020 |
| Plaza-Frostburg No 2 | CF4 | 4.2 | 10/8/2020 |
| Park Head Jct-Cherry Run (MD Portion) | PR | 0.6 | 11/28/2020 |
| Reid - Bushtown | RG1 | 0.4 | 12/31/2020 |
| Reid-Fairchild Plant2 | RA1 | 2.6 | 11/14/2020 |
| Reid-West Waynesboro (MD Portion) | REI-WWN | 1.4 | 12/24/2020 |
| Ridgeley-Ca3 Deadended (MD Portion) | CA3 | 2.2 | 11/25/2020 |
| Ridgeley-Cumberland (MD Portion) | RR | 0.1 | 9/3/2020 |
| Ridgeville-AT1 Tap | AD2 | 1.6 | 10/28/2020 |
| Skycroft-Myersville/Middletown | O2 | 8.8 | 4/17/2020 |
| SM1-SM2 Bus-Rustoleum | IP | 1.5 | 11/26/2020 |
| South Frederick-Lime Kiln | FK1 | 4.5 | 7/27/2020 |
| Swan Pond-Bg-Bg1 Bus (MELP) Tap (MD Portion) | BG | 0.3 | 9/24/2020 |
| Swan Pond-Cumb Sewage-B&O Shops (MD Portion) | BO | 0.5 | 9/11/2020 |
| Swan Pond-Pitts Plate Glass (MD Portion) | OP | 1.2 | 9/24/2020 |
| Swan Pond-Pitts Plate Glass-Sewage Plant (MD Portion) | MP | 1.2 | 9/16/2020 |
| Troutville Bus-Legore | TL1 | 1.2 | 3/24/2020 |
| Tuscarora-Canam Steel | NT | 3.1 | 12/30/2020 |

# APPENDIX B

| Substation | Circuit Name | Overhead Miles |
|---|---|---|
| Adamstown | Christian Brothers | 16.8 |
| Adamstown | Town | 23.7 |
| Bayard | #3 North Branch (MD Portion) | 1.2 |
| Beallsville | Barnesville | 25.9 |
| Beallsville | BH-12 | 38.6 |
| Beallsville | Cattail Road | 12.1 |
| Beallsville | Poolesville | 30.8 |
| Boonsboro | Zittlestown | 19.7 |
| Carroll | CW-12 | 52.6 |
| Carroll | Bark Hill Road | 38.5 |
| Carroll | Pfoutz Mill | 48.6 |
| Corriganville | Barrelville (MD Portion) | 16.6 |
| Cresaptown | Winchester Road | 11.0 |
| Cresaptown | Potomac Park | 20.8 |
| Damascus | Cedar Grove | 2.9 |
| Damascus | Etchison | 24.2 |
| Damascus | Hawkes Road | 16.1 |
| Damascus | Hawkins Creamery | 8.2 |
| Damascus | Kemptown | 17.8 |
| Damascus | Lewis Drive | 10.7 |
| Damascus | Plantations | 3.2 |
| Damascus | Sweepstakes Road | 1.7 |
| Damascus | Town | 4.5 |
| Damascus | Woodfield | 11.2 |
| Davis Mill | Brink Road | 5.9 |
| Flintstone | Chaneysville (MD Portion) | 25.8 |
| Frostburg #1 | College Avenue | 2.3 |
| Frostburg #1 | Midlothian | 21.0 |
| Frostburg #1 | Northtown | 8.2 |
| Frostburg #1 | Centertown | 72.8 |
| Frostburg #1 | Victoria Lane | 4.8 |
| General Office | Friendship | 10.3 |
| Hancock | Town Hill | 85.2 |
| Hancock | Town | 44.1 |
| Hoyes | Accident | 90.4 |
| Huyetts | North | 2.8 |
| Jefferson | Town | 20.1 |
| Jennings | Closetmaid | 2.5 |
| Jennings | Grantsville | 33.3 |
| Legore | New Midway | 62.0 |
| Middletown | Bidle Hill | 14.9 |
| Middletown | Cone Branch Road | 3.0 |
| Middletown | Town | 14.8 |
| Mt Airy | Woodville | 0.8 |
| OakPark | Loch Lynn | 44.8 |
| Oldtown | Paw Paw | 36.4 |
| Oldtown | Green Spring (MD Portion) | 0.3 |
| Oldtown | Brice Hollow | 43.7 |
| Paramount | Marsh Pike | 6.4 |

| Substation | Circuit Name | Overhead Miles |
|---|---|---|
| Paramount No 1 | Shawley Drive | 11.2 |
| Ridgeville | Tall Oaks | 6.0 |
| Sharpsburg | Dargan | 54.7 |
| Sharpsburg | Keedysville | 53.4 |
| Sharpsburg | Antietam (MD Portion) | 29.3 |
| Tuscarora | Point Of Rocks | 5.0 |
| Tuscarora | Licksville | 39.1 |
| Urbana | Rt 355 | 27.3 |
| Urbana | Carriage Hill | 0.7 |
| Urbana | Urbana | 11.5 |
| Warfordsburg | Big Cove (MD Portion) | 0.7 |
| Warfordsburg | Buck Valley (MD Portion) | 1.3 |
| Yellow Springs | Whittier | 5.4 |
| Wb Tap(Wills Mtn)-Corriganville | NK2 | 1.9 |
| West Frederick - DF1 Tap | DF | 1.1 |
| Wt4-Wt5 Tap-Raven Rock | UA | 1.0 |
| Adamstown-Tuscarora (NT Tap) & HA | FA2 | 4.1 |
| Alleghany Ballistics-Cresaptown (MD Portion) | SG4 | 1.7 |
| Aqueduct-Beallsville | AB3 | 3.9 |
| Ballenger Sewage-Thomas Bakery | AL5-1 | 0.6 |
| Bedford Road-M&M Quarries | WB1 | 4.7 |
| BG-BG1 Bus-Oldtown(MELP) Tap | BG1 | 9.8 |
| Braddock Heights-Mccain | O4 | 4.0 |
| Carroll-Taneytown | L | 7.2 |
| Catoctin-Yellow Springs | TF1 | 11.4 |
| Corriganville-Hyndman (MD Portion) | NK3 | 9.4 |
| Cumberland-Coverwood | CF2 | 4.4 |
| East Waynesboro-Catoctin (MD Portion) | EW-CTC | 2.2 |
| Emmitsburg-Worthington Pump | TT2 | 8.1 |
| Flintkote-Key Mall Frederick | AL2 | 1.5 |
| Frederick A-South Frederick & Flintkote | AL1 | 1.8 |
| Frostburg No 2-Carlos Jct | FL | 0.5 |
| Georgia Pacific & Toys-R-Us-Tamko | AL6 | 0.7 |
| Halfway Pump-HG1 Tap | WH2 | 2.3 |
| Hancock-Mercersburg (MD Portion) | HE1 | 1.5 |
| HG1 Tap-HG Tap | WH3 | 1.0 |
| Lavale-Corriganville | CV1 | 4.1 |
| Mack Truck-Fountain Head | RA4 | 1.3 |
| Maidstone-Dam 5 | S4 | 5.3 |
| Middletown-Braddock Heights | O3 | 3.2 |
| NK1-NK2 Bus(Wills Mtn)-Bedford | WB | 4.2 |
| Reid-Milnor | REI-MLN | 0.1 |
| Sharpsburg-Boonsboro | SA2 | 7.8 |
| Shepherdstown-Sharpsburg | SA1 | 5.8 |
| Swan Pond-Flintstone (MD Portion) | OF | 12.3 |
| Thomas Bakery - Georgia Pacific Toys R Us | AL5-2 | 2.0 |
| Tuscarora-Aqueduct | FA3 | 3.6 |

BY MR. WALSH:

Q Mr. Alvarez, did you and Mr. Stephens also prefile or cause to be prefiled ten exhibits which were marked as Exhibits PA/DS 1 through 10?

A (Witness Alvarez) We did.

Q Do you have any changes or corrections to make to those exhibits?

A (Witness Alvarez) We do not.

MR. WALSH: Madam Chair, I ask that the public disclosure Exhibits PA/DS 1 through 10 be marked for identification with the next staff exhibit numbers, which would be 43 through 52.

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were marked for identification as Staff Exhibits 43 through 52.)

BY MR. WALSH:

Q Mr. Alvarez, did you and Mr. Stephens also prefile or cause to be prefiled 74 pages of trade secret testimony in question-and-answer form on October 20th?

A (Witness Alvarez) We did.

Q Are there any changes or corrections that you would like to make to your prefiled trade secret testimony?

A (Witness Alvarez) No, we did not.

Q So if I were to ask you the same questions presented in that testimony, would your answers be the same?

A (Witness Alvarez) They would.

Q And did you also prefile trade secret exhibits with that testimony?

A (Witness Alvarez) We did.

Q Do you have any changes or corrections to the trade secret version of the exhibits?

A (Witness Alvarez) We do not.

MR. WALSH: Madam Chair, I would ask that the trade secret version of the panel testimony of Mr. Alvarez and Mr. Stephens, along with the trade secret exhibits, be marked for identification as Staff Exhibit No. 53.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 53.)

MR. WALSH: Thank you.

BY MR. WALSH:

Q Mr. Rana, on October 20th, 2022, did you prefile or cause to be prefiled 23 pages of public disclosure testimony in question-and-answer form?

A (Witness Rana) Yes, I did.

Q Are there any changes or corrections that you would like to make to that prefiled testimony at this time?

A (Witness Rana) Yes.

Q Can you please make them.

What are the changes?

A (Witness Rana) The changes?

Q Yes. Did you say that there were changes?

A (Witness Rana) Yes. I have three changes.

Q Yes. Can you --

A (Witness Rana) On page 4, line 19, it says "PPRE-FILED." It should be "PREFILED."

On page 14, line 3, it says the "Transmission Infrastructure" is one word. It should be "Transmission" space "Infrastructure."

And on page -- on page 14, line 11, instead of "and/or," it should be "A."

Q Thank you. If I were to ask you the same questions that are presented in your prefiled testimony, noting the corrections that you just made, would your answers be the same?

A (Witness Rana) Yes.

MR. WALSH: Madam Chair, I would ask that the prefiled testimony of Mr. Rana be copied into the record as if read from the witness stand. The public disclosure version of that testimony.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimony of Rajendrasinh (Raj) Rana follows:)

//

BY MR. WALSH:

Q Mr. Rana, did you also prefile or cause to be prefiled one exhibit that was marked as Exhibit RR-1?

A (Witness Rana) Yes.

Q Do you have any changes to make to either the public disclosure or trade secret version of that exhibit?

A (Witness Rana) No.

MR. WALSH: Madam Chair, I ask that the public disclosure version of that Exhibit RR-1 be marked for identification as Staff Exhibit No. 54.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 54.)

BY MR. WALSH:

Q Mr. Rana, did you also prefile or cause to be prefiled 23 pages of trade secret testimony in question-and-answer form on October 20th?

A (Witness Rana) Yes.

Q Other than the changes that you identified a moment ago with regard to your public disclosure testimony, are there any other changes or corrections that you would like to make at this time to your trade secret testimony?

A (Witness Rana) No.

Q So if I were to ask you the same questions in your trade secret testimony, your answers would be the same?

A (Witness Rana) Yes.

MR. WALSH: Madam Chair, I would ask that the prefiled trade secret testimony of Mr. Rana, along with the trade secret exhibit be marked for identification as Staff Exhibit 55.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 55.)

BY MR. WALSH:

Q Did you gentlemen each prepare a summary of your testimony at this time?

A (Witness Alvarez) We have.

A (Witness Rana) Yes.

MR. WALSH: Madam Chair, with the Chair's approval, I would ask that the panel provide its summary at this time.

MADAM CHAIR PRIDEMORE: Please go ahead.

MR. ALVAREZ: Thank you, Your Honor.

My name is Paul Alvarez, and appearing with me today are my testimony co-author Dennis Stephens and staff transmission expert Mr. Raj Rana, who will summarize his own testimony.

In the recent IRP docket, Mr. Stephens and I introduced our concern about the company's rapid and dramatic increase in transmission and distribution,

or T&D, capital investment.

As we investigated Georgia Power's recent proposed T&D investment increases, about triple historical investment levels before the introduction of the Grid Investment Plan, or GIP, our concern about the cost and effectiveness of that spending grew stronger.

The bottom line is, even without the Grid Investment Plan, Georgia Power proposes a doubling in the level of traditional T&D investments, including reliability, capital maintenance, and new business programs from pre-GIP levels. I direct your attention to our demonstrative exhibit with this chart in it that kind of indicates the increase with and without the GIP.

In this rate case, we do not oppose any of the extreme large increase in traditional T&D investment. What we do oppose are the parts of the GIP which will not deliver reliability improvement value in excess of rate increases.

Our testimony explains in detail why all GIP transmission spending and the vast majority of GIP distribution spending are not cost effective and, thus, not in the public interest. But first I would like to provide the Commission with four good reasons

to push the pause button on the GIP, regardless of these details.

First, as Mr. Trokey mentioned earlier, Georgia's businesses and consumers are facing significant rate increases in the near future. Given this fact alone, GIP timing is not appropriate.

Second, there is no pending reliability emergency requiring immediate action. Georgia Power's outage frequency and duration are about average for investor-owned utilities in the United States.

Third, according to the company's own research, customers are not demanding reliability improvements, nor are they willing to pay more than a 1.7 percent rate increase for reliability improvements. We estimate the GIP rate increase to be about 10 percent or almost six times higher than customers have stated they are willing to pay.

Fourth, the reliability improvements from GIP capital investments to date are not yet known. Due to the potential harm to Georgia's economy from GIP rate increases, we should know the results of spending to date before we double down on more GIP spending.

Our testimony presents strong evidence that the

vast majority of GIP spending is not cost effective. Given this and the lack of immediate need or customer demand for reliability improvements, GIP measurement and moderation is the most reasonable path forward for customers.

Mr. Stephens will now describe his concern with the transmission components of the GIP, which Mr. Rana shares.

MR. STEPHENS: Thank you, Your Honor.

The transmission component of the GIP consists entirely of the replacement of equipment operating in a safe and reliable manner simply because that equipment has reached the company's defined expectation for useful life in years. We describe this practice as premature replacement, as it deprives customers of years or decades of service for equipment that poses almost no reliability risk, and therefore, almost no reliability improvement opportunity upon replacement.

Transmission equipment that has reached the company's expectation for useful life in years poses almost no reliability risk or improvement opportunity for two reasons.

First, Georgia Power follows common industry practices for conducting objective tests and

inspections of critical transmission equipment on a routine basis.

By completing these periodic, objective tests and inspections, retaining the equipment that passes, and repairing or replacing the equipment that fails, utilities across the U.S., including Georgia Power, deliver excellent transmission system reliability at a reasonable cost.

As just one example, though the company expects a useful life of 50 years from its substation power transformers, one substation power transformer currently operating safely and reliably on the company's grid is 99 years old. And we know of a power transformer operation in Washington State that has an 108-year-old transformer.

Transmission system redundancy is the second reason premature replacement offers almost no reliability improvement opportunity. All transmission systems in North America are planned and operated with full redundancy. If any single piece of equipment fails in service, service to customers will continue to -- with no interruption. Even in the extremely rare case of transmission equipment failure that does result in a service interruption, additional redundancies and grid operator actions are

available to ensure interruption is limited.

To summarize, there is simply insufficient reliability improvement opportunity for premature replacement to justify the extremely high cost of this practice.

Georgia Power's GIP process -- I mean proposes to invest $1 billion to replace transmission lines and equipment prematurely from 2023 through 2025. Mr. Rana and I recommended that the Commission reject 100 percent of this amount. If the Commission adopts our recommendation in full, the balance of the company's transmission investment plan still represents 171 percent increase over historical investment levels in capital maintenance, reliability and new business programs. Surely the company can employ the remaining 171 percent increase to maintain or improve current transmission reliability levels by focusing capital on the largest reliability risk.

Mr. Alvarez will now describe our concerns with the two largest distribution components of GIP, circuit hardening and undergrounding.

MR. ALVAREZ: Our analysis of the two largest distribution packages in the GIP by far, circuit hardening and the undergrounding of overhead lines, indicates that neither will come close to delivering

reliability improvements of sufficient value to offset their extreme costs.

We estimate circuit hardening costs thousands of dollars per customer served and that undergrounding costs tens of thousands of dollars per customer served. As with premature transmission equipment replacement, there is simply not enough reliability improvement opportunity available from these packages to justify their extremely high costs.

Industry research into circuit hardening and undergrounding in other hurricane states, as well as our own analyses of these GIP packages applied to the company's own circuits using the company's own data, indicate that circuit hardening and undergrounding are not remotely cost-effective approaches to improving reliability.

Our analyses specific to Georgia Power's circuit hardening indicates benefits of just 46 cents per dollar of rate increase, and our analysis specific to Georgia Power's undergrounding package indicates benefits of just 36 cents per dollar of rate increase.

Another problem with Georgia Power's distribution investment plan is that far too many circuits qualify for GIP investment. Under the

company's methodology, up to 75 percent of the company's circuits qualify for GIP investment. This is the direct opposite of focused reliability improvement spending on the very worst performing circuits and equipment.

MR. STEPHENS: We are also concerned that the company's plan to improve reliability ignores two of the most common cost-effective approaches utilities employ -- more aggressive vegetation management and a more formal worst-performing circuit program.

Regarding vegetation management, the company's expenditures have varied a great deal over the last few years. For example, vegetation management spending in 2018 was just 35 percent of the amount spent in the year ending May 31st, 2022. In my experience, such inconsistency in vegetation management spending does not correlate with strong reliability performance. Focusing investment in the very worst-performing circuits would provide customers the most improvement in reliability for dramatically less investment than the GIP.

However, Georgia Power's historical investment in worst-performing circuits has been more inconsistent than vegetation management spending. The extreme variability in historical

worst-performing circuit spending is an indication that the company has not given a more formal worst-performing circuit program a fair chance to work before proceeding with this multibillion dollar GIP.

In discovery, I requested the company's worst-performing circuit program policies. The response was a single paragraph that exhibited a clear lack of formality, specificity, and sophistication relative to other such utility programs with which I am familiar.

In addition to no consistent program budget, the company described no consistent cut-off to quantify the circuits for additional attention.

No consistent approach to conducting root-cause analysis on worst-performing circuits. No company-wide program manager, and no assignments of program responsibilities. In my experience, these missing pieces are all hallmarks of cost-effective worst-performing circuit programs.

Perhaps most importantly I refer to page 53, Table 5 of our testimony. Despite investment levels that are a tiny fraction of the GIP distribution investment packages and despite the informal nature of the company's worst-performing circuit program,

small investments directed to certain very poorly -- poorly-performing circuits through the program significantly improve reliability.

We recommend the Commission order the company to formalize its vegetation management and worst-performing circuit programs and consider requiring the company to report these programs annually as other commissions have done.

MR. ALVAREZ: At this point you may be wondering how the company's Customer Benefit Study presents the distribution investment plan in such stark contrast to our findings. The reason is simple. The company's Customer Benefit Study is not a cost-effectiveness test of proposed distribution investment practices. Instead, the Customer Benefit Study answers an irrelevant question. That question is what combination of distribution investment packages result in the lowest total cost to customers relative to other combinations of distribution investments.

This analysis does not identify whether certain distribution investments are cost effective for customers. Clearly, any set of distribution investment packages, even if not a single one of them is cost effective, can be deployed in multiple ways;

and one of those deployment scenarios will exhibit a lower cost than all the others. This does not mean that the least-cost scenario is cost effective. It only means that one scenario is lower cost than all the others. As such, we recommend the Commission assign little or no weight to the company's Customer Benefit Study.

Further, we encourage the Commission to consider that circuit hardening and undergrounding are even worse for Georgia than the premature transmission equipment replacement practice we described.

This is because the company's premature transmission equipment replacement practice, at a minimum, waits until a piece of equipment has reached its expected useful life before it is needlessly replaced.

We believe the distribution plan is resulting in the premature replacement of equipment even earlier, before the equipment's capital cost has been fully recovered from customers. This will result in customers paying for new replacement equipment while continuing to pay for prematurely-retired equipment no longer providing service.

We believe there is no possible justification

for asset churn and capital bias to this extent and encourage the Commission to reject Georgia Power's request to continue the circuit hardening and undergrounding packages entirely. Even if the Commission agrees with this billion-dollar capital rejection request in its entirety, the remaining distribution capital request still represents a 55 percent increase over distribution investment levels pre GIP.

This should be more than enough for the company to improve reliability in a cost-effective manner by focusing more appropriate types of spending on fewer circuits.

MR. STEPHENS: Though smaller in size, we also recommend the Commission reject the company's $100 million request to deploy a distributed energy resource management system, or DERMS, for three reasons.

First, the company's concerns about the challenges presented by distributed energy resources, or DER, are overblown, as described in our testimony -- as described in our testimony.

Second, the company already maintains transmission and distribution management system software that can currently manage DER without

incident.

Third, the level of DER on the company's distribution grid will remain extremely low by the end of the rate case period relative to the other utilities without a DERMS.

MR. ALVAREZ: In closing, we believe our recommendations will allow Georgia Power to continue to provide safe and reliable service at a reasonable cost. Our recommendations are consistent with a concern for Georgia's economy, businesses, and consumers. We believe our recommended capital reductions, which leave a doubling over historical investment levels pre GIP intact, strike the right balance between shareholder interests and customer interests.

All Georgia businesses must make difficult choices regarding the allocation of capital. In selecting some spending choices over others, these businesses are, of necessity, deploying capital to its highest and best use. By restraining T&D capital investments through our recommendations, the Commission would not be denying reliability improvement opportunities, but would simply be asking Georgia Power to more carefully allocate capital, just like all other Georgia businesses must. We are

confident the company is up to that task and ask that the Commission adopt our recommendations in full.

We hope the Commission values our contributions to the record in this case and we look forward to answering any and all questions regarding our T&D testimony.

Mr. Rana?

MR. RANA: Thank you, Paul.

My testimony responds to some aspects of the Georgia Power Company's 2022 rate case filing related to the company's proposed transmission line investment for 2023/2025 period.

As I explain below, my primary concern is with the company's proposed transmission investment associated with the Grid Investment Plan, where the company-proposed increase in spending is too aggressive and unnecessary, leading to rate base and rate increases without the benefit of customer reliability improvement.

As Mr. Stephens just stated, the proposed grid investment for the next three years is more than double those of the 2014 through 2019 period. Among the proposed transmission investment, the company is proposing to invest $322 million as a part of its GIP plan. The -- this annual investment is in addition

to the large increases requested in traditional transmission investment categories, including capital, maintenance, reliability, and new business. The GIP introduced into 2019 is a multi-year plan to replace certain transmission equipment.

According to the company, the purpose of the GIP is to mitigate the risk of outages of transmission lines and associated station equipment that will be past their expected useful lives by 2031 for the company-defined age criteria. This practice will replace transmission lines and associated station equipment prematurely and unnecessarily. Rather than relying on the age of the transmission equipment to determine what should be replaced, the company should prioritize replacements based on the widely-accepted industry practice of evaluating the current condition of each asset based on the objective testing and inspection data analysis.

The company uses this widely-accepted industry practice for prioritizing capital investment in traditional capital maintenance and the reliability improvement programs and should for the GIP.

If the transmission facility shows signs of reduced performance or failure based on objective test results, then such facility should be scheduled

for repair or rebuild or replacement. As Mr. Stephens just stated, the likelihood of the facility outage while in service is very small, if the company identifies and prioritizes repairs, rebuild, or replacement using objective tests and monitoring results.

Transmission reliability is further enhanced by the transmission system being designed and operated to continue providing service in the event of any equipment failure.

This type of built-in redundancy will ensure that there will not be a reliability problem or customer service outage if a transmission facility fails while in service.

The company has indicated that the GIP will not improve customer reliability and has not performed a cost-benefit analysis to justify GIP capital investments.

The company claims a cost-benefit study for transmission investment under GIP is not necessary because the investment is needed to replace aging infrastructure. Given that replacing transmission assets based on age is not cost justified, or efficient, as well as will not improve reliability, the GIP will increase transmission capital investment

resulting in unnecessary rate increases and rate base.

GIP will prematurely replace transmission assets that are healthy and functioning safely and reliably and have a remaining service life. This practice will increase the replacement cost unnecessarily. GIP will not deliver customer reliability improvements sufficient to outweigh the corresponding increase in customer cost.

GIP will not reduce operating and maintenance expenditures significantly. And GIP will divert investment dollars away from funds needed in other essential areas because this plan will dispose of some healthy, functional transmission assets and replace them with the new ones, thus diverting the investments from where they are most needed.

Therefore, Mr. Dennis Stephens and I recommend the Commission not approve the -- the Commission not approve 100 percent of the $1 billion transmission investment proposed under GIP for the 2023-2025 period. If the Commission follows -- if the Commission follows these recommendations, ratepayers will benefit by avoiding unnecessary rate increases. Furthermore, continuing transmission equipment replacement under the traditional capital maintenance

and reliability programs will make the best use of transmission investment dollars in ensuring a safe and reliable transmission system.

In addition, the unnecessary premature replacement of healthy and performing transmission assets will be prevented.

I hope the Commission finds my contribution to the record in this rate case valuable. This concludes my summary.

MR. WALSH: The panel is available for cross-examination. Thank you.

MADAM CHAIR PRIDEMORE: Questions from commissioners?

VICE CHAIRMAN ECHOLS: Yes.

MADAM CHAIR PRIDEMORE: Commissioner Echols.

VICE CHAIRMAN ECHOLS: You are familiar with the expression "trust but verify"? You have heard that?

MR. ALVAREZ: Yes.

VICE CHAIRMAN ECHOLS: For me, you know, for me, I respect the company, their grid, you know, the -- you know, the great job that they have done through the years. But, you know, the rate case, the data, the research is a great opportunity for us to verify. And in the last panel, we were talking about

saving $6 million, saving $10 million. And as I look at this possible 45 percent rate increase, which scares me to death, what you are saying today, which I am so interested in, is a way to save a billion dollars.

It's -- and so if we are going to mitigate this 45 percent, we are going to have to find places to save. And that's really what I am looking for in this rate case is, you know, what needs to stay and what needs to go. And you obviously have a different opinion here than the company.

So let me just clarify that you are suggesting that we can save about a billion dollars by cutting the grid hardening and the undergrounding. Is that what you're saying?

MR. ALVAREZ: Well, actually the billion is the transmission and then another billion on top of that for the undergrounding and the circuit hardening.

VICE CHAIRMAN ECHOLS: Yeah. So it's $2 billion?

MR. ALVAREZ: Yes. And, Your Honor, that's not the revenue requirement. That's the capital investment. But Mr. Smith's testimony shows what the -- translates that into revenue requirements for you.

**VICE CHAIRMAN ECHOLS:** You know, as -- whenever the company comes to me, you know, and talks about reliability, I am -- you know, I am keenly interested in keeping things reliable. It's very important to us. And you heard, you know, the Site Selection Magazine criteria and the importance of reliability.

So it is a bit alarming to me that, you know, in '19 we were asked to make an investment, and, you know, to -- you know, to reduce the system average interruption duration goal from 130 minutes to 65 minutes. It's on page 7 and 8 of your testimony. But now the goal is changing; right?

So we're not going to make it. Is that what you're saying? That there is a revision?

**MR. ALVAREZ:** Well, we are even concerned about the 80, to be quite honest with you.

**VICE CHAIRMAN ECHOLS:** Yes. So is there a reason that we are not going to make that? Why did we miss our target? Why is it being revised, do you think?

**MR. ALVAREZ:** Well, I know one issue is that the company has pulled back some of its capital investment, but the degree of pull-back is this big and whereas the degree of, you know, performance reduction is maybe this big.

**And so -- so I think it is a -- that's a little bit to explain, is they are cutting back on the spending a little bit.**

**I think it's also just a recognition of --**

**Go ahead, Dennis. It's a recognition of their experience from the first investments. Go ahead.**

**MR. STEPHENS: Yes, that's what I was going to say. One of the things that they found out with their -- once they started doing the undergrounding, as they -- the company testified in the last hearing, or in the earlier hearings, was that they found a lot of rock and ran into rock.**

**So the cost was starting to go up. And it went up substantially. And so they found out that they couldn't possibly obtain that level of reliability improvement with the cost that they had originally in place.**

**But I think it's very important to remember that we are saying that that approach that they are using is not founded, that really what they should be doing is looking at this on a circuit-by-circuit basis and doing a cost-benefit analysis on each one of those to make sure that the investment that they are making provides more value to customers in dollars than the cost that they are implementing.**

**And when they are doing this from across the board, 800 in the first case of feeders and then a thousand feeders in the second, applying packages to, when I looked at the underground system that the investments that they made in 2020, none of them -- they reduced the -- they were going to reduce SAIDI to 20 and SAIFI to .2. I reduced it to zero.**

**I took every one of the feeders that they made their investment in, reduced it all the way to zero and, still, none of them were cost-effective.**

**VICE CHAIRMAN ECHOLS: So they had a theory and they tested it and there was some problems with it is what you're saying. And that there is possibly a better way to do it?**

**MR. STEPHENS: Yes.**

**VICE CHAIRMAN ECHOLS: Yes. You say that pretty adamantly.**

**MR. STEPHENS: Absolutely. Yes. That's what our whole testimony is about; right?**

**VICE CHAIRMAN ECHOLS: And there's nothing wrong with us making these changes; right? That's why we do this every three years, right, do our IRP and our rate case, because we aren't perfect. We do have theories and sometimes they don't work out quite the way that we thought they would.**

MR. STEPHENS: Yes. One of the things that we were recommending was that they've already spent a lot of money. We really need to have them evaluate what the results are from what they've already spent before they go spending all this other money.

VICE CHAIRMAN ECHOLS: So these worst-performing circuits -- this may be outside of your scope -- but could congested circuits, worst-performing circuits benefit actually from having distributed energy along that circuit or at the end of that circuit? Is that something that might keep them from having to do upgrades if there is distributed energy along that particular circuit?

MR. STEPHENS: Well, let me just say that generally when you're talking about DER and the value of DER, it helps capacity and not reliability that much, other than the fact of possibly helping in some switching. So there is a possibility that it could help some, certainly on a capacity side, but maybe in a small amount on the reliability side.

VICE CHAIRMAN ECHOLS: So a theory. You are not adamant on that?

MR. STEPHENS: I'm sorry? What was the question?

VICE CHAIRMAN ECHOLS: You are not adamant that

that might fix it?

MR. STEPHENS: No, no. I am not adamant that it would fix it. That's for sure, yeah.

VICE CHAIRMAN ECHOLS: But there are other non-wire solutions, right, that can -- that can help resolve capital expenditures; is that right?

MR. ALVAREZ: There's demand-response programs. There are battery storage programs. Although, that still is capital. There are different things.

VICE CHAIRMAN ECHOLS: I just remember meeting with ConEd in New York about a substation that they were going to build in the Bronx, and they -- instead of spending the capital on the substation, they tried some non-wire solutions in order to keep from having to spend that money right then.

MR. STEPHENS: Right.

VICE CHAIRMAN ECHOLS: Right? And I think that's the challenge for us, is how do we keep from spending some of this money right now because our ratepayers are about to be blasted with an enormous increase. And we need to figure out a way to curtail some of that. And what you're suggesting is you've got an answer for a couple billion dollars.

MR. ALVAREZ: (Nodding head.)

VICE CHAIRMAN ECHOLS: Yes, thank you.

MADAM CHAIR PRIDEMORE: Any other questions from Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: All right.

Americans for Affordable Clean Energy?

MR. GALLOWAY: No questions.

MADAM CHAIR PRIDEMORE: ChargePoint?

MR. FYKES: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Commercial Group?

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: EVgo Services?

MR. VIJAYKAR: I have no questions.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers?

MR. CLAY JONES: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Conservation Voters?

(No response.)

MADAM CHAIR PRIDEMORE: I see the door. Okay.

Georgia Interfaith Power and Light?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA?

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch?

MS. COYLE: Good afternoon. I have just a few questions.

CROSS-EXAMINATION

BY MS. COYLE:

Q So would you say the company's proposed non-traditional spending for the Grid Investment program is unnecessarily risking ratepayer revenue, especially in light of increase in storm damage across the state and the region, without increasing grid resilience at all?

A (Witness Alvarez) I don't know about "at all," but very little. That's certainly true.

Q So would you say that the proposed investment is not good for the company's ratepayers but very good for the company's shareholders?

A (Witness Alvarez) We would agree with that, yes.

Q And when you were answering some questions from Commissioner Echols, you talked about the company's -- what you called, I believe, an unfounded approach, and recommended instead doing a circuit-by-circuit with cost-benefit analysis.

How does the company's proposal and what they have been doing -- you referenced back to investments made in 2020, they found more rock -- how is what the company has -- has been doing and proposes to do in the future compare to their utility peers?

A (Witness Alvarez) Well, certainly, you know, utilities across the United States, you are trying to increase their rate base. So I would argue that it's somewhat -- the attempt to do this is somewhat common.

Our concern is with the effectiveness of it, not with the attempts of it. If that makes any sense.

Q It does make sense.

So would you say that the company -- so the company -- and peers -- may be attempting this. I think I heard you say to increase revenue -- to increase revenue?

A (Witness Alvarez) Grow their rate base, yes.

Q Increase revenue. Okay.

MS. COYLE: Thank you. No further questions.

MADAM CHAIR PRIDEMORE: Interstate Gas Supply?

(No response.)

MADAM CHAIR PRIDEMORE: The Kroger Company?

MR. BOEHM: No questions.

MADAM CHAIR PRIDEMORE: MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply

Management?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. DOWDY: No questions.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association?

MR. MAHAN: Good afternoon, Commission.

CROSS-EXAMINATION

BY MR. MAHAN:

Q Good afternoon, panel. I am Simon Mahan with the Southern Renewable Energy Association.

I will do my best to point out specific parts in your testimonies, but there was a fair bit of overlap between the two sets.

I have structured my questions the best I can as yes-or-no answers, so please try to answer yes or no.

Mr. Rana, you point out on page 7 of your testimony, line 7, that $7.72 of the proposed $16.29 per month of the rate increase is due to the proposed transmission and distribution program.

Is that correct?

A (Witness Rana) Yes.

Q Is that mostly due to the Grid Investment

program?

A (Witness Rana) Yes.

Q But you state on page 18, line 15 through 18, that the company did not perform a benefit-cost analysis regarding the proposed transmission investments.

Does that in include all the transmission investments or just the Grid Investment Plan?

A (Witness Rana) Only for the transmission lines. They did not carry out any cost-benefit study. For distribution they did.

Q And just to be clear, though, different types of transmission projects can provide many benefits; correct?

A (Witness Rana) Yes.

Q And reliability is just one type of benefit?

A (Witness Rana) Yes.

Q And, Mr. Stephens, do you agree with that?

A (Witness Stephens) Yes, I do agree with that.

Q Could improved system economics and competition be of benefit? Mr. Rana?

A (Witness Rana) Yes.

Q Mr. Stephens?

A (Witness Stephens) Would you ask the question again, please?

Q Could improved system economics and competition be of benefit to transmission project?

A (Witness Stephens) I'm not sure I know what you mean by "improved system economics."

Q If you build a transmission line, it enables lower-cost generation to move to a region where there's higher cost generation.

A (Witness Stephens) Yes, I agree with that.

A (Witness Rana) Yes.

Q Could reduced reserve margin be of benefit of transmission, Mr. Rana and Mr. Stephens?

A (Witness Rana) Yes, that's a benefit, too.

A (Witness Stephens) I'm sorry. I'm not sure.

Q Could access to lower cost renewable resources be another benefit, Mr. Rana and Mr. Stephens?

A (Witness Rana) Yes.

A (Witness Stephens) Yes.

Q And could the ability to retire uneconomic higher-cost resources be another benefit?

A (Witness Rana) Yes.

A (Witness Stephens) You are going to have to define "uneconomic."

Q Higher-cost resources than others available.

A (Witness Stephens) Yes, that's a possibility.

Q And is it possible, Mr. Rana, that if enough transmission benefits are calculated against the costs, that some types of transmission investments could result in more

benefits than costs?

A (Witness Rana) The transmission lines that is proposed as a part of --

Q Is it -- but is it possible that if you weigh enough benefits against the costs, that some transmission projects could result in higher benefits than costs?

A (Witness Rana) Let me explain to you that the --

Q Well, just yes or no?

MR. WALSH: Madam Chair, I think the panel has been very good about answering yes or no when they can. The witness is asking to explain his answer in this instance.

MADAM CHAIR PRIDEMORE: Sustained.

Mr. Rana, you can explain your answer.

A (Witness Rana) Okay. The transmission lines that we are talking about, the new transmission lines. The question that we are questioning, the GIP has nothing to do with the new investment associated with the new transmission. So that is totally two different aspect. We are not saying -- we are not recommending not to approve any other investment other than what is included in GIP spending.

BY MR. MAHAN:

Q That was going to be my next question. The

company didn't show that their transmission plan provides any of the benefits that you and I have just been talking about; correct?

A (Witness Rana) Can you repeat the question.

Q The company hasn't shown that any of the benefits that you and I have just gone through, they didn't calculate any of those benefits, have they?

A (Witness Rana) Related to GIP --

Q Correct.

A (Witness Rana) -- transmission lines, they did not carry out a cost-benefit study.

Q And since we have established that they didn't do that, to be fair, did anyone on this panel -- Mr. Stephens, Mr. Alvarez, Mr. Rana -- did anyone on the panel or any of the Commission staff conduct any benefit-cost analysis on the GIP plan proposed by the company?

A (Witness Alvarez) I can't answer for staff. On the transmission side, I guess it would be for the substations --

A (Witness Stephens) We did some cost-benefit analysis on substation transformers.

A (Witness Alvarez) Circuit breaker --

A (Witness Stephens) Circuit breakers. Right. Not transmission lines. So...

Q And you only looked at reliability?

A (Witness Stephens) And we only looked at reliability as a -- as the consequences part, right.

A (Witness Alvarez) Correct.

Q Okay. Mr. Alvarez and Mr. Stephens, on your testimony at the bottom of page 19 into page 20, you say, "Transmission lines, equipment, and towers are subject to formal inspections with checklists and scoring mechanisms." And have you reviewed Georgia Power's checklist and scoring mechanisms?

A (Witness Alvarez) We did get those in discovery. Am I -- is that right?

A (Witness Stephens) I didn't -- I didn't review them, so I don't know.

A (Witness Alvarez) I don't recall the degree to which we reviewed those.

Q Okay. Mr. Rana, did you receive those checklists and scoring mechanisms?

A (Witness Rana) Which line are you referring to in my testimony?

Q Well, I was just asking in general. Mr. Alvarez and Mr. Stephens says that the company has a checklist and scoring mechanisms with regards to their -- the inspections of the transmission system.

A (Witness Rana) They do inspection tests and

monitoring, yes.

Q Okay.

A (Witness Alvarez) If I could point out, too, those are pretty standard, right.

A (Witness Rana) That's the industry-wide practice and that's the best practice to maintain the assets, basically.

Q Okay.

A (Witness Alvarez) Right.

Q Mr. Alvarez and Mr. Stephens, you have Exhibit No. 1, which is also Figure Number 1, page 7 of your direct testimony. And this is where you point out that the Grid Investment Plan, along with the additional transmission and distribution capital costs over the next few years, triples the costs. But that exhibit groups both the transmission and distribution costs; correct?

A (Witness Alvarez) It does.

Q Most of the costs in that chart are driven by the distribution level cost, is that correct?

A (Witness Alvarez) Not by a lot, but, yes. And there are charts elsewhere in the testimony that do break it out, the distribution of the transmission components separately. But I would agree, yes, slightly more than half is the distribution side; that's correct.

Q And would you say it's mostly with regards to

the transmission cost, that it's not the transmission lines that are driving the additional cost, but things like new substations and transformers?

A (Witness Rana) Half and half.

A (Witness Alvarez) About half and half, according to Mr. Rana.

A (Witness Rana) Yes.

Q Okay. And so is it fair to say that it's not new transmission lines necessarily causing the capital expenditure increases, but it's just mostly maintaining the existing system and not planning for system-wide change?

A (Witness Alvarez) Yes. As Mr. Rana answered earlier, we are only focused on the GIP. We are not recommending other more traditional proposals be rejected, like for capacity expansion or new business or those types of things. We are not rejecting or recommending that those be curtailed.

Q Yes. And still on that exhibit, you point out that the costs have almost doubled and have been pretty high for the past three years already.

Have Georgia ratepayers received the benefits commensurate with the costs associated with those investments?

A (Witness Alvarez) We do not believe so.

A (Witness Stephens) No, we do not believe so.

Q So then are you recommending that within the past three years' worth -- the total transmission distribution capital spending costs, that they should be denied as imprudent in this rate case?

A (Witness Alvarez) We are not recommending that.

Q Why not?

A (Witness Alvarez) I would argue that in any evaluation of company investments, and when you are presenting testimony, you basically work with what you have been presented. We were presented with a task of looking at the company's go-forward rate plan. And so we were responding to that. We did not consider passing judgment on what has already been spent.

Q So looking forward into what the company is proposing to be spent, Mr. Alvarez and Mr. Stephens, on page 74, lines 14 and 15 of your testimony, you suggest that you support just -- "just a doubling of transmission and distribution costs."

Did you do any analysis to come up as to why that is the right recommendation to make?

A (Witness Alvarez) It is basically just our recommendation of what is not cost effective, removing those and leaving the balance.

Q And so you didn't do any sort of analysis to

figure out if 50 percent higher was the correct amount or 75 percent higher was the correct amount? You saw that the company had proposed the grid investment plan, thought that was outside of the bounds, and decided that should be left on the chopping block, and instead, they should be left -- they should be allowed to do everything else?

A (Witness Alvarez) We focused on what we thought was the most egregious practices; right? So there is only so much scope you have available, so much budget you have available on these projects. And so we focused on the most egregious practices that we encountered as we reviewed the materials.

Q And so everything else gets a pass?

A (Witness Alvarez) I think it's a --

A (Witness Stephens) I would just say it was -- it was unanalyzed.

Q Mr. Rana, on page 11 of your testimony, at line 7, you note that "the company plans to replace and rebuild a few transmission lines in 2023, 2024, and 2025."

And you cited Company Exhibit APA/SPA/ADH/MBR-8.

A (Witness Rana) Yes.

Q Did you review those specific transmission projects individually?

A (Witness Rana) No. As a package.

Q Also, Mr. Rana, on page 19 of your testimony, line 4 to 5, you explained that the company didn't perform this cost-benefit analysis on transmission. And the company's explanation was because the aging infrastructure needs to be replaced.

A (Witness Rana) Yes.

Q Couldn't that same argument simply be applied to power plants, that because a power plant is old, it needs to be replaced and therefore no cost-benefit analysis is necessary for its replacement?

A (Witness Rana) I cannot answer that question. Power plant is not something that I can comment on.

Q Sure. Mr. Alvarez and Mr. Stephens, on page 12, line 3 of your testimony, you state -- and in your summary this morning, or this afternoon -- you state that because "there is no reliability emergency," you consider the company's grid investment plan to be unnecessary.

Can you tell us what you consider to be a reliability emergency?

A (Witness Alvarez) I would say our basis for that statement is the fact that Georgia Power and Light has, over the years, been -- their reliability as measured by SAIDI -- has been pretty much the same as the industry average. And so that, in combination with the fact that they have not received overwhelming requests from their

customers to improve reliability, not complaints about their reliability, if -- if they were receiving massive complaints to the Commission about reliability, I would consider that an emergency and they would need to react to that. But that is not the case here. That's not what's happening.

Q Still, you would agree, though, that transmission plans are necessary even without a reliability emergency?

A (Witness Alvarez) Absolutely. Transmission plans are necessary, that's right. In fact, all -- distribution, all those plans are necessary.

Q And on page 25 of your testimony, Mr. Alvarez and Mr. Stephens, you talk about Georgia Power's witness -- and I'm watching the time here. I am cognizant we are going to run out here.

You talk about Mr. Robinson, how he supports the grid plan because there have been power outages in other parts of the country. And in your testimony, you mentioned wildfires in California and New Orleans, the hurricane -- after Hurricane Ida. But there's also physical risks here in Georgia, like hurricanes, tornadoes, polar vortices.

But did Georgia Power provide any analysis showing that their transmission plans include any scenario-based planning exercises that would deal with any of those types of events?

A (Witness Rana) No, those aren't -- it's not addressed all in the testimony.

Q Okay. Did you as a panel evaluate or create any sort of scenario evaluating any type of those events?

A (Witness Alvarez) We did not.

A (Witness Rana) No, we did not.

Q But all of these would be considered extreme events?

A (Witness Rana) Right.

A (Witness Alvarez) Yes.

Q Are any of you on the panel aware of the term major event days?

A (Witness Alvarez) Yes.

A (Witness Stephens) Yes.

Q Are major event days always included in SAIDI calculations?

A (Witness Alvarez) They are typically provided both ways. Both with and without major event days.

Q Does Georgia Power always include major event days in their SAIDI calculations?

A (Witness Alvarez) I think they report both.

A (Witness Stephens) Yes, I think they do too.

A (Witness Alvarez) Almost all utilities report both.

A (Witness Rana) That's the industry practice,

to report both ways.

Q Okay. So Mr. Rana, back on page 19 of your testimony, lines 6 through 10, you state that you believe the company's transmission investment plan is designed to unnecessarily grow the rate base.

And Mr. Alvarez and Mr. Stephens, you state something similar on page 17, line 11 of your testimony.

So is it fair to sum up your testimonies that you believe the Grid Investment Plan, as proposed today, is a way to -- for the company to spend more money to become more profitable?

A (Witness Alvarez) Agreed.

A (Witness Rana) Yes.

Q Does that mean you think that all transmission plans are bad? Mr. Rana?

A (Witness Rana) The -- all transmission plans are?

Q That -- does that mean that you think all transmission plans are bad?

A (Witness Rana) Bad? No. We are talking only about the transmission infrastructure replacement as a part of GIP. And here, they're -- basically what they are doing is prematurely replacing well-functioning assets they already have passed the objective test, as well as the monitoring. And they are perfect, operating finely --

perfectly. And still, as a part of the -- this GIP age criteria that they are using, they want to just replace it, just because it passed the threshold of the age limit the company has defined.

Q Right.

A (Witness Rana) As a result, what happens is that prematurely they are replacing all this. And that's why the -- the cost is really, really high because they want to do so many replacement in such a short period.

Q Thank you.

A (Witness Rana) The right way to do it is to use the objective test and based on there, identify the assets that needs to be replaced. As there are companies doing right now as a part of their capital maintenance program, and the reliability improvement programs. And as long as they do that and -- the GIP was introduced in 2019. The assets have been aging even before that and now. And it will in the future. So why not continue with the matter that they have instead of reinventing the wheel under the GIP?

Q Thank you.

Would the -- and this is for the full panel.

Would the company also have a financial incentive to avoid transmission plans that also supported increased market competition and overall lower system costs?

A (Witness Rana) That is -- nothing has been included in our testimony about that.

Q Okay. For the panel, if I talk about the North Georgia Reliability and Resilience Action Plan, do you know what I'm talking about?

A (Witness Rana) No. No.

Q Okay. If this Commission were to direct staff to conduct expert independent transmission analysis to identify transmission plans and projects to deliver greater transmission benefits for ratepayers, could the Commission do that?

MR. WALSH: Madam Chair, I am -- could I get clarification on what the question is? Are they asking -- is the question about the extent of the Commission's authority, or is it more of a practical question? I am just not sure what is being asked.

MR. MAHAN: Let me rephrase.

MADAM CHAIR PRIDEMORE: Go ahead.

BY MR. MAHAN:

Q Earlier in this cross, I believe, Mr. Alvarez, you mentioned part of the difficulty you had with regards to evaluating the proposed transmission and distribution capital expenditures was the information provided to you in this case; correct?

A (Witness Alvarez) Yes.

Q Is part of the problem associated the limited amount of time provided to you as witnesses regarding the ability to evaluate alternatives to the transmission solutions provided by the company?

A (Witness Alvarez) I think, in general, the -- we rely quite bit on discovery to get the information we need. We have very detailed -- as everyone can testify to reading our testimony -- we need a lot of data. And so typically that requires many rounds of discovery to kind of peel back the layers of the onion, you know, to get down to the nitty-gritty.

And here, in this state, honestly, the 30-day reply time is outside our experience by significant amounts. And it did significantly reduce our opportunity to dig further -- to dig further.

Q Would it be possible to provide alternative transmission plans to the Commission if you had more time?

A (Witness Rana) Alternative transmission plan for what?

Q For the Commission to evaluate.

MR. HEWITSON: Madam Chair, that seems to me to be a planning question, which is outside the scope of their testimony. It would be more an IRP question, even if it was within the scope of their testimony.

MR. MAHAN: I think it goes to the question of,

they are trying to figure out how to best plan the system and keep costs low for the ratepayers.

MR. HEWITSON: They being Georgia Power?

MR. MAHAN: The commissioners.

MR. HEWITSON: Well, this -- neither of these panels provided any testimony related to how to plan the system.

MR. MAHAN: Which is unfortunate.

MR. HEWITSON: But it's their testimony.

MADAM CHAIR PRIDEMORE: But, Mr. Mahan, that's an IRP function. So everything that's related to their testimony that's in this case is about the cost and prices. So I -- I want you to just remember that. This is about money. Make your questions about money.

MR. MAHAN: Okay. Well, with that, I will say thank you to the panel. I have no further questions for any other witnesses. So I would ask to be excluded from future roll calls going forward, for expediency. And I appreciate your time.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Mahan. Ms. Medlyn, do you have questions for this panel?

MS. MEDLYN: I have no questions.

MADAM CHAIR PRIDEMORE: You have no questions. Okay.

**With that, we are going to -- we are going to recess for the day. I want everybody to have this opportunity to go vote. This is not an opportunity just to go to the bar so you can get a chili dog. Go vote. We are adjourned. I will see y'all at 9:30 in the morning.**

**(Proceedings adjourned at 3:20 p.m.)**

C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.

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CCR-6256-8388-8026-4192

Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664

Brenda P. Elwell, RPR, CRR, B-2023

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**STATE OF GEORGIA**

**In Re:**

**Georgia Power Company's 2022 Rate Case ) Docket No. 44280**

**Hearing Room 110**

**Georgia Public Service Commission**

**244 Washington Street**
**Atlanta, Georgia**

**Wednesday, November 9, 2022**

**The above-entitled matter came on for hearing pursuant to Notice at 9:30 a.m.**

**PRESENT WERE:**

**TRICIA PRIDEMORE, Madam Chair**
**TIM ECHOLS, Vice-Chairman**
**FITZ JOHSON, Commissioner**
**LAUREN "BUBBA" MCDONALD, Commissioner**
**JASON SHAW, Commissioner**

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# I N D E X


| WITNESSES: | DIRECT | CROSS | REDIRECT | RECROSS |
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| RAJENDRASINH RANA | | | | |
| By Mr. Hewitson | | 1817 | | |
| By Mr. Walsh | | | 1893 | |
| LANCE KAUFMAN, Ph.D. | | | | |
| By Mr. Walsh | 1906 | | 2001 | |
| By Mr. Marzo | | 1966 | | |
| DANTE MUGRACE | | | | |
| By Mr. Walsh | 2004 | | 2087 | |
| By Mr. Marzo | | 2069 | | |
| JAMIE BARBER | | | | |
| BENJAMIN DEITCHMAN | | | | |
| GLENN WATKINS | | | | |
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| By Mr. Clay Jones | | 2230 | | |
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| By Mr. Hewitson | | 2292 | | |
| JOSEPH AKERS | | | | |
| RON NELSON | | | | |
| BARRY SELVIDGE | | | | |
| By Mr. Galloway | 2300 | | 2403 | |
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# I N D E X


| WITNESSES: | DIRECT | CROSS | REDIRECT | RECROSS |
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| By Mr. Walsh | | 2435 | | |
| By Mr. Hewitson | | 2442 | | |
| STEVE CHRISS | | | | |
| By Mr. Jenkins | 2445 | | 2504 | |
| By Mr. Marzo | | 2496 | | |
| COLIN MURCHIE | | | | |
| By Mr. Vijaykar | 2505 | | | |
| By Mr. Walsh | | 2544 | | |
| By Mr. Hewitson | | 2548 | | |
| ROGER C. TUTTEROW, Ph.D. | | | | |
| By Mr. Clay Jones | 2552 | | | |
| JEFFRY POLLOCK<br>BILLIE S. LACONTE | | | | |
| By Mr. Clay Jones | 2587 | | 2766 | |
| By Ms. Coyle | | 2734 | | |
| By Ms. Medlyn | | 2737 | | |
| By Mr. Hewitson | | 2739 | | |
| By Ms. Marzo | | 2751 | | |
| C. NICHOLAS DEFFLEY<br>DAVID A. NIFONG | | | | |
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| By Mr. Marzo | | 2815 | | |
| By Ms. Brown | | | 2817 | |
| MARK E. ELLIS<br>JUSTIN BARNES | | | | |
| By Ms. Whitfield | 2819 | | 3120 | |
| By Mr. Marzo | | 3092 | | |
| By Mr. Hewitson | | 3103 | | |

| EXHIBITS | FOR IDENTIFICATION | IN EVIDENCE |
|---|---|---|
| STAFF: | | |
| 56 - LK-1 | 1954 | 2003 |
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| 58 - Errata | 1964 | 2003 |
| 59 - DM1 | 2057 | 2089 |
| 60 - DM2 | 2057 | 2089 |
| 61 - Prefiled Trade Secret Testimony and Exhibits of Mr. Mugrace | 2058 | 2089 |
| 62 - BDW 1 - Barber CV | 2199 | 2300 |
| 63 - BDW 2 - Deitchman CV | 2199 | 2300 |
| 64 - BDW 3 - Watkins CV | 2199 | 2300 |
| 65 - BDW 4 - GPC Generating Unit Details | 2199 | 2300 |
| 66 - BDW 5 - GPC Base Interm. Peak CCOSS with Vogtle | 2199 | 2300 |
| 67 - BDW 6 - GPC Base Interm. Peak CCOSS without Vogtle | 2199 | 2300 |
| 68 - BDW 7 - GPC Probability of Dispatch w/ Vogtle | 2199 | 2300 |
| 69 - BDW 8 - GPC Probability of Dispatch w/o Vogtle | 2199 | 2300 |
| 70 - BDW 9 - GPC Customer Cost Analysis | 2199 | 2300 |
| 71 - BDW 10 - The Brattle Group (Confidential) | 2199 | 2300 |

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| 73 - BDW 12 - Typical Non-Residential & Residential Hourly Loads (MW) July | 2199 | 2300 |
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| 75 - BDW 14 - Electric Service Tariff: Renewable and Nonrenewable | 2199 | 2300 |
| 76 - BDW 15 - Community Solar Blocks Subscribed | 2199 | 2300 |
| 77 - BDW 16 - 2022 IRP & 2022 DSM App. STF-DEA Data Request Set #2 | 2199 | 2300 |
| 78 - BDW 17 - GPC 2022 Rate Case Staff Data Request No. STF-PIA-6 | 2199 | 2300 |
| 79 - BDW 18 - 2022 Rate Case SDR Request No. STF-TAI-1 | 2199 | 2300 |
| 80 - BDW 19 - 2022 Rate Case SDR Request No. STF-TAI-1 | 2199 | 2300 |
| 81 - BDW 20 - 2022 Rate Case SDR No. STF-PIA-6 | 2199 | 2300 |
| 82 - BDW 21 - 2022 Rate Case SDR No. STF-TAI-1 | 2199 | 2300 |
| 83 - Trade Secret Testimony & Trade Secret Exhibits of Barber, Deitchman & Wakins | 2199 | 2300 |

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| GAM: | | |
| 1 - Current Revenue Column Modified to Remove Fuel Costs - Public Disclosure | 2254 | 2768 |
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| AACE: | | |
| 15 - Ex. 1 - Akers CV | 2350 | 2373 |
| 16 - Ex. 2 - Nelson CV | 2350 | 2373 |
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| EXHIBITS | FOR IDENTIFICATION | IN EVIDENCE |
|---|---|---|
| 18 - Ex. 4 - ET Make Ready Infrastructure Program Terms & Conditions | 2350 | 2373 |
| 19 - Ex. 5 - GP Electric Trans. Make Ready Contract | 2350 | 2373 |
| 20 - Ex. 6 - Analysis of Cost Differential | 2350 | 2373 |
| GPC: | | |
| 37 - Trade Secret 2020 GPC Dismantlement Study STF-A1-1-10 | 1969 | 2089 |
| 38 - STF-LA-2-72 | 2084 | 2089 |
| CHARGEPOINT: | | |
| 1.1 - Justin Wilson CV | 2410 | 2445 |
| 1.2 - States Allowing EV | 2410 | 2445 |
| COMMERCIAL GROUP: | | |
| CG Ex. 1 (SWC-1) | 2446 | 2505 |
| GC Ex. 2 (SWC-2) | 2446 | 2505 |
| CG Ex. 3 (SWC-3) | 2446 | 2505 |
| CG Ex. 4 (SWC-4) | 2446 | 2505 |
| CG Ex. 5 (SWC-5) | 2446 | 2505 |
| CG Ex. 6 (SWC-6) | 2446 | 2505 |
| CG Ex. 7 (SWC-7) | 2446 | 2505 |
| CG Ex. 8 (SWC-8) | 2446 | 2505 |

| EXHIBITS | FOR IDENTIFICATION | IN EVIDENCE |
|---|---|---|
| EVgo: | | |
| 1 - Customer Service Agreement | 2507 | ---- |
| GIPL: | | |
| 6 - JRB 1 | 3078 | 3121 |
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| 8 - JRB 3 | 3078 | 3121 |
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| COG-3 - CND-2 | 2807 | ---- |
| COG-4 - Errata Testimony | 2807 | ---- |
| COG-5 - Trade Secret Testimony of Nifong and Deffley | 2807 | ---- |

**P R O C E E D I N G S**

**MADAM CHAIR PRIDEMORE: Good morning, everybody. Call to order Docket No. 44280: Georgia Power Company's 2022 rate case.**

**Let's go through the appearance list first. Georgia Public Service Commission.**

**MR. WALSH: Thank you, Madam Chair. For the Public Service Commission staff, Daniel Walsh and Preston Thomas. Thank you.**

**MADAM CHAIR PRIDEMORE: Georgia Power Company.**

**MR. MARZO: Thank you, Madam Chair. Brandon Marzo, Steve Hewiston and Allison Pryor on behalf of Georgia Power Company.**

**MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy.**

**MR. GALLOWAY: Good morning, Madam Chair. Newton Galloway and Terri Lyndall on behalf of AACE. Thank you.**

**MADAM CHAIR PRIDEMORE: ChargePoint.**

**MR. FYKES: Good morning, Madam Chair. Lucas Fykes on behalf of ChargePoint, Inc.**

**MADAM CHAIR PRIDEMORE: Commercial Group.**

**MR. JENKINS: Good morning. Alan Jenkins.**

**MADAM CHAIR PRIDEMORE: Concerned Ratepayers for Georgia.**

(No response.)

MADAM CHAIR PRIDEMORE: Concerned Ratepayers for Georgia.

(No response.)

MADAM CHAIR PRIDEMORE: Concerned Ratepayers for Georgia.

(No response.)

MADAM CHAIR PRIDEMORE: Cypress Creek Renewables.

(No response.)

MADAM CHAIR PRIDEMORE: Cypress Creek Renewables.

(No response.)

MADAM CHAIR PRIDEMORE: Cypress Creek Renewables.

(No response.)

MADAM CHAIR PRIDEMORE: EVgo Services, LLC.

MR. VIJAYKAR: Good morning, Commissioners. Nikhil Vijaykar on behalf of EVgo.

MADAM CHAIR PRIDEMORE: Very good.

Georgia Association of Manufacturers.

MR. JONES: Thank you, Madam Chair. Clay Jones.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments.

**MS. BROWN: Good morning, Madam Chair. Alicia Brown for the Georgia Coalition of Local Governments.**

**MADAM CHAIR PRIDEMORE: Good morning, Ms. Alicia.**

**Georgia Conservation Voters.**

**MS. OPIE: Good morning, Madam Chair. Deborah Opie on behalf of Georgia Conservation Voters Education Fund.**

**MADAM CHAIR PRIDEMORE: Good to see you, Ms. Opie.**

**Georgia Interfaith Power & Light.**

**MS. KYSOR: Good morning, Commissioners. Jill Kysor and Jen Whitfield on behalf of GIPL.**

**MADAM CHAIR PRIDEMORE: Good morning, Ms. Kysor.**

**Okay. I know we abbreviated this yesterday. So we're going to abbreviate it going forward, but, for the record, Georgia Solar Energy Industries Association, Solar Energy Industries Association, and Volt Solar, abbreviated as GSEIA.**

**MR. THOMASSON: Scott Thomasson for GSEIA.**

**MADAM CHAIR PRIDEMORE: Thank you.**

**GA Solar.**

**MR. MORELAND: Good morning. Don Moreland with Georgia Solar.**

MADAM CHAIR PRIDEMORE: Good morning, Mr. Moreland.

Georgia Watch.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Watch.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Watch.

(No response.)

MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

(No response.)

MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

(No response.)

MADAM CHAIR PRIDEMORE: Interstate Gas Supply. They didn't have cross so they may not be available today.

All right. Kroger Company.

MR. BOEHM: Good morning, Madam Chair. Kurt Boehm for Kroger.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Boehm.

MARTA.

MS. STURM: Good morning, Commissioners. Kasey Sturm on behalf of MARTA.

MADAM CHAIR PRIDEMORE: Good morning, Ms. Sturm.

Resource Supply Management.

MR. CLARKSON: Good morning. Jim Clarkson for Resource Supply Management.

MADAM CHAIR PRIDEMORE: Good morning, Mr. Clarkson.

Sierra Club.

MS. ARIZA: Good morning. Isabella Ariza on behalf of the Sierra Club.

MADAM CHAIR PRIDEMORE: Good morning, Ms. Ariza.

SACE.

MR. DOWDY: Good morning, Madam Chair, Commissioners. Craig Dowdy and Steven Jones on behalf of Southface and SACE.

MADAM CHAIR PRIDEMORE: Good morning, Mr. Dowdy.

Southern Renewable Energy Association asked to be excused -- oh, but he's here.

Mr. Mahan, how are you?

MR. MAHAN: Good morning. Yes, ma'am. I decided just to come in just to make sure that I can be excused. But I am here this morning just to say good morning.

MADAM CHAIR PRIDEMORE: Good morning.

MR. MAHAN: Good morning.

MADAM CHAIR PRIDEMORE: We're going to keep you

in roll call then. Good to see you.

MR. MAHAN: I appreciate it. But I have no cross.

MADAM CHAIR PRIDEMORE: No cross, okay.

MR. MAHAN: So I appreciate it anyway. Thank you.

MADAM CHAIR PRIDEMORE: Thank you.

United States Department of Defense and all other Federal Executive Agencies.

MS. MEDLYN: Good morning, Commissioners. Emily Medlyn on behalf of the United States Department of Defense and all other Federal Executive Agencies.

MADAM CHAIR PRIDEMORE: Good morning, Ms. Medlyn.

Utility Management Services.

(No response.)

MADAM CHAIR PRIDEMORE: All right. They have stipulated their testimony and are not present.

Okay. A couple of housekeeping things from the Chair and then we'll open up housekeeping for appearances before we move on to public witnesses.

So I made a comment yesterday that I have watched paint dry faster than how the proceedings went. However, I recognize that that's usually the

first day. Everybody is kind of getting organized and getting their thoughts together.

All five of us, we want to hear what the intervenors say. We want to hear what the witnesses have to say. But you do realize that we're on a schedule. And it's not a schedule that we want or a schedule of our making.

I don't want to keep us here until midnight for the next two nights or later. And there's just things that we can do to speed this along.

Let your yes be yes and your no be no. And if you've already elaborated on an answer once, you don't have to elaborate on it again. It's in the record.

All the intervenors, the public, the Commission staff, the Commissioners, we all have all that. And so we want to hear what you have to say. I'm just politely asking you to say it faster.

Be organized with your handouts. If you need to use breaks or some time out in the hallway to sort of get ready before you're up for cross or before your witnesses are up, please do so. It is very much appreciated by all of us; okay?

All right. Any other housekeeping matters today?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Very good.

All right. So I've got a public witness list and let's get started.

Kevin Howell.

MR. HOWELL: Good morning.

MADAM CHAIR PRIDEMORE: Good morning.

MR. HOWELL: Ma'am, sirs, my name is Kevin Howell. I'm the president of IBEW Local 84. It was also my honor to serve our nation in the U.S. Army and Georgia National Guard from 1993 to 2015, during some of the toughest days of the global war on terrorism.

I served with honor alongside some of the bravest men and women I've ever known. You heard from our business manager, Drew Stover, and executive board member Carlos Fernandez when last you heard from public witnesses.

Like them, I am elected by our membership and I serve in the trenches representing our membership participating in the contract negotiations, grievances, and other aspects of the Local's business across all of our business units in every aspect of the energy system from power generation, transmission, maintenance and nuclear operations.

I currently work for Southern Nuclear Company as a lead radiation protection technician at Plant Vogtle Units 3 and 4 and was honored to be here with you at the last hearing after I got off night shift.

Since then, I am sure that you're aware that we have completed fuel load and are well on the way to commercial operation following extensive testing. I speak on behalf of the men and women that accomplished a significant milestone in our state's energy policy history.

For many of our membership, it ranks as one of the greatest things that we've ever accomplished. We are glad to be a part of the building of Plant Vogtle Units 3 and 4. And I commend you, your tenacity and commitment in seeing this project to completion. Generations from now will benefit from your leadership and the expansion of our clean, reliable, baseload energy generation.

However, it is on a more broad topic that I come before you today. You have heard extensive testimony over the years on the importance of the electrical grid, but there is a human element to that, as well. I'm a blue collar worker representing other blue collar workers who take great pride in what we do to keep the grid up and running. It is a

particular point of pride that Georgia's reliability is so solid.

That is because of the partnership we have with you. When investments were needed to improve the overall performance of the grid, you have authorized it. We have taken your investment and made the system as robust as possible.

As robust as our system is, we can't rest on our achievements. We have to continue to make smart improvements that will enable our system to withstand more frequent and severe storms. Our industry peers are making these improvements to make their segments of the power grid more resilient and robust. Let's remember that this is about serving our customers, whether it is a family, small business, or large industrial manufacturer with more resilient power delivery systems.

Beyond the great work you do as Commissioners, I'm not aware of your personal passions or what your vocations may have been before being elected to this body. In whatever your chosen business, there surely was a moment filled with personal pride when a hard accomplishment was realized. That's the real energy behind Georgia's grid.

The enormous pride that the men and women of

Local 84 bring excellent work to remote workplaces across the state every day. It can't be measured in any spreadsheet, investment plan or transformer order sheet. It is that silent dignity that comes from our work.

The other part of the human element is the tremendous positive impact that a reliable grid has on our communities. Reliability attracts growth and brings more opportunity to our citizens with job creation. And we surely can't forget how critical reliability is for emergency services, schools, hospitals, and nursing homes. Our communities deserve the strongest grid possible.

There used to be a jingle associated with Georgia Power in the early days that said: There is a special kind of feeling that comes from the -- from deep inside when the work you do helps others live a better life.

That jingle still resonates in the efforts labor union members and many others do to energize our network. I'm honored to be one of those members and represent approximately 3,000 members who share that pride.

On behalf of those members and the citizens that live a better life because of the work we do, I

ask you to continue to make investments, smart investments, in this electrical system.

And if you will provide the resources, my commitment today is that we will continue to do the noble work behind the scenes to make sure the system is functional today and tomorrow.

Thank you for your time.

MADAM CHAIR PRIDEMORE: Thank you, Kevin. I speak for all five of us. First off, thank you for your service to our country.

MR. HOWELL: Thank you.

MADAM CHAIR PRIDEMORE: Very blessed because of it. And thank you for your service at Plant Vogtle. So you've been a mainstay there. We appreciate it.

MR. HOWELL: Thank you.

MADAM CHAIR PRIDEMORE: Anne Blair.

MS. BLAIR: Good morning, Commissioners. Great to see you. And thank you for the opportunity to provide public comment today.

My name is Anne Blair. I'm director of policy at the Electrification Coalition and also president of EV Club of the South. The Electrification Coalition is a national nonpartisan, not-for-profit organization committed to the deployment of electric vehicles on a mass scale to combat the national

security, economic and public health impacts associated with our dependence on oil.

We are working to build the electric transportation system of the future to benefit American businesses and economic interests, working to help states, like Georgia, to transition to EVs powered by domestically produced electricity.

I am here today to express our support for the proposed expansion of Georgia Power's electric transportation investments; their Make Ready Program, their Community Charging program, and the EV rate rider.

Their proposed Make Ready Programs offer an investment of $81 million over three years and utility infrastructure upgrades that we believe are necessary to support the growing EV charging industry. This is a significant investment that will ensure that Georgia is ready for the rapid market expansion of EVs.

EVs are improving ground transportation, introducing a more energy-efficient vehicle, saving owners money on fuel and maintenance, increasing vehicle safety, and cutting our dependence on oil. By utilizing electricity to charge battery technology, we can power our transportation system

with a diverse, domestic, price stable, cleaner and fundamentally scalable energy supply.

As the transportation sector transitions to electrification, Georgia must be ready to support the shift with the right price signals and rate design structures that support the new demand. EV sales are expected to triple over the next three years, making up nearly 30 percent of vehicle sales by 2030. Significant growth is expected not only in the passenger vehicle market, but also with increasing electric school buses and transit buses and freight vehicles. Every major traditional vehicle manufacturer, as well as new ones, will be manufacturing and selling mostly only -- mostly or only electric vehicles in the next ten years.

Utility investment programs around the country are an important policy mechanism that will help accelerate this adoption and make sure that we are ready. What's more, Georgia Power's proposed program is relatively small in scale. Approved utility programs across the country amount to more than $3.5 billion in investment. This is critical investment for Georgia Power to diversify its operations and bring down costs over the long term as EV adoption increases.

Georgia must take the vital steps necessary with these types of strategic investments to complement things like the new federal investment of the Infrastructure Investment and Jobs Act and increase the number of vehicles and funding available.

As you all know, the Infrastructure Investment and Jobs Act will bring millions of dollars to Georgia. $134 million here. The state plan that has been approved will deploy EV charging infrastructure that will power our vehicles across our major corridors, but there will be gaps and it's simply not enough to support the growing industry. Expanding Georgia Power's programs will make -- will provide and allow for a more strategic and effective system over the long term.

We also support the $3 million annual investment over the next three years to build additional community charging stations. As an EV driver myself, I've known that the value of those community charging stations as I've traveled across the state, knowing that they are reliable and dependable. And Georgia Power's learned a lot with the initial program and we think that should continue.

There are significant economic benefits for them also to do this, attracting EV customers, infrastructure and related services to Georgia to help the state overall. And as the program goes, I also want to recommend that the Commission support an open and transparent process for expanding both of these programs.

The PSC and the company should also work together with the Georgia Department of Transportation and others in the deployment of the National EV Corridor program and fill those gaps where private industry may not be able to do so. We believe that utility programs, as well as private investment, can and will work together effectively.

Lastly, we strongly support the proposed EV rate rider to align with the Community Charging and Make Ready Programs. Collectively, these will support and ensure that Georgia remains a leader in transportation electrification.

Thanks for your time.

VICE-CHAIRMAN ECHOLS: Hey, before you leave the podium, just a quick question. I know it came up yesterday that the public good might not be served by the Make Ready money and community chargers. That's at least our staff's contention.

With Rivian being here and Hyundai, do you think that Georgia's going -- that Georgians and counties -- I guess these vehicles are going to be on the state contract since they're manufactured in Georgia and they'll get a little bit of a favored status being manufactured here. Do you think we're going to get -- maybe not the lion's share of these vehicles, but do you feel like Georgia is going to, you know, take pride in these vehicles and that you're going to see a lot of them around the state once they're manufactured here?

MS. BLAIR: Absolutely. I mean, we are seeing the trend with growing EV adoptions as more models are available and made available to consumers. So I think this is only going to increase and we need to be prepared to support those vehicles through charging infrastructure.

VICE-CHAIRMAN ECHOLS: So I guess in a way, us putting more chargers out there, or doing more Make Ready, which has the customer paying for the charger, it winds up benefiting in the end these two economic development projects.

MS. BLAIR: Yeah. Absolutely.

Yep. And, you know, overall, the benefits will be received by all Georgians and all ratepayers as we

bring -- as charging increases, the number of EVs increases, and the demand of those chargers increases, it will ultimately bring down rates in the long term.

VICE-CHAIRMAN ECHOLS: Thank you so much.

MADAM CHAIR PRIDEMORE: Wan Smith.

MS. SMITH: Good morning, Commissioners. Since we are leading with our service credentials, I, too, am a veteran of foreign war serving in Iraqi Freedom at Anaconda -- Camp Anaconda and Balad Air Force Base. And I continue to remain in the trenches serving the least of these and working to empower folks who have been left out and are across the margins.

I'm not here today to ask for any benevolence. What I am here to do is to remind you of the charge that you have of elected officials as honorable Public Service Commissioners to ensure the safe, reliable and affordable electricity from Georgia Power Company to their ratepayers.

Now, Bubba -- Commissioner Bubba, lovingly, when you were running in the last election, you were in a town hall and you stated with all brisk: I am not a social worker. I am a businessman.

Well, I would like to charge all of you to lean

on your business acumen and the oath of office that you took as Commissioners. Could any of you have the track record and poor management in business that Georgia Power has had?

You know the numbers. Plant Vogtle. We know we're over budget. We know we're behind schedule. You know the revenue that they have.

Would any of you be rewarded for that type of management of your business?

We all believe that we need grid improvements. We all want reliable electricity. But they have it. You know, I'm not going to -- Chair, you said don't repeat. I'm not going to repeat the numbers because we all know the numbers.

But I will affirm that they have enough money to invest in the people. That they have the resources to ensure that our grid is reliable, that we are sourcing our energy from healthy places that do no harm and that the rates are affordable. Meaning that those who have served us to ensure that we have a democracy, that those who have been on the battlefield and the front line who come back and are -- you know, they don't make $2.2 million like Mr. Womack; right? But to make sure those people, working class, blue collar people can afford

**electricity.**

**Because as we seen in Texas and as Hiro Garcia said, like, we know we will die if we do not have electricity. This is a matter of life and death. In Georgia, in Atlanta, more folks die from heat exhaustion than tornadoes and hurricanes.**

**In Texas we saw the problems with the grid. No, none of us want that here in Georgia. We are blessed by the sun. We can pull from that energy.**

**But we also deserve for folks who are on the margin, for folks who have served our country admirably, for working-class people who are at Plant Vogtle, who are linemen and linewomen, who are hospitality and service workers, when they go home at night after a long, hard day, they deserve to be able to flip the switch and have the lights come on. But what they don't deserve is for that 2.9 billion or that 2.8 billion to be on their backs when Georgia Power has it.**

**And you know the numbers. Y'all know how much money they got over there. But hold them accountable. Because as business people, none of us would be able to get -- and then have the audacity to ask for an increased ROE. Somebody got to be kidding me.**

But this is your legacy. So I beseech you that when the chronicles and the annals of history look back on this season, to say: Well, Georgia went from the eighth highest in the nation to the -- to No. 1, that it doesn't happen on your watch. That you protect the people, that you protect the consumer.

Thank you.

MADAM CHAIR PRIDEMORE: Ms. Smith, thank you for your service to our country in Operation Iraqi Freedom.

The fire alarm is going off. So I'm going to ask staff to please look into that quickly. Welcome to Wednesday.

All right. They get clarification usually within 60 seconds.

So, Mr. Park, if you -- Mr. Abraham Park, if you'd like to come up and talk.

MR. PARK: No comment.

MADAM CHAIR PRIDEMORE: No comment? Okay.

All right. Mr. Miles Stager.

MR. STAGER: No comment.

MADAM CHAIR PRIDEMORE: No comment? Okay.

Ms. Betsy Rivard.

Ms. Rivard, if we have to evacuate, we will let you come back.

**MS. RIVARD: I'm excited.**

**MADAM CHAIR PRIDEMORE: Sorry. It's one thing --**

**MS. RIVARD: I could live without that excitement, that's for sure.**

**MADAM CHAIR PRIDEMORE: We're good. Okay.**

**MS. RIVARD: Okay. I am Betsy Rivard. And I'm here for Nuclear Watch South. And Nuclear Watch South has been tracking the profits of the -- of Georgia Power for -- since 2015.**

**And we get our figures from Georgia Power's annual report. So they're not just out of thin air. They're right on the annual report. And they've never refuted our figures.**

**And here is a visual. I have copies for everybody. But of the profits as they increase. This is where Vogtle construction began and this is where the deadline was missed. One of the deadlines.**

**Anyway, and this just keeps going up. And I'm thinking: They keep making profits and now they want a rate increase. I really don't understand it.**

**The mission of the PSC is to balance the interests of the powerful, for-profit monopoly, Georgia Power, against the interests of the people of state of Georgia. And Georgia's total profit in the**

11 years since Vogtle construction began is 13.388 billion. 15.296 billion pretax loss write-off.

These profits include nearly $4 billion collected in the NCCR, the Nuclear Construction Cost Recovery tax charge for Plant Vogtle. And Georgia Power profits averaged $1.217 billion per year in the years 2011 through 2021, ranging from 13 percent to 20.5 percent annual profit.

These profits soared between 20 and 80 percent above pre-Vogtle construction years in which profits still exceeded the 10.5 percent currently guaranteed by the PSC.

So we would say that Georgia Power's rate request should be denied. And this PSC should reduce Georgia Power's rates to claw back excessive Georgia Power profits since 2011.

Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Rivard.

MS. RIVARD: Should -- where do I hand the copies for the Commissioners?

MADAM CHAIR PRIDEMORE: You're welcome to put them on the court reporter's desk or you could give them to our Executive Secretary, Sallie Tanner, in the white blouse.

**MS. RIVARD: Okay.**

**MADAM CHAIR PRIDEMORE: She can accept them from you, as well.**

**MS. RIVARD: Great. Thank you.**

**MADAM CHAIR PRIDEMORE: Thank you, Ms. Rivard.**

**So they're working on the sprinkler system and this is going to get turned off as soon as they fix what's going on. But no fire. Everybody is safe.**

**These are all the signed-in -- oh, wait. I have two more. Letitia Nigise.**

**MS. NIGISE: Good morning, everyone. My name is Letitia Nigise, but people know me by Tish Nigise. And I'm here on behalf of several organizations. One is Climate Reality, Atlanta Chapter. Thank you for giving me this opportunity to speak to you.**

**As an organization that believes in climate change and the environment and saving it, we just want to ask you to please don't allow Georgia Power to increase the rates of its current customers. It's going to be a -- burdensome on some of them, especially our elderly seniors, especially our people that may be handicapped and use a lot of energy for the machines that they have.**

**And I just think that Georgia Power has done -- has not done a good job in being protective of our**

environment. And I think that that in itself should be a reason why you should deny their request to increase the rate.

Thank you, guys.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Nigise.

Dora Cray.

MS. CRAY: Good morning.

MADAM CHAIR PRIDEMORE: Good morning, Ms. Cray.

MS. CRAY: I am Dora Cray and I'm here on behalf of the Georgia Power. I have Georgia Power and I don't think you should raise the rates.

A lot of seniors, we are on fixed income. And to raise the rates, that would put a burden on some of us. You know, you just can't afford it. Everything is expensive.

So to raise our rates like that over the next three years, I don't think that would be appropriate for us seniors. So that's why I'm here to speak on that.

Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Cray.

That is all I have signed in. Any other public witnesses?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Hearing none.

It is 10 a.m. We will reconvene at 10:10.

(A recess was held from 10:00 a.m. until 10:10 a.m.)

MADAM CHAIR PRIDEMORE: Okay. Very good. Let's resume and pick up where we left off yesterday.

Good morning, gentlemen. Good to see you again.

MR. ALVAREZ: Good morning, Your Honor.

MADAM CHAIR PRIDEMORE: Please remember you're under oath still. And this is the panel of Alvarez, Stephens and Rana, staff panel. And we are at the point where the rest of the intervenors have gone and now it's time for Georgia Power.

So, Georgia Power, your witnesses.

MR. HEWITSON: Thank you, Madam Chair.

Gentlemen, good morning.

MR. ALVAREZ: Good morning.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q In May during the IRP, Mr. Alvarez and Mr. Stephens, we briefly discussed your views on the grid investment plan.

Do you recall that discussion? Very brief?

A (Witness Alvarez) Yes.

Q At that time you had not reviewed the company's grid investment plan; is that right?

A (Witness Alvarez) That's correct.

Q Now that you've reviewed the plan, your position seems to be unchanged, meaning that you believe increased spending on grid investment for reliability purposes is not justified; is that a fair statement?

A (Witness Alvarez) Correct.

Q But your conclusion is not surprising because that seems to be your predetermined conclusion every time you review utility spending on similar grid improvement plans, isn't it?

A (Witness Alvarez) That happens to be the case. I would not say it's a predisposed outcome. We look at every case individually.

Q Okay. You each filed testimony in numerous Commission proceedings; right?

A (Witness Alvarez) We have.

Q Okay. Am I correct that neither of you have ever testified that a utility's grid investment program offered benefits that outweighed costs?

A (Witness Alvarez) I would say we've had components of grid investment plans that we have suggested outweigh -- where the benefits outweigh the cost, yes. I would say we have.

A (Witness Stephens) Yeah. Definitely we have done that, yeah.

Q Small components that have -- where the benefits have outweighed the costs?

A (Witness Alvarez) Right.

Q Okay. But you've never testified in favor of an investor-owned utility's grid investment plan; right?

A (Witness Alvarez) That's correct.

A (Witness Stephens) In totality?

Q In totality.

A (Witness Stephens) No.

Q And Mr. Rana -- am I saying it right?

Rana or Rana?

A (Witness Rana) Rana.

Q Rana. Thank you.

I'm not trying to leave you out of this early discussion, but I simply wasn't able to find proceedings in which you had previously testified.

Have you testified in favor of a utility's grid investment plan in prior proceedings at all?

A (Witness Rana) No.

Q Thank you.

As we see from statements in your testimony here in Georgia Power's rate case, you have a strong belief that all investor-owned utilities are incented to maximize shareholder value. Is that your belief?

A (Witness Alvarez) Yes.

Q And that was also your conclusion when you filed testimony in the 2017 Duke Energy progress rate case on behalf of the Environmental Defense Fund; right?

A (Witness Alvarez) Correct.

Q And that was also your conclusion when you testified in Phase 2 of Dominion Virginia's grid transformation plan docket; right?

A (Witness Alvarez) Correct.

Q Okay. And in this proceeding, on page 14, lines 2 and 3, you testify that Georgia Power has a fiduciary responsibility to uphold and advance shareholder interests, which you say are bolstered by capital investment bias.

Is that your testimony?

A (Witness Alvarez) It is.

Q Okay. But Georgia Power also has a statutory obligation to generate and deliver electricity reliably and safely to customers, doesn't it?

A (Witness Alvarez) It does.

Q Okay. And I would imagine that you are aware that every capital investment the company makes must be approved for rate recovery by this Commission; right?

A (Witness Alvarez) Correct.

Q And this Commission serves as a gatekeeper and a check against unjustified spending; don't you agree?

A (Witness Alvarez) Yes.

Q Okay. You lumped Georgia Power in with all other investor-owned utilities when discussing your theory of capital bias, but did you compare Georgia Power's capital spending on grid improvements against those other utilities?

A (Witness Alvarez) No, we did not.

Q Okay. Are you aware that since 2010, Georgia Power has been in the bottom quartile among peer utilities for capital expenditures as a percentage of transmission and distribution assets?

A (Witness Alvarez) I was not aware of that, no.

Q And that would mean that at least 75 percent of Georgia Power's peer utilities spent more during that time on transmission and distribution investments as a percentage of transmission and distribution assets; right?

A (Witness Alvarez) Subject to check, yes.

Q Don't you agree that if you're going to use national trends as a reason why Georgia Power should or should not be allowed to maintain its grid investments, that you should first see where Georgia Power falls among those national trends?

A (Witness Alvarez) Well, I would argue that every distribution system and every distribution utility is different and you have to look at those cases individually. And I don't know that you can necessarily say that one

distribution plan or one utility's investment is necessarily deficient or relative to others.

A (Witness Stephens) And you have to compile the data, analyze the data, and then make your judgment.

Q Okay. Well, let's look specifically at Georgia Power's grid investment plan then. One of the underpinnings of your testimony is that there is no pending reliability emergency and so there is no need to continue with the grid investment -- grid improvement plan right now. Is that your testimony?

A (Witness Alvarez) It is.

Q Okay. Is it your testimony that Georgia Power Company should wait until there is a reliability emergency to focus on reliability improvements?

A (Witness Alvarez) I don't think you should take that implication away from the testimony.

Do you have any --

A (Witness Stephens) The answer to that is emergencies like that don't show up in reliability. They show up on an individual circuit-by-circuit basis.

And as we've said in our testimony, Georgia Power needs to look at their reliability on a circuit-by-circuit basis and then analyze whatever that increase in SAIDI or SAIFI that's happening on those circuits and make the decisions through a root cause

analysis and determine, using the data available, outage data or whatever that is, and then make a determination about a solution to remedy those powers -- those problems as they show up.

The -- typically when we say emergency, if you're really, really high in SAIDI compared to the industry average, then you may look at more circuits than you would typically. But because Georgia Power is right at the same SAIDI level as the industry average, that does not look like an emergency or an issue for them to address.

Q Okay. And talking about those averages, on page 10, lines 1 to 2, you testify that: Georgia Power service interruption duration and frequency, which is the SAIDI and SAIFI that you were talking about, Mr. Stephens; right?

A (Witness Stephens) That's correct.

Q Are about half for its peer -- or about average -- sorry. Not half. About average for its peer utilities over the last five years; right?

A (Witness Stephens) Correct.

Q So, first, do you think it's Georgia Power's goal to be an average utilities -- average utility, in terms of reliability improvement?

A (Witness Stephens) I think that they should be -- they should be looking out for the ratepayers.

Q Okay.

A (Witness Stephens) That the -- they need to do what -- what the ratepayers are asking for on an individual circuit-by-circuit basis and they need to do what's most cost-effective. And when I say cost-effective, I mean the solutions need to provide more value to ratepayers than the cost of the solution.

Q Do you agree that Georgia Power should strive and this Commission should encourage Georgia Power to be better than average?

A (Witness Stephens) If it's cost-effective.

Q Only if it's cost-effective?

A (Witness Stephens) Only if it's cost-effective, that's correct.

Q Okay. And looking at Figure 3 on page 10, it looks like Georgia Power's SAIDI and SAIFI are slightly worse than average; don't you agree?

A (Witness Alvarez) Slightly, yes.

Q Do you also agree that averages can be misleading?

A (Witness Stephens) Averages can be what? I'm sorry.

Q Misleading.

A (Witness Stephens) Averages can be misleading, that's right.

Q Did you compare Georgia Power's third and fourth quartile numbers against peer utilities?

A (Witness Alvarez) We did not.

Q Okay. That might show a different story; right?

A (Witness Alvarez) It could. It could go either way.

Q And do you think that the customers that are in the bottom half, the third and fourth quartiles of the company's circuits, would consider their reliability to perhaps be an emergency?

A (Witness Stephens) No, I do not.

Q Why not?

A (Witness Stephens) That's because from my experience, if you're looking at anything below two hours, like 200 minutes, in SAIDI, most customers are not complaining about that.

Q Did you talk to any Georgia Power customers that are in the bottom quartile of Georgia Power's circuits?

A (Witness Stephens) I did not, but we did look at the customer surveys. And it indicated that they -- that they didn't show that there was an emergency.

Q Customer surveys weren't directed only at the bottom quartile, though, were they?

A (Witness Stephens) I don't know what -- how

they were directed.

Q You are aware between 2013 and 2020, that the measures of reliability -- that's SAIDI and SAIFI -- are worsening for Georgia Power customers; right?

A (Witness Alvarez) I think there is slight deterioration over time. But, you know, there's variation from year to year. So it's hard to -- it's hard to make a judgment on a year or two.

Q Are you aware that the circuits in the third and fourth quartiles, or those targeted by the grid investment plan, are declining at a faster rate than the top half of circuits?

A (Witness Alvarez) That's what your data shows, that's correct.

Q Are you also aware that since 2020, after the grid investment plan was approved by this Commission, both SAIDI and SAIFI for circuits addressed through the plan have shown improvements?

A (Witness Alvarez) I don't know that, but I would not be surprised if that were the case.

A (Witness Stephens) Right.

A (Witness Alvarez) I think the challenge is that -- how much was that improvement relative to the cost is the critical question.

A (Witness Stephens) Right.

Q Well, would an improvement of 65 percent be a good improvement?

A (Witness Alvarez) I think it depends on the circuit, you know --

A (Witness Stephens) Right.

A (Witness Alvarez) If you're at 300 SAIDI, a 65 improvement doesn't even bring you up to the average. So I think it depends.

Q Well, you asked the question in staff data request WG2-36 and the company provided you data that shows those initial results indicate an improvement of about 65 percent for both SAIDI and SAIFI for the completed projects; right?

A (Witness Alvarez) You know, I think that varied quite a bit by package. I think some of the packages did have some fairly good improvements. We are not recommending against all packages be rejected, just some of them. And I think our analysis was that --

A (Witness Stephens) Yeah. Right. Distributed --

A (Witness Alvarez) Automation --

A (Witness Stephens) -- automation showed some good improvement; whereas, the other ones were not cost-effective basically. We're saying the undergrounding or hardening were definitely not cost-effective solutions.

Q Okay. Mr. Alvarez, you just said a second ago that you're not recommending against all packages. If you are recommending against funding the grid investment plan, isn't that recommending against all or doing any of the packages?

A (Witness Alvarez) No. Well, in the transmission side, we are recommending against this -- kind of like premature replacement of equipment. On the distribution side, we are only recommending the circuit hardening and undergrounding packages be rejected. The other packages we have no recommendation on.

A (Witness Stephens) That's correct.

Q On page 9, lines 5 through 9, you point out that reliability performance for investor-owned utilities has been worsening over the last ten years, despite increases in grid investment; right?

A (Witness Alvarez) We do.

Q But not all grid investment is targeted to improve reliability. Would you agree with that?

A (Witness Alvarez) I would.

Q And there are several reasons that somebody might invest in the grid, like customer growth, new load, new construction, things like that; right?

A (Witness Alvarez) That's correct.

Q One of your criticisms of the grid improvement

plan -- program is that there are -- was what you called a significant revision in the target system SAIDI since 2019; right?

A (Witness Alvarez) Yes.

Q And that's something that you noted in your preliminary statement that Commissioner Echols asked you about; right?

A (Witness Alvarez) That's correct.

Q And you say that this was a 23.1 percent deterioration. And you calculate that based on the target moving from 65 to 80; is that right?

A (Witness Alvarez) That's correct.

Q Okay. Shouldn't the analysis be a comparison of the revised target against the starting point, though?

A (Witness Alvarez) I think both approaches are relevant. You could compare it to the starting point or you could compare it to the previous forecast. Either way, the number is relevant and of interest.

Q Okay. And with a starting point of 130 SAIDI, that changes only about 10 to 11 percent; right?

And mindful that Mr. Walsh has already given away our secret that we can't do math, you can check my math on that.

A (Witness Alvarez) That may be true. I think we, again, question if whether the 80 target is achievable

--

Q Okay.

A (Witness Alvarez) -- with this plan.

Q Okay. Now, the change in the SAIDI target was implemented as lessons were learned during the program. For instance, the company found that investments in general were just more expensive to complete than originally estimated; right?

A (Witness Alvarez) That's the company's statement, yes.

Q And because of the higher costs it was seeing, the company re-evaluated the optimal level of investment to minimize the total cost to customers. Is that your understanding of what the company did in revising the targets?

A (Witness Alvarez) Yes. That's my understanding.

Q And from that analysis, the set of investments that will deliver an 80 SAIDI was determined to be in the best interests of customers for the dollars to be spent; right?

A (Witness Alvarez) I would not agree with that. I think --

A (Witness Stephens) No.

A (Witness Alvarez) -- what the -- what the

customer benefit study says is that of these portfolio of investments, you can allocate them to different circuits, you can apply different packages in different ways. And the one that the company came up with as optimum was lowest cost. I think there's a biggest difference between that and what -- the question you just asked me.

Q Okay. And so --

A (Witness Stephens) Let me just add that -- that, yeah, because it doesn't really look at the -- on a circuit-by-circuit basis what is the most cost-effective -- or what is in the best interest of ratepayers on a circuit-by-circuit basis.

In other words, is it cost-effective on a circuit-by-circuit basis?

A (Witness Alvarez) Or even the package.

A (Witness Stephens) Or even the package basis, right. That's true.

Q Okay. Now, the grid investment plan was approved in the 2019 rate case and it was designed to look at the SAIDI targets for the entire system; right?

A (Witness Alvarez) I believe that's the case, yes.

Q And do you agree that the Commission wanted the company to be a good steward of the investments and revise the plan to maximize the benefits for customers?

A (Witness Alvarez) Certainly.

Q Mr. Alvarez and Mr. Stephens, I did not see any mention of experience with transmission systems in your resumes. Is it fair to say your prior experience is almost exclusively related to distribution systems?

A (Witness Alvarez) That's true in my case.

A (Witness Stephens) Yeah, that's true.

Q And, Mr. Rana, you're the transmission guy; right?

A (Witness Rana) Transmission lines, yes.

Q Okay. And you spent a long time at AEP; right?

A (Witness Rana) Yes.

Q Okay. Your early career was in system planning where you worked in various roles on technical engineering studies associated with planning and operation of AEP's system; right?

A (Witness Rana) Yes.

Q Okay. Now, the last ten years of your career at AEP was spent working in RTO-related activities, including the development and advocacy of AEP policies; right?

A (Witness Rana) Yes.

Q Now, regarding your experience in transmission planning and operations, how much experience do you have in the field on the maintenance side of things?

A (Witness Rana) Can you repeat the question?

Q Yeah. How much experience do you have in the field on the maintenance of transmission-related facilities?

A (Witness Rana) I have a good bit of experience because of the planning engineers work with the operations, as well as the people to see the asset conditions and if you have to take that out for scheduling repairs and things like that. So I have visited field looking at transformers, power lines and their conditions as a part of our overall decision making and schedule for maintenance and whatnot.

Q Have you worked in the field performing maintenance work on substations?

A (Witness Rana) Yes, I have seen that.

Q You've seen that. Have you performed the work?

A (Witness Rana) I have not.

Q Have you been in charge of defining and executing a maintenance program for utility transmission assets?

A (Witness Rana) We have worked with our asset management program.

Q Okay. I understand that you have worked with them in your planning role, but have you been in charge of defining and executing the maintenance program?

A (Witness Rana) I have not.

Q Have you overseen any efforts to define and

execute transmission asset management programs for utilities?

A (Witness Rana) No.

Q Do you have any direct field operational experience with outage response for field transmission assets?

A (Witness Rana) No.

Q Do you have any direct experience with transmission system operations that are executed after a failure event to minimize impact to customers?

A (Witness Rana) No.

Q All right. Now, I think it's in the Alvarez/Stephens testimony, page 3, lines 9 to 11, it indicates that you believe the company's approach to replacing transmission equipment based on age is a new practice in the grid investment plan; right?

A (Witness Alvarez) That's our understanding, yes.

Q Okay. And you reviewed the 2019 rate case proceedings, I assume, when this was approved?

A (Witness Alvarez) To a limited extent, yes.

Q Okay. In 2019, the company put forth testimony in support for the program, showing that a significant portion of the company's transmission assets are approaching or have exceeded their expected lives; right?

A (Witness Alvarez) The company's expected life, that's correct.

Q And based on the entirety of the proceedings, the Commission approved the grid investment plan, including this approach to the transmission investment; right?

A (Witness Alvarez) I don't know that I would conclude that. I don't recall seeing in the order any mention of the grid improvement plan.

Q You do understand that the grid improvement plan was approved in the 2019 rate case; right?

A (Witness Alvarez) I understand the Commission approved a revenue requirement sufficient to cover those costs. I do not recall seeing the grid improvement plan mentioned in the order or the settlement.

Q But the revenue requirements that the company testified about were specific to the grid investment plan and those were approved by the Commission; is that the distinction we're making?

A (Witness Alvarez) I don't think you can make that distinction. I don't think that breakdown is provided in the -- in the order or the settlement agreement, honestly.

Q So is it your testimony that the grid investment plan was not approved by the Commission?

A (Witness Alvarez) Not specifically, no.

A (Witness Stephens) I would like to make a comment on expected life, though. The company's criteria using the data request, I found out that they had based their expected life on a EPRI study, EPRI report.

I reviewed that EPRI report and asked -- and showed -- asked them if they had -- if the EPRI report showed that the -- there was required replacement at those ages.

The company responded that the EPRI report was only a small portion of their approach for establishing expected life. That they based it on failure rates and subject matter experts in their company.

I actually did analysis on their failure rates and showed that the -- was not cost-effective to replace the equipment -- the substation equipment at the ages that they were replacing the equipment.

Q In what way?

A (Witness Stephens) I'm sorry. What is the question?

Q In what way? In what way was it not cost-effective?

A (Witness Stephens) It was not cost-effective because the probability of failure based on the outage reports showed a very, very low probability of failure. And when you take that probability of failure times a consequent

cost and compare it to the cost of replacement, it's not cost-effective.

Q And that's Table 2 in your testimony?

A (Witness Stephens) Yes, it is.

Q Okay. We'll get to that in a bit.

A (Witness Stephens) Okay.

Q Are you aware that the integrated transmission system participants in Georgia support this program, the grid -- the transmission portion of the grid improvement plan?

A (Witness Alvarez) I think I do recall hearing that in the company's hearings.

Q And those ITS participants would be negatively impacted if the company was ordered to stop the grid investment plan; right?

A (Witness Alvarez) I think that's an assumption. You're assuming that the --

Q Well, let me ask it this way: Is it your understanding that they would be negatively impacted?

A (Witness Alvarez) I think it depends on the nature of the investment and the cost-effectiveness of that investment. I think if the -- if the improvement is marginal enough or the deterioration is marginal enough, I don't think they would notice.

Q In 2019, when the grid investment plan was

approved, the company argued that reducing the number of system assets beyond their expected life would reduce the likelihood of failures.

Now, at the outset, let me see if you agree, as a basic principle, that as things age, they tend to get closer to failure. As assets age. I won't say things.

A (Witness Stephens) Let me just say that a piece of equipment that is one year old, when it gets to be two years old, it's closer to failure. That does not mean that it's justified to replace it when it's two years old. You have to look at the age and look at the probability of failure as it gets much, much older.

Q One aspect to that is shown in the bathtub curve on page 17 of your testimony; right?

A (Witness Stephens) That's correct.

Q All right. And we can -- we can look at that.

A (Witness Stephens) And I just want to say that that's just an example. It's not actual data, so...

Q Well, out of curiosity, why didn't you use actual data?

A (Witness Stephens) I don't think we had any actual data available from Georgia Power.

Q Would you agree that it's better to use actual data to --

A (Witness Stephens) I would agree to that. We

were not supplied with that data.

Q Well, you could have requested it; right?

You could have requested historical transformer replacement data under Georgia Power's capital investment program; right?

A (Witness Stephens) Replacement? We were not asked -- that's not a replacement curve. It is a failure curve.

Q Well, you could have asked for the failure data, too?

A (Witness Stephens) I think we -- I'm not sure. I thought we asked for failure data.

A (Witness Rana) No, we didn't.

A (Witness Stephens) No, we didn't? Oh, I'm sorry.

A (Witness Alvarez) We used the actual --

A (Witness Stephens) Oh, that's right. We used --

A (Witness Alvarez) -- outage data.

A (Witness Stephens) We used the actual outage data because it had failure rates in the outage data, that's correct.

Q Okay. And had you asked for that data, the data would have allowed you to create a bathtub curve of real data applicable to the company; right?

A (Witness Stephens) That's possible.

Q Okay. And would you be surprised to learn that the company's capital maintenance program has replaced 196 transformers in the last ten years with an average age of 43 years?

A (Witness Stephens) And -- I guess I'm not surprised at that, but I don't know what the point is.

Q Well, I was just asking if you were surprised by that.

A (Witness Stephens) Okay. I'm not surprised.

Q Checking the data.

A (Witness Stephens) Okay.

Q Okay. Now, bathtub curves show hypothetical failure rates; right?

A (Witness Stephens) That's right.

Q Okay. Early on there are assets that fail when first going into service. People call that infant mortality. And as the equipment then operates normally, on an expected basis, and then as it nears end of life, it -- failure rates increase exponentially; right?

A (Witness Stephens) Yeah. Right. Late, late in life, yes. That's right.

Q And so that really means that as assets age, and regardless of how well you maintain them, there will come a time where they will fail; right?

A (Witness Stephens) Yeah. That's pretty true.

Q Okay. And that happens at a higher rate as they get older?

A (Witness Stephens) That's true.

Q So for a utility that has a lot equipment on the system all around about the same age, it means that there will come a time when a lot of that equipment fails in a short amount of time; is that a fair statement?

A (Witness Stephens) No.

A (Witness Alvarez) I think what you -- what you have to think about is every equipment ages and fails differently. And so that's exactly the reason why the company has implemented its objective testing and inspection programs to identify and root out what those pieces of equipment are. And then that concern goes away because there's such variation from item to item.

Would you agree?

A (Witness Stephens) Yes, I agree. And I agree every piece -- different types of equipment have their own separate bathtub curves.

Q Right. But if you have a hundred transformers on the system and they're operating and they get to be about 50 years of life, they've been operating for about 50 years, performing adequately, there's going to come a time -- there's going to be a shorter period of time that those

transformers are going to fail over; right?

Because they've already operated for 50 years. They're probably not going to 75 for the most part. So now in that 25-year period, those 50 transformers can be expected to fail; right?

A (Witness Alvarez) Well, I --

Q With the bathtub --

A (Witness Stephens) They can be expected -- they can be expected to fail sometime in the future beyond 50 years. Not 51 years necessarily, just sometime in the future.

All equipment will fail sometime in the future, but that doesn't mean that you have to replace it at 50 years when a lot of equipment will last 100 years.

Q And that is a fair statement, Mr. Stephens. But as equipment reaches 50 years, the expected failure rate increases exponentially based on the bathtub curve that you show?

A (Witness Stephens) No, that's not true. The exponential part always happens much later in life. It's usually fairly regular, almost linear, in its failure rates.

A utility gets to about, like, say -- for substation transformers, it's like 60 to 70 years and then it starts that exponential curve.

Q And had you gotten the data from Georgia Power,

you would have been able to show real data by Georgia Power based on their transformer experience; right?

A (Witness Stephens) They did not -- why did they not supply that in their testimony?

Q That's not my question. Had you asked that information, you could have done a real data graph for expected failure rates or actual failure rates for transformers on Georgia Power's system, but, instead, you used hypothetical data; is that correct?

A (Witness Stephens) That would be correct. But remember that I did an actual study on actual Georgia Power data using their outage data.

Q And that's Table 2; right?

A (Witness Stephens) That's Table 2.

Q Okay. We'll get to that in a bit.

The increased failure rate would cause problems if you don't have the manpower or the spares to fix it.

I'm sorry. I'll wait.

A (Witness Stephens) I'm sorry?

Q No, no. I just -- he was having trouble hearing. That's fine.

A (Witness Stephens) Okay.

Q The increased failure rate as equipment gets older can have a negative impact on the company if you don't have the manpower or the spares to replace the equipment;

right?

A (Witness Stephens) Would you ask that question again?

Q If there was a short period of time where more things fail and you don't have the spares to replace it, that's going to cause problems on the system; right?

A (Witness Stephens) That can cause problems on the system, but they should have their spares. I don't know why they wouldn't, but that's okay.

Q Well, it means if you expect a lot of transformers to fail in a short period of time, you're going to have to have a lot of transformers on spare; right?

A (Witness Stephens) That's correct. But I did not see any data that showed that they have had such a large influx of failures.

Q Are you aware that the lead time for new transformers is now running about three years?

A (Witness Stephens) Yes, I am aware of that. That's why they need to have spares on -- available.

Q And Georgia Power has been pretty good about maintaining its equipment; do you agree?

A (Witness Stephens) I do not have any indication otherwise.

Q Through its robust and comprehensive maintenance program, Georgia Power is routinely able to

extend the life of equipment beyond industry-expected life; is that your understanding?

A (Witness Stephens) I don't know of anything that rebuts that, no.

Q And throughout your testimony you used the term expected useful life. But that's really an accounting term used for depreciation rates; right?

A (Witness Alvarez) That's correct.

Q All right. Expected useful life is typically based on industry standards; would you agree with that?

The depreciation aspect of it is usually based on industry standards?

A (Witness Alvarez) I would say it's a huge component of it, yes.

Q And you've learned through data requests, though, that Georgia Power uses its own analysis of expected life for the grid investment plan; right?

A (Witness Alvarez) Correct.

Q While the industry-expected life of transformers is 35 years, Georgia Power doesn't target them for replacement unless they will be 50 years by the end of the grid investment plan; right?

A (Witness Alvarez) I think that if the transformer can last 90 years, that's not a relevant number.

Q Okay. But that wasn't my question. My

question was: While the industry-expected life of transformers is 35 years, Georgia Power doesn't plan to replace them unless they're 50 years by the end of the grid investment plan; right?

A (Witness Alvarez) That's my understanding of the company's use of its expected useful life estimate.

Q Okay. And the industry-expected life of breakers is 25 years. Georgia Power doesn't target them for replacement unless they'll be 35 years by the end of the grid investment plan; right?

A (Witness Alvarez) Again, if a breaker will last 75 years, it's not a relevant number. But in answer to your question, yes.

Q Okay. Would you agree that if Georgia Power is able to operate a piece of equipment 15 years past its industry-expected life, then Georgia Power's maintenance programs and ability to extend the life of equipment, such as transformers, is a benefit to customers?

A (Witness Alvarez) I think you have to look at reliability improvements in relation to rate increases. And so there's a net benefit to customers that comes into play there. You can't just -- you can't assume that by relacing it at the company estimated life that that's going to net as a benefit to customer.

Q Yeah.

A (Witness Stephens) And I would point out that that industry standard life that you're talking about is a depreciation life. It's not a expected life of the actual equipment.

Q Yes. But we just established that the depreciation rate is based in large part on the industry-expected life. When -- when the industry generally expects the equipment to fail; right?

A (Witness Stephens) It's the midpoint of expected life, yeah.

A (Witness Alvarez) Yeah. I think that's an important point.

A (Witness Stephens) Yeah.

A (Witness Alvarez) It -- the depreciation rate is typically -- typically says: Well, what's the average; right?

So if the average is 50, that means units last to 100 pretty routinely. If the average is 40, that means the units last to 80 pretty routinely. So there's a big difference there between depreciation lives and actual operational experience.

A (Witness Stephens) There's nothing in the industry that says that equipment should be replaced at depreciation life of 50 years.

Q Okay. The expected life used in Georgia

Power's grid investment plan, though, is based on Georgia Power's decades of experience operating, maintaining and testing the assets; right?

A (Witness Stephens) I'm sorry. Say that again, please.

Q Georgia Power's expected life, the expected life that they use for the grid investment plan, is based on their years of maintaining, operating, replacing and testing their assets; right?

A (Witness Stephens) I think that's what they are saying.

Q Well, do you have any reason to believe that that's not what they base it on?

A (Witness Stephens) I'm just saying that that -- I guess that's what they're saying that they base it on. I can't dispute that that's what they're saying they're basing it on. I'm not saying that's correct. I'm just saying that's what they're basing it on.

Q Okay. And you are aware, aren't you, that without the transformer replacements through the grid investment plan, the percentage of transformers that would reach the company's expected life by 2031 would be more than double as compared to the continuing the grid investment plan as approved in 2019; right?

A (Witness Alvarez) Subject to check.

A (Witness Stephens) Yeah. I don't know the answer to that.

Q Well, that was asked by you in staff data request WG4-1 and that's the response in 4-1. So I can show it to you, but, subject to check, if it's in there, would you agree with me?

A (Witness Alvarez) Yes.

A (Witness Stephens) Yes.

Q Okay. Are you aware that without continuing the plan, 44 percent of substation transformers will have exceeded their expected life versus only 10 percent if the program continues?

A (Witness Stephens) Again, you're talking about the Georgia expected life.

Q Georgia Power expected life.

A (Witness Stephens) We would -- we would agree with that. That if that's what your numbers show, then, subject to check, that may be right. Again, that -- is not necessarily means that the equipment can't last longer than that.

Q But 44 percent of substation transformers is a lot of transformers to be reaching that far end of the bathtub curve, isn't it?

A (Witness Stephens) Again, it -- it -- maybe that's appropriate.

Q Having so many assets reach the end of life in a short time does prevent significant risk to the reliability of the assets; right?

A (Witness Alvarez) I think the keyword there was significant.

A (Witness Stephens) That's right.

A (Witness Alvarez) Marginal.

A (Witness Stephens) Marginal.

A (Witness Alvarez) Very marginal. Perhaps.

Q Okay. But it -- but you would agree that it increase the risk?

A (Witness Stephens) As --

A (Witness Alvarez) The question is: Does it decrease the risk sufficient relative to the cost of the practice?

A (Witness Stephens) That's correct.

Q Would it be prudent utility practice to operate a piece of equipment past its expected life without having a plan to be able to replace it?

A (Witness Alvarez) Can you repeat that question?

Q I think I can. Would it be prudent utility practice to operate a piece of equipment beyond its expected life without having a plan to replace it?

A (Witness Alvarez) The --

A (Witness Stephens) The -- the utility should

have plans to replace equipment when it's appropriate through the entire life of the equipment.

Q Okay.

A (Witness Alvarez) Based on the results of objective tests of that equipment.

Q And what are the objective tests that you say should be run on a substation transformer?

A (Witness Stephens) Gas analysis is one of them. You know, we looked at the Georgia testing program. It looks very standard with the industry practices. It looks fine to us.

Q One of the ways that you downplayed the risks of transformer failures is by pointing to the N-1 criterion for transmission planning; is that right?

A (Witness Alvarez) That's correct.

Q Page 18 of your testimony, I think.

A (Witness Alvarez) Yep.

Q Your position is that because Georgia Power complies with NERC's N-1 planning criteria it is unlikely that a transmission and distribution substation failure would cause a service interruption for customers; right?

A (Witness Alvarez) Not the entire substation. A piece of equipment.

Q Okay. I'm sorry. The transformer --

A (Witness Alvarez) Yeah. Sure.

Q -- I think is what you used as your example.

A (Witness Alvarez) Yeah.

Q Okay. Is it your position that some equipment failures are acceptable because they do not always lead to outages?

A (Witness Stephens) Ask the question again, please.

Q Is it your position that some equipment failures are acceptable if they don't always lead to outages?

A (Witness Stephens) I would say every utility accepts a certain level of equipment failure. It just happens, yeah. And so --

Q But the utility tries to prevent those failures; right?

A (Witness Stephens) They do the best they can, that's correct.

Q And so what I'm asking is: In your testimony on page 18, it seems to be -- it seems to me, in interpreting your testimony on page 18, lines 15 to 17, that it's your position that some equipment failures are acceptable because they don't always lead to outages.

Is that your position?

A (Witness Stephens) I'm saying that that's utility's approach, not my approach. It's the utility's

approach to accept some failures. And that's why they have the -- that's why they have the redundancy.

Q And that -- that's your understanding based on the N-1 planning criteria?

A (Witness Stephens) Yes. That's right.

Q Okay. And the N-1 planning criteria is focused on system reliability and stability; it is not premised on avoiding all service interruptions, is it?

A (Witness Stephens) I'm sorry. Ask the question again, please.

Q The N-1 planning criteria is based on system stability and reliability; it's not premised on avoiding all outages, is it?

A (Witness Stephens) Well --

A (Witness Alvarez) Let me just say, you can never avoid all outage. And maybe I should rephrase that. The cost of avoiding all outages would be prohibitive.

A (Witness Stephens) There you go.

A (Witness Alvarez) And so every utility has an accepted risk tolerance for service interruptions.

Q Well, going back to the N-1, though, because that is what you based your testimony on, N-1 planning ensures that there are no massive cascading interruptions due to a system failure. It doesn't look at individual service interruptions from something like a substation

transformer failure, does it?

A (Witness Stephens) It doesn't really look at anything. It's just a -- an approach --

A (Witness Alvarez) A risk mitigation --

A (Witness Stephens) Yeah, it's a risk mitigation approach.

A (Witness Rana) If the company is doing the proper maintenance using the objective tests and monitoring and everything, that's where they identify the physical condition or the current condition of the asset, whether it's a power line or whether it is station equipment.

And based on that, the company should be able to decide for the scheduled maintenance, repair or whatnot. So the chances of operating that particular asset while in service is extremely low.

Q And I understand that, Mr. Rana, and I appreciate the addition. But the testimony in the Alvarez and Stephens testimony is based on the N-1 planning criteria. N-1 planning criteria is a redundancy criteria; right?

You would agree with me on that?

A (Witness Alvarez) Yes.

Q Right. But not all substations have a redundant substation nearby; right?

If a substation fails because the transformer

fails, there are people around that that are going to be in an outage; right?

A (Witness Rana) That's right.

A (Witness Alvarez) That is true.

Q I probably should have asked it that way the first time.

All right.

MADAM CHAIR PRIDEMORE: Mr. Hewitson.

MR. HEWITSON: Yes.

MADAM CHAIR PRIDEMORE: Excuse me. So I want to go back to one of the questions just a couple of minutes ago. Because something that you said -- Mr. Stephens; correct?

MR. STEPHENS: Yes.

MADAM CHAIR PRIDEMORE: Stuck on me.

So -- so Georgia Power asked you: What do you believe to be the appropriate, we'll say cause, for having some level of equipment failure. And your answer was: Utilities accept some level of equipment failure.

I want to ask you, as an expert in this area, what's your opinion? Do you believe that there should be some level of equipment failure?

MR. STEPHENS: Yes, I agree that there should be some level of equipment of failure. That -- in my

opinion, that's right. That there's an acceptable level of equipment failure, that's right.

MADAM CHAIR PRIDEMORE: What is the line of acceptability?

MR. STEPHENS: The -- it depends on the equipment, the size of the equipment, and the number of customers affected.

MADAM CHAIR PRIDEMORE: Size of equipment and number of customers affected?

MR. STEPHENS: Yes.

MADAM CHAIR PRIDEMORE: Okay. Thank you.

BY MR. HEWITSON:

Q Okay. Does it also depend on the -- the percentage of that piece of equipment that may fail in a short period of time?

Or would that go into your analysis in the number of customers that were --

A (Witness Stephens) Yeah. The failure rates does go into the -- into that equation, that's right.

Q So if you expected a large number of transformers to fail in a short period of time, that's going to affect more customers than fewer; right?

As a general -- let me ask --

A (Witness Stephens) Yeah, yeah. Generally, I would say that's right, yes.

Q All right.

A (Witness Stephens) Kind of depends, but you're right.

Q And if at any time I ask a question that you're not fully -- you don't fully understand, then just tell me to rephrase it.

A (Witness Stephens) Okay.

A (Witness Alvarez) Well, the premise of your question is if you have a whole bunch of things you know are going to fail at the same time. We just don't know that; right?

That's why you do the testing.

A (Witness Stephens) Yeah.

A (Witness Alvarez) So that premise is flawed.

A (Witness Stephens) Well, I would say that in the industry we have found times where there have been specific types of equipment that have failed at a high rate. There's the AB chance cutouts, for example, across the industry.

And there was notices sent out that this is a problem and they were having a high rate failure. And the utilities went out and replaced those because they -- they were failing at a high rate. And so they did the analysis, decided that it was cost-effective to replace that equipment, and they did it.

So, to answer your question, yes, that can be a case, but we did not see that in Georgia Power.

Q Speaking of those objective tests, you think there are more accurate predictors of equipment failure than age; is that a fair way of characterizing your testimony?

A (Witness Stephens) Yes.

Q Okay. And it would be your understanding that Georgia Power, in setting its Georgia Power expected life, relied on its long history of using these objective tests and measures in determining the expected life of that equipment; right?

A (Witness Stephens) I think they probably took that into account, yes.

Q And it's not your understanding in any way that Georgia Power plans to abandon using the objective tests and measures in terms of determining whether a specific piece of equipment is closer to failure?

A (Witness Alvarez) That's correct. But your question calls into question why you would replace a piece of equipment when you have an objective test that tells you when to replace it.

Why would you need to replace that equipment early?

Q Well, would you agree with me that objective tests, like the dissolved gas analysis that you mentioned,

Mr. Stephens, they're not foolproof, are they?

A (Witness Stephens) No.

Q Okay. Some equipment passes all the objective tests that you give it and it still fails?

A (Witness Stephens) That's correct.

Q And earlier I had mentioned that the company has replaced 196 substation transformers in the last 10 years due to failure. Are you aware that 108 of those failed transformers passed their most recent objective tests prior to failure?

A (Witness Stephens) Sure. I mean, I don't know that, but I can understand that --

Q It doesn't surprise you?

A (Witness Stephens) Yeah. It seems reasonable.

Q Okay. And so 55 percent of the failed transformers over that time period would not have been identified for replacement through the objective tests?

A (Witness Alvarez) And how does that compare to the number of transformers --

A (Witness Stephens) Right.

A (Witness Alvarez) -- the company currently operates?

A (Witness Stephens) If you have 2,000 transformers on your system --

A (Witness Alvarez) There are more 2,000.

A (Witness Stephens) Yeah. So the --

A (Witness Alvarez) Several thousand.

A (Witness Stephens) So that is the failure rate. That's a very small failure rate. Less than 1 percent.

Q Well, but you were comparing it over the entire asset base of Georgia Power. What I'm talking about is the 196 transformer failures -- or replacements, sorry, in the last ten years. And 108 of those had to be replaced, but they had -- because they failed, but they had passed their objective tests.

And that's 55 percent of what historic real data shows; right?

A (Witness Alvarez) Which falls into that level of tolerance that we talked about.

A (Witness Stephens) That's right. And 55 -- that 55 percent is not a pertinent number. The pertinent number is the failure rate as compared to the systemwide transformer --

A (Witness Alvarez) Population.

A (Witness Stephens) -- population.

Q When transmission equipment fails, like a substation transformer, it can fail catastrophically; right?

It can be a massive explosion that takes out the other equipment in the substation; right?

A (Witness Stephens) There has been catastrophic

incidents, that's right.

Q Okay. And that's not the type of equipment failure that anyone wants to see happen. Would you agree with that?

A (Witness Stephens) Right.

Q All right. Let's look at Table 2 on page 22. In this you attempt to calculate the capital use age required to avoid one service interruption per year; right?

A (Witness Stephens) That's right.

Q The analysis in this table assumes the frequency of failure in the future would be the same as historic rates; right?

A (Witness Stephens) I'm sorry. Ask again, please.

Q The analysis in the table assumes that frequency of failure in the future will be the same as historic?

A (Witness Stephens) That's correct.

Q You do not account for a potential increase frequency of failures in your analysis; right?

A (Witness Stephens) That's correct.

Q Okay. But we have established that as equipment gets older, it tends to fail at a quicker -- at a more frequent rate; right?

A (Witness Stephens) Yes. This is based on

averages because the population has different ages. They're not all the same age.

Q But Georgia Power has a lot of equipment that is around the same vintage; right?

A (Witness Stephens) I don't know that.

Q Okay. Well, did you hear Mr. Robinson testify to that in the direct hearing --

A (Witness Stephens) I am sorry.

Q -- about how a lot of equipment that was all put in place in the '50s, '60s, and '70s and it's all getting to 50, 60 years old at the same time?

A (Witness Stephens) I did not. But I don't have any -- I don't have any reason to disagree with that.

Q Looking at Table 2 in Column B, these are your calculations for likelihood of failure; right?

A (Witness Stephens) That's correct.

Q Okay. You --

A (Witness Alvarez) Wait. It's the likelihood of failure resulting in a service interruption.

A (Witness Stephens) That's right.

Q Thank you. Thank you.

And in this -- excuse me. In this you included the total number of that type of equipment on the system; is that right?

A (Witness Stephens) That's correct.

Q For instance, for power transformers, you used the total number on the system, which is 2,264; right?

A (Witness Stephens) That's correct.

Q Now, you did not limit your calculations only to the equipment currently on the system that would be subject to the company's grid investment plan; right?

A (Witness Stephens) I'm sorry. Would you ask the question again?

Q You used the entire universe --

A (Witness Stephens) That's right.

Q -- on the system of transformers. You didn't look at only those that are --

A (Witness Stephens) That's correct.

Q -- by the grid investment?

A (Witness Stephens) That's correct.

Q But including all power transformers would include those that are one and two years old, like the --

A (Witness Stephens) That's correct.

Q And you gave the likelihood of a customer outage from failure of those transformers, the one-, two-, five-year-old transformers, equal weighting as you did with those that are 50 years old, didn't you?

A (Witness Stephens) That's correct.

Q Okay. But as we discussed earlier, age is directly correlated with failure rates; right?

A (Witness Stephens) That's correct.
Q The company does not include in its grid investment plan transformers that are five years old, does it?
A (Witness Stephens) I would -- I would assume so, that's right.
Q To qualify for the grid investment plan, the transformer must be 50 years old by 2031; right?
A (Witness Stephens) Right.
Q Do you know how many substation transformers were 50 years or older in 2021 that were also included in the grid investment program?
A (Witness Stephens) I do not.
Q Had you asked for that data, you could have calculated the increased risk of failure for the equipment that the company had identified as higher risk; right?
A (Witness Stephens) That's right. I could have.
Q Okay. But you didn't ask for that data?
A (Witness Stephens) I did not ask for that data, no.
Q Would it surprise you to learn that that number is 230?
A (Witness Stephens) That the number of transformers is 230?
Q Yeah. The number that the company has

identified as higher risk.

A (Witness Stephens) Okay.

Q Okay. And so that's about 10 percent of the population if it's 2,200 transformers; right?

A (Witness Stephens) That's true. But the failures -- I guess we don't know what the failure rate -- what -- what was the age of the failures that failed in service?

Q That's not part of your calculation. We're talking about your calculation, Table 2.

A (Witness Stephens) But my calculations are based on the entire population, based on the failure rates of the entire population, not on the failure rates of the just 200 that you had in your GIP.

Q Right. But had you looked at only those that the company is targeting in its grid investment plan, it would have been a better indicator of what the company is looking at in its grid investment plan; right?

A (Witness Stephens) Yes, I agree with that.

Q Okay. Let me look at -- or let us look at Column C in this table, please.

Did you calculate 690 as the average number of customers per interruption for a power transformer?

A (Witness Stephens) Yes, I did.

Q Okay. There is a difference between a

pole-mounted transformer used to serve a deer camp in rural Georgia and a substation power transformer that's used in Macon; right?

A (Witness Stephens) That's correct.

Q Are you aware that it appears around half of the transformers in your calculation include transformers that serve less than 10 customers -- fewer than 10 customers?

A (Witness Stephens) Again, it's based on averages. So, right.

Q Okay. Are you aware that those transformers serving small numbers of customers are not part of the grid investment plan?

A (Witness Stephens) I was not aware of that, no.

Q Including transformers like that in your calculation vastly reduces the number of customers per interruption shown in your calculation; right?

A (Witness Stephens) Yeah. That's true.

Q Do you also understand that a customer count of one in the spreadsheet you used to develop Table 2 can represent one of the ITS participants, such MEAG or the City of Dalton?

A (Witness Stephens) Yes. That's right.

Q Okay. And MEAG and Dalton serve thousands of customers on their own, don't they?

A (Witness Stephens) Yes. That's right.

Q And because Georgia Power doesn't have access to their data, MEAG is counted as just one?

A (Witness Stephens) Right.

Q So knowing that information, the conclusions you draw from the calculations in Columns D and E seem to be overstated, don't they?

A (Witness Stephens) I would also -- I agree with that, but I would also point out that these numbers are -- and these probabilities or so low that you could triple some of these numbers or double or make them a lot bigger, maybe ten times bigger, and it still would not be cost-effective.

Q Okay. Let's move to the distribution side of things. The distribution investment plan, as you call it in Section 4 of your testimony. And I want to start by talking about circuit hardening and undergrounding. Your opinion is that these strategies should be excluded from the grid investment plan because they are not cost-effective; right?

A (Witness Alvarez) Correct.

Q Your opinion is that more aggressive vegetation management and a more rigorous worst-performing circuit program would be more cost-effective. Is that your opinion?

A (Witness Stephens) Yes.

A (Witness Alvarez) Correct.

Q Is it fair to say that you recognize that the

company already has a vegetation management and worst-performing feeder program, but you think they should be more aggressive and formalized?

A (Witness Alvarez) Correct.

A (Witness Stephens) Correct.

Q You say on page 47, lines 17 through 18, that the company's optimization model does not consider such programs. Is that your testimony?

A (Witness Alvarez) Yes.

Q It doesn't consider a more aggressive vegetation management program?

A (Witness Alvarez) Correct. Those are the -- those are not the packages that were evaluated as part of the customer benefit study.

Q Okay. Is it your understanding that the grid investment -- or, yeah, the grid investment plan is designed to address the root causes of reliability challenges?

A (Witness Stephens) Sorry. Would you ask the question again, please?

Q Yeah. Would you agree that the grid investment plan is designed to address the root causes of reliability challenges?

It's trying to solve the reliability challenges on certain circuits; right?

A (Witness Stephens) It -- it is a -- it's

across-the-board application of a specific package to reduce or improve reliability. It is not necessarily a circuit-by-circuit analysis of the root cause and applying a solution to that root cause on a circuit-by-circuit basis.

Q But it -- would -- the replacement is looking to be a permanent solution to that reliability problem on that circuit?

A (Witness Alvarez) Well, I would argue any solution that a utility would apply to a root cause analysis is intended to be permanent.

A (Witness Stephens) Right.

Q Would you agree that vegetation management is not a permanent solution?

A (Witness Alvarez) Yes. It must be repeated.

Q Okay. Are you aware that many of the outages the company experiences are the result of trees from off of the right-of-way that the company can't touch?

A (Witness Stephens) I would agree with that.

Let me qualify our -- the previous answer in that if you're talking about -- so let's say hardening; okay?

You're going to apply hardening to a circuit and that hardening may help a distributed automation or hardening may help improve reliability. But as the trees grow back, the reliability will be degraded even with the

application of the permanent solution.

So vegetation management still has an impact on circuits that have been hardened or had distribution automation applied.

Q And the reliability challenges that the company is addressing through the grid investment plan are still occurring, despite the company already trimming the trees and managing the vegetation; right?

A (Witness Alvarez) Yes. But, again, I think as we pointed out in our testimony, we didn't feel like that was being done very consistently.

A (Witness Stephens) Yep. That's right.

Q You reviewed the criteria for package investment included in the grid investment plan; right?

A (Witness Stephens) Yes.

Q And you understand then that to qualify for undergrounding, a circuit must, among other criteria, be experiencing reliability concerns and be in the third or fourth quartile of vegetation management spend; right?

A (Witness Stephens) That was your -- that was the company's criteria.

Q That means those circuits have poor reliability that has not been able to be cured by additional vegetation management spend; is that your understanding?

A (Witness Alvarez) Well, I think without the

circuit's specific root cause analysis --

A (Witness Stephens) Right.

A (Witness Alvarez) -- we don't know whether or not the vegetation management had been applied.

Q No, no. But to apply -- or to qualify for undergrounding, you have to have -- or that circuit has to be experiencing reliability concerns and already have had more aggressive vegetation management; right?

A (Witness Stephens) That may be true, but that does not make undergrounding cost-effective.

Q Did you undertake any analysis of the current vegetation management practices related to the circuits for which undergrounding was selected as the solutions?

A (Witness Alvarez) We reviewed -- we asked in discovery for the company's vegetation management policies and procedures. We did review those and found them to be lacking.

Q Well, that wasn't my question, though. Did you undertake any analysis of the current vegetation management practices related to the circuits for which vegetation -- I'm sorry -- for which undergrounding was selected as the solution?

A (Witness Stephens) Only if the vegetation management was applied in the same year that the equipment was installed. We did look at that. That's the -- that's

very minimal, but that's -- we did do that.

Q You would have to do that analysis to say that vegetation management would be an effective alternative; right?

A (Witness Stephens) Vegetation management can be an effective alternative.

Q But that wasn't my question. My question is: You would have to do the analysis of what vegetation management was being done on an individual circuit to be able to say vegetation management is an effective alternative to undergrounding; right?

A (Witness Stephens) That is correct. But that does not preclude the fact that undergrounding is not cost-effective.

Q Okay. But if your testimony is there's a more effective way or a more cost-effective way of fixing this, and that's vegetation management, but you didn't look at whether vegetation management could solve that problem, then you can't make that statement, can you?

A (Witness Stephens) We can only -- that's true. But we can only assume that if undergrounding is not cost-effective, that vegetation management is more cost-effective.

Q So, I guess, to put it simply, you made an assumption that vegetation management can fix a problem that

the company had decided wasn't being fixed by vegetation management?

A (Witness Stephens) We did an analysis that showed that undergrounding was not cost-effective and -- in any way it was not cost-effective. So it doesn't matter.

Q Right.

A (Witness Stephens) The -- a more -- a more cost-effective -- a better way to do it would be through vegetation -- enhanced vegetation management.

Q But there was --

A (Witness Stephens) That was our -- and there was an assumption in there.

Q Okay. And there wasn't a single circuit that you looked at for which undergrounding had been identified that you specifically looked at that circuit to see if vegetation management would be effective at resolving the reliability problems; is that a fair statement?

A (Witness Alvarez) I would say that's correct.

I'd also say it goes the other way. You mentioned earlier that your circuits had a 65 percent improvement.

How much of that improvement was due to the vegetation management that was completed on those circuits? You don't know that.

Q Well, if you have a reliability problem when

you're doing a vegetation management program and then you have to do a grid investment plan investment, then one would assume that the vegetation management was not the cause of the improvement; right?

If you're doing it before and you're doing it after, the only thing that changed was the investment in the new equipment; right?

A (Witness Alvarez) That's true. But typically vegetation management is completed concurrently with, for example, a circuit rebuild project. So you can't tell how much of that improvement was due to the recent vegetation management and how much of that improvement is due to the capital investment.

Q Okay. The company's current vegetation management program is designed to maintain reliability; right?

It's not designed to improve it, I guess, is the best way to put it?

A (Witness Alvarez) It's designed to maintain --

A (Witness Stephens) Yeah, certainly. Right.

A (Witness Alvarez) -- reliability.

Q And have you done any analysis of how much it would cost to improve reliability solely through vegetation management on these circuits?

A (Witness Alvarez) I think we do have that

comparison in here somewhere. I'd have to think about where that is.

Q I didn't find it in your testimony.

A (Witness Stephens) I don't remember that, no.

A (Witness Alvarez) Okay.

Q Okay. Well, if it's in your testimony, it's in your testimony.

A (Witness Alvarez) Okay.

Q Have you done any analysis as to which -- well, there are many activities that fall within vegetation management; right?

A (Witness Alvarez) Yes.

Q Have you done any analysis as to which activities would need to be added or increased to get reliability improvements through the vegetation management?

A (Witness Stephens) No.

Q Have you considered how much customers in the state of Georgia, particularly the Atlanta area, value their tree canopies?

A (Witness Stephens) No.

Q Atlanta's been called the city in a forest; right?

Have you heard that term?

A (Witness Stephens) No.

MADAM CHAIR PRIDEMORE: You've flown over

Atlanta, haven't you?

MR. STEPHENS: I'm sorry?

MADAM CHAIR PRIDEMORE: You've flown over Atlanta, haven't you?

MR. STEPHENS: At nighttime.

MADAM CHAIR PRIDEMORE: Well, I encourage you to take a day flight. Mr. Stephens, you need to take a day flight and you need a window seat. Get out of that aisle.

MR. STEPHENS: I'm looking for a day flight this afternoon.

MADAM CHAIR PRIDEMORE: Sit in that window seat.

MR. STEPHENS: Come on. Get me out of here.

MADAM CHAIR PRIDEMORE: And I need you -- well, Mr. Stephens, you have more control over that than anybody else.

Sit in a window seat and look out.

MR. HEWITSON: All right.

COMMISSONER MCDONALD: I don't know how many more trees we can cut this morning.

BY MR. HEWITSON:

Q Are you aware that some municipal ordinances in Georgia require application and approval to remove trees?

A (Witness Alvarez) Sure.

Q Okay. Vegetation management can't solve all of the problems that some of the circuits have. Would you agree with that?

A (Witness Stephens) That's correct.

Q It doesn't address all causes of outages, like vehicles routinely crashing into distribution assets or wildlife that impacts the circuits; right?

A (Witness Stephens) A little bit on wildlife, but I generally agree.

Q By keeping the wildlife away?

A (Witness Stephens) Yeah. Right, yeah.

Q And vegetation management can't address causes of reliability concerns that originate from outside the right-of-way, like those big tall pine trees we have here in Georgia; right?

A (Witness Stephens) It depends on the utility's status with the city. Some utilities have the ability to do some trimming outside of the right-of-way. But, in general, I understand what you're saying and I agree.

Q And I know you suggested a legislated expansion of utility rates as a way of -- a potential approach of improving reliability; right?

That's on page 50 of your testimony?

A (Witness Alvarez) It's an option, yes.

Q Did you undertake any analysis as to how long

it would take to pass such legislation?

A (Witness Alvarez) No.

Q Did you undertake any analysis of potential customer dissatisfaction with increased right-of-way rights for Georgia Power?

A (Witness Alvarez) I would balance that against the customer satisfaction impact of the rate increases, especially with the grid investment plan.

Q Did you undertake any analysis as to how much it would cost to get that legislation passed?

A (Witness Alvarez) I would guess it's far less than the grid investment plan cost.

Q Did you undertake any analysis as to how much it would cost Georgia Power to acquire additional rights-of-way to address reliability issues?

A (Witness Alvarez) No. But I would argue that analysis should be completed.

Q On page 45, lines 6 through 18, you suggest that Georgia Power should focus its attention on circuits that are performing 2.5 times worse than the average; is that right?

A (Witness Alvarez) Correct.

Q That approach does not require performance of any type of cost-benefit analysis, does it?

A (Witness Stephens) Not necessarily, no.

Q Okay. You looked at the benefits to be gained, but you didn't discuss the costs; right?

A (Witness Stephens) That's typical in the industry. That's what we're basing that on.

Q So what if all the circuits in the bottom 5 percent required undergrounding to improve reliability; would you say those should be done?

A (Witness Alvarez) Required? I don't know why you would underground -- why undergrounding would be required to improve reliability. I think that's a premise that's not --

A (Witness Stephens) Yeah.

A (Witness Alvarez) -- accurate.

A (Witness Stephens) I've got 36 years of experience and we've never found a situation, at least where I worked in Colorado -- now, it's different here -- that was not unsolvable and there was required undergrounding.

The only cases are sometimes you may have to do some undergrounding for very short spans to solve a specific issue. But long stretches of undergrounding are never required as a reliability improvement process.

Q And what if all the circuits in the bottom 5 percent had an average of only a few hundred customers each; would you still support those being the ones that get targeted?

A (Witness Stephens) I'm not sure if I understand the question.

Q Your target of the bottom -- those with two and a half times the average --

A (Witness Stephens) Right.

Q -- or two and a half times worse of the average reliability, that's the bottom 5 percent?

A (Witness Stephens) Right.

Q If one of the circuits in the bottom -- or several of the circuits in that bottom 5 percent only had a few hundred customers, would you still say that those should be the targets?

A (Witness Stephens) Yes.

Q You also say that the company is retiring distribution equipment with book value remaining. That's on page 55 of your testimony.

A (Witness Alvarez) That's correct.

Q On the other hand, you also criticize the company for replacing assets with low or no book value simply to increase rate base and profits; right?

That's page 55 of your testimony, lines 12 to 14.

A (Witness Alvarez) That's correct.

Q Okay. It seems that you claim foul either way. In your view, the company simply should not make any capital

investments through the grid investment program?

A (Witness Alvarez) That is absolutely not correct. As the testimony states, even if all our recommendations are followed in full, the transmission investments are about 170 percent greater than prior to the grid investment plan, and the distribution investments are 55 percent greater than prior to the grid investment plan.

Q But you -- you recommend no -- I'm sorry. I didn't mean to cut you off.

Dan was about to get up, but I stopped him. So I do cut off his objection more than I cut them off.

A (Witness Alvarez) Yeah. So the -- so even with that -- even assuming the Commission approves all our recommendations, the transmission component represents 171 percent growth.

Q Of the normal transmission spend?

A (Witness Alvarez) Of the previous to the grid investment plan spending, correct.

Q Right. And you recommend no transmission spend in the grid investment program?

A (Witness Alvarez) That's correct. Because it consists entirely of the premature replacement that we've been discussing. And then on the distribution side, the number is 55 percent increase prior to the grid investment plan.

So it was -- we are not recommending that the grid investment plan be abandoned or that capital investment in the grid be abandoned. We are -- the net of our recommendations is a healthy amount of growth and capital investment in our testimony.

Q Okay. Before we move on from this section, I want to look at your interpretation of the distribution equipment being retired with net book value remaining. Initially, do you agree with me that just because an asset has net book value remaining does not mean it is operating properly?

A (Witness Alvarez) That happens.

A (Witness Stephens) That's correct.

Q It simply means that it has not yet been fully depreciated; right?

A (Witness Alvarez) Right. So you can imagine a storm where the accident convention would require replacement of something that has no book value, absolutely.

A (Witness Stephens) Yeah.

Q Well, or a piece of equipment that's just faulty?

A (Witness Alvarez) Yeah. Sure.

A (Witness Stephens) Yeah. That's true.

Q And you state that almost 25 percent of the distribution capital that the company is requesting would

replace assets that have not reached their estimated life. Is that your interpretation?

Page 3 --

A (Witness Alvarez) Yeah, I don't think we say it exactly that way.

Q You say nearly a quarter. I'm sorry. I said the percentage.

A (Witness Alvarez) No. But even beyond that, I think the testimony says something to the effect of the amount of net book value being retired equals or approximates 25 percent of the amount being invested.

Q Okay.

A (Witness Alvarez) I don't know if it says it exactly the way you phrased it.

Q On lines 3 to 5 of page 55: Our interpretation is that almost one quarter of the distribution capital the company is requesting replaces assets that have not reached their estimated life.

A (Witness Alvarez) Okay. Thank you. That's correct.

Q And I think -- I think you mean the estimated useful life; right? The accounting term?

A (Witness Alvarez) Yes.

Q Your assumption is that the assets with net book value remaining are operating properly; right?

A (Witness Alvarez) Certainly a great deal of them.

Q Okay. But assets identified for replacement in the grid investment plan may be having reliability problems because they're not operating properly; right?

A (Witness Alvarez) I think that's also an assumption.

A (Witness Stephens) Yeah.

A (Witness Alvarez) You haven't done the root cause analysis on a circuit basis so you really don't know.

A (Witness Stephens) Yeah.

Q Well, they may be identified for replacement because the material used in the original design are contributing to outages, like wood or metal crossarms on a pole where there are lots of squirrels and other critters; right?

A (Witness Stephens) That's a possibility. We were not provided any information about what percentage of these replacements were preemptive versus failure.

Q And you arrived at your nearly one-quarter number by comparing the net book value on equipment to be retired against the capital expenditure budget for the next three years; right?

A (Witness Alvarez) Correct.

Q But shouldn't the real comparison be against

the entire distribution asset base?

A (Witness Alvarez) I think they -- both numbers would be relevant.

Q Okay. But you didn't do the math compared to the entire asset base?

A (Witness Alvarez) No.

Q If you did --

A (Witness Alvarez) Correct.

Q -- it would be about 5 percent; right?

A (Witness Alvarez) Subject to check.

Q And, again, math. Lawyers. We get it.

You point this Commission to the Maryland Commission's efforts on reliability. I have a few questions on that comparison.

You say that there's a focus in the reporting on vegetation management and worst-performing circuit programs, but you don't provide any baseline comparison to the Maryland program, do you?

A (Witness Alvarez) Baseline comparison in --

Q Of what they were doing before.

A (Witness Alvarez) Oh, it's our understanding they were doing no such reporting before.

Q Okay. Well, what were those utilities doing prior to the reporting requirements --

A (Witness Alvarez) Oh.

Q -- being initiated in terms of --

A (Witness Alvarez) Certainly they had those program, yes.

Q Okay. Were the utilities doing more or less vegetation management prior to 2012 than Georgia Power?

A (Witness Alvarez) I would argue somewhat less.

Q Okay. Did the -- did each of the utilities have worst-performing circuit programs like Georgia Power's?

A (Witness Alvarez) I don't know that answer to that question. I would imagine so. It's just --

A (Witness Stephens) Right.

A (Witness Alvarez) -- such a practice.

A (Witness Stephens) Yeah, it's a standard practice in the industry.

A (Witness Alvarez) But we don't know that for sure.

Q Do you know what percentage of their distribution assets are already underground?

A (Witness Alvarez) Not off the top of my head, no.

Q And BG&E serves Baltimore City; right?

A (Witness Alvarez) Correct.

Q And it's my understanding that a majority of Baltimore City lines are underground. Is that your understanding, as well?

A (Witness Alvarez) Yes.

Q What has Maryland's weather been like since 2012 compared to Georgia's?

A (Witness Alvarez) I don't have a basis to answer that.

Q Okay. Are you aware that -- well, hold on.

Do you know what reporting the Maryland Commission required prior to 2012?

A (Witness Alvarez) Yeah. As I mentioned, I don't think they had any specific to these programs.

Q You did say that.

Are you suggesting that simply creating more onerous reporting mechanisms can improve the utility's reliability?

A (Witness Alvarez) I would not categorize them as onerous. But I think what gets measured gets managed.

Q But you still have to do the work; right?

A (Witness Alvarez) Yeah. I think you have to compare, again, the relative cost of reporting compared to the improvement that those people have enjoyed without massive capital investment is pretty significant.

Q Okay. All right. Last section. I want to talk about DERMs. This is on page 69 of your testimony.

You identify two benefits of DERMs as tracking DER installations and monitoring and controlling DERs

remotely; right?

A (Witness Alvarez) Uh-huh.

Q Okay. Are you also aware that DERMs can help utilities forecast resources more accurately?

Would you agree that that's a benefit?

A (Witness Stephens) Yes.

A (Witness Alvarez) Yes.

Q Would you agree that DERMs can provide greater situational awareness for system operators?

A (Witness Stephens) Given the appropriate communication installations, yes.

Q Do you agree that DERMs can allow for grid optimization solutions to be executed in real time?

A (Witness Stephens) Again, depending on the infrastructure used to apply DERMs, yes.

Q And do you agree that DERMs can assist with demand response measures in an electric system?

A (Witness Alvarez) Yeah. I think some -- I could see how a utility could use DERMs in that way, yes.

Q And do you agree that DERMs --

A (Witness Stephens) Uh- --

Q I'm sorry. I didn't mean to cut you off, Mr. Stephens.

A (Witness Stephens) Well, the -- I guess -- I guess I would agree with that.

Q Okay. Do you agree that DERMs can assist with emergency load shed?

A (Witness Alvarez) Well, there are other systems can do that, too.

A (Witness Stephens) Yeah. Right. But it could assist with -- it could assist with -- emergency load shed. I guess I would agree with that.

Q Okay. And do you agree that DERMs can assist with economic dispatch determinations in real time?

A (Witness Alvarez) Yes, I would agree with that.

Q And do you agree that DERMs can allow for consideration of demand-side resources alongside supply-side resources in future IRPs for Georgia Power, which is something the Commission addressed in the 2019 -- or 2022 IRP?

A (Witness Alvarez) Yeah. Again, I think there are many ways you could do that, though.

Q You noted that few utilities have implemented DERMs and you point to Hawaiian Electric in particular.

A (Witness Alvarez) Yes.

Q Have you reviewed Hawaiian Electric's "Customer Energy Resources for Hawaii" publication from May of 2021?

A (Witness Alvarez) No, we have not.

Q Okay. In that publication, which I have here -- and in the interest of time, I won't give it to you.

But might you be incorrect; might Hawaiian Electric have instituted a DERMs program already?

A (Witness Alvarez) They may have very recently, yes.

Q All right. You recommend that the Commission reject the company's DERMs request because of the low penetration of distributed energy resources that will be on the grid by 2025; right?

A (Witness Alvarez) Correct.

Q Okay. You're aware, though, that the Commission just approved 250 megawatts of retail -- of a retail DER program in the 2022 IRP; right?

A (Witness Alvarez) Yes.

Q And the Commission has also directed Georgia Power to consider additional demand-side reserves as -- which would all have to be integrated; right?

A (Witness Alvarez) They have to be integrated? I don't know about the -- there was an opportunity to integrate them, yes. I don't know that they would have to be -- I would characterize it as they have to be integrated.

Q Well, if those demand-side resources are going to be used for the grid, they would have to be integrated; right?

A (Witness Alvarez) In some kind of system. Not necessarily a DERM.

A (Witness Stephens) That's right.

A (Witness Alvarez) But yes.

Q And at what level of penetration would you support a DERMs program?

A (Witness Alvarez) I think it varies by the type of DERMs, the sizes of the DERMs, the locations of those DERMs.

A (Witness Stephens) Yeah.

A (Witness Alvarez) It's certainly greater than the percentage that the company would expect based on the IRP -- the IRP issues you just identified.

Q But you're not going to give me a number?

A (Witness Alvarez) Well, I think it's a trade secret number, honestly.

Q No, no, no. Number at which -- at which level of penetration --

A (Witness Alvarez) Oh.

Q -- that you would support DERMs.

A (Witness Alvarez) Well, again, I think it depends on the --

A Well, it does. NREL did a study, National Renewable Energy Laboratories, did a study on the impacts of DER on a circuit-by-circuit basis in Xcel Energy and they found that some penetrations could be as much as 100 percent with no impacts on protection equipment and all that stuff,

and as low as 10 percent.

And so it varies. And so you can't answer the question what percentage it's going to take. It's got to be analyzed by the company. And we think that they need to look at it from a cost-effectiveness standpoint for the ratepayers.

A (Witness Alvarez) For example, you mentioned the Hawaii experience. Let's just say -- I'm going to take you at your word that they have recently implemented a DERMs. They were almost 50 percent, until recently, distributed energy resource penetration if -- before they implemented that DERMs on Oahu.

Q But Southern Company and Georgia Power is a larger system than Hawaiian Electric's; right?

A (Witness Alvarez) Sure. Yes.

Q And do you agree with me that integrating DERMs can be much more complicated given a system's larger size?

A (Witness Stephens) I think that's true. The -- let me qualify that, though. What you need to be doing is looking at this on a circuit-by-circuit basis. And as you find the circuits that need to be -- these need to be applied to, as they did in Hawaii -- they did that.

They started looking at DERMs and they -- I mean, started looking at DER penetrations and looked at the effect on their systems and then they made decisions about

what they needed to do and how they needed to control DER on those individual feeders.

The growth in Hawaii was much faster than it is in Georgia from a penetration level. So even though they were smaller, they probably had to do more analysis than Georgia needs to do at this time.

Q Have you ever been involved in implementing a DERMs solution?

A (Witness Stephens) No.

Q Okay. Would you be able to tell me how long it takes to get a DERMs solution up and running?

A (Witness Stephens) No.

MR. HEWITSON: Gentlemen, that's all the questions I have for you.

MR. STEPHENS: Thank you.

MR. ALVAREZ: Thank you.

MR. HEWITSON: Thank you very much for your time.

MADAM CHAIR PRIDEMORE: Redirect.

MR. WALSH: Thank you, Madam Chair.

REDIRECT EXAMINATION

BY MR. WALSH:

Q You were asked whether the company should wait for a pending emergency to address system reliability. Do you recall --

A (Witness Alvarez) Yes.

Q -- those questions?

Okay. In your opinion, has Georgia Power Company managed its system reliably up to this point?

A (Witness Alvarez) Yes.

A (Witness Stephens) Yes.

Q If your recommendation is adopted by this Commission, would that still result in an increase in the dollar amounts devoted to system reliability to the grid as compared to what the spending is now?

A (Witness Alvarez) Significantly. Well, prior to the GIP.

Q Right.

A (Witness Alvarez) Significant improvement -- or significant increase over pre-GIP spending, that's correct.

Q So, to be clear, you're not recommending cuts to what the company spends on reliability, but you are recommending that the Commission not approve the entirety of the company's proposed increase?

Is that what your testimony is?

A (Witness Alvarez) That's correct.

A (Witness Stephens) That's correct.

A (Witness Alvarez) Based on pre-2019.

Q Right.

A (Witness Alvarez) The running rate before the

GIP, correct.

Q And let me take this opportunity -- because there were -- you were asked questions about what the Commission approved as part of the 2019 rate case. Do you recall that?

A (Witness Alvarez) I do recall that.

MR. WALSH: Madam Chair, I would like to approach and present the panel with the testimony of Mr. Poroch, Ms. Adams and Mr. Robinson from the 2019 rate case.

MADAM CHAIR PRIDEMORE: You may approach.

Mr. Walsh, I just want to encourage you to keep it moving.

MR. WALSH: Oh. Okay. I'm sorry.

MADAM CHAIR PRIDEMORE: Please.

BY MR. WALSH:

Q Could I direct your attention to the question and answer at the top of page 56.

A (Witness Alvarez) Yes.

Q Could you please read the question and the first sentence of the response?

A (Witness Alvarez) The question is: What approvals are you seeking in this case for T&D investments?

And the answer is: As with prior cases, the company is seeking approval to undertake these investments

and cost recovery of these investments made during the period covered by the ARP. In this case, such investments include, but are not limited to, investments related to the transmission upgrades required should Bowen 1 and 2 or future coal units be retired, as well as the work the company will begin that is necessary to effectuate the grid investment plan.

Both of these efforts will expand over multiple years, and for long-term investments, like the grid investment plan, the company will continue to update the Commission on the progress of these initiatives in future cases.

Q So based on this response, do you understand that the company asked for approval for investments during the three-year accounting rate plan approved in that case?

MR. HEWITSON: Well, I'm going to have to object to that question. If we're going to ask that question, we're going to have to give them the entirety of the testimony.

We're also going to have to give the rebuttal testimony where Mr. Robinson described at length the grid investment plan that the company was requesting. This is the direct testimony in the 2019 rate case, not the rebuttal testimony. So Mr. Walsh isn't giving the witnesses the full picture.

MR. WALSH: I'm giving the -- you're correct that I'm not giving the witnesses the entire record from the 2019 case as it related to this. However, I'm giving them the complete response to what the question was in their direct when they're presenting their request to the Commission as to what approvals they are seeking in this case for T&D investments.

What I can do is I can acknowledge that this is not the entire record. And I can just ask the panel what its understanding of the request that the company made and the record for the 2019 case in its entirety will speak for itself. But I don't think that it's objectionable that I point to a question and answer in the direct case that -- where the company says what it's asking from the Commission simply because I'm not also presenting it with everything else in the case.

I can acknowledge that this is not the entirety of the case, but I can -- still think that the panel should be able to respond to what their understanding is of what the company asked for in the 2019 case.

MR. HEWITSON: But I asked them that question on cross and they gave me their answer. And if you're going to ask them what the company asked for in the 2019 rate case in its entirety, you have to

show them what we actually asked for, which was in the rebuttal testimony. That's not what he's showing them.

MADAM CHAIR PRIDEMORE: Mr. Walsh, I like to know the full story before I answer a question. And so I think in this case -- I think that you should ask a question that's not based upon this direct testimony.

What they originally asked for in 2019 is a part of the record. It was not what this Commission ordered Georgia Power. We ordered them something completely different.

And so I would ask -- ask your question, but not specific to the testimony, unless you're going to provide the full scale of the testimony to the witnesses.

MR. WALSH: Okay. And, for the record, just -- I was not attempting to piecemeal anything. It was -- this is consistent with the staff's understanding. But I understand that there's more to the record, so I will ask the question differently.

MADAM CHAIR PRIDEMORE: There you go.

BY MR. WALSH:

Q What is your -- did you understand that the company was requesting approval that was related to the 2019

accounting rate plan or did you understand that the company's request was for the Commission to approve a plan that would commit it to approving investments going forward beyond that time period?

A (Witness Alvarez) It's my understanding it's only that rate case, period.

Q Thank you.

Does equipment become incrementally less reliable every year of its service?

A (Witness Stephens) Generally, yes.

Q What purpose does testing equipment serve in determining whether the equipment has become unreliable in --

A (Witness Stephens) Well, the purpose of the testing is actually to determine whether or not the equipment is -- has become -- has become -- has evolved to a state that is not -- where the equipment will fail very shortly.

In other words, it is when -- dissolved gas, those kinds of things, are really strong indications that the equipment is about to fail. And, therefore, that's a good time to replace the equipment before it fails.

Q If equipment passes testing, what factor does the age of the equipment have in whether the equipment should be retired?

A (Witness Stephens) I'm sorry. Ask the question again.

Q If the equipment passes testing, what factor does the age of the equipment have in whether the equipment should be retired?

A (Witness Stephens) Well, it has -- it doesn't have any -- it needs to be analyzed. Because equipment -- the age -- if something is -- is very old, then the -- it is possible that the -- that the -- within a specific type of equipment class that the failure rates have achieved -- or start to fail at a rate that makes it cost-justified to replace. But generally age doesn't have an impact. It really should be the testing.

Q Okay. You were asked questions around transformers and questions about roughly 200 transformers that failed with 55 percent of them having passed a test. Do you recall those questions?

A (Witness Stephens) I do.

Q Is the 55 percent the significant number or would it be more appropriate to look at the total number of transformers that were tested and that actually passed the testing?

A (Witness Stephens) Yes. The 55 percent is not the significant number. You need to look at how the failure rates compare to the total -- the total population.

**MADAM CHAIR PRIDEMORE:** But you would admit, Mr. Stephens, that 55 percent of the equipment failures still failing after a test, the problem's the test?

**The test is obviously inadequate.** It's not -- it's not --

**MR. STEPHENS:** No.

**MADAM CHAIR PRIDEMORE:** It's not meeting the needs of being able to determine the authenticity of the equipment; right?

**MR. ALVAREZ:** I think the -- the numbers of equipment that are tested are much greater than the population we talked about.

**MR. STEPHENS:** Right.

**MR. ALVAREZ:** I believe the company suggested that of the units that were replaced, right, so that's a limited universe already --

**MR. STEPHENS:** Right.

**MR. ALVAREZ:** -- that 55 percent of them passed their test. But that doesn't mean that 55 percent of all tests; right?

**MR. STEPHENS:** Right.

**MR. ALVAREZ:** The percentage of equipment that passed -- the percentage of all equipment that passed their test was much, much greater than that.

MR. STEPHENS: Yeah. The --

MADAM CHAIR PRIDEMORE: Yeah. Mr. Alvarez, it's -- it's not 55 percent of candy canes. It's still 55 percent that they passed the test, then the equipment failed.

That's what I'm -- that's what I can't -- this just --

MR. ALVAREZ: Right. But if you think about over that period -- I think it was about a ten-year period -- they probably tested every one of those pieces of equipment three times for thousands and thousands of tests.

MR. STEPHENS: Right.

MR. ALVAREZ: And out of those, 55 that passed failed anyway.

MADAM CHAIR PRIDEMORE: It's just a disproportionately large number.

Go ahead, Mr. Walsh.

BY MR. WALSH:

Q You were asked a number of questions in different -- on different issues about what information you asked for the company to provide you and why you didn't ask for certain information.

Are you aware that it's the company that has the burden of proof in this case?

A (Witness Alvarez) Yes.

A (Witness Stephens) Yes.

Q Would you describe what Georgia Power Company is proposing in its GIP as a dramatic increase in spending?

A (Witness Alvarez) Prior to the 20- -- to the last rate case, yes.

Q Would you have expected the company to present the information necessary to support its request as part of its direct case?

A (Witness Alvarez) Yeah. In fact, I have to say, relative to what we've seen in other utilities, the amount of information presented relative to such a massive increase is very small --

A (Witness Stephens) Right.

A (Witness Alvarez) -- relative to what we would -- you would experience.

Q You were asked some questions on undergrounding. Is it your recommendation that undergrounding is not cost-effective?

A (Witness Alvarez) Yes. As our testimony says, it's tens of thousands of dollars per premise passed. That's the cost. And so you just can't -- there's just not enough reliability improvement available from the practice to cover such cost.

As Mr. Stephens mentioned, he did some analyses

where he brought the reliability down to perfect from undergrounding --

A (Witness Stephens) That's correct.

A (Witness Alvarez) -- and still couldn't get the cost-benefit analysis to come out positive.

Q In your discussion of alternatives, was your testimony meant to suggest that the company should rely solely on vegetation management for reliability?

A (Witness Stephens) No.

Q What was the purpose of your discussion of vegetation management?

A (Witness Stephens) The discussion basically says that they could improve reliability if they would have a much more regulated vegetation management program. That's what we're trying to say. That could improve reliability. And that improvement could be more cost-effective approach.

A (Witness Alvarez) And if I could just add to that. Again, the customer benefit study did not include, as one of the things it evaluated, more aggressive vegetation management, or more consistent vegetation management, or more consistent worst-performing circuit budgets; right?

Those -- those were not packages that were evaluated as part of the customer benefit study. So if you haven't looked at all the alternatives, then you don't know that your proposed capital investment plan is lowest cost.

Because you've -- you've constrained that analysis to what the company has defined as its options. And those vegetation management and worst-performing circuit were not among the options.

MADAM CHAIR PRIDEMORE: Mr. Walsh, I am going to ask you: Please don't ask the witnesses questions that have already been asked or for them to recap answers that they've already provided to previous questioners.

MR. WALSH: I'm actually done with my redirect, so...

MADAM CHAIR PRIDEMORE: Well, just remember it for next time.

MR. WALSH: Okay.

MADAM CHAIR PRIDEMORE: Yes. Thank you.

MR. WALSH: Thank you.

I would ask that the witness panel's exhibits be admitted into evidence.

MADAM CHAIR PRIDEMORE: So moved, so marked.

(Staff Exhibits 11 through 55 were admitted into evidence.)

MR. WALSH: That concludes our redirect and I'd ask that the panel be excused.

MADAM CHAIR PRIDEMORE: There you go.

Witnesses, you are excused. You're going to

make that flight after all.

MR. ALVAREZ: Thank you.

MR. STEPHENS: Thank you very much.

(Witnesses excused.)

MADAM CHAIR PRIDEMORE: Okay.

All right. We're going to tee up the next one. We have a panel of Lance Kaufman, single-person panel; is that correct, Mr. Thomas?

MR. WALSH: That's correct.

MADAM CHAIR PRIDEMORE: Okay, Mr. Walsh.

Okay. And Mr. Mugrace is by himself, as well?

MR. WALSH: That's correct.

MADAM CHAIR PRIDEMORE: Am I saying that correctly?

MR. THOMAS: That's how I'd say it.

MADAM CHAIR PRIDEMORE: Okay. Thank you. Just looking for some validation, Preston. Thank you.

Okay.

MR. WALSH: If you can remain standing, I'll swear you in.

Thereupon,

LANCE KAUFMAN, Ph.D.,

having been duly sworn, testified as follows:

MR. WALSH: Thank you. You may be seated.

DIRECT EXAMINATION

BY MR. WALSH:

Q Dr. Kaufman, could you please state your full name for the record and by whom you're employed.

A Lance Kaufman. I am employed by Aegis Insight.

Q Dr. Kaufman, on October 20th, 2022, did you prefile or cause to be prefiled 44 pages of public disclosure testimony in question-and-answer form?

A I did.

Q On November 3rd, did the Commission staff file with this Commission an errata that included changes or corrections to your testimony?

A It did.

Q Okay. Noting the changes that were in the errata, if I were to ask you the same questions that are presented in your prefiled testimony, would your answers be the same?

A They would.

MR. WALSH: Madam Chair, I would ask that the public disclosure of the prefiled direct testimony of Dr. Kaufman be copied into the record as if read from the witness stand.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimony and errata of Lance Kaufman follows:)

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**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | | |
|---|---|---|---|
| **IN RE:** | **GEORGIA POWER COMPANY'S 2022 RATE CASE** | **)** **)** | **DOCKET NO. 44280** |

# DIRECT TESTIMONY

# AND EXHIBITS

# OF

# LANCE KAUFMAN

**ON BEHALF OF THE**
**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

**OCTOBER 20, 2022**

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**EXHIBIT LIST**


Exhibit LK-1: Qualification Statement of Lance D. Kaufman

Exhibit LK-2: Kaufman Depreciation Study Results

## I. INTRODUCTION AND SUMMARY

**Q. PLEASE STATE YOUR NAME AND OCCUPATION.**

A. My name is Lance D. Kaufman. I am a consultant providing expert testimony before state public utility commissions in the Northwest, Southwest and Intermountain West and Georgia.

**Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.**

A. I am testifying on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("Staff").

**Q. PLEASE SUMMARISE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.**

A. I have a Ph.D. in Economics from the University of Oregon with field work in industrial organization and econometrics. I have worked in the utility industry for 10 years performing analysis and providing testimony on depreciation, cost of capital, rate spread and rate design, net power costs, cost allocations, decoupling mechanisms, load forecasting, and resource planning. I am a Certified Depreciation Professional. My Curriculum Vitae is provided in Exhibit LK-1.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A. I make the following recommendations:

1. Use the 2022 IRP economic lives of 2054 and 2058 as the terminal retirement dates for Hatch Units 1 and 2 respectively.
2. Remove the 25 percent contingency adder from the terminal net salvage of coal and gas production facilities.
3. Require the Company to file a decommissioning study of solar assets as part of its next rate case.

4. Calculate remaining lives using the survival curves identified in Exhibit LK-2 pages 20 through 22.

## II. OVERVIEW OF DEPRECIATION RATES AND EXPENSE

**Q. WHAT IS DEPRECIATION EXPENSE?**

A. Depreciation is an expense that represents recovery of the Company's capital investment over the expected life of the investment. Depreciation expense also accounts for the expected cost of removal (COR) and salvage value over the expected life of the investment.

**Q. HOW DOES RECOVERY OF INVESTMENT DIFFER FROM RETURN ON INVESTMENT?**

A. Recovery of investment is the recovery of the original investment, while return on investment represents the financing cost on the asset. Assets are financed with a combination of debt and equity.

**Q. HOW IS DEPRECIATION EXPENSE CALCULATED?**

A. Depreciation expense is calculated by multiplying the gross plant balance in each Federal Energy Regulatory Commission ("FERC") account or subaccount by a depreciation rate specific to that account or subaccount. Depreciation rates are approved by the Commission in each general rate case and typically are not changed between rate cases. Depreciation rate recommendations made to the Commission are usually supported by a depreciation study.

**Q. WHAT ARE GEORGIA POWER COMPANY'S RECOMMENDATIONS FOR DEPRECIATION RATES AND WHAT ARE THEY BASED ON?**

A. Georgia Power Company's (Company or Georgia Power) proposed depreciation rates are contained in Appendix Exhibit 2 of the Company's filing. This appendix is a depreciation study performed on behalf of Georgia Power by the Alliance Consulting Group ("Alliance

Study").[1] The Alliance Study includes a general discussion of depreciation at pages 6 through 20. I agree with this general discussion and refer the Commission to it for detail on how depreciation rates are calculated. However, I disagree with certain parameters and findings in the Alliance Study related to specific assets and plant accounts. In this testimony I identify the parameters that I disagree with, recommend alternate parameters, and provide the rates resulting from these alternate parameters.

**Q. WHAT GENERAL ISSUES DO YOU RAISE IN THIS TESTIMONY?**

A. I address the terminal retirement date for Hatch plant, the decommissioning costs for coal and gas plants, and the survivor curves used to model future retirements.

**Q. HOW SHOULD THE COMMISSION EVALUATE AND RESOLVE THE DISPUTED ISSUES THAT YOU RAISE?**

A. The Commission should weigh the evidence in the record that is specific to each plant or account and make a conclusion about the expected retirement outcomes based on that evidence.

**Q. HOW DOES CHANGING A DEPRECIATION RATE IMPACT BOTH THE COMPANY AND CUSTOMERS?**

A. The primary function of depreciation is to allocate costs to customers across time over the service life of the asset. Thus, an increase or decrease in depreciation rates does not have a direct impact on the total amount collected from customers or returned to the Company over time. The primary impact from changing a depreciation rate is the year in which the capital is

[1] The Company's filed case deviates from the Alliance Study for the following plants: Bowen 1 and 2 coal units and Ft. Benning and Ft. Gordon solar facilities. The Alliance Study was produced prior to the Commission's order in the 2022 IRP denying the early retirement of Bowen Units 1 and 2. The Company's filed case contains rates for Bowen Units 1 and 2 that adopt the same interim retirement characteristics but extend the terminal retirement date to December 31, 2030. The Company's filing also contained formula errors affecting the depreciation expense calculations for Ft. Benning and Ft. Gordon solar facilities. I understand the Alliance Study contains the correct rates for these facilities and Company has or expects to submit a correction related to this.

fully recovered. A lower depreciation rate shifts the recovery of invested capital from the current time period to a future time period. A higher depreciation rate shifts the recovery of invested capital from a future time period to a current time period.

**Q. WHY DO YOUR RECOMMENDATIONS FOCUS ON THE EXPECTED RETIREMENT OUTCOMES?**

A. A commonly accepted premise of fairness is that those who benefit from a cost should bear the cost. This concept is applied when using cost of service studies to support the allocation of costs across customers. The same concept is used to support the recovery of capital across time. Customers benefit from utility plant only as long as the plant is in service. Thus, the recovery of the investment in plant should be spread across time that plant is expected to be in service. Depreciation rates calculated based on expected retirement outcomes accomplish this goal.

**Q. IS IT SOUND POLICY TO COLLECT EXTRA EXPENSE IN ORDER TO ESTABLISH A BUFFER FOR UNEXPECTED RETIREMENTS OR COST OF REMOVAL?**

A. No, this is not sound policy for several reasons. Expected outcomes are outcomes that represent what is expected on average. While retirements occasionally exceed or fall short of expectations, these shortfalls and excesses are expected to balance out. One property of a depreciation system is that it typically provides a mechanism for these shortfalls and excesses to accumulate and offset over time. Both the Alliance Study and my analysis adopt the Average Remaining Life Procedure. This procedure spreads excess and deficient depreciation reserves across the remaining lives of assets. In addition to the remaining life procedure, reserve transfers and regulatory asset accounting can be used to mitigate and address temporary excesses or shortfalls.

Because the expected outcome represents the outcome that is most likely to happen, collecting extra depreciation expense to establish a buffer beyond the expected outcome will over-allocate costs to current customers. This is unfair to current customers.

**Q. THE ALLIANCE STUDY NOTES THAT INFORMED JUDGMENT PLAYS A ROLE IN STUDYING DEPRECIATION. HOW DO YOU RECOMMEND INFORMED JUDGMENT BE APPLIED?**

A. The National Association of Regulatory Utility Commissioners ("NARUC") publication "Public Utility Depreciation Practices" offers the following guidance on the use of informed judgment:

> The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and weighed by importance. For example, the following forces of retirement need to be considered: Do the past and current service life dispersions represent the future? Will scrap prices rise or fall? What will be the impact of future technological obsolescence? Will the company be in existence in the future? The analyst must rank the factors and decide the relative weight to apply to each. The final estimate might not resemble any one of the specific factors; however, the result would be a decision based upon a combination of the components.

The NARUC manual highlights that informed judgment is a logical process that employs specific information and factors. This is important because it means that, when informed judgment is applied, the information considered and the logic that was applied should be identifiable. In this testimony, when I apply informed judgment, I identify the factors that I considered and the logic that I apply in order to aid the Commission in determining whether my judgment is reasonable.

**Q. WHAT GUIDANCE CAN AID THE COMMISSION IN WEIGHING THE MERITS OF THE INFORMED JUDGMENT THAT YOU APPLY AND THAT OF THE COMPANY?**

A. I recommend the Commission apply the results of academic research into the reliability of judgmental forecasts. This research offers five principles for reliable judgmental forecasting:

1. Organize and present information in a form that clearly emphasizes relevant information.
2. Limit the amount of information used in judgmental forecasting. Use a small number of particularly important cues.
3. Use mechanical methods to process information.
4. Combine several forecasts.
5. Require justification of forecasts.[2]

I applied these principles in developing the recommendations in my testimony. However, I recommend the Commission place particular emphasis on the final principle of justification of forecasts. This principle is important to follow in a regulatory setting.

**Q. HOW ARE DEPRECIATION RATES CALCULATED?**

A. The depreciation expense for an account is an amount that, if collected over the average remaining life for the assents in the account and combined with current accumulated depreciation, will be equal to the amount that needs to be recovered, or the original investment in the assets less expected net salvage. Annual depreciation expense, or accrual, is expressed as a formula below.

[2] Stewart, T. R. (2001). Improving reliability of judgmental forecasts. In J. S. Armstrong (Ed.), Principles of Forecasting: A Handbook for Researchers and Practitioners (pp. 81-106): Kluwer Academic Publishers.

$$Annual\ Depreciation\ Expense = \frac{Plant\ in\ Service - Total\ Net\ Salvage - Reserve}{Average\ Remaining\ Service\ Life}$$

The depreciation accrual rate is a rate that, when multiplied by the total investment or plant balance, will return the depreciation expense. This is expressed as a formula below.

$$Depreciation\ Accrual\ Rate = \frac{Annual\ Depreciation\ Amount}{Plant\ in\ Service}$$

Exhibit LK-2 contains the calculation of depreciation rates based on my recommendations. Working backwards through the calculations on Exhibit LK-2 page 1, the Accrual Rate-Staff Proposed (depreciation rate) column is the Annual Depreciation Amount divided by the Plant in Service. Thus, when the depreciation rate is multiplied by the Plant in Service it will result in the Annual Depreciation Amount. The Annual Depreciation Amount is the Amount to Be Recovered divided by the Remaining Life. The Amount to Be Recovered is the Plant in Service minus Net Salvage Amount minus Allocated Depreciation, and the Net Salvage Amount is the Amount to Be Recovered multiplied by the Net Salvage %.

Thus, the depreciation rate requires four inputs, Plant In Service, Allocated Depreciation (or Reserve), Net Salvage %, and Remaining Life, and the depreciation rate is calculated with the following formula:

$$Depreciation\ Accrual\ Rate = \frac{Plant\ in\ Service * (1 + Net\ Salvage\ Rate) - Reserve}{Plant\ in\ Service * Remaining\ Life}$$

Plant in Service and Reserve are typically undisputed values that are adopted from the utility's accounting records.[3] The primary focus of a depreciation study is the calculation of the net salvage rate and remaining life.

[3] Occasionally Plant in Service or Reserve are disputed, but I do not dispute these amounts in this testimony.

**Q. HOW DO THE ISSUES YOU MENTIONED EARLIER REGARDING TERMINAL RETIREMENT DATE, DECOMMISSIONING COSTS, AND SURVIVOR CURVES RELATE TO THE NET SALVAGE RATE AND REMAINING LIFE?**

A. The terminal retirement date affects the remaining life calculation for assets where an entire group of assets is scheduled to be retired collectively, such as generating units. The decommissioning cost is an input into the net salvage rate for assets that are decommissioned as part of terminal retirement. The survivor curves are statistical distributions that are used to calculate the remaining lives of assets.

## III. TERMINAL RETIREMENT DATES

**Q. WHAT TERMINAL RETIREMENT DATES ARE PROPOSED BY THE COMPANY FOR HATCH NUCLEAR PLANT DEPRECIATION RATES?**

A. The Company uses a terminal retirement date of 2038 for Hatch Common and Hatch Unit 2, and a terminal retirement date of 2034 for Hatch Unit 1 when calculating depreciation rates.[4]

**Q. WHAT ARE THE COMPANY'S EXPECTED TERMINAL RETIREMENT DATES FOR THE HATCH PLANT?**

A. The Company currently expects to retire Hatch Unit 1 in 2054 and Unit 2 in 2058. In Docket No. 44160 the Company requested and received Commission approval for the capital and O&M costs that the Company will incur for the subsequent license renewal for Plant Hatch Units 1 and 2.[5] The Company expects to submit an application for, and receive approval of, a license extension of this plant.[6]

[4] Appendix Exhibit 2 pages 117 and 118.
[5] Company Direct Hearing Transcript Day 1 page 329.
[6] Georgia Power Response to Staff Data Request STF-AI-1-34.

**Q. HOW HAS THE COMMISSION TREATED DEPRECIATION LIVES FOR NUCLEAR PLANTS PRIOR TO FINAL NUCLEAR REGULATORY COMMISSION ("NRC") APPROVAL FOR PAST LICENCE EXTENSIONS?**

A. The Commission has granted extended depreciable lives prior to final approval in the past. In the Company's 2007 rate case docket, Docket No. 25060, the depreciable life for the currently operating Plant Vogtle Nuclear Units 1 and 2 was extended prior to NRC approval of the corresponding license extensions.

**Q. DOES THE COMPANY AGREE THAT THE COMMISSION'S TREATMENT OF VOGTLE'S DEPRECIABLE LIFE CAN REASONABLY BE APPLIED TO HATCH?**

A. The Company has agreed that if the facts and circumstances for the Hatch plant are similar to those of Vogtle, it is reasonable to apply a similar treatment of depreciable life to the Hatch plant.[7]

**Q. ARE THE FACTS AND CIRCUMSTANCES OF HATCH SIMMILAR TO VOTGLE?**

A. Yes. While there are some differences between these two plants, these differences are immaterial in the context of setting depreciation rates. Depreciation rates reflect expectations about future plant retirements. While there is a small chance that the Hatch plant will not have its license extended, the expected outcome is a life extension, and thus depreciation rates should reflect this.

**Q. WHAT IS THE BASIS FOR YOUR JUDGMENT THAT THE EXPECTED OUTCOME FOR THE HATCH PLANT IS RETIREMENT IN 2054 AND 2058?**

A. I considered that the Company currently expects to apply for and receive a license extension for such dates. Based on the information provided by the Company, it appears highly likely that the extension will occur. There is a small but unquantified chance that the Company does

[7] Company Direct Hearing Transcript Day 1 page 332.

not receive the license or finds it economical to retire early despite the license extension. However, given the current national concerns regarding fuel security, energy diversity, and greenhouse gas emissions, this seems unlikely. There is also a small chance that the Company extends the life beyond 2058. I concluded that impact of these alternate outcomes offset each other, and a reasonable expectation is to rely on the expected outcome of retirement in 2054 and 2058.

**Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

A. Exhibit LK-2 pages 1 through 15 provides a comparison of my recommended rates with the Company's filed depreciation study. My recommendation reduces depreciation expense under December 31, 2020 plant balance by approximately $128 million per year.[8] The impact of my recommendations within the overall context of Staff's case is provided in the Direct Testimony and Exhibits of Ralph Smith and Robert Trokey.

[8] Calculated as the difference between the Alliance Study composite depreciation rate and the Staff composite depreciation rate of -0.371% times the December 31, 2021 plant balance of $34,499,288,719. *See* Exhibit LK-2 page 15. I understand that the Company's filing may differ from the Alliance Study with respect to Bowen Units 1 and 2 and other minor changes.

## IV. DECOMMISSIONING COSTS

**Q. WHAT TREATMENT HAS THE COMPANY REQUESTED FOR GENERATION PLANT DECOMMISSIONING COSTS?**

A. The Company has requested that the results of its most recent decommissioning study be implemented when calculating depreciation rates.

**Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S RECOMMENDATION?**

A. The Company's study appears reasonable for hydro generation. However, decommissioning expense for coal and gas plants appear overstated while decommissioning expense for solar plants appear understated. I recommend that the contingency component of coal and gas plants be removed from depreciation rates and that the Company be required to submit a revised study of solar decommissioning costs in its next general rate case.

**a. Coal Plants**

**Q. WHY HAVE YOU CONCLUDED THAT THE DECOMMISSIONING EXPENSE FOR COAL AND GAS PLANTS IS OVERSTATED?**

A. The Company has finished decommissioning or is in the process of decommissioning 11 coal plants.[9] The actual expenses incurred for decommissioning these plants provides a base line of actual decommissioning costs against which the Company's decommissioning study can be evaluated. Of these plants, two plants, McDonough-Atkinson and Branch, have completed decommissioning and have similar size characteristics to the Company's four remaining coal plants.[10]

[9] Response to Staff DR STF-AI-1-15 Attachment A.

[10] Yates is a coal plant that has been converted to gas fire. I analyze Yates with other coal plants because the primary structures to be demolished are likely more similar to coal plants than gas plants.

**Q. WHAT ARE THE CHARACTERISTICS OF THE COMPANY'S REMAINING COAL PLANTS?**

A. The table below summarizes the capacity of the Company's remaining coal or converted coal plants.

*Table 1*

| Plant | MW | Units | MW per Unit |
|---|---|---|---|
| Bowen | 3,376 | 4 | 844 |
| Scherer | 3,720 | 4 | 930 |
| Wansley | 1,840 | 2 | 920 |
| Yates | 700 | 2 | 350 |

Three plants consist of multiple large, nearly gigawatt-sized units, while Yates consists of two midsized 350 megawatt (MW) units. All four units are situated in geographically accessible locations without apparent decommissioning complications. The Company's decommissioning study does not note any specific circumstances for these plants that would cause decommissioning to be more complex or costly than normal.

**Q. WHAT ARE THE CHARACTERISTICS OF THE DECOMMISSIONED PLANTS THAT ARE COMPARABLE TO REMAINING PLANTS?**

A. The table below summarizes the size and decommissioning costs for comparable decommissioned plants.[11] The Branch plant is most similar to the remaining plants in size and scope.

*Table 2*

| | | | WM | Decomm. Cost | |
|---|---|---|---|---|---|
| Plant | MW | Units | per Unit | Total | Per MW |
| Total McDonough-Atkinson Steam | 490 | 2 | 245 | $10,718,205 | $21,874 |
| Total Branch Steam | 1540 | 4 | 385 | $29,546,844 | $19,186 |

[11] The Company's discovery response, prior decommissioning study, and website all disagree on the capacity of the Branch plant. This table uses the capacity reported on the company's website.

**Q. HOW DID THE DECOMMISSIONING COST FOR MCDONOUGH-ATCKINSON AND BRANCH PLANTS COMPARE TO THE FORECASTED COSTS?**

A. No decommissioning study was available for the McDonough-Atkinson plant.[12] The Actual decommissioning cost of the Branch plant was half of the amount forecasted in the decommissioning study.[13]

**Q. HOW DOES THE COMPANY'S FORECASTED DECOMMISSIONING COSTS OF COAL PLANTS COMPARE TO ACTUAL COSTS FOR COMPARABLE PLANTS?**

A. The Company's forecasted cost for decommissioning the remaining steam plants is provided in the Table 3 below.[14] Note that on a $ per MW basis, the forecasted decommissioning costs exceed actual decommissioning costs in Table 4.

*Table 3*

| Plant | MW | Total Cost | $/MW |
|---|---|---|---|
| Bowen | 3,376 | $92,081,875 | $27,275 |
| Scherer | 3,720 | $106,546,060 | $28,641 |
| Wansley | 1,840 | $56,218,640 | $30,554 |
| Yates | 700 | $18,351,977 | $26,217 |
| All Plants | 9,636 | 273,198,552 | $28,352 |

**Q. WHAT ACCOUNTS FOR THE DIFFERENCE BETWEEN ACTUAL AND FORECASTED COAL PLANT DECOMMISSIONING COSTS?**

A. The decommissioning study includes a 25 percent contingency adder for each plant. When the costs in Table 3 are adjusted to remove the contingency component forecasted costs are consistent with actual costs, as shown in Table 4 below.

[12] Response to Staff DR STF-AI-1-15.
[13] Response to Staff DR STF-AI-1-15 Attachment J Trade Secret page 3.
[14] Appendix Exhibit 2 pages 166 and 167.

*Table 4*

| Plant | MW | Company Cost | Contingency | Adjusted Cost | $/MW |
|---|---|---|---|---|---|
| Bowen | 3,376 | $92,081,875 | $18,416,375 | $73,665,500 | $21,820 |
| Scherer | 3,720 | $106,546,060 | $21,309,212 | $85,236,848 | $22,913 |
| Wansley | 1,840 | $56,218,640 | $11,243,728 | $44,974,912 | $24,443 |
| Yates | 700 | $18,351,977 | $3,670,395 | $14,681,582 | $20,974 |
| All Plants | 9,636 | $273,198,552 | $54,639,710 | $218,558,842 | $22,681 |

**Q. SHOULD CONTINGENCY COSTS BE INCLUDED IN DEPRECIATION RATES?**

A. No, depreciation rates should reflect expected outcomes rather than unexpected outcomes. Contingency costs are costs that are intended to account for unexpected outcomes.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING COAL PLANT DECOMMISSIONING?**

A. I recommend that contingency cost be removed from the coal plant terminal retirement cost forecast.

**Q. WHAT IS THE BASIS FOR YOUR JUDGMENT THAT CONTINGENCY COSTS SHOULD BE REMOVED FROM DEPRECIATION RATES?**

A. I considered that the Company's historic decommissioning cost per MW is substantially lower than the forecasted costs, the Company's history of over forecasting coal plant decommissioning cost, and that contingency costs represent costs that are not expected to occur.

**b. Gas Plants**

**Q. WHY HAVE YOU CONCLUDED THAT GAS PLANT DECOMMISSIONING COSTS ARE OVERSTATED?**

A. This conclusion is based on a similar rationale as coal plants. Specifically, historic experience does not support the utility's decommissioning study and contingency fees are inappropriate to include when calculating depreciation rates.

**Q. HOW DO HISTORIC GAS PLANT RETIREMENT COSTS COMPARE TO THE COMPANY'S FORECAST?**

A. The table below summarizes historic gas plant retirement costs. The total retirement costs are presented with and without three potentially abnormal costs.

*Table 5*

| Plant Retired | MW | Plant In Service | COR | Salvage | Net Salvage | Net Salvage Per MW |
|---|---|---|---|---|---|---|
| Arkwright | 30.58 | $ 4,830 | $ 61 | $ (190) | $ (129) | $ (4.22) |
| Atkinson | 78.72 | 6,937 | 245 | (810) | $ (565) | $ (7.18) |
| Boulevard Units 2 & 3 | 39.40 | 942 | 533 | (72) | $ 461 | $ 11.70 |
| Bowen Unit 6 | 39.40 | 3,614 | 403 | 72 | $ 476 | $ 12.07 |
| Intercession City | 57.00 | 12,553 | - | (8,139) | $ (8,139) | $ (142.79) |
| Kraft | 22.00 | 2,886 | 32 | (10) | $ 23 | $ 1.02 |
| McManus Diesel | 61.00 | 626 | - | - | $ - | $ - |
| Mitchell Units 4A, 4B, & 4C | 39.40 | 12,373 | 2 | (990) | $ (987) | $ (25.06) |
| All Plants | 367.50 | 44,761 | 1,276 | (10,138) | (8,862) | $ (24.11) |
| All Except Intercession | 310.50 | 32,208 | 1,276 | (1,999) | (723) | $ (2.33) |

**Q. WHAT HAS THE COMPANY FORECASTED FOR THE COST TO RETIRE THE REMAINING GAS PLANTS?**

A. The table below summarizes the decommissioning costs included in the Company's study.

*Table 6*

| Plant | Total Cost | MW | $ per MW |
|---|---|---|---|
| Boulevard | $ 6,881 | 19 | $ 2,382 |
| McDonough | 14,181,833 | 2,772 | 5,116 |
| McIntosh CC | 8,695,953 | 1,360 | 6,395 |
| McIntosh CTs | 3,879,000 | 756 | 5,131 |
| McManus | 2,344,557 | 499 | 4,702 |
| Robins | 1,483,423 | 186 | 7,975 |
| Wansley | 4,287,715 | 32 | 133,574 |
| Wilson | 1,509,586 | 353 | 4,271 |

The proposed cost per MW for future gas plant retirements far exceeds the historic cost per MW. In fact, historic costs show that salvage value has on average exceeded cost of removal. Georgia Power's decommissioning study includes a 25 percent contingency. This contingency

does not reflect expected decommissioning costs, and thus is inappropriate to include in depreciation rates.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING DECOMMISSIONING OF GAS PLANTS?**

A. I recommend the costs associated with the 25% contingency factor be removed from the decommissioning expense used to calculate depreciation rates for gas plants.

**c. Nuclear Plant**

**Q. PLEASE SUMMARIZE YOUR ANALSYS OF NUCLEAR PLANT DECOMMISSIONING COSTS.**

A. Nuclear decommissioning and decommissioning funding are regulated by the Nuclear Regulatory Commission. Georgia Power collects decommissioning funds from rate payers to fund nuclear decommissioning and contributes these funds to a trust. Georgia Power has represented that its nuclear plant decommissioning trust is fully funded and does not require additional contributions. No funds are requested in this rate case related to nuclear plant decommissioning. I recommend the Commission accept the Company's filed nuclear plant decommissioning expense included in rates.

**d. Hydro Plant**

**Q. PLEASE SUMMARIZE YOUR ANALYSIS OF HYDRO PLANT DECOMMISSIONING COSTS.**

A. Georgia Power has a limited history of hydro generation plant decommissioning, with only two decommissioned facilities. Georgia Power's hydro decommissioning study does not appear to include contingency costs. I recommend the Commission accept the Company's filed hydro plant decommissioning related depreciation expense included in rates.

**e. Solar Plant**

**Q. PLEASE SUMMARIZE YOUR ANALYSIS OF SOLAR PLANT DECOMMISSIONING COSTS.**

A. The Company has assumed no net decommissioning costs for its solar facilities. This assumption is not realistic as solar facilities are expected to have decommissioning costs. One solar developer has estimated solar decommissioning costs to range from $25,000 to $50,000 per MW.[15] However, these estimates are not specific to the Company's facilities. Although there is no basis for the Company's assumption of no cost, I do not recommend an alternate rate because a formal study of the Company's specific costs has not been performed. I recommend the Commission approve the Company's proposed solar decommissioning expense, but also direct the Company to sponsor a solar decommissioning study of Company owned solar facilities and to incorporate these costs into its next depreciation study.

## V. REMAINING LIVES

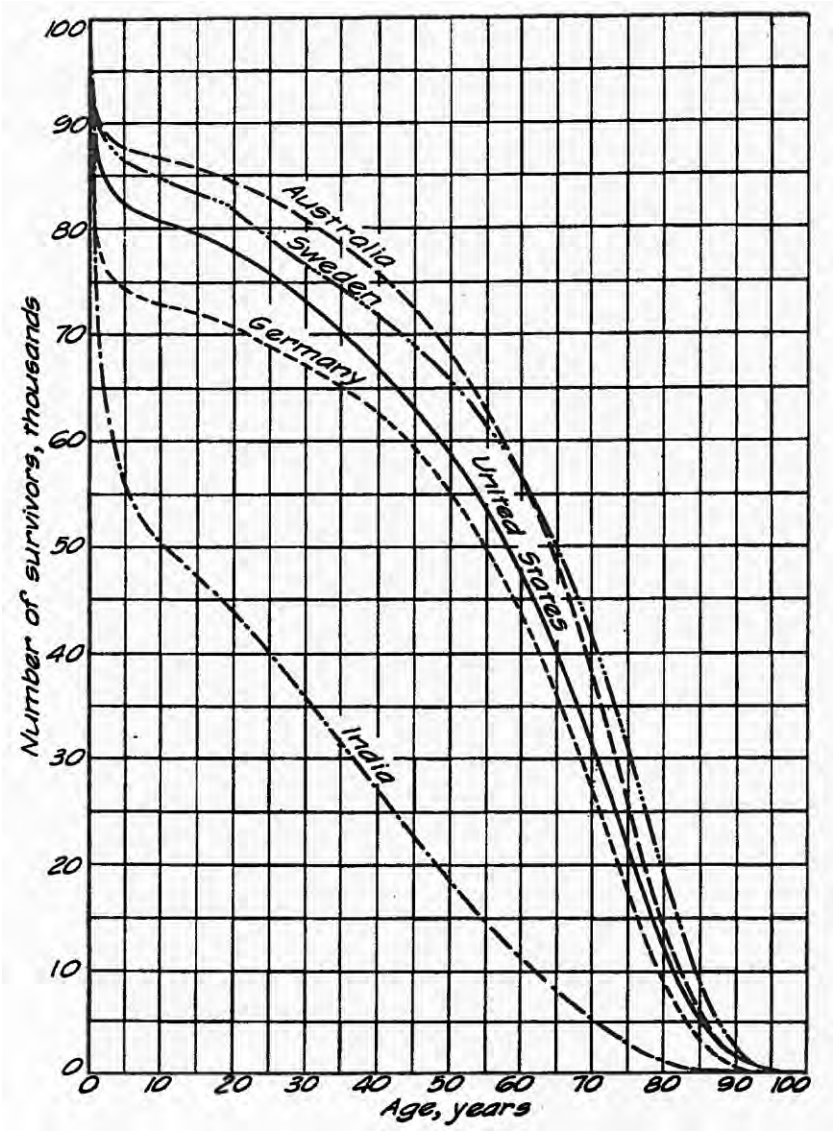
**Q. HOW IS AN ACCOUNT'S EXPECTED REMAINING LIFE CALCULATED?**

A. Remaining life is determined by modeling when each asset in an account is expected to retire. Like humans, not all assets retire at the same age. The average age of human retirement in the United States is currently 61 years old, but some retire before or after that age. . Retirements of both people and assets follow a statistical distribution, and the shape of that distribution determines the average age of retirement. The figures below illustrate examples of different

[15] Calculated from https://solunesco.com/2018/09/10/decommissioning-of-solar-sites-a-key-consideration-of-the-project/

distributions, expressed as percent surviving.[16] This figure expresses distributions as proportion surviving. In depreciation studies, retirement distributions are typically represented in this format and referred to as survivor curves.

*Figure 1*




[16] These distributions represent human mortality distributions from 1921, as presented in Robley Winfrey, (1935) Bulletin 125, Iowa Engineering Experiment Station page 16. Available at https://hdl.handle.net/2027/mdp.35128000776532.

Remaining life is the difference between current age and retirement age. For any given retirement distribution, remaining life is a function of current age. In the simplest example, suppose every person retires at age 61, and no person retires early or late. Under this distribution remaining life follows the function:

$$Remaining\ Life = 61 - Current\ Age$$

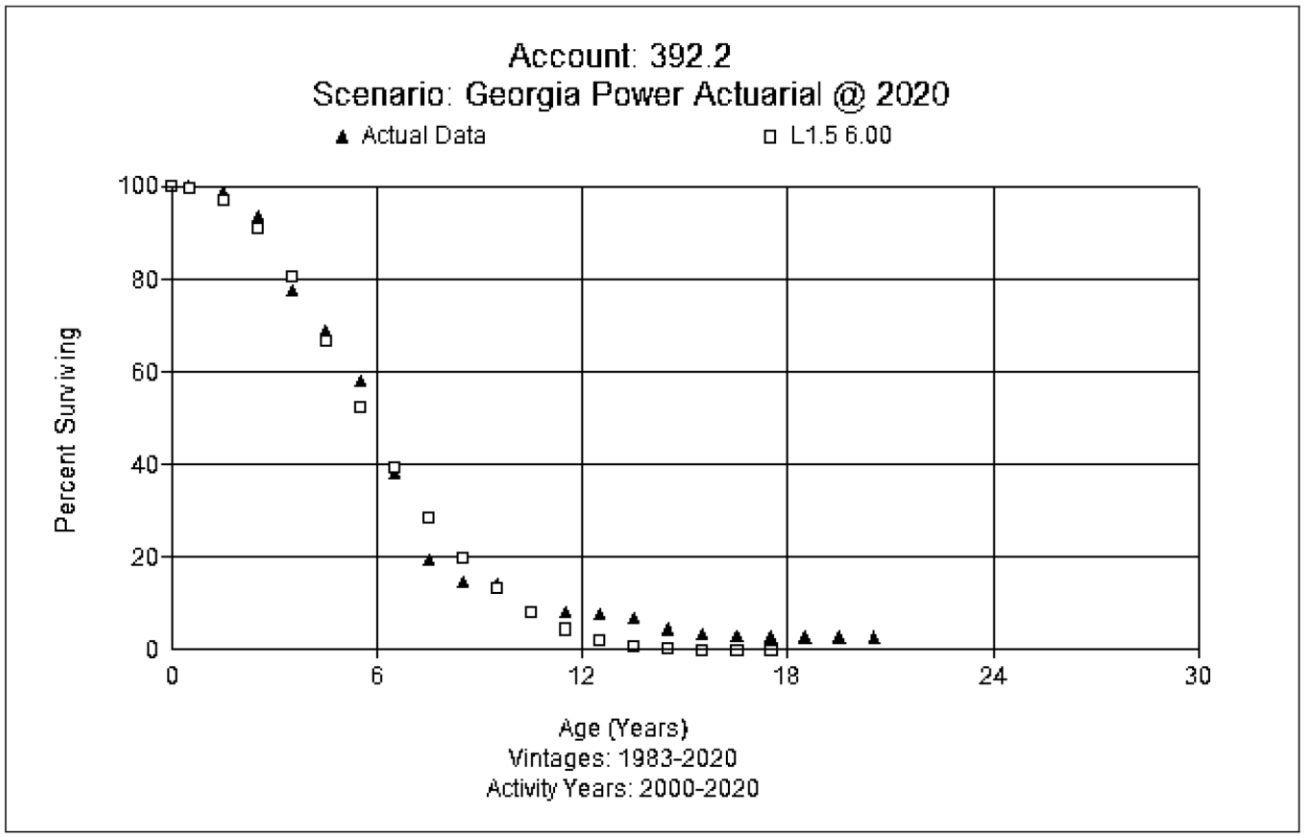
Different retirement distributions have different remaining life functions; however, each retirement distribution corresponds to a single remaining life function. Remaining life is thus dependent on the expected distribution of future retirements.

**Q. HOW IS THE DISTRIBUTION OF FUTURE RETIREMENTS DETERMINED?**

A. The distribution of retirements is typically expressed as a distribution shape, an average age, and for some accounts a terminal retirement date. The Alliance Study estimates distribution shape and average age by visually matching historical retirements to various standardized survival curves.[17] For example, for the account 392.21 Light Trucks the Alliance Study recommends the use of the L1.5 shaped Iowa curve and an average life of 6 years. This distribution produces a reasonable visual fit of the historic data, as seen below.

[17] Alliance Study page 17. For some accounts the Alliance study uses an alternate method called the "Simulated Plant Record Procedure". I do not dispute the Alliance results that rely on this procedure, and thus focus on the survival curve fitting procedure.

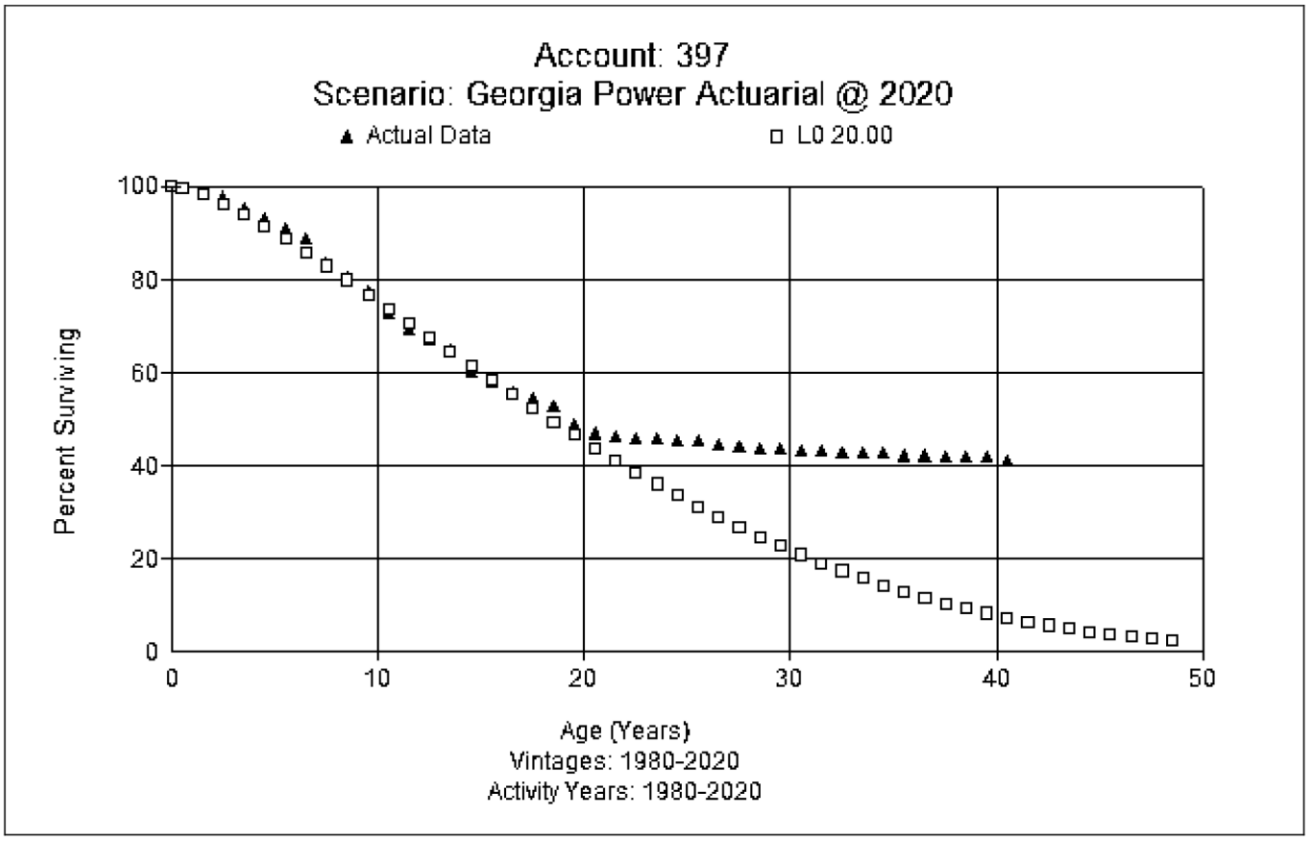
*Figure 2: Company Proposed Survivor Curve for Account 392.2*




The Alliance Study also notes that judgment was applied in modeling survivor curves.[18] For some specific curves the Alliance Study's recommended fit is, even on a visual basis, poor. I understand that for these curves the Alliance Study may be relying on the application of judgment to substantiate deviating from historic data. An example of a poor visual fit is provided below.

[18] Alliance Study page 19.

*Figure 3: Company Proposed Survivor Curve for Account 397*




I have alternate recommendations for some accounts where the Alliance Study recommends a curve that visually deviates from historic data. These alternate recommendations are based in part on a difference in judgment. The Alliance Study provides the following information regarding judgment:

> Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, property mix in accounts, or a multitude of other considerations that affect the analysis (potentially in various directions), judgment is used to take all of these considerations and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one consideration in these cases may have a substantial impact on the analysis, but overall, the collective effect of these considerations may shed light on the use and characteristics of assets.

The Alliance Study's description of the use of judgment is problematic because it includes a long menu of factors and involves an ill-defined process of synthesis and is not transparent. This contradicts the principles of judgmental forecasting that fewer factors be considered and that forecasts be justified.[19] The Alliance Study's approach to judgment also conflicts with the NARUC depreciation guidance that judgment involve giving specific weight to specific factors.

**Q. WHAT ACCOUNTS DO YOU MAKE ALTERNATE RECOMMENDATIONS FOR?**

A. I have alternate recommendations for the distributional shape and average life for the following accounts, grouped by type of asset rather than function:

1. Easements
2. Structures and Improvements
3. Miscellaneous

**a. <u>Easements</u>**

**Q. WHAT ARE THE CHARACTERISTICS OF EASEMENTS THAT AFFECTED YOUR JUDGMENT?**

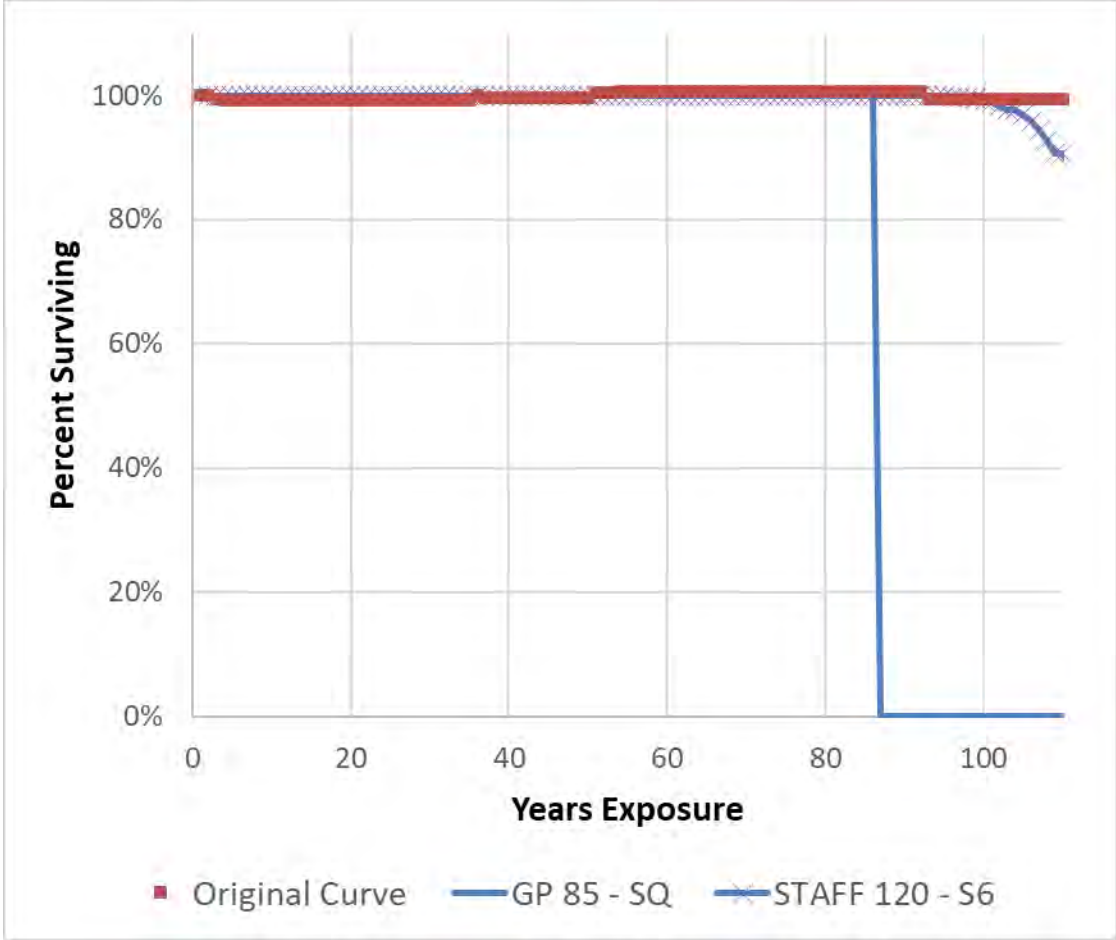
A. Easements are not physical assets that degrade and fail over time. The Company's easements have a theoretically unlimited life, but individual easements may be vacated if the Company no longer uses the easement. Thus, if an easement is never vacated, the easement will never be retired.

[19] Stewart, T. R. (2001). Improving reliability of judgmental forecasts. In J. S. Armstrong (Ed.), Principles of Forecasting: A Handbook for Researchers and Practitioners (pp. 81-106): Kluwer Academic Publishers.

**Q. WHAT IS YOUR RECOMMENDATION FOR ACCOUNT 350 TRANSMISSION EASEMENTS AND HOW DOES IT COMPARE TO THE COMPANY'S RECOMMENDATION**

A. The figure below illustrates both Georgia Power and Staff's proposed distributions for Account 350 Transmission Easements.

*Figure 4: Account 350 Transmission Easements*




The Original Curve reflects the historic data. The solid blue line reflects the Company's proposed square (SQ) survival curve with an average life of 85 years.[20] The blue line with x represents the Staff proposal of an S6 curve and an average life of 120 years. The Company's

[20] Alliance Study page 63.

recommendation provides a poor visual fit after age 85 because the original survivor curve remains at 100 percent while the Company's proposed survivor curve drops to zero percent, resulting in 100 percent error in every age after 85 years.

The Company offers the following rationale for these parameters: "Since the longest life in this functional group is 85 years, this study recommends retaining an 85-year life and SQ dispersion for this account." While not explicitly stated, the underlying assumption is that all transmission easements will survive for the expected average life of the longest lived transmission asset (in this case transmission structures and improvements), and that all easements will be abandoned the year following the average life.

The unreasonableness of this assumption is demonstrated by the Company's grid investment program. As transmission assets are retired in the grid investment program, rather than vacating the corresponding easements, the Company is rebuilding transmission assets, thus extending the expected use of the transmission easements. There is no technology currently being contemplated that would lead to the wholesale abandonment of the Company's easements. While it is possible that the Company occasionally abandons transmission easements in the future, I expect that the majority of the Company's easements will be retained as transmission lines are rebuilt rather than retired and vacated. While technological change could bring about a systematic retirement of transmission lines, no such change is likely to occur in the near future.

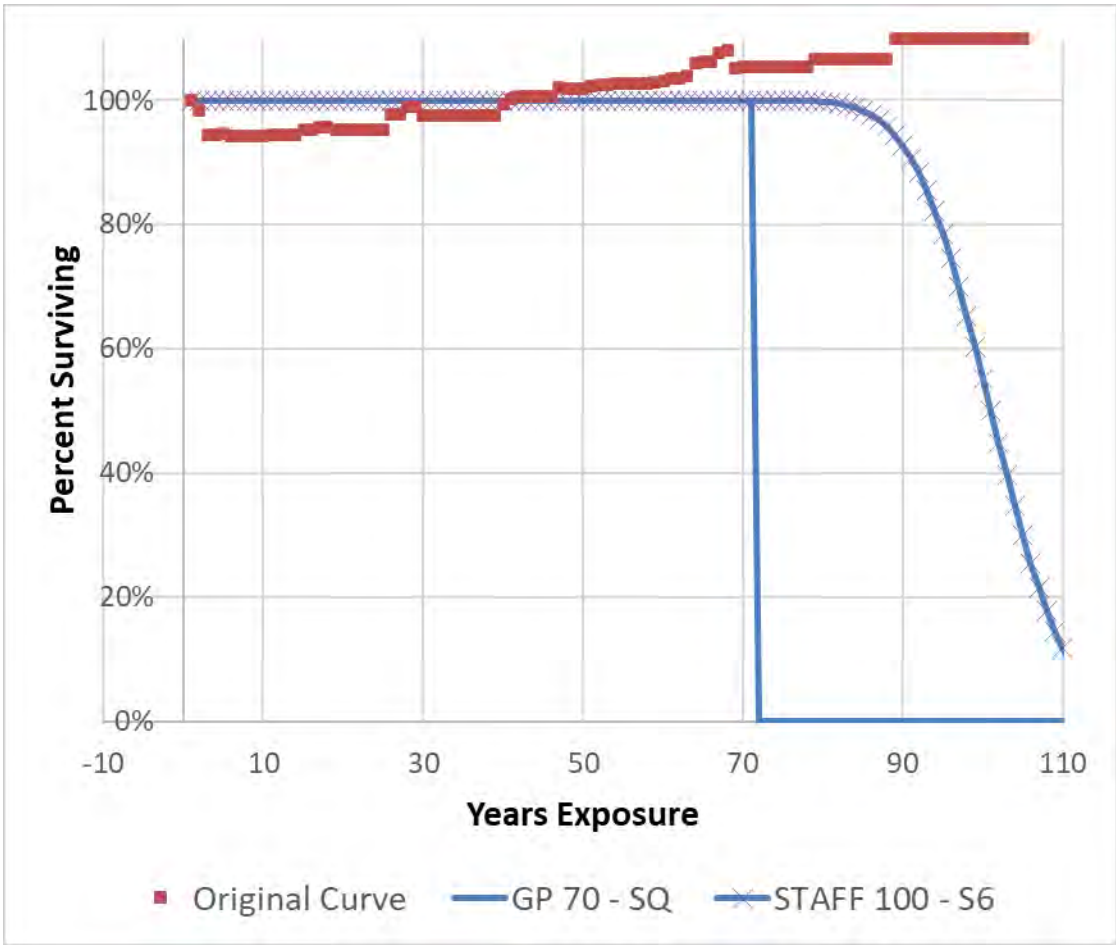
The historic data indicates 100 percent survival for throughout the entire age range, which is nearly 110 years. Thus, it is reasonable to expect that the actual average life will exceed 110 years by some amount. A square curve is an unreasonable shape for this asset because it is extremely unlikely that all transmission easements will be retired at a fixed age.

Every retirement curve, other than a square curve, that fits the historic data predicts life in excess of 140 years. I recommend adopting the 120-S6 curve because this curve is consistent with historical data and the Company's reinvestment in aging transmission but does not assume substantial life beyond the observed data. This recommendation also gives some weight to the Company's forecast of an 85-year average life by shortening the life indicated by historical data, which suggests an average life of at least 140 years.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 360 DISTRIBUTION EASEMENTS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 5: Account 360 Distribution Easements*




As with the transmission easement account the Company proposes a square curve but with a shorter average life of 70 years. The Company's proposed curve is a poor visual fit of the data after the age of 70. The Company makes this proposal "Based on lives for many assets in this function."[21] The rationale for the Company's recommendation in this account suffers from the same flaws as transmission easements. Specifically, it is unlikely for distribution easements to be vacated after the retirement of the distribution assets associated with the easements. It is

[21] Alliance Study page 77.

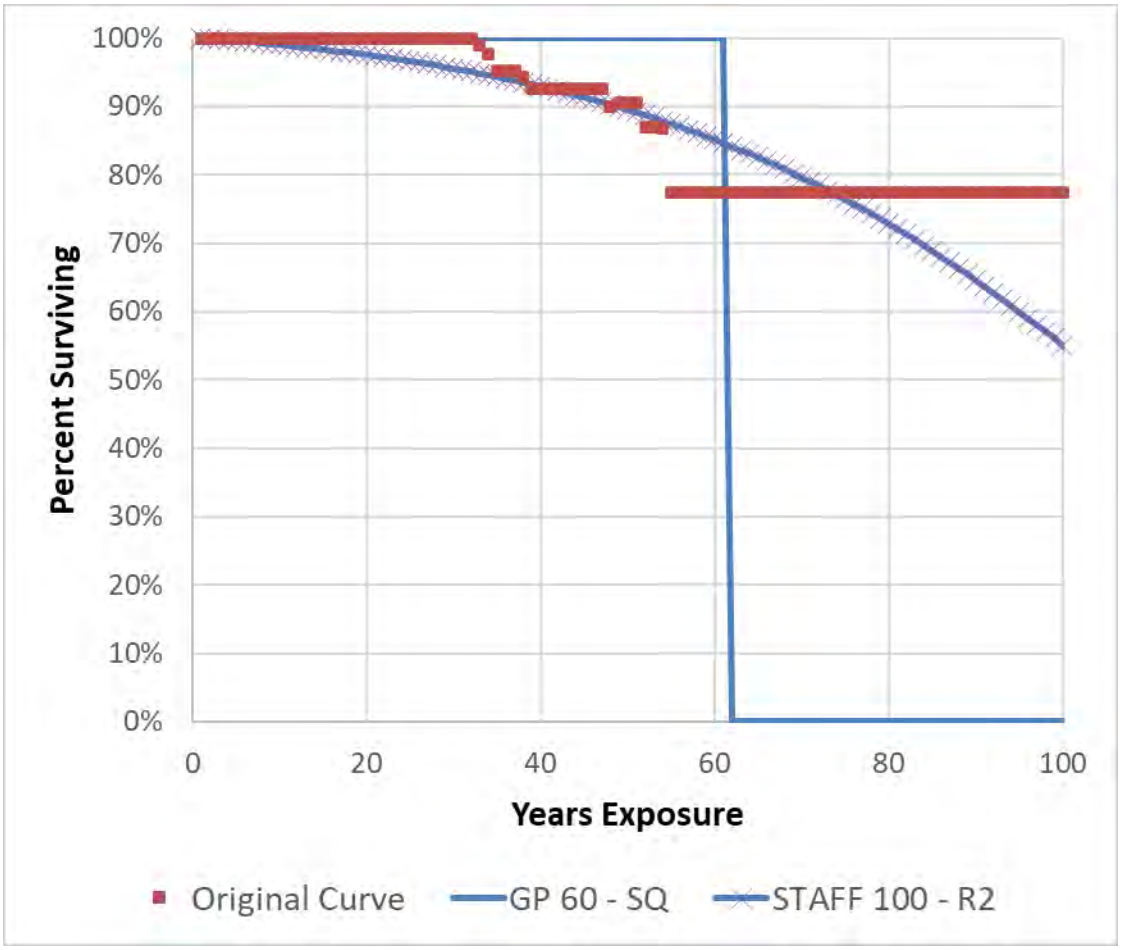
more reasonable to expect that the Company replaces retired distribution assets, extending the life of the distribution easement.

I recommend the 100-S6 curve be used for this account for similar reasons as Account 350. I recommend a lower average life for the distribution easement relative to transmission because my recommendation includes consideration of the Company's forecast, and because the historic data includes some retirements.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 389 GENERAL PLANT EASEMENTS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 6: Account 389 General Plant Easements*




The Company recommends an SQ curve with a 60-year average life. The Company's proposed curve is a poor fit of the data after age 30. The Company's recommendation for this curve is different than its recommendation for the other easement accounts. The Alliance Study states "Since most of the assets in this account have retained the existing life, this study recommends retention of the existing 60-year life with an SQ dispersion."[22] The Company's justification appears to be circular, as the reason that the assets have retained the existing life is that the study recommends retention of the existing life.

[22] Alliance Study page 97.

Unlike transmission and distribution easements, the Company's data shows material retirements of general plant easements. I recommend the use of an R2 curve with a 100-year average life. This results in a curve that visually fits the data when less weight is placed on the oldest historical retirements. My recommendation is based primarily on the Company's historical retirements.

**b. Structures and Improvements**

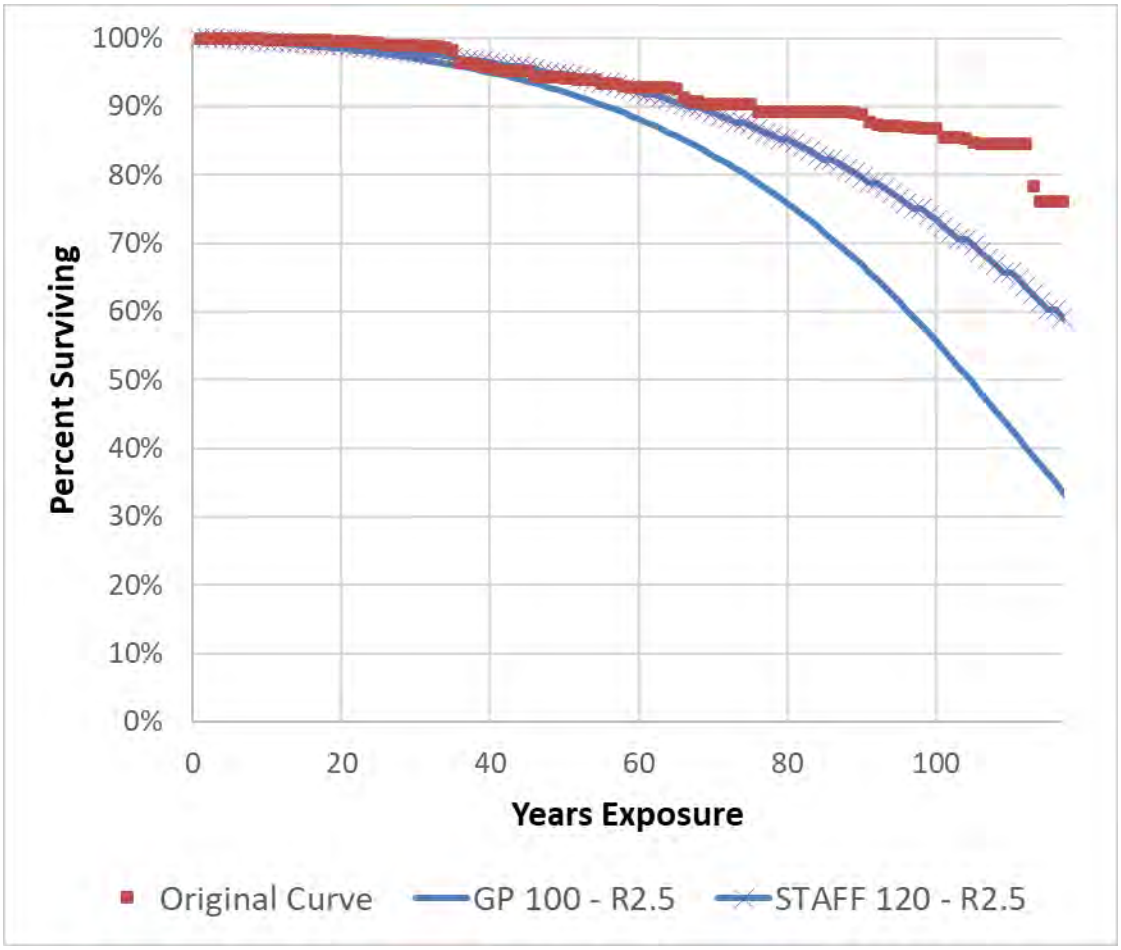
**Q. WHAT COMMON FACTORS AFFECT YOUR ANALYSIS OF STRUCTURES AND IMPROVEMENTS ACCOUNTS?**

A. Structures and improvements accounts include building structures, individual components of structures such as roofs, lighting, and heating, and other property improvements such as fencing. Typically, the primary building structures account for most of the total value in these accounts. Certain building types and systems can, with proper maintenance, survive for hundreds of years or more. Other types of buildings with less durable materials or more integrated materials have can have lives from 50 to 100 years, and individual building components such as roofing and lighting typically range in expected life from several years to 40 or more years. Changing land value or land use typically drives the retirement of entire building systems rather than failure of the primary building structure. For accounts with terminal retirement dates, building structures are expected to survive.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 331 STEAM STRUCTURES AND IMPROVEMENTS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 7: account 331 Steam Structures and Improvements*




The Company proposes an R2.5 curve with an average age of 100 years. This curve begins to deviate from the actual retirement data at an age of 20 years and exhibits substantial deviation for survival past 50 years. The Alliance Study offers no explanation for the basis of the proposed curves or the deviation from the historic data.[23] The primary structures for this account house coal generation facilities and are unlikely to be retired prior to the terminal retirement dates for the corresponding units. Furthermore, many of these units are approaching retirement. As assets approach terminal retirement maintenance becomes more economical

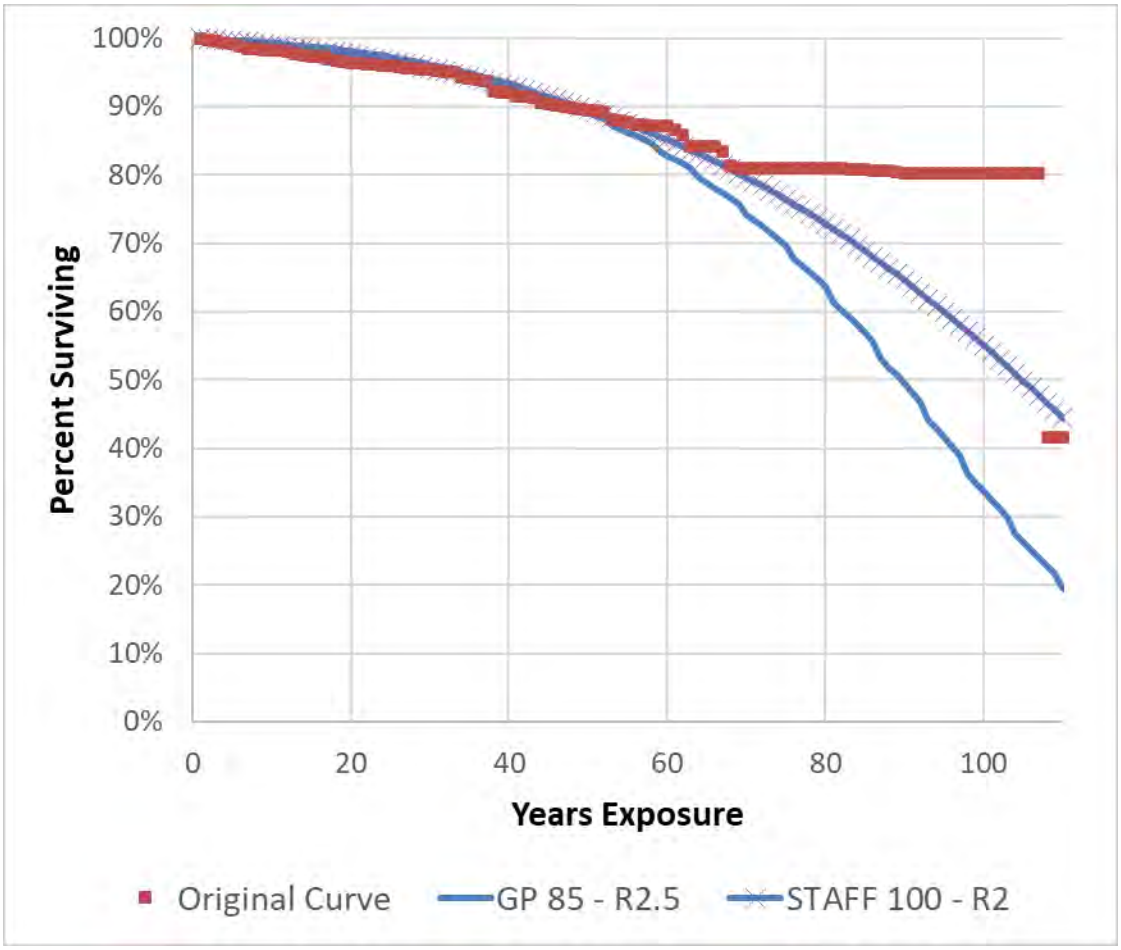
[23] Alliance Study page 45.

than replacement. Deteriorating building systems such as roofing and heating that would typically be replaced mid-life are more economical to repair towards a plant's end of life because of the short duration over which replacement facilities would function. I recommend the use of an R2.5 curve with a 120-year average life. This recommendation is based on the factors described above and includes consideration of the Company's analysis and expectations.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 352 TRANSMISSION SUBSTATION STRUCTURES AND IMPROVEMENTS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 8: Account 352 Transmission Substation Structures and Improvements*




The Company proposes an R2.5 curve with an 85-year average life. The Company's proposed curve is a poor fit of historic data for assets of 50 years old. The Company justifies its proposed curve based on the potential for the Grid Investment Program to retire some substation structures.[24] However, the Grid Investment Program is only expected to affect 2.6 percent of substations over the next three years.[25] Furthermore, brownfield substation

[24] Alliance Study page 64.

[25] Response to Informal Data Requests Depreciation Study Meeting 2022-08-18.

investments will retain all structures except control houses, and control houses are expected to be more robust in the future.[26]

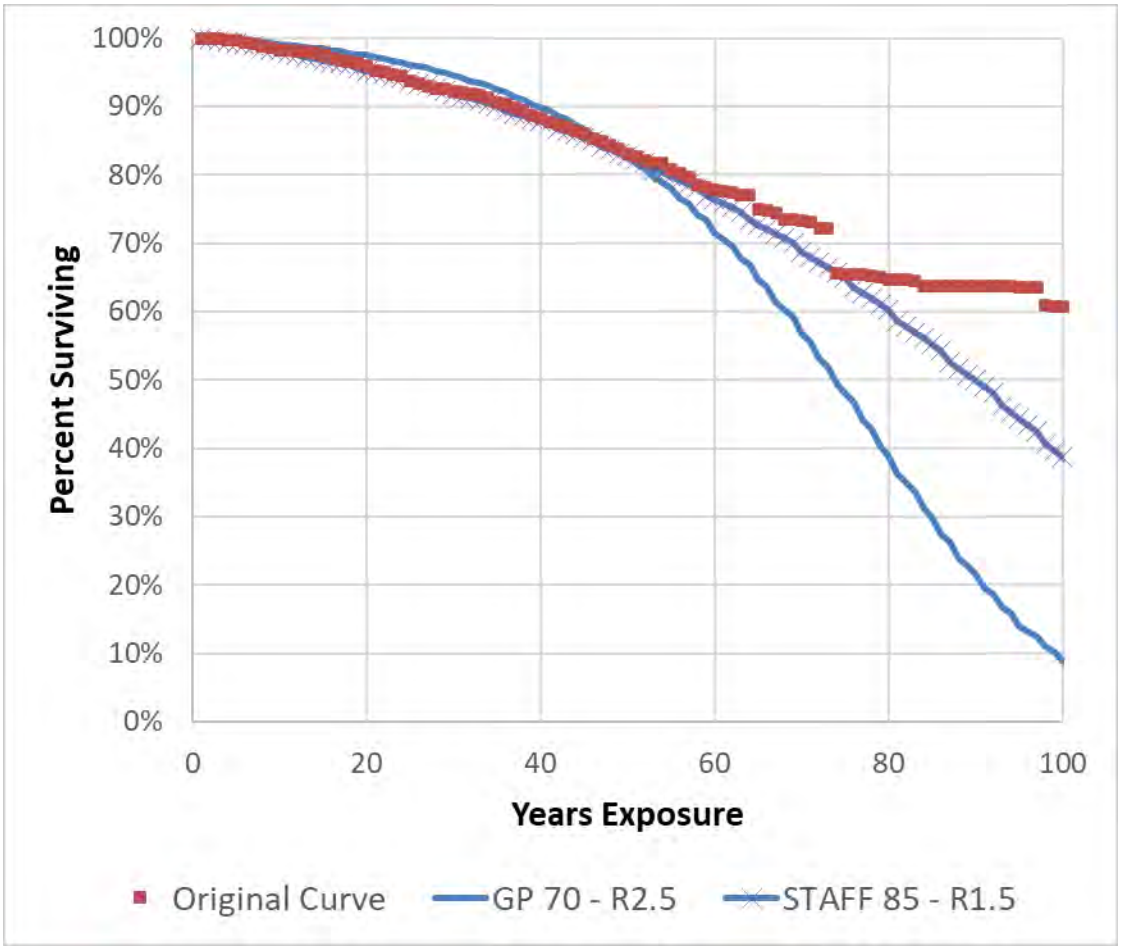
I recommend an R2 survival curve with a 100-year average life be used for this account. This recommendation is based on a visual fit of the data, with less weight placed on the ages 70 through 100 to reflect the potential impact of the Grid Investment Program and the Company's expectation that control houses will be more robust in the future.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 361 DISTRIBUTION SUBSTATION STRUCTURES?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

[26] Alliance Study page 64.

*Figure 9: Account 361 Distribution Substation Structures*




The Company proposes an R2.5 survivor curve with an average life of 70 years. This curve results in a marginal deviation from the data for ages 20 through 40 and deviates materially from the historical data after age 50. The Company bases its recommendation on the potential impact of the Grid Investment Program and actuarial analysis.[27] As I noted for Account 352 however, the Grid Investment Program affects only 2.6 percent of the Company's substations and will therefore have a minimal impact on the average life. Furthermore, the Actuarial analysis does not support the Company's recommended curve. Staff proposes a curve that has

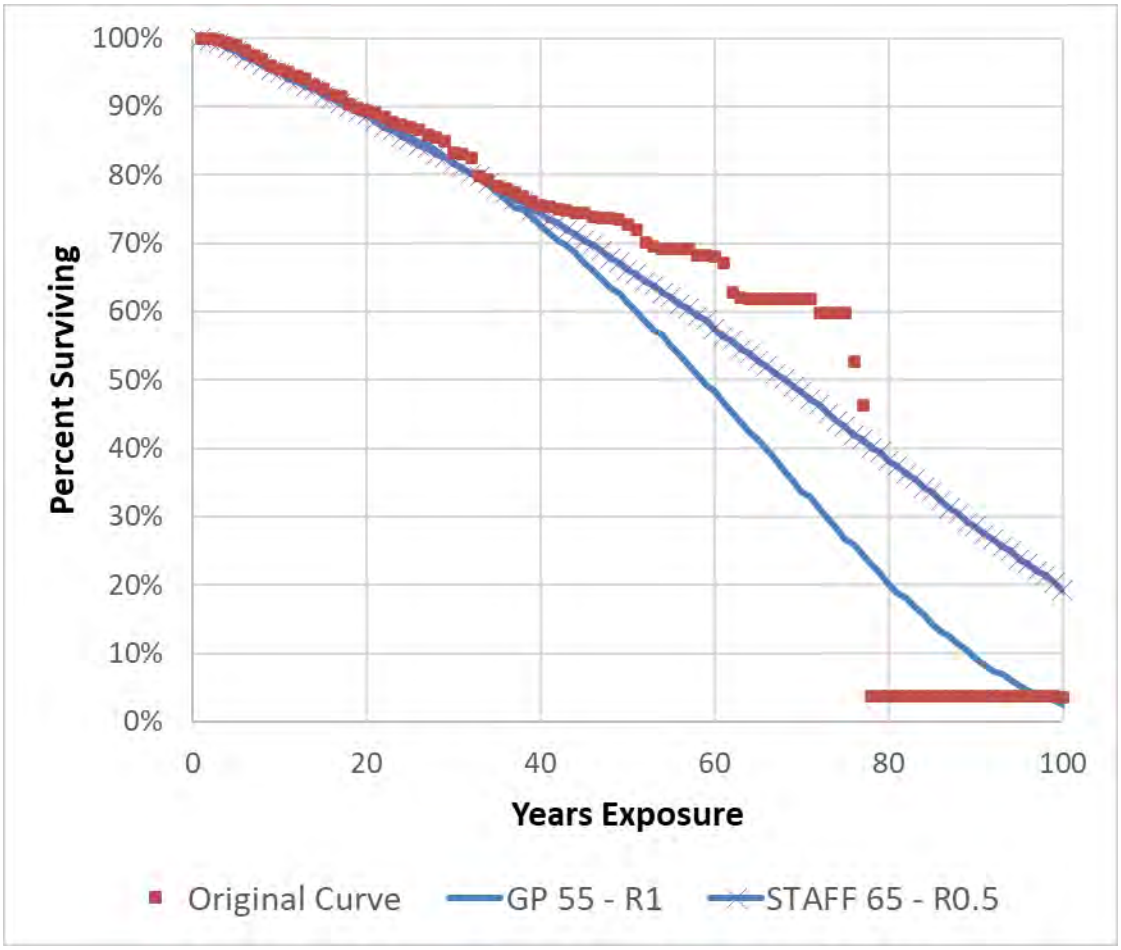
[27] Alliance Study page 78.

an improved fit for both the 20 to 40 age band and the 50 and later ages. Staff proposes an R1.5 curve with an 85-year average life. This recommendation provides an improved fit of the Company's data and remains consistent with the Company's expectations related to the Grid Investment Program and more robust control houses.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 390 GENERAL STRUCTURES AND IMPROVEMENTS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 10: Account 390 General Structures and Improvements*



The Company proposes an R1 survivor curve with an average life of 55 years. This curve deviates materially from the historical data between ages 40 and 90. The Company's recommended curve is based on Company expectations regarding the lives of various building components ranging from 15 to 55 years and the main structures of the buildings surviving 60 to 80 years.[28] As with the other structure accounts, I recommend basing the survivor curve for this account on historic data with less weight given to the oldest assets. I recommend an R0.5 curve with a 65-year average life. Unlike my recommendations for most other asset accounts, my recommendation for this account materially exceeds the actual percent surviving for later ages. I attribute this to a single abnormal retirement that is not representative of expected outcomes.[29] My consistent treatment of placing less weight on tail or older aged portions of the historic survival curves is consistent with the Alliance Study which, quoting Depreciation Systems, states "Points at the end of the curve are often based on fewer exposures and may be given less weight than those points based on larger samples."[30] My recommendation for this account applies judgment that is consistent with the judgment used for my other recommendations. I consistently recommend curves that are fit to the Company's historic data but that have lower weight placed on the oldest portions of the survivor curves.

[28] Alliance Study page 98.

[29] Ga Power Actuarial Data Set at 2020.xls rows 25877 to 25879 show that retirement in 2001 accounts for all of the change in the historic survival curve from experience years 74 through 76, indicating that a single building or building system was retired which had multiple vintages. Response to Staff DR STF-AI-1-1 Attachment.

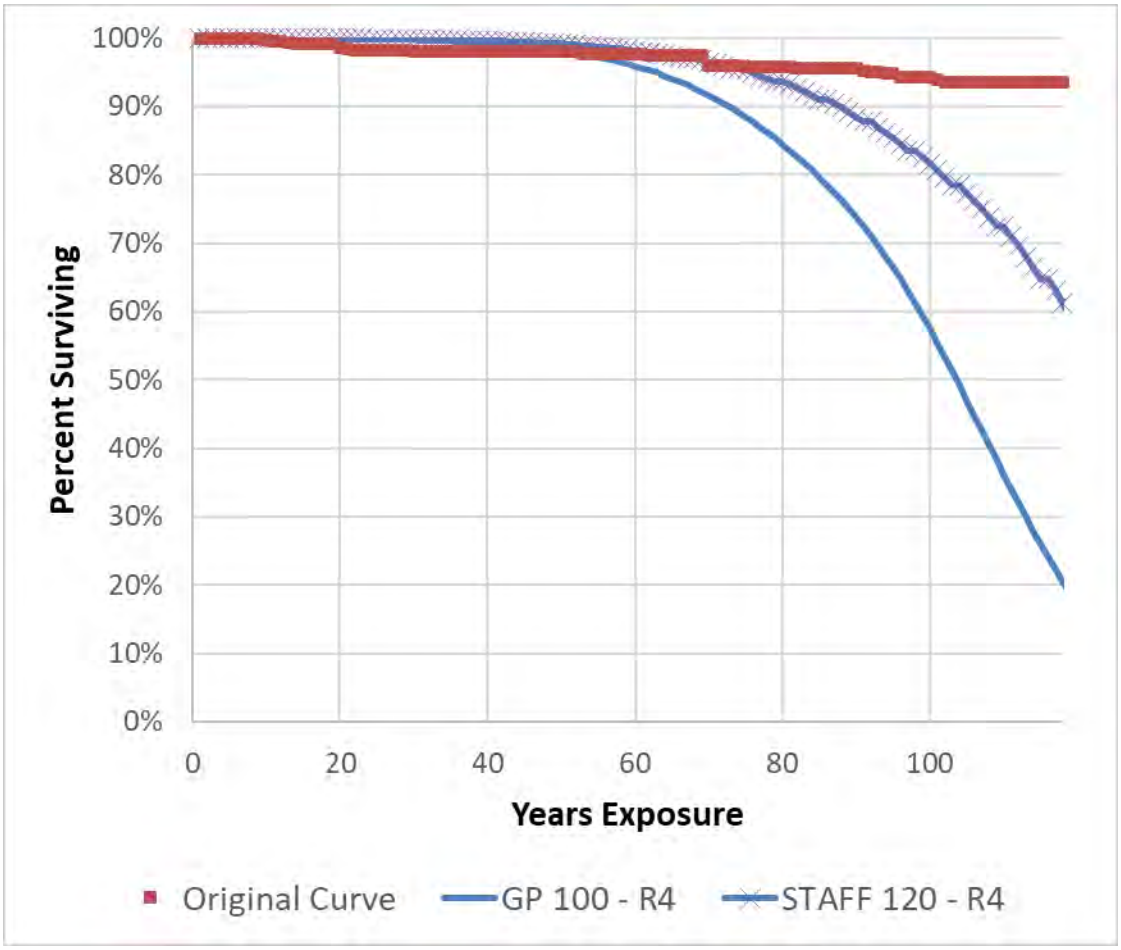
[30] Alliance Study page 16.

### c. Miscellaneous Accounts

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 332 RESERVOIRS, DAMS, AND WATERWAYS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 11: 332 Reservoirs, Dams, and Waterways*




The Company proposes an R4 survivor curve with an average life of 100 years. This curve deviates materially from the historical data after 60 years of exposure. The Company provides no basis for its proposed curve or to justify the deviation from historic data.[31] I recommend an

[31] Alliance Study page 46.

R4 curve with an average life of 120 years. The majority of assets in this account are concrete structures or earthworks that will not be retired until the terminal retirement of corresponding hydro facility. Other hydro asset accounts have a similar length of history but display substantially greater retirements. This indicates that the retirement experience of the older assets in this account is reliable.

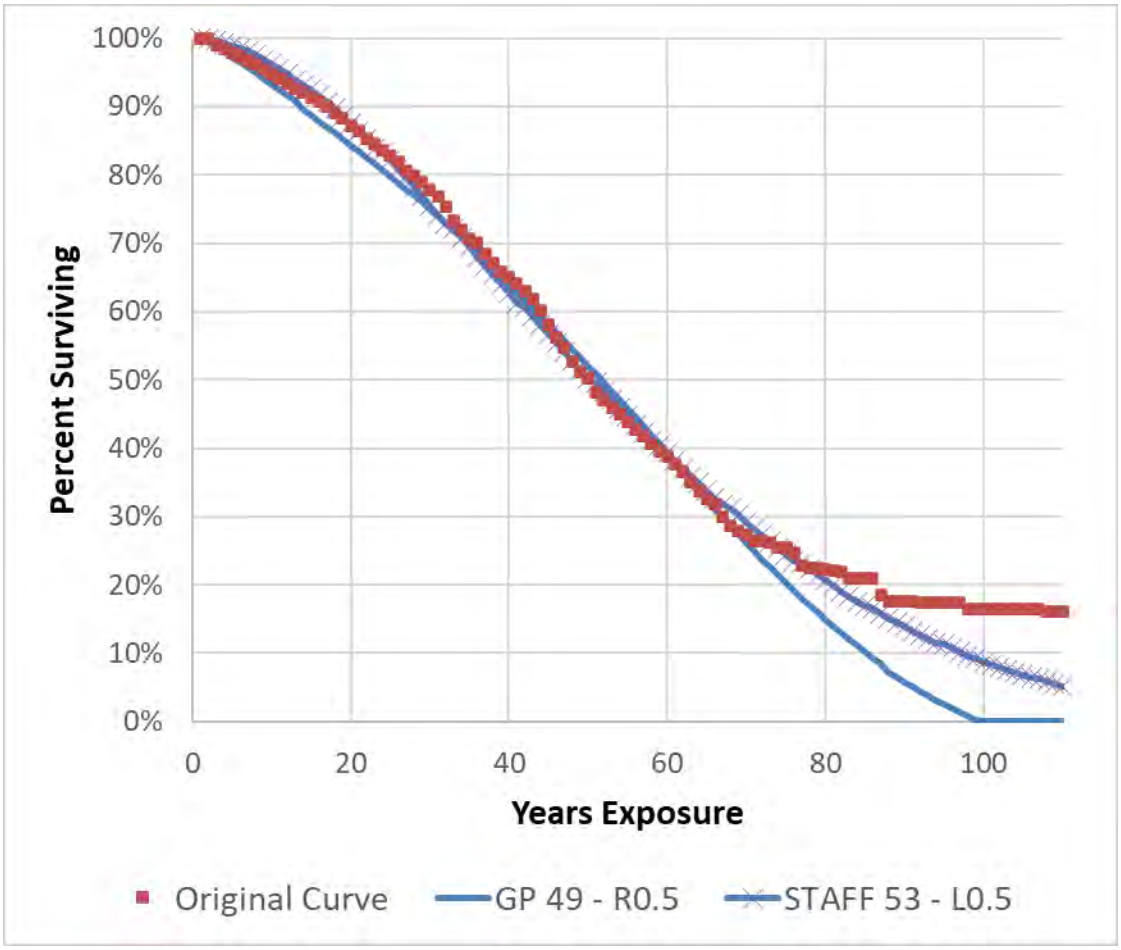
I recommend an R4 curve with a 120-year average life be used for this account. This recommendation reflects consideration of the Company's opinion regarding the appropriate shape of the retirement curve while also incorporating the extended average life suggested by actual retirement data and the fact that most assets in this account will survive to terminal retirement. I understand that the Company is undertaking a hydro modernization program to extend the lives of some hydro facilities. However, based on my review of the retirement units in this Account I do not expect the modernization to result in a material change in the Company's actual survival curve because most of the value in these accounts will not be retired as part of the modernization.[32] Furthermore, my recommended curve shows a substantially shorter life than the company's historic data indicate in order to account for the potential of the modernization project.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 353 STATION EQUIPMENT?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

[32] Response to Staff DR STF-AI-1-1 Attachment "Georgia Power RTU at 2020.xlsx".

*Figure 12: Account 353 Station Equipment*




The Company proposes an R0.5 survivor curve with an average life of 49 years. This curve results in a marginal deviation from the data for ages 10 through 30 and deviates materially from the historical data after age 70. The Company's recommendation is based on input from Company personnel and actuarial analysis.[33] The Company identities changing equipment type and operating equipment with closer tolerances as factors that may shorten asset lives relative to historic data. I recommend the use of an L0.5 curve with a 53-year average life. This curve has an improved fit of the Company's data for 10 to 30 years of experience relative to the

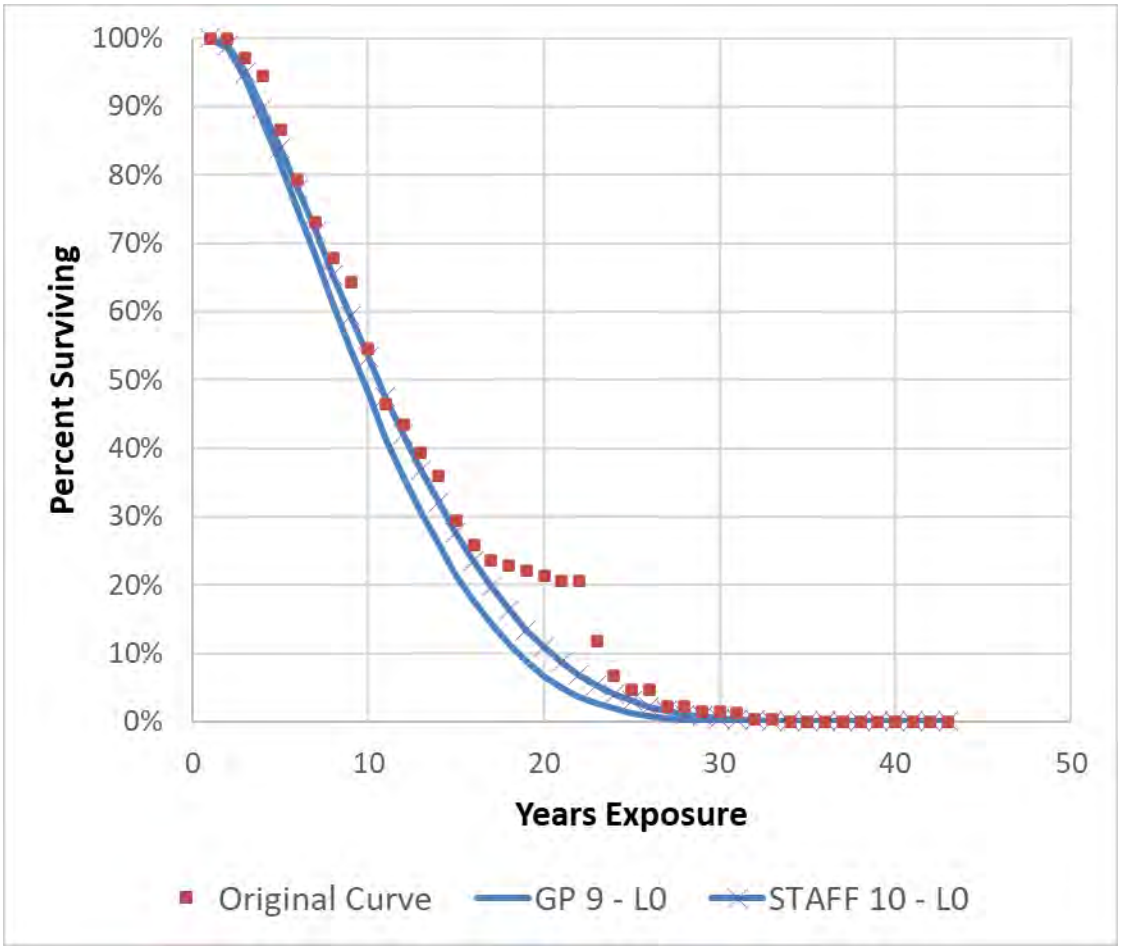
[33] Alliance Study page 65.

Company's proposed curve while still achieving a shorter average life than indicated in the tail of the data.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 392.3 HEAVY TRUCKS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 13: Account 392.3 Heavy Trucks*



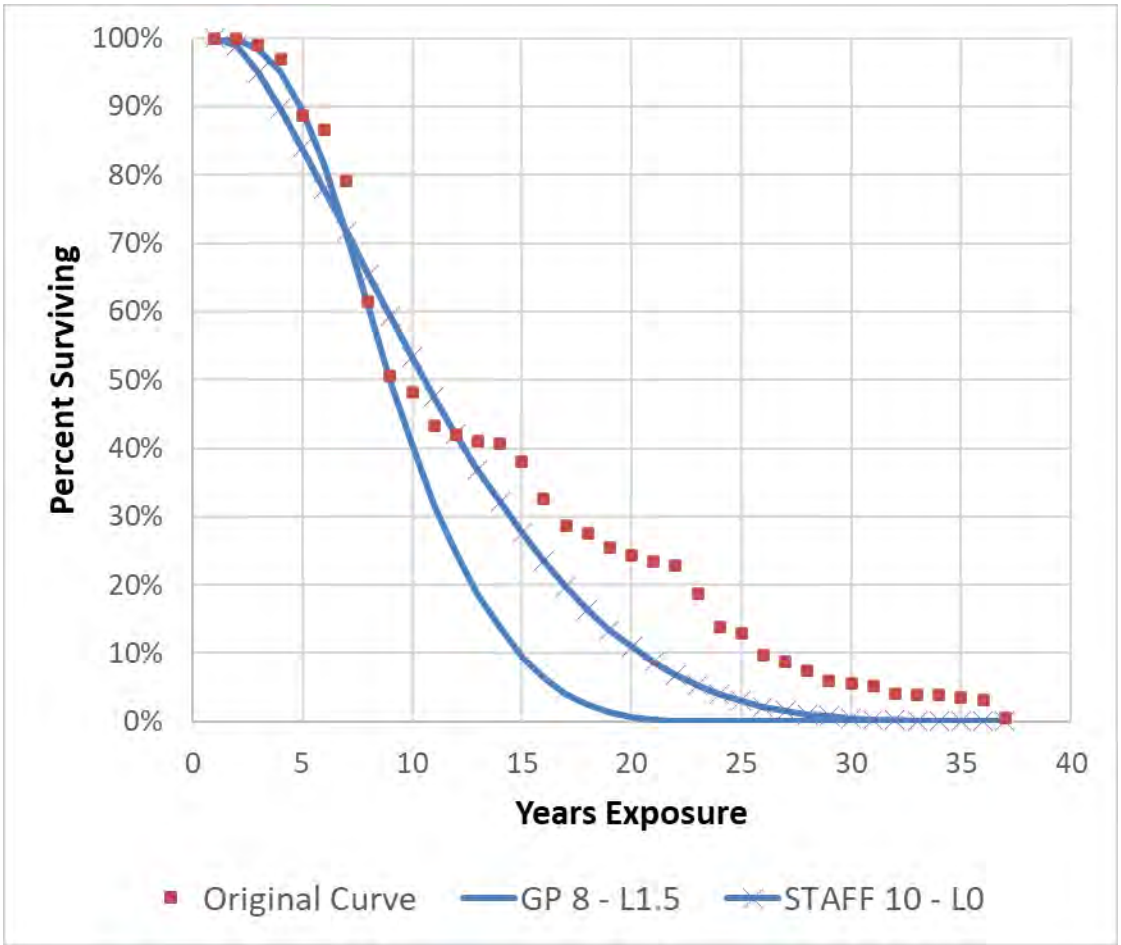

The Company proposes an L0 survivor curve with an average life of 9 years. This curve results in a marginal deviation from the data for ages 3 through 25. The Company's recommendation is based on actuarial analysis and information gathered from Company personnel, who report

that certain trucks are used on double shifts, potentially increasing mileage.[34] I recommend the use of an L0 curve with a 10-year average life. Actuarial analysis supports an L0 with 10 years over one with 9 years, as can be seen by the improved fit across the entire exposure period.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 392.4 TRAILERS AND ATVS?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

*Figure 14: Account 392.4 Trailers and ATVs*




[34] Alliance Study page 102.

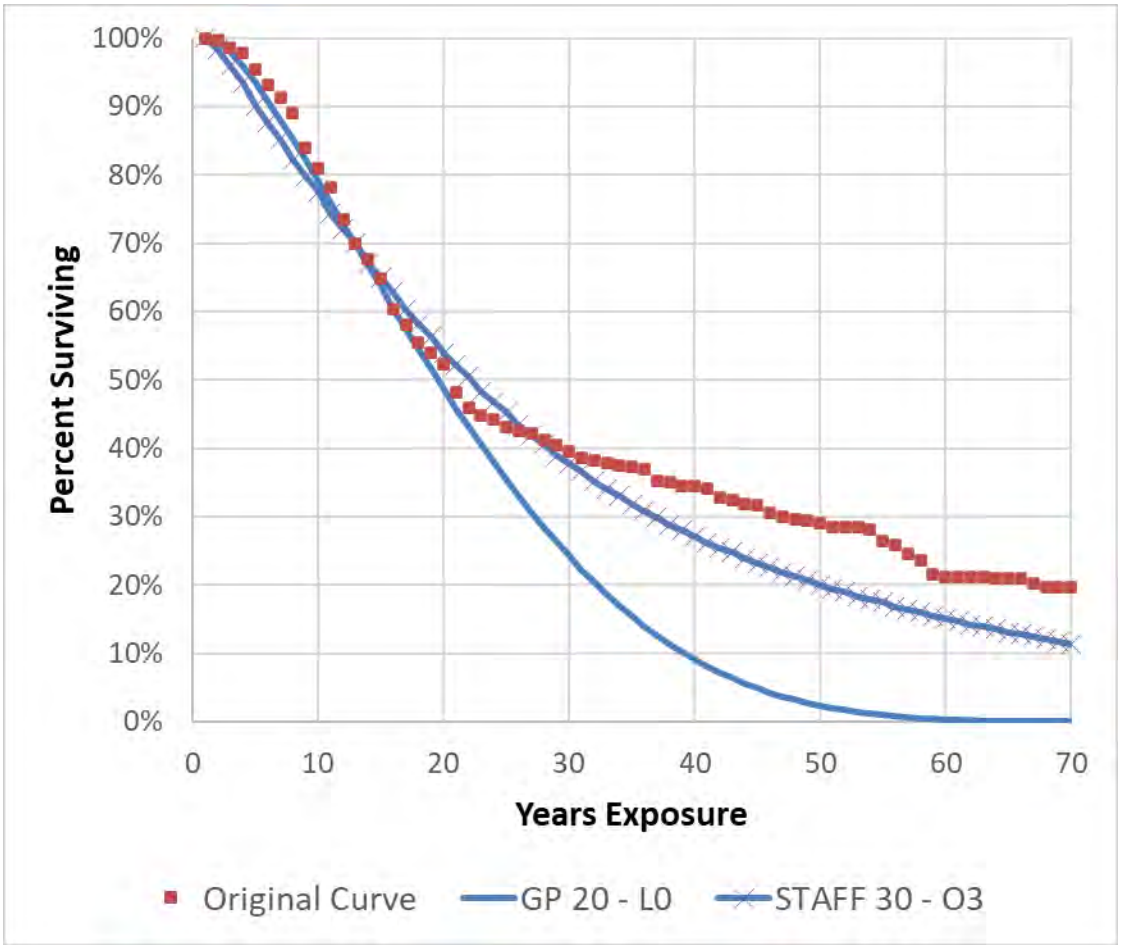
The Company proposes an L1.5 survivor curve with an average life of 8 years. This curve deviates materially from the historical data after year 8. The Company justifies the recommendation based on the variety of assets in the account and actuarial analysis. However, this curve performs poorly at modeling the mixed asset nature of the account, which has short lived assets like ATVs and long-lived assets such as trailers. [35] While the Company's recommended curve fits the short-lived assets well, the fit of the Company's recommended curve is poor for trailers which is reflected in the deviation of the fit after age 8. I recommend the use of an L0 curve with an average life of 10 years. This curve sacrifices some fit of the early survival curve but achieves a large improvement in the fit of the longer-lived assets.

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ACCOUNT 397 COMMUNICATIONS EQUIPMENT?**

A. The figure below compares the Company's historic data with the Company's proposed survivor curves and Staff's recommended survivor curve.

[35] Alliance Study page 103.

*Figure 15 Account 397 Communications Equipment*




The Company proposes an L0 survivor curve with an average life of 20 years. This curve deviates materially from the historical data after year 20. The Company's recommendation is based on an input from Company personnel and life analysis results.[36] However, the Company personnel input is that approximately half of the accounts value will consist of fiber, microwaves towers, and antennae, which have expected lives of 40 years. As with the previous account 392.4, the Company's proposed curve in this account fits short lived assets well, but at the cost of poorly fitting the retirement characteristics of long-lived assets such as fiber. I

[36] Alliance Study page 105.

recommend the use of an O3 curve with a 30-year average life. This curve provides a reasonable fit of the short-lived assets in this account while still appropriately representing expectations for longer lived assets.

**Q. WHAT IS YOUR ASSESSMENT OF THE DEPRECIATION PARAMETERS NOT DISCUSSED IN THIS TESTIMONY?**

A. I have reviewed the proposed remaining lives and net salvage rates for each account in this case that accumulates depreciation. I found the remaining parameters proposed by the Company to be reasonable and consistent with the data and expectations.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

BY MR. WALSH:

Q Dr. Kaufman, did you also prefile or cause to be prefiled two exhibits, which were marked as Exhibits LK-1 and LK-2?

A I did.

Q Do you have any changes or corrections to make to those exhibits that were not identified already in the errata?

A I do not.

MR. WALSH: Madam Chair, I ask that Exhibits LK-1 and LK-2 be marked for identification with the next two staff exhibit numbers.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibits 56 and 57.)

BY MR. WALSH:

Q Dr. Kaufman, did you present a -- did you prepare a summary of your testimony?

A I did.

MR. WALSH: Madam Chair, may the witness provide the summary at this time?

MADAM CHAIR PRIDEMORE: Please go ahead with your summary, Mr. Kaufman.

DR. KAUFMAN: Thank you.

Good afternoon, Madam Chair and Commissioners.

I'm here today to discuss my testimony on everyone's favorite rate case topic, which is depreciation.

MADAM CHAIR PRIDEMORE: You know us so well.

DR. KAUFMAN: Georgia Power's annual depreciation expense is over one and a half billion dollars. So this is a very large component of their annual expenses. And due to the importance and the interest that everyone has in depreciation, I encourage you to consider carefully the issues that are raised in my testimony.

Depreciation expense is the recovery of Georgia Power's investment in generation, transmission, distribution, and other capital investments. Depreciation expense is calculated by multiplying depreciation rate by the gross plant in service. And my testimony is focused specifically on the calculations of the rates that are used in this case.

The company's filed case included a depreciation study. I have reviewed the company's depreciation study and most of the study appears to be reasonable. However, I do recommend several changes be made to certain parameters that were used in the study.

My recommendations are presented as changes to the company's depreciation study, rather than changes

to the company's filed case. So my recommendation reduces annual depreciation expense as filed in the study by $128 million.

However, it -- when compared to the company's filed case, or when my recommended rates are implemented in the filed case, it only reduces depreciation expense in 2023 by $54 million. And I'll speak to the difference there shortly.

So the recommendation has four components. And the first component is not highlighted in my testimony because it accounts for that difference between the 128 million and the 43 million. And it has to do with the treatment of Bowen Units 1 and 2.

The study that was filed used the retirement date proposed in the IRP of, I believe, 2028. And the depreciation rates that were used in the company's filing and the depreciation rates that were used in my testimony used the current life of 2035 consistent with the outcome of IRP.

So that accounts for about $86 million and that's the majority of the difference between the 123 and the -- or 128 and the 54 million.

VICE-CHAIRMAN ECHOLS: Just a quick question on that. So by stretching it from '28 to '35, you pick up the extra years and then in the formula that

reduces the total amount; is that right?

DR. KAUFMAN: Right. Yeah.

So moving to the second component of my recommendation, I recommend extending the terminal retirement date of Hatch's Units 1 and 2 by 20 years. This is to reflect the expectation that Georgia Power files for and receives a 20-year license extension on those units. That would be extending the units' lives from 2034 and 2038 to 2054 and 2058.

Georgia Power has requested and received Commission approval for capital O&M costs in order to initiate the process of extending these lives. And I recommend that the extended life or the result of the -- the license extension be reflected in depreciation rates.

This treatment is consistent with the company's plans and expectations. And it would be unfair for current customers to pay the expenses associated with extending the lives without also recognizing the benefits associated with spreading the remaining capital investment over the longer expected life.

My recommendation to account for renewal in the lives when calculating rates is consistent with the Commission's treatment of depreciation rates for Vogtle Units 1 and 2 where the lives were extended

while their renewal license was still pending.

Third, I recommend removing the contingency component from the company's decommissioning studies for gas and coal plants. This recommendation reduces depreciation expense by approximately $2 million.

Georgia Power's depreciation rates include recovery of the expected cost to ultimately decommission their power plants. And the study that Georgia Power submitted included the results of specific decommissioning -- a further decommissioning study of coal and gas plants.

The -- the decommissioning study included a study of the -- both the cost, you know, of specific attributes of retiring the plant, and a 25 percent contingency cost on top of the expected decommissioning cost. And my recommendation is to remove the 25 percent adder that is just representing unexpected costs from the rates that are calculated. These costs don't respect -- these costs don't reflect any specific costs, but they're added for unexpected costs.

And, fourth, I recommend several changes to the retirement curves used to forecast the retirements of miscellaneous assets. This recommendation reduces depreciation expense by approximately $15 million

under 2020 plant balances.

My recommendations regarding retirement curves use the forecast retirements involves actuarial analysis of historical retirements, moderated by informed judgment. My judgment generally involved placing weight -- reduced weight on the company's oldest retirement records, considering changes in the company's maintenance and capital investment, and giving weight to the curves recommended by the company's own depreciation study.

I either adopt the company's recommended rates or recommended curves, or I recommend retirement curves that reflect shorter lives than those indicated by the actuarial analysis, but longer lives than those recommended by the company.

My testimony provides further details about each specific recommendation on these curves and the factors that I considered for the individual curves and accounts.

And that concludes my testimony and I'm happy to answer any questions.

MADAM CHAIR PRIDEMORE: Questions from Commissioners?

Commissioner Echols.

VICE-CHAIRMAN ECHOLS: Yes. Were you here

yesterday, by chance?

DR. KAUFMAN: I was here for about two hours.

VICE-CHAIRMAN ECHOLS: Yeah. So -- and if we try to mitigate this trifecta of increases for next year, you know, I'm listening for little things that we might could save some money on. 6 million here, a billion over there. You know, for the -- you know, for the grid improvement plan. You know, a reduction in the stock compensation. You know, the lower ROE.

I mean, you know, we're going to pick something. And it seems like what you're suggesting would be the least painful to the company; right? It would seem like it would have the least objection from them.

Why would they object to what you're suggesting in these areas?

What's the harm to them for doing it?

DR. KAUFMAN: Well, there is -- I mean, from a -- from a truth and beauty perspective, the goal is to accurately forecast when plants are going to retire. The goal is not to decrease rates for present customers just to try and, you know, keep rates low.

So it's possible -- one objection could be that they disagree with my forecast and they just think,

you know, that their -- their plant actually will have shorter lives than we're forecasting.

There is also a financial incentive to have low depreciation rates. Sorry. To have high depreciation rates for the company.

The financial incentive has to do with regulatory lag and the impact of depreciation on -- on rate of return. So when depreciation rates are high, depreciation expense is high and rate base does not grow as quickly. And because rate base does not grow as quickly, while rates are fixed, it's easier to manage return on investment.

VICE-CHAIRMAN ECHOLS: What do you mean by easier to manage?

DR. KAUFMAN: Well, all else equal, given a fixed rate and a higher rate base, ROE is lower; right?

If you keep rates fixed and you increase your rate base, then your ROE goes down.

And so when depreciation rates are high, your rate base doesn't grow as quickly and so it's just more feasible to hit your target ROEs.

VICE-CHAIRMAN ECHOLS: And what's the benefit to our consumers to taking your advice?

Is it that -- is it that $128 million

reduction? The $50 million reduction? These --

DR. KAUFMAN: Well, it's -- it's -- the primary impact is not really a cost savings. It's a shifting of costs from today to tomorrow. So that would be the primary benefit.

Current ratepayers would experience a lower rate by -- you know, marginally lower rate. But we would expect that that would -- that would be picked up by future ratepayers.

Also, there's a slight offset on the -- on the rate base. So we would also see rate base growing a little bit more quickly. And so future ratepayers would also have a higher rate base.

VICE-CHAIRMAN ECHOLS: I mean, shifting might be good; right?

If we have a lot hitting us next year, shifting provides some relief, like -- just like the witnesses said yesterday about shifting the increase. Not doing any of the increase in '23, but waiting until '24. So when we don't have the fuel case and we don't have the Vogtle capital cost. So it just kind of spreads out the increase. It is inevitable --

DR. KAUFMAN: Yes.

VICE-CHAIRMAN ECHOLS: -- though; right?

DR. KAUFMAN: Yes. That's correct.

VICE-CHAIRMAN ECHOLS: Okay. Thank you.

MADAM CHAIR PRIDEMORE: Any other questions from Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: All right. Hearing none, we're going to recess for lunch. We're going to come back at 1:00.

(A recess was held from 11:57 a.m. until 1:05 p.m.)

MADAM CHAIR PRIDEMORE: Okay. Let's go ahead and get started. I understand we may have a brief interruption, but we're just going to go ahead and get going because we're constantly looking at the clock.

So, Mr. Walsh, your witness. Mr. Kaufman is still with us.

Mr. Kaufman, remember that you're still under oath.

And I believe we have a housekeeping matter.

MR. WALSH: Thank you, Madam Chair. Yes, the errata that I referenced during the introduction of Dr. Kaufman's testimony, I would like to make one change to it, which is on the first line of it where it says: Line 10, change 73 million to $80 million. We can just strike that.

And with that one change, I would ask that it

be marked for identification as Staff Exhibit 58.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 58.)

MR. WALSH: Thank you. And the witness is available for cross-examination.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh.

All right. Americans for Affordable Clean Energy.

MR. GALLOWAY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: ChargePoint.

MR. FYKES: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Commercial Group.

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: EVgo Services.

MR. VIJAYKAR: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers.

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments.

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Conservation Voters.

MS. OPIE: No questions.

**MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light.**

**MS. KYSOR: No questions.**

**MADAM CHAIR PRIDEMORE: GSEIA.**

**MR. THOMASSON: No questions, Madam Chair.**

**MADAM CHAIR PRIDEMORE: Mr. Thomasson, I can't see anything of you. So if you don't mind, like wave your hands when you stand up because you're behind one of the stability poles.**

**Mr. Moreland, GA Solar.**

**MR. MORELAND: No questions.**

**MADAM CHAIR PRIDEMORE: Okay. Georgia Watch.**

**MS. COYLE: No questions.**

**MADAM CHAIR PRIDEMORE: The Kroger Company.**

**MR. BOEHM: No questions.**

**MADAM CHAIR PRIDEMORE: MARTA.**

**MS. STURM: No questions.**

**MADAM CHAIR PRIDEMORE: Resource Supply Management.**

**MR. CLARKSON: No questions.**

**MADAM CHAIR PRIDEMORE: Sierra Club.**

**MS. ARIZA: No questions.**

**MADAM CHAIR PRIDEMORE: SACE.**

**MR. DOWDY: No questions.**

**MADAM CHAIR PRIDEMORE: Southern Renewable**

Energy Association.

(No response.)

MADAM CHAIR PRIDEMORE: I believe his cross is finished.

United States Department of Defense and all other Federal Executive Agencies.

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: Okay. Sorry, Mr. Kaufman.

DR. KAUFMAN: Well, it is everyone's favorite subject.

MADAM CHAIR PRIDEMORE: I thought depreciation would be more popular today.

All right. With that, Georgia Power Company.

MR. MARZO: Just a few questions for you, Dr. Kaufman, on your testimony.

CROSS-EXAMINATION

BY MR. MARZO:

Q Brandon Marzo on behalf of Georgia Power Company. I think, as you mentioned earlier, probably the only thing worse than depreciation is depreciation after lunch. So I will try to be kind.

I did hear something in your summary that I did want to make a clarification question before I get into my cross. You had mentioned, I believe, that Bowen 1 and 2 the

life was out to 2035. And I wanted to confirm that the life is actually, as approved in 2019 rate case set at 2030.

Is that your understanding?

A Let me just double-check my work papers on that.

Q Sure.

A Yes. That's right. I used 2030 for 1 and 2 and 2035 for 3 and 4.

Q Okay. Thank you, Dr. Kaufman.

Now, would you agree with me that depreciation cannot be calculated with precision?

A It can be calculated with precision, but it is an estimate.

Q Okay. And I think in your testimony you talk about how it requires judgment and that's what I'm trying to get to.

It requires you to apply your judgment?

A Yes.

Q And you wouldn't be surprised if a different depreciation expert, for example Mr. Watson, might have a different judgment call for various depreciation rates; is that correct?

A That's correct.

Q Okay. And can we agree that at the end of the day, the Commission must exercise its own judgment in

assessing the rationale and the data that rely on alternative depreciation rates that have been presented to them and they must ultimately make a decision; correct?

A That's correct.

Q Okay. Now, you've made certain recommendations related to decommissioning cost; is that correct?

A Yes.

Q Okay. And your -- you recommended that the contingency component of coal and gas plants be removed from depreciation rates and that the company be required to submit a revised study for solar decommissioning costs in the next general rate case; is that correct?

A That's correct.

Q And I just want to take those two recommendations in turn, if we can. First, as it pertains to your recommendation, when we discuss contingency, we're referring to the application of contingency to the company's estimates to dismantle its coal and gas-fired generation units; is that correct?

A Yes.

Q Okay. And you're aware that to determine the cost of dismantlement, the company, through Southern Company Services, performs dismantlement studies; is that correct?

A Yes.

Q Okay. And the most recent study covers

dismantlement costs as of December 31st, 2020; is that correct?

A Yes.

Q Let me show you what I would ask be marked as Georgia Power Trade Secret Exhibit No. 37, which is, for the record, the 2020 Georgia Power Dismantlement Study which was provided to staff as STF-A1-1-10.

(GPC Ex. 37 marked for identification.)

MR. MARZO: May I approach, Madam Chair?

MADAM CHAIR PRIDEMORE: You may approach.

MR. MARZO: Okay. Madam Chair, because it is trade secret, I'm going to ask the witness very limited questions.

I do have copies for the Commission, but to avoid being disruptive and having to take those back up, if it pleases the Commission, I just will proceed to ask the questions without handing it out.

MADAM CHAIR PRIDEMORE: I don't object, unless one of my fellow Commissioners objects.

BY MR. MARZO:

Q Okay. And I do plan to ask you a couple of questions about this particular exhibit, Dr. Kaufman, but I do not plan to ask you anything that's trade secret.

A Okay.

Q If you would, I believe you were handed a copy

and its tabbed to page 19 in the Section 5.0, which is entitled: Cost basis. Do you see that?

A I do.

Q Okay. I'm not going to ask you to read that, but I can tell you the questions I'm going to ask you are not going to elicit trade secret.

Now, in this section it defines the scope and definition; is that correct?

A Yes.

Q And do you see the highlighted section where it explains that the company in coordination with Brandenburg developed the cost basis for the dismantlement study?

A Yes.

Q Okay. And are you aware that Brandenburg is an internationally-recognized demolition contractor that performs demolition work all across the company?

A Yes.

Sorry. I'm not familiar with the extent of their work.

Q Okay. But you've heard of Brandenburg, I take it?

A Yes.

Q Okay. And are you aware that they've worked on more than 6,000 decommissioning projects in the United States?

A I'm not familiar with the number that they've worked on.

Q Now, in looking at your background, you're not an engineer, are you, Dr. Kaufman?

A No.

Q And you've never bid on a utility construction project; is that correct?

A Only as a consumer.

Q Okay. And you've never bid on a decommissioning project, I take it?

A I'm sorry. What was the last question?

Q Yeah. You never bid on a utility construction project; correct?

A Yeah. Sorry. I misheard you. No, I've never bid on a project.

Q Yeah. Bid, not been. Yeah, to be clear.

You never bid on a decommissioning project; correct?

A Only on reviews of studies of decommission, not on actual decommission projects.

Q Okay. You haven't actually bid, like Brandenburg has bid on projects, correct?

A That's correct.

Q Okay. Now, did you review the engineering documents furnished by Technical Project Solutions

engineering that Brandenburg reviewed in this case?

A No.

Q Okay. And did you review the engineering drawings, equipment specifications, and associated engineering records in coming to your conclusion on contingency?

A Can you ask the question again?

Q Sure. Did you review the engineering drawings, the equipment specifications and the associated engineering records in coming to your conclusions on contingency in this case?

A Well, I reviewed the site plans for the projects, but that review did not relate to my conclusion about contingency. And I would point out that the contingency that's included is 25 percent for every single plant, which suggests that it is -- is not based on a specific review of plant attributes.

Q Okay. So let me just try to unwrap that a bit. So is it your testimony then that you did not rely upon any engineering drawings, equipment specifications, or other similar work product in coming to your contingency recommendation in this case; is that correct?

A That's correct.

Q Okay. And you mentioned sites, but you didn't do any site visits in coming to your recommendation; is that

correct?

A That is correct.

Q And can we agree that the purpose of the dismantlement study is to provide the most reasonable cost to decommission plants at the end of their useful life?

A Can you restate the question?

Q Sure. Can we agree that the purpose of the dismantlement study is to provide the most reasonable cost to decommission plants at the end of their useful life?

A That is how the study is being used in this case. That's not -- I wouldn't characterize that as the sole purpose or primary purpose of the study.

Q But that's the purpose of it in a rate proceeding; correct?

A Correct.

Q Okay. And isn't it true that the estimates for decommissioning can range from hundreds of thousands to multiple millions of dollars given the size and complexity of the project?

A Yes.

Q And, to be clear, these are very large projects. And in your review, is it prudent -- well, let me ask you this. Is it your view that it's prudent to undertake such a large project without having any contingency?

A What do you mean by without having contingency?

Q Okay. So the company has proposed a contingency. And my understanding is that you are simply taking the contingency out; correct?

A That's correct.

Q Okay. So you haven't proposed something -- some different contingency level. You just propose zero contingency; correct?

A I'm proposing that contingency be excluded from the calculation of depreciation rates.

Q Okay. So my point is: You think it's prudent to proceed with these large-scale dismantlement projects without any contingency in the budget?

A Well, this is not a -- the study is not designed to establish a budget for dismantling of the plant. The study, as we've just discussed, is designed to inform depreciation expected cost removal. It is appropriate from the perspective of evaluating expected cost of removal to exclude contingency because from a mathematical perspective, the expected outcome is what we would expect to happen, you know, absent unforeseen circumstances. Unforeseen circumstances could lead to higher or lower costs.

I'm not making any recommendations with respect to the budget that's used. In the event that the plant is actually decommissioned, it certainly is possible that it's

appropriate to budget for contingencies. But that's a separate -- that's a separate decision from the decision to include in depreciation rates contingency.

Q Okay. So let me unwrap that. You don't disagree, then, Brandenburg in its significant experience doing just decommissioning projects, that there should be a 25 percent contingency. You just disagree with it being included in rates; is that correct?

A Well -- excuse me. The study -- sorry. Let me try and answer your question. Please state the question again.

Q Sure. Sure. I'm trying to understand what your recommendation truly is. I take your recommendation to be that you thought there should be zero contingency. And what I'm hearing you say is that, no, you don't disagree with Brandenburg that there should be a 25 percent contingency. You just don't want that to be included in depreciation rates; is that correct?

A I think that we need to be specific about what we're talking about and when contingency is being included and what to include it in.

This -- this dismantlement study is a very high-level study and it would not be used by the company to set a budget. The company would conduct a more detailed dismantlement study prior to budgeting for the actual

dismantlement of any specific plant.

So even with a contingency in here, it would not be used when budgeting for the actual removal of the plant. And from the perspective of setting rates and pre-collecting the dismantlement costs, it's appropriate to only pre-collect the costs that are known and measurable that we expect to occur. It's not appropriate to pre-collect the contingency component of the budget or the potential budget.

Q Well, are you aware, Dr. Kaufman, that the Commission has approved some level of contingency in dismantling cost estimates for at least the past decade?

A I am aware of that, but I was not involved in testifying in those cases.

Q Okay. But is it fair to say that your particular client, Public Interest Advocacy Staff, was involved; correct?

A That's correct.

VICE-CHAIRMAN ECHOLS: Dr. Kaufman, would it surprise you to hear that when we started building Units 3 and 4 at Plant Vogtle that we had zero contingency in that budget?

Would that be surprising to you?

DR. KAUFMAN: That's -- yes, that's surprising.

VICE-CHAIRMAN ECHOLS: No. That's good.

MADAM CHAIR PRIDEMORE: Mr. Marzo, how many more questions do you have for Mr. Kaufman?

MR. MARZO: Just a few more.

MADAM CHAIR PRIDEMORE: Less than five?

MR. MARZO: Very, very little. Just one more topic I want to go over.

MADAM CHAIR PRIDEMORE: Oh, okay.

BY MR. MARZO:

Q Now, Dr. Kaufman, it's important, is it not --

MR. MARZO: Some latitude, Madam Chair.

BY MR. MARZO:

Q It's important, is it not, that when we are trying to estimate and use a dismantlement study, what we're trying to do in setting depreciation rate is to try to reflect what the ultimate cost of removal will be so that's collected over time; is that fair?

A Not necessarily. For example, the dismantlement study is based on 2020 costs. It's not escalated to account for inflation. There is a reason for that.

And so it -- we're not specifically trying to collect, as you put it, you know, the exact costs of dismantlement.

Q Well -- and the reason I ask you that is because in your own testimony you compare Plant

McDonough-Atkinson and Branch as having comparable characteristics as part of your justification for removing the contingency; is that correct?

A I evaluated the cost of removal for those plants on a cost-per-megawatt basis and I compared that to the dismantlement study, correct.

Q And I'll summarize this very quickly and not go through all the details here. But is it fair to say that you looked only at the costs; you didn't look at particular characteristics of what Plant McDonough-Atkinson and Branch, what they have at their sites versus what plants we're looking at including in this particular depreciation study for removal?

A Well, I considered the -- that's not correct. I considered the relative size of the units. For example, comparing a unit that was 50 megawatts to a unit that is 400 megawatts would not be appropriate because of economies of scale.

And, similarly, I looked at -- as I mentioned before, I looked at the site -- site plans to -- to, you know, evaluate whether they had similar characteristics, in terms of encroachments or other things that would make dismantlement more complicated from a geographic perspective.

Q Well, let me ask you this. Are you aware that

Plant McDonough-Atkinson and Branch did not have air-related environmental controls?

A No.

Q Okay. And are you aware that environmental controls increase the plant's footprint in the dismantlement cost?

A Generally, yes, but not specifically for that -- sorry. Which plants were you referring to?

Q I was talking about McDonough-Atkinson and Branch that they did not have environmental controls.

A Right.

Q Thank you.

A And the question after that was --

Q I said: Are you aware that environmental controls increase the plant's footprint and dismantlement cost?

A Yes. On -- I would say, yes, generally. Not necessarily on footprint. It depends on the design of plant. But, yes, generally on dismantlement costs.

Q And one last question on this. Are you aware that the inclusion of contingency and dismantlement is provided for in several southeastern utilities, like Duke Energy Carolinas, Duke Energy Progress, Florida Power & Light?

A Yes. However, I'm also familiar with utilities

that include dismantlement in their studies -- sorry -- include contingency in their studies, but do not include them in depreciation rates. The specific example I'm thinking of is PacifiCorp.

Q Okay. But we can agree utilities that -- or do you know the utilities I just named, in fact, include them in rates?

A I have not looked at those utilities.

Q Okay. Now, you recommended the company file decommission study on solar assets as part of the next rate case; is that correct?

A That's correct.

Q And you say that the company has assumed that there is no net decommissioning costs for its solar facilities, which is not realistic as solar facilities are expected to have decommissioning costs.

Is that a correct recitation of your testimony?

A That's correct.

Q And, to your knowledge, are asset retirement obligations costs included in the company's depreciation or dismantlement rates?

A No.

Q And are you aware that the company includes estimates for solar dismantling costs as an asset retirement obligation?

A No.

MR. MARZO: Okay. Thank you, Dr. Kaufman. I appreciate your time.

Thank you, Madam Chair.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Marzo.

Before we move on to redirect, we are going to pause for just a minute. Mr. Kaufman, if you don't mind just relaxing.

We have a guest who is with us today. And so this body, as part of the executive branch, we have a lot of partners across government, in all three branches of government. And a friend of mine and a friend of this Commission, Chairman of the House Transportation Committee, Alan Powell is with us today.

He asked if he would be able to come and talk to the Commission about some things that are on his mind. Come on up, Chairman Powell.

COMMISSONER MCDONALD: Regulated industries.

MADAM CHAIR PRIDEMORE: Regulated industries. Thank you.

REPRESENTATIVE POWELL: Well, thank you very much most distinguished Chair Lady. I want to thank the Commissioners for allowing me to come up and say just a word. And I did want to just address some

things for the benefit of the Commission.

You know, I got involved last session -- legislative session on this electric vehicle issue that seems to be the law of the land. And as we all know, the Congress in its infinite wisdom because of carbon pollution that they had basically steered things to the 2035 deadline.

Now, much to my interest -- you know, we know we're -- y'all are -- been around and a lot smarter than I am. But y'all know how the government operates. It's when the federal government does something, then it catches fire, especially when their baiting the trap with money.

Electric vehicles and the EV, as we would say, has become the one size that's going to fix everything for the future. I tend to disagree with that because I don't think they're looking at a -- I really and truly don't think that they're looking at what research and development is going to do about other forms. And I'll address that in a minute.

But I've prepared a few comments. And these are not the comments that came from the EV study committee, the joint House study committee. These are some of my own -- some of my own thoughts that came from passing House Bill 13, whatever it was, out

of the Public Utilities Committee over in the House this year, which it passed pretty well overwhelmingly. But it's some thoughts I had as it relates to the EV business and to our regulated utilities in the state.

And, if you would, I want to to -- I'm going to read these and I'll be glad to furnish copies of this to the committee members. But some of the recommendations that came from that legislation that passed out of the committee and was stranded in rules with the infinite wisdom that we would have a study committee during the summer, which we've had and we're putting together those recommendations now.

And I'll start off with these: To allow that the electric vehicle charging should be done by kilowatt hour as opposed to time, charging the kW rates permitted under the Territorial Act.

Now, at that time, before the distinguished Chair Lady -- and I had heard some of her comments that it wasn't needed. But to just -- in the point of clarification, under the Territorial Act that they would be able to sell and the C stores should be able to sell and those other business interests should be able to resell power, if that's going to be the direction that we're going in.

Georgia Power at that time as -- and I'm not so sure that maybe the EMCs, but the argument -- all the arguments that they had was that they want to be in the business of retailing EVs.

So I will go with the next point. To allow electric suppliers to participate in the EV charging business only through a separate and deregulated subsidiary, so like they do gas today.

Electric suppliers regulated by the PSC, it means its rate base couldn't be used to subsidize the EV charging -- EV charging business. Quite frankly, the utilities shouldn't be in business with the private sector. They're out their selling power and such.

To require that the electric suppliers provide EV charging under the same rates, terms and conditions to all EV providers, including electric suppliers themselves.

To require all electrical suppliers to have an EV charging rate that collects electricity cost through the volumetric kilowatt only charge, which would ultimately address any concerns for demand charges associated with EV charging.

Last, but not least, the genesis of a lot of my thoughts that I've heard through these committee

meetings and during the legislative session, that this committee, as well as everybody else, needs to be cognizant of the fact of potential future developments in other forms of fuel for vehicles in Georgia and the roadways; hydrogen cell, propane, natural gas in various forms. There's a lot of other ways they could do it.

Because, quite frankly, what I suspect and what it is my true belief, and having been in the legislature for just a couple years -- not as long as my dear friend McDonald -- I've had an opportunity to make a lot of observations. And the American public under today's circumstances when they are traveling from -- traveling public and they want the convenience, they're not going to be stuck somewhere for 30 minutes on the side of the road charging up a vehicle.

So there's -- when I say to be cognizant of other forms, which gives me -- goes back to my friends at the regulated utility. At some point I told them: If nothing else, I hope I'm saving them from themselves from being able to build stuff into the rate base.

That one day I suspect that we will be traveling down the road and we're going to see

popsicle sticks stuck all over the landscape where folks have used the BBB moneys and stuff like that to put these chargers up all over when they will always somewhere down the road there's going to be some other form of power source for these vehicles.

I'm sure that this committee also knows -- this Commission knows that a lot of the things that have been done in Congress, the trillion dollars that was passed, a lot of that money is going to this electric vehicle to pump this. But at some point I think a lot of those are going to be stranded because a lot of the investments they have made, but if they made it with federal dollars, when other forms of power come onboard.

So that's the comments I wanted to address. Be glad to answer any questions I can. Be glad to furnish my comments that I've made recommendations to the committee.

MADAM CHAIR PRIDEMORE: Thank you, Chairman Powell. Appreciate you being here. And please know how much I enjoy serving on the Electric Vehicle Study committee with you.

I believe that Commissioner Echols has a question for you.

VICE-CHAIRMAN ECHOLS: Hey, Representative.

Thank you for coming. And I really agree with you wholeheartedly about charging by the kilowatt instead of by the minute.

And having had six electric vehicles, having been stuck at many places for 30 minutes, as that battery gets hotter and as you get towards the end of your charge, consumers are actually paying even more for that power because it's going slower. And when you're paying by the minute, you are -- at the very end of your charge, you're probably paying double what you paid at the beginning of your charge.

So not only does it make sense from the perspective of the C stores, but it really makes sense. And I think EV -- EV drivers -- and we've got tens of thousands of them would -- you know, would put up a photo of you in their home probably if you were able to pull that off. So that's exciting.

And let me say that having C stores that sell, you know, electricity for EVs is great because there's a restroom there. There's food there. And there's a human being there that can call 9-1-1 if there's a problem.

So from a safety perspective, it makes a lot of sense. Because I think what we're going to see is exactly what you're predicting, is that all of this

federal money being thrown at this is going to wind up with some siting issues. They are going to be in the wrong place. There's not going to be any security. And there's going to be some serious issues.

So keep -- keep plugging away at this. And I wish you good luck as you try to make this a better experience for consumers.

REPRESENTATIVE POWELL: Well, I thank you for those comments. But these aren't necessarily all of my comments. These are comments that were made by legislators across both parties during the session.

When the discussion came up about building in cost and the demand rate to buy these chargers and do all this type of stuff, there was one point that came out and it came out more from the minority party members and that was the fact that fairness.

We do not want our utility bills to reflect any cost about EV chargers if we're not going to have them or use them ourselves. And it's about fairness. And that's the things that I think I wanted to relate, as well as the pathway to what I'm hoping that we're going to see.

Because when the legislature meets, there will be a report from the joint committee and then we'll

move forward. We've already cured the one issue thanks to the good people at Georgia Power and the EMCs, but especially Georgia Power, that we were able to cure one of the issues and that was how to allow a lot of the independent business, whether it be the C stores or the restaurants or whoever -- because I assure you we're going to see a change.

Because unless R&D takes place that they can extend that battery life and such as that, you will see the day that the C stores of today, if they don't have enough land mass to separate the chargers and the gas facilities or whatever else it may be -- and if it stays at a 30-minute charge with a Level 3 charger, then it's going to be a situation that they're going to go to a Cracker Barrel or they'll go to some place that they can sit, they can eat, they can shop, they can go to game rooms or whatever. Nobody is going to want to sit. The only people I know that will sit in their car for 30 minutes until it charges is us politicians that live on the telephone.

MADAM CHAIR PRIDEMORE: Any other comments or questions from Commissioners?

VICE-CHAIRMAN ECHOLS: Just one more thing, Madam Chair. It is inconvenient, Representative, to

drive an electric vehicle. You do have to plan. You do have to have something to do while you're sitting there.

And that's why that EV tax credit that you guys did was so important. Because not only did we take a risk in getting the vehicle, that the battery might degrade faster than we thought. And in some cases it did.

Not only was it inconvenient, but these were pioneers who -- essentially entrepreneurial people, geeky people that said: You know what, I'm willing to get one of these, even though it only has a 100-mile range. Even though I'm going to have to sit there for 30 minutes, I'm willing to do it.

And that's why that tax credit that you guys had was so important. Because it allowed us to justify all of that time we're sitting there checking our email.

And so with the state flushed with cash, next year would be a great time for you all to simply restore that tax credit so that folks can get these Rivians and these Hyundais, some of which will not qualify for the new federal tax credit because the cars are too expensive. They're over $80,000 or their final assembly is in Korea.

**And those -- we would go a long way to helping our Rivian friends and our Hyundai friends feel better about the egregious details of the, quote, Inflation Reduction Act and the fact that they are left out by simply restoring that $5,000. So if you could see a way to consider that over there, I think that would be a wonderful thing.**

**REPRESENTATIVE POWELL: Well, I thank you for those comments to my distinguished and observant friend. The legislative process, one of the things that I did not address, but one of the primary focuses of this committee, is that if we -- as we move into EV or whatever system, right now the Department of Transportation's funding is based on motor fuel tax. And this is going to be the big issue. There's going to have to be a lot of work on a formulary of how we replace and supplant the gas tax to DOT funding.**

**So that's one of the problems. And we're going to have to be doing this. And at that point what you're speaking of is credits.**

**Well, those credits were to somewhat help us to replace some of that profits or to the tax to support DOT projects. So we'll be moving forward with that and that would be the proper time to address that**

with a lot of policymakers.

And, quite frankly, a lot of them might be above my pay scale. I'm not the executive branch. I'm just a member of the legislative branch. And we do tend to operate on the majority rule in the legislative process.

So that's when perhaps the experience of the distinguished members of this Commission that they would reach out.

But I know that for certainty from discussion that I do not believe that the legislature is going to allow any regulated utility to basically create any type of a further monopoly, nor do I think that they're going to be enticed to allow their base rate for their homes and businesses to reflect this type of cost. This needs to be in a different venue.

VICE-CHAIRMAN ECHOLS: Madam Chair, just indulge me just one more second with our distinguished guest.

In 2015, when that credit was taken to zero -- it's still sitting out there. It's just zero credit; right?

So it's still there. It's just $0. The $200 fee was imposed annually --

REPRESENTATIVE POWELL: Right.

**VICE-CHAIRMAN ECHOLS:** -- on EVs. Inflation adjusted. So I think my fee this year was $238, which is more than my F-150 long wheel base, you know, crew cab truck pays. And the road impact of my Nissan Leaf compared to my F-150 is minimal.

So I really think we've solved that. That fee is there. It hasn't been taken away. I'm still paying it every year on every EV that I own. So I think we've got that. The other issues you raise are great concerns.

**REPRESENTATIVE POWELL:** Thank you so much.

**MADAM CHAIR PRIDEMORE:** Commissioner McDonald.

**COMMISSONER MCDONALD:** Senator Powell, this Commission has a history if you look at the solar program that was imposed -- not imposed, but embraced in 2013 by this Commission, capitalism was the -- was the big thing with our solar development.

No upper pressure on our ratepayers and no state subsidies. And it has proven itself to be a very successful program. Georgia now ranks in the top ten, somewhere five or six in the nation in solar development.

With that said, with all due respect to my colleague there, with his long wheel base Ford truck -- when you're paying 19 cents plus on federal

motor fuel tax and -- what's our state motor fuel tax; 28?

REPRESENTATIVE POWELL: 27 or 28.

COMMISSONER MCDONALD: 27 cents. That truck sat in the driveway all the time. It didn't go anywhere paying road tax, did it?

With all due respect, those EVs are going to be riding on the roads. And when you look at the cost of construction and everything, it's just got to be a balance in there somewhere that -- that those of us that won't be driving an EV for a long time because of the price or whatever or the inconvenience of not having those charging stations yet, that will come, and the time factor that we have -- you know, when you get to be 83 plus, almost 84 years of age, time is very important to you because I haven't got a lot left.

So if we move from point A to point B that's -- let's do keep in mind that that cost doesn't need to be placed on somebody that's not going to be able to afford to utilize that service. I don't think that we're going to abolish, as California says, the fossil fuel business by 2030 or 2035, but that's just this Commissioner's opinion.

REPRESENTATIVE POWELL: Thank you for your

comments. And I think with the -- some of these issues and public policies in California, by that time there may be a few more people out wielding hammers.

MADAM CHAIR PRIDEMORE: Mr. Shaw, do you have anything?

COMMISSONER SHAW: I just wanted to personally thank you for taking the time to come address us and thank you for your work on this issue.

I always appreciate your perspective and your wisdom and your experience in this -- in the legislature. But you're also a rural Georgian like me and I appreciate you looking after rural Georgia on this issue, as well.

Because it's like Commissioner Echols said, it's not always convenient to drive an electric vehicle. I can tell you as somebody that drives three and a half, four hours up here, it's just not even -- it just don't even make sense.

But as this market evolves as a result of all the federal dollars that are coming this way and the fact that DOT is getting involved in it now with that money and the main corridors, it will become more of a -- you know, more of a doable thing for even us in rural Georgia to travel a farther distance.

But what you said about the fairness issue and the bipartisan agreement on that between y'all, that -- that resonates with me because, you know, I was involved, too, in that 2015 transportation funding issue. I know that was a tough one for all of us, especially those of us that live on the state lines like you and I do. But hopefully that -- what y'all will work out -- and I know that's something y'all were talking about in this discussion on the study committee. But hopefully -- there's definitely a way to make that fair just like you do with the motor fuels with the excise-based tax. So the more you drive, the more you pay.

I mean, y'all have got that opportunity to do the same thing with the electric vehicles and whatever y'all come up with. And I've got confidence and faith in y'all. And I look forward to seeing what y'all come out of as far as a recommendation.

REPRESENTATIVE POWELL: Well, I appreciate your comments. And I also am one who has a lot of faith and confidence in the people of Georgia. And I tend to believe that this idea that I was talking about -- about, you know, what happened in the session. And we had people of both political parties that spoke up very quick and very, very succinctly to the public

utilities committee, was that we don't want our power bill to reflect a bunch of costs if I'm not driving an EV.

Because the case was made about what -- the pathway of what should have been. If Georgia Power or whomever wants to serve an underserved area, which I think that's going by the wayside with this BBB Act in Congress. But if they want to serve them, let them do it with a third party, a unregulated subsidiary without any question.

And I'll give a caveat to my comments about a lot of this. You know, the Congress has done what they've done. They passed a trillion dollar BBB plan.

Throughout a half dozen or so hearings that we had, you know, every meeting we were besieged to folks who were going to be in the EV charging business. They've had business models. They're going to put them up, whether they're going to deal with the C stores or existing landowners or whatever it may be. But I saw real quick that there was a common thread that these folks are going to be the beneficiaries of a lot of this federal money. It's going to be weeded down.

That's the reason I say that nothing good comes

out of dealing with the federal government in most cases. There's no such thing as a free lunch. And I look forward to one day, if I live long enough -- it will be like the once upon time a time when Chairman -- Member McDonald and I both know in North Georgia we used to ride the roads and you'd see the old country stores that were shut down and the old obsolete gas pumps were still sitting there.

The day will come that you will ride around and you're going to see these popsicle sticks stuck all over the landscape because they were funded by the federal government. And then all of a sudden hydrogen cell or propane or something else will replace that.

But I truly do believe that there's been a few events in my lifetime that I've seen that have had the major, major correction in America. One was the events of 9/11 as it related to public safety and people's concerns for their public safety.

The second was this COVID epidemic that we've seen. It has changed everything that we know in our society today. People working at home, people not working, people doing whatever they're doing.

And this is going to probably be the next, because each and every one of us has been raised in a

generation of get in the car and go. And if you needed gas, you stopped.

There were always plenty of C stores. The services at C stores and those types of operations have provided. Well, this is going to come to an end because of -- quite frankly, until R&D moves us forward.

The 300-mile max, or whatever it may be, is not going to be sufficient to a lot of folks. It's not -- certainly not sufficient to me. Now, I'm kind of anal about it. I fill up every vehicle.

I keep every vehicle I've got filled up because I don't know when I'm going to be running for the state line at some point.

But, that being said, this is going to change the nature of everything we know.

We know that the EV chargers have not been fully vetted. We know that the insurance industry has concerns about homes, people having these things -- these chargers installed because they've seen fires that -- which ultimately means that if there's any destruction, then they'll start putting surcharges on these homes and such where the garages are attached.

You might have to start almost dealing like

flood insurance. That you might have to -- if you've got an EV charger in your home or whatever, you might have to use that as an attachment to your policy. We know that the raw material is going to put us more susceptible to foreign countries to get the raw materials.

So, you know, there's too many unanswered questions. But the one that's going to affect the public the most is going to be traveling. They're used to traveling and being able to get the motor fuel to propel that vehicle.

So that being said, these are just a few things that I want to address. And I have spoke way too long. And I certainly do want to thank y'all for your indulgence to let me come over here. First time I've ever been here and probably will be my last, unless you all want to --

MADAM CHAIR PRIDEMORE: Please stay. We have a whole panel on depreciation of power plants coming up. I think you're going to love it.

REPRESENTATIVE POWELL: Listen, my life is consumed legislatively with enough paint drying on the wall. But I certainly do appreciate y'all for taking time and indulging me and hearing what I have to say.

MADAM CHAIR PRIDEMORE: Thank you, Chairman Powell. You have a good day.

REPRESENTATIVE POWELL: Thank you, Mr. Chairman.

MADAM CHAIR PRIDEMORE: Redirect of Mr. Kaufman. Go ahead, Mr. Walsh.

MR. WALSH: Thank you, Madam Chair.

REDIRECT EXAMINATION

BY MR. WALSH:

Q Mr. Kaufman, you were asked a number of questions on your recommendation to not include the contingency costs as part of your recommended depreciation rates. Do you recall those questions?

A I do.

Q But just very fundamentally, am I correct the contingency costs are on top of what the expected costs are?

A That's correct. The trade secret document that was handed out has specific line items for each component of the dismantlement, each part of the facility, the cost to dismantle that facility. And then at the very bottom as a line item, in addition to all the identified expected costs, there's a 25 percent adder for unknown costs.

Q Is it fair to say that actual costs may end up being more or less than what the expected costs are?

A That's correct.

Q And is it also fair to say that your recommended depreciation rates are not based on costs being more than the expected outcome, but they're also not based on the costs being less than the expected outcome?

A That's correct.

Q You were asked questions about what this Commission has done previously with regard to contingency costs. Do you recall those questions?

A I do.

Q Okay. Were you aware that there was no rate case in 2016 and that the Commission staff did not have a depreciation witness in 2019?

A I was aware of the 2019 not having a witness. I was not familiar with the 2016 outcome.

Q Now, considering those facts, would you agree that it could be said it has been a long time since the Commission has had the opportunity to fully vet the issues related to depreciation?

A I would agree with that.

Q You were asked about whether and how much you looked into the specifics of each plant. Do you recall those questions?

A I do.

Q Okay. Did you understand the company's filing to be supporting its requested contingency based on the

specifics of each individual plant?

A I did not see that in the filing. As I -- as I mentioned earlier, the contingency -- contingency rate of 25 percent was applied to every single plant in the study and it was applied regardless of the individual plant's characteristics.

MR. WALSH: Okay. Thank you, Dr. Kaufman.

Madam Chair, that concludes my redirect. I would ask that Staff Exhibits 56 through 58 be admitted into evidence.

MADAM CHAIR PRIDEMORE: Very good. So moved.

(Staff's Exhibits 56 through 58 were admitted into evidence.)

MR. WALSH: And I would ask that Dr. Kaufman be excused.

MADAM CHAIR PRIDEMORE: Thank you, Dr. Kaufman. You're excused.

(Witness excused.)

MADAM CHAIR PRIDEMORE: Next panel is Mr. Mugrace. I am going to ask for verification on if I'm saying that right. I'd like to remind everybody, we are just going to kind of keep going this afternoon just because of the time. But we are very supportive of our friends at the snack bar in the next building over. She is closing today at

2:45, so if you do find yourself that you might want a snack for later, good time to go over there and see her.

MR. WALSH: If you could raise your right hand.

Thereupon,

DANTE MUGRACE,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WALSH:

Q Could you please state your full name for the record and by whom you are employed.

A My name is Dante Mugrace. I am employed by PCMG & Associates as a senior consultant.

Q Mr. Mugrace, on October 20th, 2022, did you prefile or cause to be prefiled 48 pages of public disclosure testimony in question-and-answer form?

A Yes.

Q On November 3rd, did staff file an errata that included changes to your testimony?

A Yes.

MR. WALSH: Madam Chair, the changes to Mr. Mugrace's testimony were captured as well on Staff Exhibit 58 that was admitted as part of Dr. Kaufman's testimony. I just wanted say that for the record.

**MADAM CHAIR PRIDEMORE: Okay. For the record.**

**BY MR. WALSH:**

**Q Mr. Mugrace, do you have any other changes or corrections to your testimony that you would like to make at this time?**

**A I have several typos I would like to address --**

**Q Please do so.**

**A -- in both versions.**

**On page 12, line 16, remove the word "and." So I believe it is appropriate and reasonable.**

**Q On page 16, line 29, it should be "company proposed" with a "D."**

**On page 17, line 21, "explanation" is incorrect. It should remove the "I" from that.**

**Line 22 -- page 22, line 11, "This results in a reduction" instead of "is."**

**Page 39, line 21, it should be dollar amounts.**

**Page 43, line 3 should be -- remove the "R."**

**Page 44, line 22, remove the "S" from expenses. And that's it.**

**Q Thank you. Noting the corrections that you just made to your testimony and that are contained in the errata, if I were to ask you the same questions that are presented in your prefiled public disclosure testimony, would your answers be the same?**

**A Yes.**

**MR. WALSH: Madam Chair, I would ask that the public disclosure prefiled direct testimony of Mr. Mugrace be copied into the record as if read from the witness stand.**

**MADAM CHAIR PRIDEMORE: So moved.**

**(Whereupon, the prefiled direct testimony of Dante Mugrace follows:)**

**BEFORE THE**

**GEORGIA PUBLIC UTILITY COMMISSION**

| | | |
|---|---|---|
| **In the Matter of** | **)** | |
| **GEORGIA POWER COMPANY'S** | **)** | **DOCKET NO. 44280** |
| **2022 RATE CASE** | **)** | |

# DIRECT TESTIMONY AND EXHIBITS

**OF**

**DANTE MUGRACE**

**ON BEHALF OF THE**

**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

**October 20, 2022**

**PUBLIC DISCLOSURE VERSION**

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## I. STATEMENT OF QUALIFICATION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

**A.** My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

**Q. WHAT IS YOUR PRESENT OCCUPATION?**

**A.** I am a Senior Consultant with the Economic and Management Consulting Firm of PCMG and Associates, LLC. (PCMG). In my capacity as a Senior Consultant, I am responsible for evaluating and examining rate and rate related proceedings before various governmental entities, preparing expert testimony recommending revenue requirement, as well as, offering opinions on economic policy, policy issues and methodologies used to set a value on a utility's rate base and cost of service components of revenue requirement.

**Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.**

**A.** PCMG is an association of experts in utility regulation and policy, economics, accounting and finance. PCMG's members have over 75 years collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water and wastewater utilities that operate under local, state and federal jurisdictions. PCMG focuses on areas regarding revenue requirement, cost of service, rate design, cost of capital and rate of return. Prior to my association with PCMG, I was employed as a Senior Consultant with the consulting firm of Snavely King Majoros and Associates (SKM) from 2013 to 2015, in the same capacity as PCMG. Prior to SKM I was employed by the New Jersey Board of Public Utilities (NJBPU) from 1983 to my retirement in 2011. During my tenure at the NJBPU, I held various Accounting, Rate Analyst, Supervisory and Management Positions. My last position was Bureau Chief of Rates in the Agency's Water Division (Bureau Chief of Rates). I held this position for nearly 10 years. My resume is attached as DM-1.

**Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?**

**A.** In my capacity as Bureau Chief of Rates at NJBPU, I was responsible for overseeing the rate process regarding administrative, financial, and managerial functions of the Rates

Bureau. My primary duties were to ensure that the jurisdictional utilities had sufficient revenues to cover their operating expenses, the ability to earn a reasonable rate of return on plant investments, and to ensure that the provision of safe, adequate and proper service at reasonable rates was met. During my time at the NJBPU, I was involved in hundreds of rate and rate related proceedings. In my capacity as a Senior Consultant previously with SKM and now with PCMG, I have been and am currently involved in rate and rate related proceedings before the Commissions in the Commonwealth of Massachusetts and Pennsylvania, and the States of Maine, Maryland, New Jersey, New York, North Dakota, and Ohio. I was involved in the Generic Proceedings to Establish Parameters for the Next Generation Performance Based Rate Plans before the Alberta Utilities Commission. I was involved in transmission formula rate plans before the Federal Energy Regulatory Commission (FERC) regarding the PECO Energy Company on behalf of the Pennsylvania OCA and the Rockland Electric Company on behalf of the NJ Division of Rate Counsel.

**Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

**A.** I hold a Master of Business Administration (MBA) degree with a concentration in Strategic Management from Pace University-Lubin School of Business in New York, New York. I hold a Master of Public Administration (MPA) degree from Kean University in Union, New Jersey. I hold a Bachelor of Science (BS) degree in Accounting from Saint Peter's University in Jersey City, New Jersey.

## II. PURPOSE OF TESTIMONY

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

**A.** I am testifying on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("PIA Staff" or "Staff").

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

**A.** The purpose of my testimony is to review and make recommendations with respect to the Georgia Power Company's (GPC or Company) 2022 Rate Case's Operation and Maintenance (O&M) Expenses for the test year ending July 31, 2023 and for the three

Alternate Rate Plan (ARP) Years 2023, 2024 and 2025 with respect to just and reasonableness of the expenses and whether any of the expenses have been overestimated. My testimony addresses the Company's historical O&M Expenses that were used as a basis to set the test year O&M Expenses for the twelve months ending July 31, 2023. My testimony addresses the setting of the prospective O&M Expenses related to the Company's ARP for the periods 2023-2025.

## III. CASE OVERVIEW AND STRUCTURE OF TESTIMONY- PIA STAFF RECOMMENDATIONS

**Q. PLEASE PROVIDE A BRIEF OVERVIEW OF GPC'S RATE CASE FILING?**

**A.** On June 24, 2022, GPC filed a base rate case proceeding with the Georgia Public Service Commission requesting recovery of a Levelized Revenue Deficiency applicable to traditional base rate tariffs of $738.661 million each year in 2023, 2024 and 2025. The Company is also requesting increases in Environmental Compliance Cost Recovery (ECCR), Demand Side Management (DSM) and Municipal Franchise Fee (MFF) tariffs' revenue requirements to be recovered from customers. The Company is proposing to recover an additional $312.245 million during the test year period ending July 31, 2023 and $426.415 million is proposed to be recovered during the 2023-2025 Levelized Adjustment periods ending December 31, 2023, December 31, 2024 and December 31, 2025 (Company Exhibit APA/SPA/ADH/MBR-1 Schedule 2 Traditional Base).

**Q. DID THE COMPANY UPDATE ITS FILING SUBSEQUENT TO THE JUNE 24, 2022 FILING?**

**A.** Yes. On August 22, 2023, the Company updated its filing which contained revenue requirement impacts from various items included in the Final Order approved by the Commission in the 2022 Integrated Resource Plan (IRP) and DSM Certification proceedings in Docket Nos. 44160 and 44161, respectively (August 22, 2022 petition).

**Q. WHAT O&M EXPENSE ADJUSTMENTS ARE YOU RECOMMENDING?**

**A.** Based upon the use of the Company's test year ending July 31, 2023, I have the following recommendations:

- My recommended O&M Expenses for the test year ending July 31, 2023 is $886 million which is $192 million lower than the Company's expense of $1,078 million.
- My recommended O&M Expenses for the rate year ending December 31, 2023 is $907 million which is $147 million lower than the Company's expense of $1,053 million.
- My recommended O&M Expenses for the rate year ending December 31, 2024 is $906 million which is $147 million lower than the Company's expense of $1,043 million.
- My recommended O&M Expenses for the rate year ending December 31, 2025 is $886 million which is $169 million lower than the Company's expense of $1,055 million.[1]
- I have accepted the Company's Production Expenses for the test year period and for each of the rate year periods (2023-2025) as indicated below:

| | |
|---|---|
| Test Year | $3,303 million |
| Rate Year 2023 | $3,242 million |
| Rate Year 2024 | $3,147 million |
| Rate Year 2025 | $3,272 million |

**Q. WHAT APPROACH DID YOU USE IN DETERMINING YOUR ADJUSTMENTS TO THE COMPANY'S O&M EXPENSES?**

**A.** In developing my adjustments to certain of the Company's O&M Expenses, I determined whether the expenses were reasonable, prudent, known and measurable and realistic, and whether the Company should recover these expenses from ratepayers, and whether they were a necessary part of the Company's operations. I reviewed the Company's historical expense data, as well as the Company's forecasted data to determine my recommended O&M expense levels related to the Company's category of expenses for the test year and for each of the rate year periods. The more reliance on forecasted data the more subjectivity was used to determine the estimates proposed in the Company's rate year periods. My

[1] Any differences are due to rounding.

review and recommendation of the Company's O&M Expense levels reflects cost that are recurring over time. My approach incorporates whether expenses should be normalized or averaged out based upon prior historical data and/or whether expenses should be recovered consistently over the rate year periods. The ultimate goal in setting rates for service is to provide the ratepayers with safe and reliable service at reasonable rates with the Company being provided the opportunity to earn a reasonable rate of return on its funded plant investments, and to recovery all known and measurable expenses.

**Q. WHAT DID THE COMPANY STATE REGARDING O&M EXPENSES?**

**A.** Mr. Womack stated that despite inflation and increased labor and healthcare costs over the last three years, the Company has worked hard to hold O&M cost escalation below the rate of historical inflation, budgeting about $1.7 billion in 2023 compared to about $2.0 billion of O&M expenses in current rates (Womack testimony at 12). Included in the revenue requirement proposal are incremental inflation adjustments totaling $94 million and adjustments to its non-fuel O&M expenses that reflects a reduction of $163 million that are attributable to projected decreases in costs for employee benefits and effective cost management and reductions for outages and maintenance work on existing and retired coal units (Abramovitz, Adams, Houston and Robinson testimony (hereinafter as AAHR) at 18). The Company stated that storm damage expenses have been reduced from $213 million per year to $65 million per year which reflects the average annual storm damage costs incurred over the past ten years (AAHR testimony at 19).

**Q. DO ANY OF THE COMPANY'S O&M EXPENSES INCLUDE COSTS RELATED TO SOUTHERN COMPANY AND SOUTHERN NUCLEAR OPERATING COMPANY?**

**A.** Yes. Southern Company services (SCS) expenses include various engineering costs, system costs, terminal processing charges, miscellaneous computer charges and other general charges to Georgia Power Company (STF-LA-2-6 page 18). With respect to Southern Nuclear Operating Company (SNOC) the Company is allocated costs related to Incentive Compensation and restricted stock awards (STF-LA-2-78 TRADE SECRET and STF-LA-2-81).

## IV. OPERATION AND MAINTENANCE EXPENSE (O&M) ISSUES SUMMARY[2]

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS TEST YEAR OPERATION AND MAINTENANCE EXPENSES FOR THE JULY 31, 2023 PERIOD AND FOR THE THREE YEAR ALTERNATE RATE PLAN DECEMBER 31, 2023, DECEMBER 31, 2024 AND DECEMBER 31, 2025?**

**A.** As shown on Exhibit APA/SPA/ADH/MBR-1 Schedule 1, Supplemental, the Company proposed the following (retail) O&M Expenses for the years as indicated below:[3]

| | Production ($ million) | All Other O&M ($ million) |
|---|---|---|
| Test Year | $3,303 | $1,078 |
| 2023 | $3,242 | $1,053 |
| 2024 | $3,147 | $1,043 |
| 2025 | $3,272 | $1,055 |

**Q. WHAT HAS THE COMPANY RECORDED AND BOOKED WITH RESPECT TO ITS OPERATION AND MAINTENANCE EXPENSES FOR THE CALENDAR YEARS 2018 THROUGH 2022?**

**A.** As identified in response to STF-PIA-7.1, the Company has recorded the following (retail) O&M Expenses for the years as indicated below:

| | Production ($ million) | All Other O&M ($ million) |
|---|---|---|
| 2018 | $3,445 | $999 |
| 2019 | $3,278 | $959 |
| 2020 | $2,839 | $1,036 |
| 2021 | $3,648 | $1,180 |
| TME June 30, 2022[4] | $5,723 | $1,283 |

[2] All expenses referred to in this testimony are in thousand dollars, unless otherwise noted.
[3] In STF-PCMG-3-4 the Company's adjustment from the June 24, 2022 filing to the Supplemental August 22, 2022 filing was as a result of the 2022 IRP Filing Order approved by the Commission in Docket No. 44160, along with errata items discovered and filed by the Company through data requests. Not all functional O&M expenses are impacted by the items addressed in the 2022 Base Rate Case Supplemental filing.
[4] The Company has not prepared the regulatory and wholesale adjustments for the twelve months ended June 30, 2022 (STF-PIA-7-1).

**Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT OF YOUR TESTIMONY?**

**A.** I have relied on the Company's direct testimonies and related Exhibits referenced in the filing, and the responses to sets STF-PCMG, sets STF-PIA and sets STF-LA interrogatories.

### 1. Production Expenses

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS PRODUCTION EXPENSES FOR THE TEST YEAR PERIOD AND FOR THE RATE YEAR PERIODS?**

**A.** As shown in response to STF-PCMG-1-7 and on Company Exhibit APA/SPA/ADH/MBR-1 Schedule 1, (Supplemental), the Company has proposed Production Expense of $3.303 billion in the test year period, $3.242 billion in the rate year period 2023, $3.147 billion in the rate year period 2024 and $3.272 billion in the rate year period 2025.

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PRODUCTION EXPENSES?**

**A.** After a review, I do not have any adjustments with respect to the Company's Production Expenses.

### 2. Transmission Expenses

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TRANSMISSION EXPENSES IN THE TEST YEAR AND IN EACH OF THE RATE YEARS?**

**A.** As shown on Company Schedule APA/SPA/ADH/MBR-1 Schedule 1[5] and in response to STF-PCMG-1-7, the Company proposed the following balances for related years shown:

| | ($ Millions) |
|---|---|
| Test Year | $139 |
| 2023 | $118 |
| 2024 | $122 |
| 2025 | $129 |

[5] In its Supplemental Filing dated August 22, 2022, the Company did not make any adjustments to its Transmission Expenses for the test year and the rate year periods as shown.

**Q. IN REVIEWING THE DOCUMENTS IN THE FILING AND EVIDENCE PROVIDED THROUGH DISCOVERY, WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S TRANSMISSION EXPENSES FOR EACH OF THE YEARS SHOWN ABOVE?**

**A.** I am recommending averaging out the following Accounts for the Test Year period, and for each of the Rate Year periods 2023-2025):

| | (In Thousands $$$) | | | |
|---|---|---|---|---|
| | TY 2023 | RY 2023 | RY 2024 | RY 2025 |
| Account 566 | ($1,942) | | | |
| Account 569 | ($2,187) | | | |
| Account 570 | ($1,282) | $767 | ($25) | ($1,164) |
| Account 571 | ($5,268) | ($4,945) | ($3,193) | ($2,748) |

**Q. PLEASE EXPLAIN YOUR APPROACH AND REASONING FOR EACH OF YOUR ADJUSTMENTS WITH RESPECT TO THE COMPANY'S TRANSMISSION EXPENSES FOR EACH OF THE YEARS SHOWN.**

**A.** With respect to my averaging out of certain expenses in the Test Year 2023, I reviewed the Company's prior three years of actual data as shown in response to STF-PIA-7-1. I utilized the most recent three years of data (2019, 2020 and 2021) to perform my expense averaging. The Accounts listed above (under the Test Year period) revealed variations and fluctuations over the 2019-2021 periods. Expenses under Account 566 are related to miscellaneous transmission expenses and typically fluctuate from year to year depending on the nature of the work involved. Expenses under Account 569 are related to maintenance of structures including computer hardware, computer software, support services and regional transmission services. These costs have fluctuated during the 2019-2021 periods, and I believe are appropriate and reasonable to use as a basis for the projections. By averaging out these costs in the Test Year period, it smooths out any variations and provides for a steady recovery of incurred expenses over the life of the ARP. Expenses under Account 570 are related to maintenance of station equipment and storage equipment. These costs have fluctuated during the 2019-2021 periods, and I believe it is appropriate to average out these costs in the Test Year period, which smooth out any variations providing for a steady recovery of incurred expenses. In calculating my

adjustments, I removed the Labor costs that were included in each of these accounts as shown in response to STF-LA-2-72 and utilized the non-labor costs to average out these expenses for the 2019-2021 periods. Regarding Account 571, these expenses are related to Tree Trimming Expenses – Transmission Forestry (STF-LA-2-65). To calculate my adjustment to the Test Year period I averaged out the costs that were incurred in 2019-2021 and adjusted the sum of the average to the Company's proposed Test Year period balance of $28,596,000. Tree Trimming Expenses vary from year to year as the expenses show in response to STF-LA-2-65, and it is appropriate to average out these costs based upon actual historical balances during the 2019-2021 periods. My adjustments are shown on my Schedule DM-3.

**Q. HOW DID YOU ADJUST THESE SAME EXPENSES FOR THE RATE YEARS 2023-2025?**

**A.** In reviewing these expenses for the Rate Years 2023-2025, only two accounts varied considerably from the Test Year period to the Rate Year periods. These are Accounts are 570 and 571. I removed the labor portion that was included in Account 570 [6] and utilized the non-labor costs to average out this expense for the 2023-2025 periods. My reasoning for averaging out this expense is the same as indicated above for averaging out the expenses under the Test Year period. For Account 571, I took the average of Tree Trimming Expenses for the actual historical balances in 2020, 2021 and budgeted 2022 and adjusted the sum of the averages to the Company's proposed Rate Year 2023-2025 balances shown in response to SFT-LA-2-65. The balance in Account 570 shows an annual recovery of $20.296 million (which includes the Tree Trimming- Transmission Forestry expenses) for each of the Rate Years 2023-2025. My adjustments are shown on Schedule, DM-4, DM-5 and DM-6 for the Rate Year periods 2023, 2024 and 2025, respectively. A summary of my adjustments are as follows:

[6] The Company did not provide Contract Labor for 2019 (STF-LA-2-72) so I substituted 2020 for 2019. This is for all three year averages for certain accounts that I utilized a three-year average.

| | Company Proposed ($ million) | Staff Recommended ($ million) | Reduction ($ million) |
|---|---|---|---|
| Test Year | $139 | $128 | $10.7 |
| 2023 | $118 | $114 | $4.2 |
| 2024 | $122 | $119 | $3.2 |
| 2025 | $129 | $125 | $3.9 |

### 3. Distribution Expenses

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO DISTRIBUTION EXPENSES IN THE TEST YEAR AND IN EACH OF THE RATE YEARS?**

A. As shown on Company Schedule APA/SPA/ADH/MBR-1 Schedule 1 [7] and in response to STF-PCMG-1-7, the Company proposed the following Distribution Expense balances for the related years shown:

| | ($ Millions) |
|---|---|
| Test Year | $332 |
| 2023 | $318 |
| 2024 | $328 |
| 2025 | $340 |

**Q. IN REVIEWING THE DOCUMENTS IN THE FILING AND EVIDENCE PROVIDED THROUGH DISCOVERY, WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S DISTRIBUTION EXPENSES FOR EACH OF THE YEARS SHOWN ABOVE?**

A. I am recommending averaging out the following Accounts for the Test Year Period, and for each of the Rate Year periods 2023-2025):

[7] In its Supplemental Filing dated August 22, 2022, the Company did not make any adjustments to its Distribution Expenses for the test year and the rate year periods as shown.

| | (In Thousands $$$) | | | |
|---|---|---|---|---|
| | TY 2023 | RY 2023 | RY 2024 | RY 2025 |
| Account 581 | $876 | | | |
| Account 583 | $540 | | | |
| Account 584 | ($821) | | | |
| Account 586 | ($885) | $1,248 | $230 | ($1,504) |
| Account 587 | $91 | | | |
| Account 588 | $591 | | | |
| Account 591 | $592 | | | |
| Account 592 | ($1,977) | | | |
| Account 593 | ($19,527) | $2,630 | $29 | ($4,183) |
| Account 594 | ($1,590) | | ($587) | ($1,453) |
| Account 596 | ($1,484) | | | |

**Q. PLEASE EXPLAIN EACH OF YOUR ADJUSTMENTS WITH RESPECT TO THE COMPANY'S DISTRIBUTION EXPENSES FOR EACH OF THE YEARS SHOWN.**

**A.** With respect to my averaging out of certain expenses in the Test Year 2023, I reviewed the Company's prior three years of actual data as shown in response to STF-PIA-7-1. I utilized the most recent three years of data (2019, 2020 and 2021) to perform my expense averaging. The Accounts listed above under the Test Year period, revealed variations and fluctuations over the 2019-2021 periods. Expenses under Account 581 relate to expenses for load dispatching operations pertaining to the distribution of electricity. These fluctuations occur depending on the year to year activities and any construction going on including emergency purposes. Expenses under Account 583 and 584 relate to overhead line expenses and underground line expenses and do vary from year to year depending upon the annual activities for overhead and underground distribution lines and stations. Expenses under Account 586 relate to meter expenses and do vary from year to year depending upon the installation, relocations, inspections, testing and other various supplies and materials. Expenses under Account 587 relate to customer installation expenses and do vary from year to year depending upon inspection of premises, investigations, locations

and installations of fuses, as well as testing and adjusting fixtures on customers' properties. Expenses under Account 588 relate to miscellaneous distribution expenses, include general materials and supplies not provided elsewhere and tend to fluctuate from year to year. Expenses under Account 591 include structure maintenance and tend to vary from year to year. Expenses under Account 592 relate to station equipment maintenance and also tend to vary from year to year depending on the activities incurred and needed to maintain electrical structures. Regarding Account 593, these costs relate to Tree Trimming expenses – Distribution Forestry (STF-LA-2-65) Tree Trimming Expenses tend to vary from year to year as the expenses show in response to STF-LA-2-65, and it is appropriate to average out these costs based upon actual historical balances during the 2019-2021 periods. Company actual costs for the 2019-2021 periods show varying fluctuations from $44.289 million in 2019, $37.548 million in 2020 and $73.656 million in 2021. The Company proposed a balance of $71.358 million for the Test Year period. Given the past actual and historical balances, it is appropriate to average out these costs providing for a steady and consistent recovery over the life of the ARP. These costs have fluctuated during the 2019-2021 periods, and I believe it is an appropriate and reasonable to use them as a basis for the projections. I removed the Labor costs that were included in each of these accounts as shown in response to STF-LA-2-72 and utilized the non-labor costs to average out these expenses for the 2019-2021 periods. My adjustments are shown on my Schedule DM-3.

**Q. HOW DID YOU ADJUST THESE SAME EXPENSES FOR THE RATE YEARS 2023-2025?**

**A.** In reviewing these expenses for the Rate Years 2023-2025, only two accounts varied considerably from the Test Year period to the Rate Year period 2023 and three accounts for the Rate Year periods 2024 and 2025. These are Accounts 586 and 593 in Rate Year 2023, and Accounts 586, 593 and 594 for Rate Years 2024 and 2025. I removed the labor portion that was included in these Accounts and utilized the non-labor costs to average out this expense for the 2023-2025 periods. My reasoning for averaging out this expense is the same as indicated above for averaging out the expenses under the Test Year period. For Account 593, I reviewed the activities from the 2029-2021 and compared actual balances to the Company's projected balances for 2022, the Test Year period 2023 and the projections for 2023-2025 Rate Year periods.

I took the average of Tree Trimming Expenses – Distribution Forestry for the actual historical balances in 2020, 2021 and budgeted 2022 and adjusted the sum of the averages to the Company's proposed Rate Year 2023-2025 balances shown in response to SFT-LA-2-65. The Company's Distribution Forestry expenses were $97.237 million for the 12-months ending May 31, 2022 and $99.040 million for the calendar year 2022. The Company budgeted $52.016 million, $54.603 million and $57.320 million for the Rate Years 2023-2025, respectively. I averaged out these expenses arriving at a yearly recovery of $54.646 million beginning in the Rate Year 2023 and through the Rate Year 2025, providing for a consistent and stable expense recovery. The balance in Account 593 shows an annual recovery of $120.260 million (which includes the Tree Trimming- Distribution Forestry expenses) for each of the Rate Years 2023-2025. My adjustments are shown on Schedule, DM-4, DM-5 and DM-6 for the Rate Year periods 2023, 2024 and 2025, respectively. A summary of my adjustments are as follows:

| | Company Proposed ($ Millions) | Staff Recommended ($ Millions) | Reduction ($ Millions) |
|---|---|---|---|
| Test Year | $332.091 | $308.497 | ($23.593) |
| 2023 | $318.294 | $323.698 | $5.402 |
| 2024 | $327.694 | $327.366 | ($.308) |
| 2025 | $339.616 | $332.475 | ($7.140) |

**4. Customer Accounting**

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CUSTOMER ACCOUNT EXPENSES IN THE TEST YEAR AND IN EACH OF THE RATE YEARS?**

**A.** As shown on Company Schedule APA/SPA/ADH/MBR-1 Schedule 1[8] and in response to STF-PCMG-1-7, the Company proposed the following balances for related years shown:

| | ($ Millions) |
|---|---|
| Test Year | $181.949 |
| 2023 | $188.178 |
| 2024 | $195.468 |
| 2025 | $199.520 |

[8] In its Supplemental Filing dated August 22, 2022, the Company did not make any adjustments to its Customer Accounting Expenses for the test year and the rate year periods as shown.

**Q. DID YOU NOTICE ANY MAJOR INCREASES IN PRIOR YEARS 2019-2021 AND FOR THE TEST YEAR, AND FOR EACH OF THE RATE YEARS 2023-2025 RELATED TO ANY OF THE CUSTOMER ACCOUNTING EXPENSES?**

**A.** Yes. In Accounts 902 (Meter Reading), and 903 (Customer Records and Collection), these expenses increased from a balance of $5.422 million (Account 902) in 2019 to $26.146 million in 2021; and for Account 903 from a balance of $90.235 million to $102.493 million in 2021. For the Test Year 2023, Account 902 increased to $30.296 million and leveled off to $30.789 million for 2025. For the Test Year 2023, Account 903 increases to $127.255 million and increased further to $142.368 million for 2025.

**Q. WHAT WERE THE REASONS THE COMPANY PROVIDED FOR THESE INCREASES IN THE CUSTOMER ACCOUNTING EXPENSES?**

**A.** In response to STF-PIA-9-3, the Company stated that the increase in this category is primarily due to the Customer Information System (CIS) project of $15.1 million; labor costs of $5.8 million; incremental inflation of $4.6 million; customer payment transaction fees of $4.6 million; Southern Linc of $2.6 million; corporate IT billing of $2.5 million; customer billing administration of $2.2 million, Advanced Metering Infrastructure (AMI) tower lease budget of $1.5 million; and Customer Service System (CSS) of $1.4 million. In response to STF-PIA-9-4, the Company stated that these drivers were the reason for the increase in this category. The Company stated that its CIS is dated (1998) and need to be replaced, given the importance of investing in technology, applications and equipment that allow the Company to provide the best level of service to its customers. The Company stated that it delayed the implementation of a new CIS for as long as possible (STF-PIA-9-5) but Georgia Power, along with other Southern Company electric operating companies are the last major utilities utilizing the current platform and it is becoming increasingly challenging to support as the resources available to support the current system are diminishing. With respect to Transaction Fees, the Company's updated platform will allow multiply payment options to the increasing number of customers who choose to utilize these options (PayPal, Venmo, Amazon Pay, Apple Pay, Google Pay), as well as payment card autopay.

**Q. IN REVIEWING THE DOCUMENTS IN THE FILING AND EVIDENCE PROVIDED THROUGH DISCOVERY, WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CUSTOMER ACCOUNTING EXPENSES FOR EACH OF THE YEARS SHOWN ABOVE?**

**A.** Given that the Company's current CIS has not been replaced in over 20 years, and the fact that current support services are dwindling as resources to support the current CIS system are currently diminishing, I am accepting the Company's invested costs of $40 million which will continue over the ARP needed to upgrade and enhance its Customer Accounting System through the Test Year and the Rate Year periods, however, I am recommending averaging out these costs over the life of the ARP (Rate Years 2023-2025). In response to STF-PIA-9-3, the Company stated that the amount reflected with respect to the update to its CIS system are average increases or decreases over the three year (2023-2025) period. Therefore, a three-year average would reflect incremental adjustments over the Test Year period and provide for a gradual recovery of costs over the life of the ARP. In calculating my three-year average, I removed the labor portion that was included in this Account and utilized the non-labor costs to average out this expense for the 2023-2025 periods (STF-LA-2-72). What I am also recommending is that the Company should provide the implementation dates, actual costs by project (STF-PIA-9-3) and other relevant information and cost components, so that the Commission can track and verify that the costs the Company has included in this filing have actually been expensed and costs components have been implemented, with any differences identified in a separate filing. A summary of my adjustments with respect to the Company's CIS System which is included in Account 903 are as follows:

| | Company Proposed ($ Millions) | Staff Recommended ($ Millions) | Reduction ($ Millions) |
|---|---|---|---|
| Test Year | $127.255 | $127.255 | $0 |
| 2023 | $132.824 | $134.127 | $1.303 |
| 2024 | $139.236 | $134.127 | ($5.109) |
| 2025 | $142.368 | $134.127 | ($8.241) |

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT WITH RESPECT TO THE COMPANY'S CUSTOMER ACCOUNTING EXPENSES – UNCOLLECTIBLE ACCOUNTS FOR THE TEST YEAR 2023.**

**A.** With respect to Uncollectible Accounts, I averaged out these costs for the 2019-2021 period to set a balance for the Test Year 2023. This reduces the Company's Uncollectible Accounts balance by $16,000. Uncollectible Accounts expenses fluctuate from year to year depending on the number of customers unable to pay their utility bill, as well as other reasons beyond the Company's control. This adjustment is shown on my Schedule DM-3.

**Q. DOES THE COMPANY SELL ANY OF ITS UNCOLLECTIBLE ACCOUNTS, BAD DEBTS OR WRITTEN-OFF AMOUNT TO THIRD PARTY DEBT COLLECTORS OR TO ITS AFFILIATES?**

**A.** No. As indicated in response to STF-PIA-11-2, the Company did not sell any of its uncollectible accounts, bad-debt, or written off amounts to third party debt collectors or to affiliates.

**Q. DID YOU MAKE ANY ADJUSTMENTS TO THE COMPANY'S UNCOLLECTIBLE ACCOUNTS EXPENSE FOR THE RATE YEARS 2023-2024?**

**A.** No. I am accepting the Company's balance of Uncollectible Accounts Expense for the Rate Years 2023-2025.

**Q. WHAT ARE YOUR OVERALL ADJUSTMENTS TO THE COMPANY'S CUSTOMER ACCOUNTING EXPENSES?**

**A.** My overall adjustments are as follows:

| | Company Proposed ($ Millions) | Staff Recommended ($ Millions) | Reduction ($ Millions) |
|---|---|---|---|
| Test Year | $181.948 | $181.932 | ($.016) |
| 2023 | $188.177 | $189.480 | $1.303 |
| 2024 | $195.467 | $190.358 | ($5.109) |
| 2025 | $199.520 | $191.279 | ($8.241) |

**5. Customer Service & Information**

**Q. WHAT HAS THE COMPANY PROPOSE WITH RESPECT TO ITS CUSTOMER SERVICE AND INFORMATION EXPENSES?**

**A.** As shown on Company Schedule APA/SPA/ADH/MBR-1 Schedule 1 (Supplemental) and in response to STF-PCMG-1-7, the Company proposed the following expenses for related years shown:

| | ($ Millions) |
|---|---|
| Test Year | $135.075 |
| 2023 | $137.246 |
| 2024 | $138.578 |
| 2025 | $138.418 |

**Q. WHAT WAS THE COMPANY'S CUSTOMER SERVICE AND INFORMATION EXPENSE FOR 2017 - 2021?**

**A.** Customer service and information expense ranged from $79 million to $100 million per year with an average of $91 million per year over the five year period 2017 through 2021.

**Q. WHY HAS CUSTOMER SERVICE AND INFORMATION EXPENSE INCREASED BY $46 MILLION PER YEAR OR 50 PERCENT?**

**A.** The Company has included $23 million, $17 million, $18 million and $19 million of regulatory adjustment related to DSM tariff additional sum for the test year, 2023, 2024 and 2025, respectively. The remainder of the increase is from the expansion of existing cost from an average $91 million per year 2017 thought 2021 to $112 million, $120 million, $121 million and $119 million in test year, 2023, 2024 and 2025, respectively.

**Q. DID THE COMPANY PROVIDE AN EXPLAINATION FOR THE LARGE INCREASE IN EXISTING CUSTOMER SERVICE AND INFORMATION EXPENSE FROM $91 MILLION PER YEAR TO $120 MILLION PER YEAR?**

**A.** Yes. With respect to data responses to STF-PCMG-3-1, the Company stated that the increase in this account is due to the DSM program expenses in the 2022 Base Rate Case Supplemental filing being recorded in FERC Account 908 and the regulatory adjustment associated with the DSM tariff additional sum, as approved by the Commission in the 2022 DSM Certification Docket No. 44161. In response to STF-PIA 9-8, the Company stated that the increase was due to the DSM returning to full activities in the test period when the pandemic greatly reduced DSM program activities.

**Q. WHAT IS STAFF'S RECOMMENDATION?**

**A.** Staff believes that some increase in existing customer service and information expense is warranted but not 33 percent without support from the Company. Staff recommends that existing customer service and information expense grow by five percent per year and regulatory adjustment related to DSM tariff additional sum be recovered.

| | Company Proposal ($ millions) | Staff Recommendation ($ millions) | Reduction ($ millions) |
|---|---|---|---|
| Test Year | $135 | $118 | $17 |
| 2023 | $137 | $117 | $20 |
| 2024 | $139 | $123 | $16 |
| 2025 | $138 | $129 | $9 |

### 6. Marketing Expenses

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS MARKETING EXPENSES?**

**A.** As shown on Company Schedule APA/SPA/ADH/MBR-1 Schedule 1[9] and in response to STF-PCMG-1-7, the Company proposed the following balances for related years shown:

| | ($ Millions) |
|---|---|
| Test Year | $32.355 |
| 2023 | $32.578 |
| 2024 | $33.510 |
| 2025 | $34.996 |

**Q. IN REVIEWING THE DOCUMENTS IN THE FILING AND EVIDENCE PROVIDED THROUGH DISCOVERY, WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S MARKETING EXPENSES FOR EACH OF THE YEARS SHOWN ABOVE?**

**A.** I am recommending that the following costs associated with Innovation Center for the Test Year 2023 and for each of the Rate Years 2023-2025 be removed for ratemaking purposes:

[9] In its Supplemental Filing dated August 22, 2022, the Company did not make any adjustments to its Marketing Expenses for the test year and the rate year periods as shown.

| | |
|---|---|
| Test Year 2023 | $1,187,079 |
| Rate Year 2023 | $1,215,019 |
| Rate Year 2024 | $1,217,717 |
| Rate Year 2025 | $1,219,983 |

In response to STF-PCMG-2-21, the Company identified that Innovation Center costs support evolving and emerging technologies and business practices for the energy and utility industry. These costs bring together internal and external stakeholders to exchange ideas on the evolving technology landscape to help the Company continue to achieve its objectives around reliability, affordability, sustainability, and customer engagement. However, I believe these costs are akin to research and development costs in that these costs are aimed at discovering new knowledge or bring about a significant improvement with the hope that it would be useful in developing a new service or product that might benefit customers. These types of costs incorporate conceptual ideas, designs and testing of alternative similar to prototypes and pilot programs. I believe these types of costs are not known and measurable, as they may not come to fruition or realization in the provision of utility service. These types of costs may not achieve any objective with respect to reliability, affordability, sustainability or customer engagement. The Company has not provided any indication that these types of costs benefit customers. My recommendation is shown on my Schedule DM-3 for the Test Year Period 2023 ($1.187 million), and Schedule DM-4, ($1.215 million) DM-5 ($1.217 million) and DM-6 ($1.219 million) for each of the Rate Years 2023-2025, respectively. My overall summary is as follows:

| | Company Proposed ($ Millions) | Staff Recommended ($ Millions) | Reduction ($ Millions) |
|---|---|---|---|
| Test Year | $32.355 | $31.168 | ($1.187) |
| 2023 | $32.578 | $31.363 | ($1.215) |
| 2024 | $33.510 | $32.294 | ($1.217) |
| 2025 | $34.996 | $33.776 | ($1.219) |

## 7. Administrative & General Expenses

**Q. WHAT HAS THE COMPANY PROPOSED WIH RESPECT TO ITS ADMINISTRATIVE AND GENERAL EXPENSES?**

**A.** As shown on Company Schedule APA/SPA/ADH/MBR-1 Schedule 1[10] and in response to STF-PCMG-1-7, the Company proposed the following balances for related years shown:

| | ($ Millions) |
|---|---|
| Test Year | $258.335 |
| 2023 | $258.747 |
| 2024 | $225.063 |
| 2025 | $213.912 |

**Q. IN REVIEWING THE DOCUMENTS IN THE FILING AND EVIDENCE PROVIDED THROUGH DISCOVERY, WHAT ARE YOUR ADJUSTMENTS AND WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ADMINISTRATIVE AND GENERAL EXPENSES?**

**A.** In reviewing the documents in the filing, and the evidence provided through discovery, I have several adjustments to the Company's Administrative and General (A&G) expenses for the Test Year period 2023, and for each of the Rate Year periods 2023-2025). My recommendations are included in the each of the items addressed below.

**Q. PLEASE EXPLAIN EACH OF YOUR ADJUSTMENTS WITH RESPECT TO THE COMPANY'S A&G EXPENSES FOR EACH OF THE YEARS SHOWN.**

**a. Employee Retention Costs**

**Q. WHAT HAS THE COMPANY INCLUDED WITH RESPECT TO EMPLOYEE RETENTION COSTS?**

**A.** In response to STF-PCMG-2-20 and STF-LA-2-94, the Company proposed costs related to Employee Retention. In response to STF-PCMG-2-20, the Company stated that these costs cannot be identified to certain FERC Accounts to which the costs are recorded. I have made adjustment to these expenses in Account 920 – Administrative and General Salaries. The Company has included the following costs related to Employee Retention: **(BEGIN TRADE SECRET)**

[10] In its Supplemental Filing dated August 22, 2022, the Company did not make any adjustments to its Administrative & General Expenses for the test year and the rate year periods as shown.

[redacted] **(END TRADE SECRET)**

**Q. WHAT IS YOUR RECOMMENDATION RELATED TO THESE COSTS INCLUDED IN THE COMPANY'S EXPENSES?**

**A.** I am of the opinion that these costs should not be recovered from ratepayers but rather recovered from the Company (shareholders). But for the response noted above, the Company has not provided any further need or reasoning to include these costs in expenses. In response to STF-LA-2-94 **(BEGIN TRADE SECRET)** [redacted] **(END TRADE SECRET).** Ratepayers should not be required to pay for costs related to retention agreements if there is no showing of benefits accrued to them. Therefore, I am recommending that these costs not be recovered from ratepayers. My adjustments are shown on my Schedules DM-3 (Test Year period) and on Schedules DM-4, DM-5 and DM-6, Account 920 – Administrative and General Expenses.

**b.** **Office Supplies and Expenses** Account 921.

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO OFFICE SUPPLIES AND EXPENSES UNDER ITS TEST YEAR PERIOD AND FOR EACH OF THE RATE YEARS 2023-2025?**

**A.** In response to STF-PCMG-2-9, the Company proposed to include and recover the following balances related to Office Supplies and Expenses:

| | ($ Millions) |
|---|---|
| Test Year | $19.980 |
| 2023 | $20.387 |
| 2024 | $21.222 |
| 2025 | $21.913 |

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S BALANCES FOR ITS OFFICE SUPPLIES AND EXPENSES FOR EACH OF THE PERIODS INDICATED ABOVE?**

**A.** I am recommending averaging out the expenses for Office Supplies and Expenses in the Test Year period and accepting the balances in the Rate Year periods 2023-2025. In reviewing the Office Supplies and Expense balances for the historical years 2019-2021, I found variability and fluctuations starting from a balance in 2019 of $20.390 million, $13.546 million in 2020, and $16.747 million in 2021. (STF-PIA-7-1). In determining the three year average balances for these periods, I removed the labor portion in Account 921 as shown in response to STF-LA-2-72, so my average represents only non-labor adjustments. This results is a reduction of $3.124 million from the Company's balance (less Labor) of $13.231 million. I believe it is appropriate to average out these costs under the Test Year period because historical actual prior costs show a trend of fluctuations from year to year depending on the overall general administrative and general department operations, and other functional organizational expenses within the Company. My adjustment is shown on my Schedule DM-3 Account 921. With respect to the Rate Year periods 2023-2025, I reviewed the Company's balances and did not find such variability and fluctuations as I did under the historical years. The variability across the Rate Year periods were minimal and did not result in the need to average out the costs. Given the lack of variability I am recommending accepting the Company's balances for its Office Supplies and Expenses for the Rate Year periods 2023-2025. My adjustments are shown on my Schedule DM-4 Account 921, and Schedules DM-5 and DM-6 Account 921.

**c. <u>Outside Services Employed</u>** Account 923.

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OUTSIDE SERVICES EXPENSES?**

**A.** As shown in response to STF-PCMG-2-10, the Company proposed to include and recovery the following balances related to Outside Services Employed:

| | ($ Millions) |
|---|---|
| Test Year | $90.109 |
| 2023 | $90.771 |
| 2024 | $91.462 |
| 2025 | $92.869 |

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S BALANCES FOR ITS OUTSIDE SERVICES EMPLOYED EXPENSES FOR EACH OF THE PERIODS INDICATED ABOVE?**

**A.** I am recommending averaging out the expenses for Outside Services in the Test Year period, and in each of the Rate Year periods 2023-2025. In reviewing the Outside Services balances for the historical years 2019-2021, I found variability and fluctuations starting from a balance in 2019 of $73.812 million, $77.138 million in 2020 and $82.707 million in 2021 (STF-PIA-7-1). In determining the three-year average balances for these periods, I removed the labor portion in Account 923 as shown in response to STF-LA-2-72, so my average represents only non-labor adjustments. This results in a reduction of $7.090 million from the Company's balance (less Labor) of $71.339 million. ($64.249 million (three-year average of non-labor expenses) less $71.339 million (three-year average of non-labor expenses). I believe it is appropriate to average out these costs under the Test Year period because historical actual prior costs related to Outside Services Employed shows a trend of fluctuations from year to year depending on the overall use of contracted services related to the number of engagements for consultants, professional services (accountants, auditors, actuaries, appraisers, attorneys, engineers and other professionals employed). These costs vary from year to year depending on the overall administrative and general purpose costs of the Company and the nature of the services performed from year to year. My adjustment is shown on my Schedule DM-3 Account 923. With respect to the Rate Year periods 2023-2025, I reviewed the Company's balances and found the same variability and fluctuations as I did under the historical years. I am recommending an adjustment of $940,000 for Rate Year 2023, $2.319 million for Rate Year 2024 and ($3.258) million for Rate Year 2025. My adjustments are shown on my Schedule DM-4 Account 923, and Schedules DM-5 and DM-6 Account 923.

**d. <u>Property Insurance</u>** Account 924.

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO PROPERTY INSURANCE?**

**A.** As shown in response to STF-LA-2-69 and in response to STF-PCMG-1-7, the Company proposed the following balances related to Property Insurance: (Account 924).

| | ($ Millions) |
|---|---|
| Test Year | $149.776 |
| 2023 | $85.362 |
| 2024 | $85.447 |
| 2025 | $85.470 |

**Q. WHAT WERE THE REASONS FOR THE DECREASE IN THE COMPANY'S PROPERTY INSURANCE FROM $149.776 MILLION IN THE TEST YEAR AND APPROXIMATELY $85 MILLION IN THE RATE YEARS?**

**A.** As stated in response to STF-LA-69, the Company stated that the decrease in Property Insurance is due to insurance market conditions, adverse claim experience, joint owner allocation ratios, and Nuclear Primary Property Insurance (NEIL) distributions that off-set premium payments. Other changes relate to annual accruals approved by the Commission through base rate proceedings. The largest adjustment is related to the Natural Disaster Reserve- Distribution, which the balance went from $203.551 million in 2020 to $119.221 million in the Test Year 2023. In the Rate Years 2023-2025, the Property Expense related to this account is projected to be approximately $59 million.

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PROPERTY INSURANCE?**

**A.** After a review of the documents related to Property Insurance, I do not have any adjustments in the Test Year 2023 and for the Rate Years 2023-2025. The decline in Property Insurance reflects the most recent experience and it appears that prior Property Insurance balances are not expected to recur prospectively. As shown in response to STF-LA-2-69, the Company's Property Insurance is expected to be $239.729 million at the end of 2022 and taper off in the Rate Year 2023 at $85.362 million and maintain that balance through the Rate Years 2024 and 2025. Therefore, I am accepting the Company's Property

Insurance balances for the Test Year period and for each of the Rate Years periods 2023-2025. This is reflected on my Schedules DM-3, DM-4, DM-5 and DM-6 Account 924.

**e. Injury and Damages** Account 925

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO INJURY AND DAMAGES?**

**A.** As shown in response to STF-LA-2-70, the Company proposed the following balances related to Injury and Damages:

| | ($ Millions) |
|---|---|
| Test Year | $26.786 |
| 2023 | $27.235 |
| 2024 | $29.142 |
| 2025 | $29.394 |

**Q. HOW DID THE COMPANY DEVELOP ITS COSTS RELATED TO INJURY AND DAMAGES?**

A. As indicated in response to STF-LA-2-70, the Company assessed the need for an accrual for probable and reasonable estimated losses related to Injury and Damages (I&D), claims, and litigation monthly. The costs in Account 925 (I&D) includes workers compensation, safety and health, claims, and the costs of various liability insurance coverages. The Test period expenditures are based upon historical trend, analysis of current cases/outside litigation and other pertinent information known during the budget preparation. None of the costs included in the Test Year and Rate Years are considered extraordinary or non-recurring and are representative of normal business activities.

**Q. WHAT ARE YOUR RECOMMENDATIONS AND REASONINGS WITH RESPECT TO YOUR ADJUSTMENTS RELATED TO INJURY AND DAMAGES?**

**A.** I am recommending averaging out the expenses for I&D in the Test Year period and in each of the Rate Year periods 2023-2025. In reviewing the I&D balances for the historical years 2019-2021, I found variability and fluctuations starting from a balance in 2019 of $21.963 million, $19.915 million in 2020, and $33.470 million in 2021(STF-LA-2-70). In determining the three-year average balances for these periods, I removed the labor portion in Account 925 as shown in response to STF-LA-2-72, so my average represents only non-

labor adjustments. This results in a reduction of $1.640 million from the Company's balance (less Labor) of $26.786 million. ($26.786 million less $25.146 million). I believe it is appropriate to average out these costs under the Test Year period because historical actual prior costs related to I&D show a trend of fluctuations from year to year depending on the damage claims incurred, litigation claims, the costs of various liability insurance coverage, and other various claims shown on STF-LA-2-70. These costs vary from year to year depending on the overall clams, injuries, claims of others, compensation payments and the cost of safety, accident prevention and occupational injuries. My adjustment is shown on my Schedule DM-3 Account 925. With respect to the Rate Year periods 2023-2025, I reviewed the Company's balances and found the same variability and fluctuations as I did under the historical years. I am recommending an adjustment of $622,000 for Rate Year 2023, ($1.285) million for Rate Year 2024 and ($1.537) million for Rate Year 2025. My adjustments are shown on my Schedule DM-4 Account 925, and Schedules DM-5 and DM-6 Account 923.

**f. <u>Employee Pension and Benefits</u>** Account 926

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS EMPLOYEE PENSION AND BENEFITS?**

**A.** As shown in response to STF-LA-2-71, the Company proposed the following balances related to its Employee Pension and Benefits:

| | <u>($ Millions)</u> |
|---|---|
| Test Year | ($62.054) |
| 2023 | ($62.456) |
| 2024 | ($101.017) |
| 2025 | ($123.295) |

**Q. HOW DID THE COMPANY DEVELOP ITS BALANCES RELATED TO EMPLOYEE PENSIONS AND BENEFITS FOR THE TEST YEAR AND FOR EACH OF THE RATE YEARS?**

**A.** As stated in response to STF-LA-2-71, the Company's test year expenses and projections are derived from a combination of departmental and Southern Company Services-provided data. These costs are based upon historical trending of previously incurred expenses and

for major component costs associated with pension and benefits programs based upon projections from Aon Hewitt. The Company stated that the costs for these periods do not include any extraordinary or non-recurring expenses and are representative of normal business activities.

**Q. WHAT HAS THE COMPANY STATED REGARDING THE NEGATIVE BALANCES RELATED TO EMPLOYEE BENEFITS?**

**A.** As indicated in response to STF-PCMG-2-1, the Company stated that the decreases in this account were largely driven by a reduction in non-service pension costs primarily due to actual and projected asset gains resulting from expected strong market performance. The Company is experiencing changes in asset return, which are expected to cause an adverse impact on non-service pension costs and increase pension expenses in account 926.

**Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE CONTINUALLY DECLINING BALANCES IN THE COMPANY'S EMPLOYEE PENSION AND BENEFITS?**

**A.** Given the continued declining balances related to the Company's asset gains, lower pension costs, post-retirement costs and lower group insurance, I am accepting the Company's balances in the Test Year and for each of the Rate Years. Since 2020, the Company has realized a decline in this account from a positive balance of $18.980 million, to a negative balance of $7.159 million in 2021, and a negative balance as of the twelve months ending 5/31/2022 of $21.406 million.

**Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO SERP AND SERP-NON-SERVICE COSTS, SERVICE AWARDS AND RECREATION?**

**A.** In response to STF-LA-2-71 the Company proposed the following costs related to SERP Expenses, Service Awards and Recreation:

| | Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| SERP | $2,750,000 | $2,700,000 | $2,820,000 | $2,930,000 |
| Non SERP | $10,091,000 | $9,970,000 | $9,550,000 | $9,140,000 |
| Service Awards | $807,000 | $818,000 | $836,000 | $856,000 |
| Recreation | $10,000 | $10,000 | $10,000 | $10,000 |
| **Total** | **$13,658,000** | **$13,498,000** | **$13,216,000** | **$12,936,000** |

As shown in response to STF-PCMG-2-12, the Company stated that the SERP and SERP-Non-Service Costs are related to Southern Company SERP and Supplemental Benefits Plan (SBP-Pension) which are non-qualified pension benefits for senior management level employees and represent the increase in the projected benefit obligation resulting from an additional year of service provided by the eligible employee. The SERP-Non-Service Costs are related to the non-service cost portion of SERP and SBP-Pension and represents interest costs, amortization or prior service costs, and any gains or losses from prior years. With respect to the Service Awards costs, the Company stated these represent awards provided to employees based upon various years of service. With respect to Recreation the Company stated that these costs represent miscellaneous meals and travel expenses. The Company stated that these costs were inadvertently budgeted to Employee Pension and Benefits account 926 and should have been budgeted to Office Supplies and Expenses account 921.

**Q. WHAT ADJUSTMENT DO YOU HAVE RELATED TO THE COMPANY'S VARIOUS SERP EXPENSES?**

**A.** With respect to SERP and SERP-Non-Service Costs, I am recommending removing these costs from the Test Year period and for each of the Rate Year periods 2023-2025. I believe these types of costs do not benefit ratepayers in the provision of safe and reliable utility service, but rather benefit top executives by rewarding them to be retained by the Company. These types of SERP and related SERP costs are based upon certain agreements to obtain a certain amount of retirement income based upon various eligibility conditions that must be met. SERP costs are used by companies seeking to incentivize key executives in staying with the company. Further, SERP and SERP related costs benefit the Company in that the Company gets the tax benefit because it pays the premiums on the insurance, and even if

the employee quits or passes away, the Company still has access to the insurance cash value and is a beneficiary of the payout. Given this scenario, I see no benefits going to ratepayers and therefore recommend these costs be removed from the Employee Pension and Benefits balance in the Test Year and in each of the Rate Years 2023-2025.

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO SERVICE AWARDS AND FOR RECREATION COSTS?**

**A.** I am recommending removing these costs from the Company's Test Year period and for each of the Rate Year periods 2023-2025. For the Service Award costs, these costs represent premature anticipated costs in the event an employee reaches a certain number of years of service and are not a known and measurable cost. In the past, the Company has booked $331,000 in 2020, $535,000 in 2021 and $115,000 for the twelve months ending 5/31/2022. In the Test Year the Company is proposing to recover $807,000 and $818,000, $836,000 and $856,000 in the Rate Years 2023-2025, respectively. The Company has not provided any further information as to whether or not employees attained another year of service or whether any criteria was needed to be met in order to receive the bonus. Given this lack of information, I am recommending these costs be removed from the Company's Employee Pension and Benefits account. With respect to Recreation costs, the Company has not booked any costs in 2020, 2021 or for the 12 months ending 5/31/2022. The Company began booking these Recreation costs in the Test Year and for each of the Rate Years 2023-2025 (STF-LA-2-71). The Company has not provided any further reasoning in recovering these costs but for representing it for meals and travel expenses (STF-PCMG-2-12). I do not see these costs as benefitting ratepayers, in that the Company's response does not fully explain the need for these costs (utility services related, customer services related, regulatory related etc.). Therefore, I am recommending these costs be removed from the Company's Employee Pension and Benefits account 926.[11]

[11] I am including this adjustment in Account 926, as the Company has not updated this inadvertent adjustment in its schedules.

**g. Miscellaneous General /General Advertising** Account 930.

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS MISCELLANEOUS GENERAL/GENERAL ADVERTISING EXPENSES?**

**A.** As shown on STF-PCMG-1-7 the Company proposed the following Miscellaneous / General Advertising Expenses (In Thousands $$$):

| Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|
| $28.109 | $27.808 | $26.493 | $25.385 |

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S MISCELLANEOUS GENERAL/GENERAL ADVERTISING?**

**A.** I reviewed the responses to STF- LA-2-57 and STF-LA-2-58, I am recommending removing the following expenses from the Company's Miscellaneous General / General Advertising Expenses (In Thousands $$$):

| STF-LA-57 | Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| Misc. Gen. Exp | $.691 | $.702 | $.719 | $.737 |
| Assoc. Dues | $1.442 | $1.459 | $1.515 | $1.576 |
| Community Svc. | $.093 | $.094 | $.097 | $.098 |
| Total | $2.226 | $2.255 | $2.331 | $2.411 |
| STF-LA-58 | Test Year | 2023 | 2024 | 2025 |
| Add'l Misc. Gen. Exp | $2.656 | $2.807 | $.828 | $0 |
| Experimental | $1.053 | $1.060 | $1.077 | $0 |
| Grand Total | $5.935 | $6.122 | $4.236 | $2.411 |

**Q. WHY ARE YOU RECOMMENDING REMOVING THESE COSTS?**

**A.** I am recommending these costs be removed from the Company's Miscellaneous General /General Advertising because these costs do not benefit ratepayers in the provision of safe and adequate utility service. These costs are directly related to membership fees, state and county chambers of commerce, various civic and community organizations, and other community related development, economic development and other business issues. With

respect to Experimental costs these are related to general research, experimentation and other development work that is not assigned to a specific function on anticipated research administration activities such as strategic research and development, planning and budget (STF-LA-2-58). I believe these types of costs do not benefit ratepayers because they relate to costs that should be borne by local, municipal, and state organizations or the shareholders of the Company. These types of costs are not the sort of expenditures that ratepayers should pay as they are not related to the core business of providing utility service nor are they related to assisting customers in retaining access to utility service. The Company has not provided any evidence to support ratepayer benefits. Further, ratepayers do not have a say as to which entities these costs are paid to, nor do these entities provide any customer with utility service benefits. With respect to Experimental costs, the Company has not provided any results nor has the Company provided whether any research has come to fruition or has been proven useful in the provision of utility service. These types of costs are uncertain in nature. Ratepayers should be responsible for costs that relate to providing utility service that are known and measurable and prudent. These costs provide neither. My recommendation is shown on my Schedule DM-3 Test Year 2023 Account 930, and on Schedules DM-4, DM-5 and DM-6, Account 930 for the Rate Years 2023, 2024 and 2025, respectively.

**h.** **<u>Maintenance of General Plant</u>** Account 935.

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS MAINTENANCE OF GENERAL PLANT?**

**A.** The Company proposed the following balances related to Maintenance of General Plant: (In Thousands $$$)

| Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|
| $20.631 | $22.480 | $22.869 | $23.172 |

**Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S MAINTENANCE OF GENERAL PLANT?**

**A.** I am recommending averaging out the expenses under the Test Year period utilizing the expenses in the 2019, 2020 and 2021 periods. I am accepting the Company's expenses

under the Rate Year 2023-2025 periods. In averaging out the expenses to set the Test Year period, I removed the labor portion in Account 935 as shown in response to STF-LA-2-72, so my average represents on non-labor adjustments. The result is a reduction of $1.821 million from the Company's balance (less Labor) of $8.654 million. I believe it is appropriate to average out these costs under the Test Year period because prior costs have fluctuated from year to year depending on the overall maintenance of expense items within Account 935 (materials, office furniture and equipment, miscellaneous equipment, general equipment etc.). The use of a three year average is a reasonable and appropriate approach to use as a basis for projections as it takes into consideration actual historical costs/balances and provides for a stable recurring recovery for costs going forward. With respect to the Rate Years expenses 2023-2025, the fluctuations and variability were minimal, and did not result in the need to average out costs prospectively. My adjustments are shown on my Schedule DM-3 Account 935, and Schedules DM-4, DM-5 and DM-6. My overall summary of adjustments related to A&G Expenses are shown below:

| | Company Proposed ($ Millions) | Staff Recommended ($ Millions) | Reduction ($ Millions) |
|---|---|---|---|
| Test Year | $258.335 | $224.813 | ($33.522) |
| 2023 | $258.747 | $240.504 | ($18.243) |
| 2024 | $225.063 | $208.561 | ($16.502) |
| 2025 | $213.911 | $193.743 | ($20.168) |

**8. Inflation Adjustments**

**Q. WHAT DID THE COMPANY PROPOSE RELATED TO THE IMPACT ON INFLATION?**

**A.** Company witness Womack stated that the recent levels of significant inflation are impacting the Company. This is due to the unprecedented economic environment, resulting in high uncertainty and increasing costs of goods and services, challenges related to geopolitical tensions, stressed supply chains, and historically high inflation and tight labor markets all exacerbated by a rising interest rate environment that resulted in a tightening federal monetary policy (Womack testimony at 10-11). Mr. Womack stated that the current significant level of inflation, fueled by national and local economic forces, impacts the cost

to serve customers and must be appropriately reflected in the Company's rates (Womack testimony at 11). In AAHR at 18, Company witnesses stated that the incremental inflation resulted in an increase of about $94 million in the Company's revenue requirement.

**Q. HOW DID THE COMPANY DEVELOP ITS ADJUSTMENT RELATED TO INFLATION?**

**A.** As indicated in response to STF-LA-2-10, the Company does not create a budget by applying an inflation rate to all the actual or historic year expense. Expenses are reviewed and based upon known increases or decreases the budget amounts are adjusted accordingly. Based upon the type of expenditure, inflation rates may be applied to derive projected expenses. The budget guidelines and assumptions for the 2022 budget process include escalation rates for both labor and non-labor costs. The labor escalation rates are based upon data supplied by the Employment Cost Index (ECI) Private Sector Wage and Salaries and non-labor escalation rates are derived from the Bureau of Economic Analysis Gross Domestic product (GDP) index values as of April 2022. The Company provided the following cost indexes for the ECI and for the GDP:

| | ECI | GDP |
|---|---|---|
| 2022 | 5.8% | 5.8% |
| 2023 | 5.4% | 2.9% |
| 2024 | 4.5% | 2.4% |
| 2025 | 4.2% | 2.3% |

**Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S PROPOSAL RELATED TO INFLATION ADJUSTMENTS?**

**A.** In response to STF-PCMG-1-5, the Company provided a breakdown of its proposed Inflation adjustment of $94 million by FERC Account No. and by the test year and rate year periods. While not specifically showing the $94 million, the Company provided the incremental inflation adjustments for each of the O&M Expense categories for the time periods in the test year and the rate years (STF-PCMG-2-2). The Company stated that the overall $94 million also includes inflation costs related to capital investments in addition to the operation and maintenance expense adjustments (STF-PCMG-2-3).

| | Overall ($ Millions) | Production ($ Millions) | All Other O&M ($ Millions) |
|---|---|---|---|
| Test Year | $58.543 | $19.968 | $38.574 |
| 2023 | $67.083 | $22.178 | $44.905 |
| 2024 | $75.185 | $23.845 | $51.340 |
| 2025 | $80.193 | $24.351 | $55.841 |

In response to STF-PCMG-2-3, the Company stated that the $94 million is attributable to both -- capital investment and in addition to operations and maintenance expenses.

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S INFLATION ADJUSTMENT IN THE AMOUNT OF $94 MILLION?**

**A.** I am accepting the ECI index for labor wage increases, as there is no other way to calculate the adjustment of wages but for cost of living adjustments and bargaining unit agreements. With respect to O&M Inflation, I am accepting the cost adjustments related to Production expenses as these costs adjustments result in a >1.00% increase with respect to the overall Production expenses in the Test Year and in each of the Rate Years 2023-2025. Given that energy costs have been particularly high I have no issues with these expenses in what the Company has proposed. With respect to the remaining expenses All Other O&M expenses, I did an analysis which computed the Company's proposed Inflation Adjustments for All Other O&M Expenses in relation to the Test Year and Rate Years Inflation Adjustments as shown above. The results are shown in the following:

| | (In Thousands $$$) Co. All Other O&M | % Increase | GDP%[12] | Difference |
|---|---|---|---|---|
| Test Year | $1,078,429 | 3.577% | 4.35% | .773% |
| 2023 | $1,053,069 | 4.264% | 2.90% | -1.34% |
| 2024 | $1,042,622 | 4.924% | 2.40% | -2.524% |
| 2025 | $1,055,311 | 5.291% | 2.20% | -3.091% |

As shown above, the expense adjustment related to Inflation in the Test Year are below the GDP of 4.35%. However, the expense adjustments related to Inflation in the Rate Years 2023-2025 are higher than the GDP in these years. I am recommending adjusting the

[12] The GDP % is computed by the average of the 2022 % of 5.80% and the 2023 % of 2.90% or 4.35%.

inflation by limiting the incremental costs beyond 2023 to 2.90%, 2.40% and 2.20% for Rate Year 2023, 2024 and 2025, respectively (STF-LA-2-10), as these costs cannot completely be known and measurable in a future period.

**Q. PLEASE EXPLAIN YOUR OVERALL REASONING RELATED TO THE COMPANY'S PROPOSED INFLATION ADJUSTMENTS AS IT PERTAINS TO THE SETTING OF RATES.**

**A.** It is my opinion that the use of inflation rates and factors to set rates for service in ratemaking are not a known and measurable cost, in that these types of cost increases do not reflect the actual costs the Company will incur, but rather estimates with no foundational reasoning. These types of costs are essentially broad economic adjustments that do not particularly address any one individual expense category. Inflation adjustments are overall blanket type adjustments that are applied to all goods and services that may or may not be related to costs incurred by the Company, especially if the GDP is used, which is a broad basket of consumer goods and services such as housing, clothing, food, etc. While such inflation costs adjustments are typically used to develop economic data, they should not be used for ratemaking purposes in most cases. In this case, under the Company's ARP, inflation may not stay elevated during the term of the 3-year rate plan. I believe that the Company's inflation adjustment forecast is too high, and it may result in rates being set too high for utility service. Given this situation, I am recommending lowering the Company's proposed Inflation Adjustments in the Rate Years as follows:

| | | Recommended O&M Expense Level (In Thousands $$$) | | | |
|---|---|---|---|---|---|
| | | Test Year | 2023 | 2024 | 2025 |
| | | $996,396 | $1,009,270 | $997,109 | $999,562 |
| | GDP | 4.35% | 2.90% | 2.40% | 2.20% |
| Adjustment | | $43,343 | $29,269 | $23,930 | $21,990 |
| Co. Proposed | | $38,574 | $44,905 | $51,340 | $55,841 |
| Difference | | $4,769 | ($15,543) | ($27,378) | ($33,717) |

Based upon the above analysis, I am recommending no adjustment to Inflation in the Test Year, but adjustments to the Rate Years 2023-2025, of ($15,636), ($27,409) and ($33,851),

respectively. My adjustments are summarized below and are shown on my Schedule DM-2.

| | Test Year | 2023 | 2024 | 2025 |
|---|---|---|---|---|
| Co. Proposed | $38,574 | $44,905 | $51,340 | $55,841 |
| Staff Recommend | $38,574 | $29,269 | $23,930 | $21,990 |
| Reduction | $0 | ($15,543) | ($27,378) | ($33,717) |

**9. Contract Labor**

**Q. WHAT HAS THE COMPANY IDENTIFIED WITH RESPECT TO LABOR COSTS FOR THE TEST YEAR AND FOR EACH OF THE RATE YEAR PERIODS?**

**A.** As shown on STF-LA-2-72, the Company has proposed the following levels of Contract Labor:

| | ($ Millions) |
|---|---|
| Test Year | $428.468 [13] |
| 2023 | $387.339 |
| 2024 | $373.920 |
| 2025 | $363.444 |

**Q. WHAT WERE THE REASONS GIVEN BY THE COMPANY REGARDING THE VARIATIONS OF CONTRACT LABOR FROM THE TEST YEAR PERIOD THROUGH THE RATE YEARS 2023-2025?**

**A.** As more specifically addressed in response to STF-LA-2-72, the Company stated the reasons for the variations of Contract Labor were due to outages schedules, maintenance activities, permanent reduction in maintenance expense on steam production, variations in yearly spending in both asset and vegetation management driven by workload and economic conditions, participation levels in DSM programs, DSM program evaluation, and growth in electric transportation programs, facility management, legal spend, rate case costs and advertising. In response to STF-LA-2-73, the Company stated that the decrease in employee headcount from prior years are the result from attrition, turnover and cost

[13] A more detailed breakdown is shown on STF-LA-2-72 Attachment.

containment initiatives by the Company. The Company stated that it continues to review business processes to enhance customer experience as well as focus on efficiency. The actual headcount has been reduced by about 438 employees since 2019. In response to STF-PCMG-2-13, the Company further stated that the decrease in projected contract labor O&M from $448.492 million in 2022 to $363.444 million in 2025, was largely due by decreases in contract labor related to steam generation, transmission, and distribution functions. The projected decrease in steam generation contract was driven by lower outage spend in 2024 and 2025 as well as projected steam unit retirements. The reduction in distribution contract labor was driven by lower vegetation management spend and the completion of the distribution backlog in 2022. The projected decrease in transmission contract labor was driven by lower asset management spend due to current and forecasted economic conditions.

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S CONTRACT LABOR COSTS FOR THE TEST YEAR AND FOR EACH OF THE RATE YEAR PERIODS?**

**A.** After reviewing the responses to the discovery and the Company's labor escalation rates as identified in STF-LA-10, I am accepting the Company's adjustments related to salaries and wages in the Test Year and for each of the Rate Years (2023-2025). My adjustments are related to the Company's (a) Overtime Expenses; (b) Incentive Compensation- Long Term Performance Pay Program (LTPP); (c) Incentive Compensation – Performance Pay Program (PPP); (d) Incentive Compensation – Stock Based Compensation and: (e) Vacancy Rate Ratio- Employee Headcount. I will explain each of my adjustments below.

**a. <u>Overtime (See LA-2-75)</u>**

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO OVERTIME EXPENSES FOR THE TEST YEAR PERIOD AND FOR EACH OF THE RATE YEAR PERIODS?**

**A.** As shown in response to STF-LA-2-75, the Company projected Overtime O&M Expenses as follows:

| | | Different |
|---|---|---|
| Test Year | $20,680,981 | |
| 2023 | $20,629,677 | ($51,304) or .2% |
| 2024 | $21,199,176 | $569,499 or 2.76% |
| 2025 | $21,389,942 | $190,766 or .9% |

**Q. WHAT ADJUSTMENTS DO YOU HAVE?**

**A.** I am recommending averaging out the Overtime Costs to set the Test Year period 2023 and accepting the Overtime costs for the Rate Years (2023-2025). In reviewing the Overtime Costs in STF-LA-2-75, the Company had overtime expenses of $19.013 million in 2020, $25.857 million in 2021 and $21.029 million in 2022. Averaging out these costs results in a normalized level of $21.966 million in the Test Year. This results in an increase of $1.286 million from the Company's Overtime Costs in the Test Year of $20.680 million. Prior Overtime costs has fluctuated from a low of $19.013 million in 2020 to a high of $31.685 million as of the twelve months ended 5/31/2022. My adjustment is shown on my Schedule DM-11.

**b. Incentive Compensation Performance Pay Program (PPP)**

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS PPP?**

**A.** As shown on Confidential response to STF-LA-2-81, the Company included the following PPP in its filing, specifically in its Operating Expenses for Georgia Power Company, allocated from Southern Company Services and allocated from Southern Nuclear Company(a full breakdown is shown in response to STF-LA-2-81):

| | (In Millions)<br>PPL |
|---|---|
| Test Year | $115.336 |
| 2023 | $119.171 |
| 2024 | $89.427 |
| 2025 | $128.286 |

**Q. PLEASE DESCRIBE THE COMPANY'S PEFORMANCE PAY PROGRAM (PPP)**

**A.** As more fully described in the response to STF-LA-2-78 Attachment A **(BEGIN TRADE SECRET** [redacted] **(END TRADE SECRET).**

**Q. HOW ARE PERFORMANCE GOALS WEIGHED?**

**A.** As identified in response to STF-LA-2-79, the Company has weighed the components of the overall program by one-third operational goals,[14] one-third business unit financial goals (net income for Georgia Power) and one-third earnings per share.

**Q. DID YOU ASK THE COMPANY WHAT THE ACTUAL RESULTS OF THE COMPANY'S PPP WERE IN PRIOR YEARS?**

**A.** Yes, in response to STF-PCMG-2-18, I asked the Company to provide the actual results of the Company's PPP for the years 2017-2021 and for the expected year 2022, including the dollar amount associated with each program component and the dates of payouts.

**Q. WHAT WERE THE RESULTS OF THE COMPANY'S PPP FOR THOSE YEARS?**

**A.** The Company stated that results for the 2017-2021 years were in excess of 100% of the Performance Goal factors(STF-LA-2-79). These included assumptions for directly incurred – GPC, allocated from SCS to GPC and allocated from SNC to GPC. The 2022 actual results will not be available until the year is complete. The PPP is funded at the total performance level and, therefore, the dollar amount associated with each program component are not available.

**Q. WHAT IS YOUR RECOMMENDATION?**

**A.** Based upon the criteria of the PPP which allocates one-third of the overall annual Performance Based Compensation by operational goals, business unit financial goals and

[14] Operational Goals refer to Safety, Customer Satisfaction, Generation Reliability, Plant Vogtle Unit 3 & 4, Project Assessment, Transmission Reliability, Distribution Reliability and Culture.

earnings per share, I am recommending that only the operational goals be allowed in the O&M Expenses.

**(BEGIN TRADE SECRET)**

[redacted]

**(END TRADE SECRET)**

**Q. PLEASE EXPLAIN YOUR ADJUSTMENTS.**

**A.** I am recommending that the Company not recover PPP compensation related to financial goals (Net Income for Georgia Power) and for earnings per share, but only for operational goals that related to ratepayer benefits in the area of safety, culture, customer satisfaction, major projects, availability, reliability and such goals that benefits the provision of safe and reliable utility service to customers (STF-LA-2-78 Attachment B page 6). I do not believe that incentive compensation related to increasing net income and financial performance goals that affect the Company's, SCS's and SNC's earnings per share should be afforded recovery from ratepayers. These types of incentive costs benefit the Shareholders of the Company, and of SCS and SNC, and do not directly benefit the ratepayers in the area of safe and reliable utility service[15]. My recommendation is shown on my Schedule DM-11 Performance Pay Plan.

**c. <u>Vacancy Rate Ratio Adjustment</u> (Employee Headcount)**

**Q. HAS THE COMPANY PROPOSED A VACANCY RATE RATIO IN ITS DEVELOPMENT OF ITS TEST YEAR EXPENSES OR IN EACH OF ITS RATE YEAR EXPENSES 2023-2025?**

[15] In response to STF-LA-2-78 Attachment B page 6, refers to Appendix C related to Financial and Operational Goals. Although it has not been specifically identified, page 15 of 15 appears to be Appendix C.

**A.** No, not of which I am aware.

**Q. WHAT HAS THE COMPANY PROVIDED WITH RESPECT TO ITS VACANCY RATIO RATE FROM 2017 THROUGH 2021?**

**A.** As shown in response to STF-PCMG-2-14, the Company calculated a vacancy ratio rate of 10% in 2017, 6% in 2018, 6% in 2019, 9% in 2020 and 10% in 2021.

**Q. WHAT HAS BEEN THE EMPLOYEE LEVEL OR EMPLOYEE HEADCOUNT FROM 2016 THROUGH THE RATE YEAR 2025?**

**A.** As shown in response to STF-LA-2-73, the Company had the following Employee Headcount for the years in question:

| Number of Employees | Year | Difference |
|---|---|---|
| 7,527 | 2016 | |
| 6,986 | 2017 | (541) or 7.18% |
| 6,967 | 2018 | (20) or .28% |
| 6,984 | 2019 | 17 or .24% |
| 6,835 | 2020 | (149) or 2.13% |
| 6,583 | 2021 | (252) 3.68% |
| 7,016 | 2022 | 433 or 6.57%[16] |
| 7,016 | 2023 | |
| 7,016 | 2024 | |
| 7,016 | 2025 | |

**Q. WHAT WERE THE REASONS THAT THE COMPANY CLAIMED TO EXPLAIN THE YEAR TO YEAR VARIANCES?**

**A.** In response to STF-LA-2-73, the Company stated that the decrease in headcount from 2016 through 2021 was primarily due to attrition, turnover and cost containment initiatives by the Company. The Company has continued to review business processes to enhance customer experience as well as focus on efficiency. The actual headcount has been reduced by about 438 employees since 2019.

**Q. HAS THE COMPANY EXPLAINED THE NEED TO HIRE APPROXIMATELY 470 EMPLOYEES FROM THE MAY 2022 ACTUAL HEADCOUNT TO THE TEST YEAR AND RATE YEAR PERIODS?**

[16] Actual Headcount as of May 2022 was 6,546 (STF-LA-2-73).

**A.** In response to STF-PCMG-2-15, the Company stated that its staffing level at any point in time is dynamic and will fluctuate as hiring and attrition are a part of normal business operations. Therefore, vacancies will occur throughout the rate year periods as part of normal business and will fluctuate accordingly. The hiring and attrition process will also vary based upon the needs of the business at that time. Because of the normal inflows and outflows of headcount throughout the year, it is difficult to project or develop a schedule of expected hirings. During the interim when vacancies are not filled, labor cost continues to be incurred as the work is performed by overtime from existing workforce and contract labor.

**Q. WHAT IS YOUR RECOMMENDATION?**

**A.** For the Test Year, I am recommending a vacancy ratio rate based upon the prior three years of historical data (2019, 2020 and 2021). Averaging out the vacancy ratios for these periods results in an average vacancy ratio rate of 8.33%. (6%+9+10%)/3.

**Q. PLEASE EXPLAIN YOUR REASONING FOR A VACANCY RATE RATIO ADJUSTMENT.**

**A.** As stated in response to STF-PMCG-2-14, the Company stated that vacancies occur throughout the year and will fluctuate from month to month. Attrition rates are on the rise and replacing positions externally has been challenging with the current competitive labor market. The Company's historical vacancy rate ratio trend provides a good indicator of what is to be expected going forward, given the current labor market and based upon the Company's staffing plans and individual business unit work plans. Given that the Company experiences vacancies throughout the year, it is appropriate to take these vacancies into consideration when setting labor costs. These vacancies are due to a number of factors -- employee stability, voluntary and involuntary leave by employees, increased / decreased work load, shifting of employees from one affiliated entity to another (business unit staffing), difficulty to fill vacancies due to the challenge of attracting and retaining employees and overall business strategy. Using the Company's projected Contract Labor of $428,467,945 minus my recommended reduction related to Performance Pay Incentive Compensation booked in the Test Year, my net Contract Labor for purposes of calculating my vacancy rate ratio is $322,291,871. Using my average vacancy rate ratio of 8.33%, I

compute an adjustment of $29,286,360 for the Test Year period. This is shown on my Schedule DM-11.

**Q. WHAT ADJUSTMENTS ARE YOUR RECOMMENDING RELATED TO THE COMPANY'S PROPOSED ADDITIONAL EMPLOYEES OF 470?**

A. I am recommending phasing these employees over the Company's three-year rate plan (2023-2025). Using the Company's proposed additional 470 employees and dividing that by the Company's current employee staff level of 6,546 as of May 2022, this results in a ratio of 7.18%. Dividing the 7.18% over the three-year rate plan an annual rate of 2.39% is computed. I then reduced the employee additions in the Rate Year 2023 by taking the Company's proposed Contract Labor in 2023 of $387,339,165 (minus my recommended adjustments related to Performance Pay - Incentive Compensation) and multiplying that amount by two-thirds of the overall 470 additional employees (2.39% times 2= 4.786%) to arrive at an adjustment of $14,737,684 for the Rate Year 2023. For the Rate Year 2024 I reduced the employee additions by taking the Company's proposed Contract Labor of $373,920,349 and multiplying that amount by one-third or 2.39% or $7,522,258. Finally, in the Rate Year 2025, I assumed that the Company will have hired the remaining one-third of the employees, so there will be no reduction in the employee additions. My adjustments are shown on my Schedule DM-11 Additional Employees. Below is a summary of my recommended employee head count:

| Number of Employees | Year | Difference | Head count Staff Recommended | |
|---|---|---|---|---|
| 7,527 | 2016 | | | |
| 6,986 | 2017 | (541) or 7.18% | | |
| 6,967 | 2018 | (20) or .28% | | |
| 6,984 | 2019 | 17 or .24% | | |
| 6,835 | 2020 | (149) or 2.13% | | |
| 6,583 | 2021 | (252) 3.68% | | |
| 7,016 | 2022 | 433 or 6.57%[17] | | |
| 7,016 | 2023 | | 6,702 | (314) |
| 7,016 | 2024 | | 6,860 | (156) |
| 7,016 | 2025 | | 7,016 | 0 |

[17] Actual Headcount as of May 2022 was 6,546 (STF-LA-2-73).

## 10. Rate Case Expenses

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO RATE CASE EXPENSES AND EXPENSES ASSOCIATED WITH COSTS RELATED TO STAFF CONSULTANTS?**

**A.** As shown in response to STF-LA-67, the Company provided for a total rate case expenses of $4.682 million. The Company stated that all rate case expenses for the test year are projected to be expensed in 2022. In addition to $4.682 million of budgeted rate case expenses, the Company included $785,405 as a regulatory adjustment for costs paid by the Company for GPSC Staff Consultants as defined in the Procedural Scheduling Order and are expensed as incurred by the Company. In response to STF-LA-2-67, the Company provided a breakdown of these costs:

| | |
|---|---|
| A&G Labor (FERC 920) | $ 801,000 |
| Print, Postage, Meals/Travel & Office Supplies (FERC 921) | $ 95,000 |
| Outside Legal Counsel (FERC 923) | $2,500,000 |
| Consulting Fees (FERC 928) | $1,286,000 |
| **Total** | **$4,286,000** |

**Q. DO YOU AGREE THAT THE COMPANY SHOULD EXPENSE ALL OF ITS RATE CASE COSTS IN 2022?**

**A.** Yes. By expensing rate case cost in 2022 will avoid any impact on customers' bills in 2022 or future years (2023 – 2025).

**Q. WHAT REASONS DID THE COMPANY PROVIDE TO EXPENSES THESE COSTS IN 2022?**

**A.** In response to STF-PCMG-2-11, the Company stated that it is not proposing to defer and amortize the 2022 rate case expenses. The total amount of $4.682 million are projected to be incurred in the 2022 calendar year and will be expensed as incurred.

**Q. WHAT IS YOUR RECOMMENDATION REGARDING RECOVERY OF RATE CASE EXPENSES AND RECOVERY OF EXPENSES FOR COSTS PAID BY THE COMPANY FOR COMMISSION CONSULTANTS?**

**A.** I am accepting the Company's balance to rate case expenses with the proposal of expensing them in 2022.

## 11. Taxes Other Than Income

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS PROPERTY TAXES?**

**A.** As shown on Exhibit APA/SPA/ADH/MBR-1 Schedule 1 Total Company Supplemental, the Company has proposed the following balances of Taxes Other Than Income Taxes:

| | | Difference |
|---|---|---|
| Test Year 7/31/2023 | $306.198 million | |
| Rate Year 2023 | $312.588 million | $6.389 million |
| Rate Year 2024 | $338.778 million | $26.190 million |
| Rate Year 2025 | $362.821 million | $24.043 million |

**Q. WHAT IS INCLUDED IN THE COMPANY'S TAXES OTHER THAN INCOME TAXES CATEGORY?**

**A.** Included in the Company's Taxes Other Than Income are Real and Personal Property Taxes, Payroll Taxes, and Other Taxes such as State of Georgia Taxes, State of Alabama Taxes and Other Taxes not identified (STF-PCMG-1-13).

**Q. WHAT REASONS DID THE COMPANY PROVIDE REGARDING THE DIFFERENCES BETWEEN THIS ACCOUNT IN THE TEST YEARS AND DURING THE RATE YEARS?**

**A.** In response to STF-LA-2-42, the Company stated that the projected year-to-year major differences are increases to assessment values resulting in increased real and personal property taxes, as well as variances to the municipal franchise fees and fluctuations in payroll taxes in future years. In response to STF LA-2-43, the Company indicated there were no property tax valuation true-ups for the forecasted test year period and for the rate year periods 2023-2025.

### a. Property Taxes

**Q. DID THE COMPANY PROVIDE A BREAKDOWN OF ITS PROPERTY TAXES FOR THE TEST YEAR PERIOD AND FOR EACH OF THE RATE YEAR PERIODS?**

**A.** Yes. In response to STF-PCMG-1-13, the Company provided a breakdown of its Property Taxes for the test year period and for each of the rate year periods. Below is a breakdown:

| | ($ Millions) | Difference |
|---|---|---|
| Test Year | $278.4 | |
| 2023 | $285.2 | $6.7 |
| 2024 | $310.6 | $25.5 |
| 2025 | $333.8 | $23.1 |

**Q. WHAT WERE THE REASONS THE COMPANY STATED FOR THE NEED TO PAY FOR PROPERTY TAXES IN OTHER STATE JURISDICTIONS?**

**A.** In response to STF-PCMG-2-6, the Company stated that the need to pay for property taxes in other State jurisdictions is that the Company owns operating property located in Alabama, Mississippi and South Carolina which includes stored gas, hydro and solar generation sites, transmission lines, substations and general equipment that supports the Company's electric operations in Georgia. The Company pays real and personal property taxes in these States.

**Q. WHAT ADJUSTMENTS DO YOU HAVE?**

**A.** I reviewed the Company's balances with respect to its UPIS balances for the Test Year and for each of the Rate Years and am recommending the use of the following ratio percentages to calculate the property taxes.

| | ($ thousands) UPIS Balance | ($ thousands) Property Taxes | Ratio |
|---|---|---|---|
| Test Year | $42,412,823 | $278,454 | .657% |
| 2023 | $43,460,812 | $285,190 | .656% |
| 2024 | $46,296,211 | $310,649 | .671% |
| 2025 | $48,852,298 | $333,789 | .683% |

My calculations related to the Property Tax ratios are shown on my Schedule DM-7, DM-8, DM-9 and DM-10.

**b. Payroll Taxes**

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS PAYROLL TAXES?**

**A.** As stated in response to STF-PCMG-1-13, the Company proposed the following Payroll Taxes expense for the years as indicated below:

| | ($ Millions) | Difference |
|---|---|---|
| Test Year | $29.958 | |
| 2023 | $29.657 | ($.301) |
| 2024 | $30.169 | $.512 |
| 2025 | $31.114 | ($.945 |

**Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PAYROLL TAXES?**

**A.** My adjustments are related to my overall Contract Labor adjustments shown on my Schedule DM-11. Using my recommended balances in the Test Year and for each of the Rate Years 2023-2025 and the Payroll Tax Ratios for each of these years, I've calculated my Payroll Taxes as follows, which includes a comparison to the Company's proposed expense:

| | Company Proposed In Millions) | Staff Recommended ($ Million) | Difference ($ Millions) |
|---|---|---|---|
| Test Year | $29.9 | $22.5 | ($7.4) |
| 2023 | $29.6 | $22.4 | ($7.2) |
| 2024 | $30.1 | $24.7 | ($5.4) |
| 2025 | $31.1 | $23.7 | ($7.3) |

**c. Other Taxes [18]**

**Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO OTHER TAXES?**

**A.** As shown on STF-PCMG-1-13, the Company proposed a balance of Other Taxes in the amount of $21 million for the test year period and for each of the rate year periods (2023-2025).

**Q. DO YOU HAVE ANY ADJUSTMENTS?**

**A.** No. I am accepting these Other Taxes expense unless any other additional information arises.

[18] With respect to the State of Georgia Taxes and the State of Alabama Taxes shown in response to STF-PCMG-1-13, I do not have any adjustments related to these expenses.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

**A.** Yes, it does. I reserve the right to update my testimony in the event subsequent information becomes available that may affect my recommended adjustments in this proceeding.

BY MR. WALSH:

Q Mr. Mugrace, did you also prefile or cause to be prefiled two public disclosure exhibits which were marked as Exhibits DM 1 and 2?

A Yes.

Q Do you have any changes or corrections to make to those exhibits at this time that were not already captured in the errata?

A No.

MR. WALSH: Madam Chair, I ask that Exhibits DM 1 and 2 be marked for identification as Staff Exhibit Nos. 59 and 60.

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were marked for identification as Staff Exhibits 59 and 60.)

BY MR. WALSH:

Q Mr. Mugrace, did you also prefile or cause to be prefiled 48 pages of trade secret testimony in question-and-answer form on October 20th?

A Yes.

Q Other than the changes that have already been detailed, are there any other changes that you would like to make to the trade secret testimony or the exhibits that were attached to the trade secret testimony?

A No.

Q So if I were to ask you the same questions that are presented in your trade secret testimony, would your answers be the same?

A Yes.

MR. WALSH: Madam Chair, I would ask that the prefiled trade secret testimony, along with exhibits, of Mr. Mugrace be marked for identification as Staff Exhibit No. 61.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 61.)

MR. WALSH: Thank you.

BY MR. WALSH:

Q Mr. Mugrace, did you prepare a summary of your testimony?

A I did.

MR. WALSH: Madam Chair, may he --

MADAM CHAIR PRIDEMORE: Please go ahead with your summary, Mr. Mugrace.

MR. MUGRACE: Good afternoon. My name is Dante Mugrace. I am a senior consultant with the consulting firm of PCMG and Associates. PCMG provides regulatory consulting service to various governmental entities in utility regulation and policy, economics, accounting and finance.

PCMG focuses on the regulation of electric, gas, water and wastewater utilities that operate under local, state, and federal jurisdictions. My responsibilities are to evaluate, verify, and analyze public utilities' revenue requirements, proposals, and the development of those components that are used to set rates for utility service.

My testimony recommends a level of expenses to be recovered from ratepayers with respect to the Georgia Power Company's proposed operating and maintenance expenses that was developed for the test year period ending July 31, 2023, and for each of the company-proposed plan years, 2023, 2024, and 2025.

The test year data should generally be adjusted by the utility to reflect a normal operating condition and is then used to forecast future costs and revenue requirements by adjusting for future expenditures and other costs expected to be incurred.

The forecasted data or expenses should also be adjusted for expenses that are part of the historical test year, but is not expected to be incurred in the future test years.

The approach I used to develop staff's forecast of the company's operation and maintenance expenses, or O&M expenses, in the test year and in the plan

years, is based upon regulatory and economic principles that can affect rates and a determination of whether those expenses should be allowed to be recovered from ratepayers and whether these costs are prudent in nature (judged on their reasonableness and based upon information received) used and useful (whether the expenses are used to provide services that are useful to the ratepayer) and known and measurable (justified based upon documentation, facts, and are legitimate in nature.)

In other words, to allow recovery of O&M expenses, the company should show that these expenses are realistic and a necessary part of the normal day-to-day operations.

The more reliance on forecasted data the more subjectivity was used to determine the estimates proposed in the rate years. There is a measure of interpretation when reviewing forecasted data and different levels of interpretation can vary among the parties to the proceeding and ultimately be determined and included by the Commission.

In developing my adjustments related to the company's O&M expenses, I relied on the company's direct testimony and related exhibits in the filing and responses to discovery sets STF-PCMG, STF-PIA,

and STF-LA (Interrogatories).

The company has a future test year period ending July 31st, 2023, and has requested recovery of its production expenses of about $3.3 billion and O&M expenses in the amount of $1.78 billion. The company has requested production expenses that average around $3.22 billion and O&M expenses averaging about $1.05 billion over the three-year alternative rate plan period.

I have accepted the company's proposed production expenses for the test year period and for each of the rate year periods. I have made adjustments to the O&M expenses, amounts the company has proposed to recover from ratepayers. In calculating my recommended O&M expenses for the test year, I have reviewed the company's historical expense data, 2019 to 2021, as well as forecasted and budget expenses data, to determine my O&M expense level.

My recommended O&M expense adjustment results in an overall annual reduction of about 15 percent or $161 million (on average) from the company's proposed O&M expense (on average) of $1.05 billion.

The O&M expenses areas in which I made adjustments to the company's proposed O&M expenses

are related to non-fuel O&M expenses: Labor adjustments, inflation adjustments, transmission expenses, distribution expenses, customer accounting expenses, customer service and information expenses, marketing expenses, and administrative and general expenses. I also made adjustments to the property taxes and property tax -- payroll tax rates.

I recommend that the Commission limit the approval of O&M expenses to those costs that reflect normal operating conditions. This means examining the company's O&M expenses to determine whether these O&M costs are recurring over time and from operating period to operating period.

When calculating my adjustments to the company's proposed O&M expenses, I reviewed whether any of the company's O&M expenses were nonrecurring or one-time costs. And in that instance, I either normalized the cost, amortized the cost, or did not include those costs prospectively. Normalizing or amortizing adjustments that are related to costs basically that are nonrecurring in nature and do not occur from year to year; i.e., rate case expenses, storm costs or extraordinary expenses.

The rationale for normalizing costs is that you spread the costs over the period that benefits the

expenses in order to prevent overcollection of rates. By not normalizing certain costs, there is a tendency to overcollect expenses in future periods.

One example in which I normalized costs was in the area of my adjustment to the vacancy rate. Given that the company is proposing to include an increase of 470 employees in the test year and through the rate year periods, I normalized this adjustment over the 2023-2025 period, allowing one-third in each of the rate years.

I also averaged out certain costs by taking the median or midpoint of the historical cost to determine or calculate the costs to be included in the test year. I also performed the same analysis when calculating my adjustments for the rate years.

I also determined whether such costs should be recovered consistently over the rate year, stabilization, or gradually over time.

The ultimate goal in setting rates -- utility rates to provide -- the ultimate goal in setting utility rates is to provide the ratepayer with safe and reliable service at reasonable rates, with the utility being provided the opportunity to earn a reasonable rate of return and to recover its known and measurable costs under the efficient and economic

management.

My adjustments to the company's proposed revenue -- proposed expenses will allow the company to recover all reasonable costs and strike an appropriate balance between ratepayers and the company.

MR. WALSH: Does that conclude your summary?

MR. MUGRACE: Yes.

MR. WALSH: Madam Chair, the witness is available for questions from the Commission and for cross-examination.

MADAM CHAIR PRIDEMORE: First, questions from Commissioners? Commissioner Echols.

VICE CHAIRMAN ECHOLS: Yes. By my calculation, your testimony and advice would save us $655 million for your recommendations.

MR. MUGRACE: Over the rate year --

VICE CHAIRMAN ECHOLS: Yes.

MR. MUGRACE: -- the test year and the rate years, yes.

VICE CHAIRMAN ECHOLS: Yes, that's $655 million here, a billion there. I mean, now we are seeing some substantial -- substantial opportunities.

Let me ask you, what did you -- you used the word "vacancy" just then, and I didn't quite

understand what you meant by "vacancy."

MR. MUGRACE: Usually at any point in time a company has a certain level of vacancy rates that they can't fill in because maybe there's a low -- low labor market or they just can't get the right people to fit into that position.

So the vacancy rates usually is a percentage of the total -- the total allowed spots in the company that they can fill in without getting any further approval.

VICE CHAIRMAN ECHOLS: Okay. In your testimony, you mentioned their innovation center as something where you felt like that should be really something under R&D, maybe something that Southern Company paid for.

Were you talking about The Innovation Center over at 75 Fifth Street at Tech Square? Is that the facility?

MR. MUGRACE: Not -- I think it was a general innovation center. It was in general.

VICE CHAIRMAN ECHOLS: I mean, they actually have a facility called The Innovation Center at Tech Square. And I wondered if you had -- you know, they're doing so much teleworking over there, I wonder, you know -- when you said vacancy, I was just

wondering, you know, how -- how much are we utilizing that facility or how many people are actually coming in to 75 Fifth Street in the Innovation Center and if ratepayers were paying for that. You know, is it really being utilized? I don't know how much longer is on the lease.

Did you look at -- you didn't look at that in specific, did you?

MR. MUGRACE: No, I did not.

VICE CHAIRMAN ECHOLS: And you mentioned the tree trimming. That was a part of your testimony.

You mentioned Southern Company Services. Did you drill down into employee travel, use of Southern Company Services' aircraft? Did you have any recommendation regarding that? Did you feel that any of that was out -- you know, out of -- out of whack, so to speak, and needed a reduction?

MR. MUGRACE: I did look at the aircraft and the number of hours that were used to provide the services that the company needed, but there was not a dollar amount attached to that, so I couldn't make an opinion or make an adjustment on that because there's no dollar amount. It was just hourly -- hourly -- hours used of the aircraft. But I didn't see anything out of the ordinary.

**VICE CHAIRMAN ECHOLS:** Okay. And other aspects of employee travel or anything like that? Did anything -- anything stand out there in your audit, so to speak?

**MR. MUGRACE:** No. Georgia is a big state, so I know they have to use commercial aircraft and other forms of transportation to get from point A to point B. I didn't see anything out of the ordinary.

**VICE CHAIRMAN ECHOLS:** All right. Thank you so much.

**MADAM CHAIR PRIDEMORE:** All right. Questions from Commissioners?

(No response.)

**MADAM CHAIR PRIDEMORE:** Let's start the list. Americans for Affordable Clean Energy?

**MR. GALLOWAY:** No questions, Madam Chair.

**MADAM CHAIR PRIDEMORE:** ChargePoint?

**MR. FYKES:** No, questions, Madam Chair.

**MADAM CHAIR PRIDEMORE:** Commercial Group?

**MR. JENKINS:** No questions.

**MADAM CHAIR PRIDEMORE:** EVgo Services?

**MR. VIJAYKAR:** No questions.

**MADAM CHAIR PRIDEMORE:** Georgia Association of Manufacturers?

**MR. CLAY JONES:** No questions.

**MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?**

**MS. BROWN: No questions.**

**MADAM CHAIR PRIDEMORE: Georgia Conservation Voters?**

**MS. OPIE: No questions.**

**MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light?**

**MS. KYSOR: No questions.**

**MADAM CHAIR PRIDEMORE: GASEIA?**

**MR. THOMASSON: No questions.**

**MADAM CHAIR PRIDEMORE: GA SOLAR?**

**MR. MORELAND: No questions.**

**MADAM CHAIR PRIDEMORE: Georgia Watch?**

**MS. COYLE: No questions.**

**MADAM CHAIR PRIDEMORE: Kroger?**

**MR. BOEHM: No questions.**

**MADAM CHAIR PRIDEMORE: MARTA?**

**MS. STURM: No questions.**

**MADAM CHAIR PRIDEMORE: Resource Supply Management?**

**MR. CLARKSON: No question.**

**MADAM CHAIR PRIDEMORE: Sierra Club?**

**MS. ARIZA: No questions.**

**MADAM CHAIR PRIDEMORE: SACE?**

MR. DOWDY: No questions.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association?

(No response.)

MADAM CHAIR PRIDEMORE: I think he is done for the day.

United States Department of Defense and all other Federal Agencies?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: Okay. Very good. Georgia Power.

MR. MARZO: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. MARZO:

Q Good afternoon, Mr. Mugrace.

A Good afternoon.

Q I am saying that correctly; right?

A Mugrace, yes.

Q We had a debate about that earlier this week, so I wanted to make sure I didn't mess your name up.

A No worries.

Q I want to ask you some questions about your recommendation. Now, you are presenting testimony today regarding the appropriate amount of O&M expenses. And this includes, as I think you discussed earlier,

transmission/distribution, customer accounting, customer service information, research and development and labor.

Is that likely part of...

A Yes.

Q And is your position that the O&M budgets proposed by Georgia Power Company in these areas do not reflect what is actually needed to provide safe and reliable service? Is that fair?

A Well, these are the forecasted amounts the company proposed for 2023 to 2025. I looked at historical data and see what costs the company incurred in prior periods and used that to trend my adjustments going forward. So since most of this is forecasted data, there is a measure of interpretation on how to reflect what should be included going forward. So what the company proposed, to me, is an overestimate, going forward.

Q Okay.

A Based on prior costs.

Q And I guess what I am asking, Mr. Mugrace, if -- in your example, if you make a cut to a budget, and there are budgeted activities that the company believes are important in order to provide safe reliable service, you are then making a determination that the company doesn't need those funds to provide that service; correct?

MS. OPIE: I make a determination of whether or

not it should be in the normal day of operations and provide service to the customer, yes.

Q Okay. And, Mr. Mugrace, you don't have an engineering degree; correct?

A No, I do not.

Q And you have never managed a transmission system of a utility; correct?

A No, I did not.

Q You never managed a distribution system of a utility; correct?

A No.

Q And you've never managed the generation assets of a utility; is that right?

A No.

Q And, in fact, you never worked in transmission, distribution, or generation, operations functions of a utility; is that correct?

A Correct.

Q Now, you propose a substantial reduction to the company's O&M budgets and you just discussed that with Commissioner Echols. And you stated that you arrived at the conclusion that the company's test year and three-year forecast of O&M expenses for 2023, 2024, and 2025 are not intended to provide safe and reliable service for customers by reviewing the company's historical and forecasted

expenses. Is that correct?

A Yes.

Q Okay. And when you say you reviewed the company's historical expense data as well as the company's forecasted data to make that determination, we are talking about the historical years of 2019, 2020, 2021?

A Yes. That was in response to a data request. I think it was PIA 7.1.

Q Okay. And that's the historical data that you looked at, was my question?

A Yes.

Q Okay. And in making your recommendation in adjustments for the majority of the company's O&M accounts, you used the historical expense data and calculated an average, which was the basis of your recommendation -- recommended adjustment? Is that fair?

A Yes.

Q Okay. And essentially, just to be clear, you identified specific FERC accounts that showed -- I think you used the term "variations or fluctuations," as you termed them. From year to year, you looked at those variations and fluctuations and you made the determination to average those accounts?

A Yes, when needed.

Q Okay. And now are you aware that the company

has provided variance explanations for the FERC accounts that you averaged, described in the test year variations in exhibits provided by Mr. Abramovitz, Ms. Adams, Mr. Robinson, Mr. Houston?

A I think I looked at them, yes.

Q Okay. And so, for example, if you reviewed those exhibits, those exhibits gave you detail as to the drivers for the increases in the O&M budgets by function; correct?

A Yes.

Q Okay. And for example, I think on page 11 of your testimony -- and I'm just using this as one example -- you refer to Account 581, which relates to load dispatching. If you want to get there -- do you need to get there, Mr. Mugrace?

A Number 11, Account 581, yes.

Q Yes, page 11, line 22 through 24 is what I am quoting. And you state that fluctuation in this account occurs depending upon the year-to-year activities and any construction going on, including emergency purposes.

Do you see that?

A Yes.

Q Now, if fluctuations are caused by year-to-year activities, isn't it important to understand what those year-to-year activities are and their timing before

determining a simple averaging approach?

A In some instances, yes. But you can look at the numbers and you can see where it's trending, up or down, or it's varying from year to year.

Q Okay. And I guess my question, Mr. Mugrace, is that in each of these budgets, there are activities that build out these budgets.

Before you make an averaging sort of cut to those budgets, isn't it important to understand what the underlying activities are that you are cutting?

A Yes. Or adjusting. Because I adjust up or down.

Q Okay. And in this case, is it fair to say you didn't do that, or at least you didn't provide any explanation as to what activities you thought were not necessary to perform when making your adjustments in your testimony?

A I basically took, like, a threshold of what I should look at. If they fluctuated very little, I wouldn't make any adjustments. But if they fluctuate, like, over a million dollars or $2 million, there is some activity there that doesn't go on from year to year. There is fluctuations. So to stabilize the rates for ratepayers, I took a three-year average.

Q And I guess my point is, Mr. Mugrace, you

didn't do an analysis of the specific operations that the company was going through in those particular budgets. You just simply decided: I've seen fluctuations in one year, I have seen fluctuations in another year. Let me just average that out to smooth it over.

But would you agree with me that there are activities that are occurring in a particular year; it's important to understand that?

MR. WALSH: Madam Chair, I would just ask -- the witness -- I'm sorry -- counsel characterized what he viewed the witness did without asking the witness if that was a fair characterization.

And he just moved on. He said: You simply did this. I would ask if the witness could speak to whether he agreed.

MR. MARZO: I just spent the first 15 minutes asking him what he did.

MADAM CHAIR PRIDEMORE: Would you agree that he described your statement accurately?

MR. MUGRACE: Yes. I looked at --

MADAM CHAIR PRIDEMORE: Okay.

BY MR. MARZO:

Q And I want to be fair to you, Mr. Mugrace. If I mischaracterize something, please let me know.

A I looked at all the line items that were

responded to in PCMG 1-7. I looked at all the line items for all the four years. And I just made a determination -- a determination, interpretation of what I believe which costs are fluctuating and should be adjusted.

Q Okay. And you just simply looked at the budgets and historical span; right?

A Yes. Based on the evidence that's been provided to me.

Q Okay. So if you -- for example, if you are going to make cuts to transmission and distribution and you are going to make a determination that those dollars are not needed to reliably serve customers, would you agree with me that it might be important to speak to people like Mr. Mike Robinson, who is the VP of Planning Operations and Policy for Georgia Power, to determine if there were expenses that could be deferred or delayed?

A I didn't -- I didn't take that into consideration. I just looked at what the evidence was provided to me through discovery.

Q Okay. But am I correct that the PIA staff has discovery rights? Correct?

A Yes.

Q Okay. The PIA staff can ask for specific information about details in our annualized budgets and rate cases; correct?

A Yes.

Q And PIA staff can ask to speak to specific people at the company; correct?

A Correct.

Q And they do indeed do that and they have done that in this case; is that correct?

A Correct.

Q Now, did you schedule any visits to the company to review transmission distribution plans in coming to your recommendation?

A No.

Q And in coming to your transmission recommendation, did you meet with Chris Caldwell, VP of transmission?

A No.

Q Did you meet with John Cornelius, VP of distribution?

A No.

Q Did you examine any cost projections?

A Well, whatever was provided to me in discovery.

Q Okay. Just that. Now, did you question what the costs you recommended reducing through averaging, were specifically related to in transmission distribution?

A (The witness reviewing document.)

I averaged out in the test year -- for

transmission, I averaged out costs in Account 566, 569, 570, and 571.

And for distribution, I averaged out accounts in 581, 582, 583, 586, -87, -88, -90 through -94 and -96. Those show the most fluctuations in the test year. Prospectively, there was less fluctuations in the rate years 2023, 2024, so I didn't average out as much as I did in the test year.

Q And I know that obviously for the purposes of rate cases, we have to refer to things and things are accounted for as FERC accounts. But I guess more specifically, my question to you, Mr. Mugrace, is that underlying each of those FERC accounts are specific activities.

And perhaps this is a better question: Did you inspect, for example, the company's transmission and distribution right-of-ways to determine how much more vegetation management could be cut back in a given year?

A I didn't take that into consideration.

Q All right. So do you have any analysis -- and I think you've -- I won't ask that, because I think you've already answered that one. You don't have any -- well, let me just ask it now, to put it on record.

Do you have any analysis regarding things like vegetation management and any specific activities in those

accounts?

A Just what the company provided to me in discovery.

Q Now, you similarly used, as we talked a bit ago, this averaging approach for tree trimming.

Were you here earlier during the testimony of staff's transmission distribution witness panel?

A Yes.

Q And so you made cuts to tree trimming. Did staff talk about that, whether or not that's consistent with their position on transmission distribution in this case?

A I believe so.

Q Okay. And they still thought it was appropriate to cut tree trimming?

A To maintaining tree trimming levels.

Q Now, in the process of coming to your recommendation in this case, did you bother to review the process that was utilized by the company to develop its O&M budgets?

A No, I did not, no.

Q Okay. So it's fair to say you didn't articulate any criticisms to the company's budgeting process; correct?

A No, I didn't criticize that, no.

Q Now, in preparing your prefiled testimony

recommendations, did you review prior rate case decisions from this Commission?

A No, I did not.

Q Okay. And is it -- let me ask this: And in any of those prior decisions, did the Commission ever adjust the company's O&M requests based on averages?

A I was -- I am unaware of that.

Q Now, your historical average is based upon the company's operations in 2019 and 2020 and 2021.

Is it your position that the year 2019 through 2021 were normal years for the purposes of averaging certain O&M expenses?

A Well, COVID existed between the late part of 2019 to 2021. But the company still had to provide services to operate the utility. The electrical grid.

Q So it's your opinion that the COVID-19 pandemic had no material effect on the usage patterns and electric consumption of the company's customers?

A It could. But it still should average out the cost to see -- to stabilize the rate going forward. In 2022, coming out of it in 2023, you should be up to full activity. That's only a one-year outlier. But I still had to include that because the company was still -- the company still had to provide service to its customers regardless of what incident occurred in 2020.

**Q So is it your testimony that the COVID-19 pandemic affected your life for one year?**

**A Well, no. It affected our lives for multiple years, but we still have to move forward. And now we have to be mindful of that and things were disrupted in 2020, but we still had to work remotely. We still had to provide the service. We still had to make a paycheck. And the utility still had to provide safe and reliable service under those circumstances.**

**Q So, Mr. Mugrace, can we agree that the Commission -- well, let me say this: You understand, obviously, the company doesn't agree with your averaging approach; correct?**

**A I assume that.**

**Q Okay. Could we agree that the Commission can also, in looking at your averaging approach, determine that the three years that you determined that were important for averaging were also years that, for all intents and purposes, were unique due to the COVID pandemic?**

**A The company can accept, reject or modify my position, yes.**

**Q Now, Mr. Mugrace --**

**A The Commission can.**

**Q Yeah. The company would like to as well, but I understand.**

A The company can accept, reject, or modify and the Commission can accept, reject, or modify. Or --

MADAM CHAIR PRIDEMORE: Mr. Marzo, do not start doing our job now.

MR. MARZO: What I say doesn't matter here.

What you say, absolutely. What you and the commissioners say does.

BY MR. MARZO:

Q Mr. Mugrace, did you review the company's Integrated Resource Plan that the Commission approved on July, 29, 2022?

A No, I did not.

Q And at the end of page 17 of that order, there is a discussion about the DSM budgets that will be approved by -- that were approved by this Commission.

Are you aware of that?

A I was aware of that.

Q Okay. Did you discuss this adjustment with Staff Witness Barber, your adjustment to DSM, who is responsible for overseeing the company's DSM activities?

A If it is -- not specifically, but through e-mails we discussed what adjustments should be made to the DSM -- the customer -- customer service and information adjustments.

Q So are you aware that the DSM budget was

approved in the IRP?

A Yes, I am aware of that.

Q And did you know that the company's expense is based on what was approved in the IRP?

A Yes.

Q And is it your recommendation that the Commission increase these DSM expenses at a 5 percent increase to the three-year average, rather than just implement the DSM budgets that were approved by the Commission?

MS. OPIE: I am recommending a 5 percent increase from year to year. Because it looks like the company's increase was about a 33 percent over previous levels. So I am recommending a 5 percent going forward.

Q Well, do you understand, based upon this discussion, that the company's budgets on DSM were driven by what this Commission had ordered the company to do?

A Yes, I am aware of that.

Q Okay.

A It is an alternative.

Q Is it an alternative to not act in --

A It is an alternative that I am recommending at a 5 percent rather than a 33 percent. It's whatever -- it's a 5 percent increase rather than a 33 percent. It's my

recommendation.

Q Okay. Well, you understand that the company doesn't have the option not to do what the Commission tells it to do?

A They are directives, I understand that.

Q Okay. Now, Mr. Mugrace, on page 9 of your testimony, you say that you removed the labor costs that were included in each of the accounts that proposed -- that you proposed to reduce as shown in response STF-LA 2-72.

Do you see that?

A Yes.

Q And you say -- and you utilized a non-labor cost to average out these expenses for 2019 to 2021, and you did that with all the averaging adjustments; correct?

A I did. So as not to overlap any other adjustments or be duplicative of my adjustments.

Q Now, although the company, as I mentioned earlier, disagrees with your methodology, let me show you STF-LA-2-72 that you referred to.

MR. MARZO: Madam Chair, my I approach?

MADAM CHAIR PRIDEMORE: You may approach.

MR. MARZO: Madam Chair, I would like to mark STF-LA-2-72 as Georgia Power Exhibit 38.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for

identification as Georgia Power Exhibit 38.)

MR. MARZO: Thank you.

BY MR. MARZO:

Q Mr. Mugrace, I will let you have a chance to look at that and then ask you some questions.

And you just let me know when you're ready.

A I'm ready.

Q Okay. Mr. Mugrace, now, LA-2-72, which you referred to in your testimony for your labor adjustment, am I correct that this is, in fact, referring to contract labor?

A Yes.

Q Okay. And it was your intent to adjust for contract labor?

A No, it was not my intent. I have accepted a contract labor. What I did is if I took an overall three-year average of the total cost, there is contract labor embedded in that expense.

So if I averaged it out, I will be averaging out contract labor, too, which I am not adjusting. So what my goal was to take the non-labor expense and average that out.

Q Okay. So -- and maybe my question is: Did you accomplish your goal? Because it appears, from my reading of your testimony, that you used the information provided to

you in LA-2-72, which is the contract labor information; correct?

A I used that.

Q Okay.

A I used the accounts of those contract labors to correlate with my adjustments to various expenses.

Q Okay. And it's your testimony that that was what you intended to do?

A That was my intent.

Q Okay. So you didn't intend to actually use the numbers that related to the company's actual employees, not the contract labor?

A Whatever the balance was in each of these test-year periods, that's what I used. The total is on page 3 of 3. Total contract labor O&M. That's all contract labor.

Q And it's our understanding -- I guess this is more of a clarification question, is, it was my understanding in looking at your testimony that your intended adjustment would have been to actual noncontract labor, or the company's labor. But you're saying that you intended contract labor?

A Yes.

Q Okay. And so you adjusted out the company's ordinary labor?

A It's whatever the balances are shown on STF LA 2-72. I took each of the individual FERC accounts and lined them up with my adjustments that I recommended in those FERC accounts, subtracted it, and then averaged it out. Subtracted out the contract labor and averaged out the non-labor expense.

Q Now, did you remove payroll taxes from that as well?

A No.

Q Okay. Well, Mr. Mugrace, that's all the questions I have for you. I appreciate your time.

Madam Chair.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Marzo.

Redirect?

MR. WALSH: Very briefly. Thank you, Madam Chair.

REDIRECT EXAMINATION

BY MR. WALSH:

Q Mr. Mugrace, you were asked if you met with numerous company employees. Do you recall those questions?

A Yes.

Q Okay. But those employees, to your knowledge, did the company present them as witnesses in this case to present their -- and support their case?

A I think in the first day of hearings, those --

just those employees that filed direct testimony the first -- the first day. Abramovitz -- that panel.

Q Okay. And did you --

MR. MARZO: Madam Chair, just for the record, I would like the record to speak for itself.

Mr. Robinson, one of the people asked for, who was a transmission distribution discussion that I took the witness through, he was, in fact, a witness in this case.

MADAM CHAIR PRIDEMORE: It's on the record.

BY MR. WALSH:

Q And did you review the testimony of Mr. Robinson that he presented in the case?

A Just what Exhibit APA/SPA/ADH/MBR, that testimony. Those four witnesses. I reviewed that.

Q Okay. Thank you.

And you were also asked about whether you worked in -- held positions in distribution, generation, or transmission. Do you recall those questions?

A Yes.

Q Okay. Why is it your position that you are able to support your recommendations without having held any of those jobs?

A The numbers speak for themselves. I review the historical data. It is all numbers. I am accountant. I

reviewed any fluctuations and variations from year to year based on the FERC account line items. It is all numbers.

Q Thank you.

MR. WALSH: That's all the redirect I had, Madam Chair.

I would ask that Staff Exhibits 59 through 61 -- 59 through 61 be admitted into evidence and that the witness be excused.

MADAM CHAIR PRIDEMORE: So marked. Mr. Marzo?

(Staff Exhibits 59 through 61 were admitted into evidence.)

MR. MARZO: Madam Chair, I didn't move my exhibits with Mr. Walsh's earlier witness. I ask those be moved in, and I also ask my exhibit with Mr. Mugrace be moved into the record.

MADAM CHAIR PRIDEMORE: Let's move both sets in. So moved.

(The documents referred to were admitted into evidence as GPC Exhibits 37 and 38.)

MADAM CHAIR PRIDEMORE: You are excused, Mr. Mugrace. Good to see you.

MR. MUGRACE: Thank you.

Okay. Next panel, Jamie Barber, Benjamin Deitchman, Glenn Watkins.

MR. THOMAS: Good afternoon, Madam Chair. At

this time I would like to call the panel of Jamie Barber, Benjamin Deitchman, and Glenn Watkins.

Thereupon,

JAMIE BARBER,
BENJAMIN DEITCHMAN,
GLENN WATKINS,

having been duly sworn, testified as follows:

MR. THOMAS: You may be seated.

DIRECT EXAMINATION

BY MR. THOMAS:

Q Ms. Barber, I would like to start with you. Can you please state your full name, by whom you are employed, and your responsibilities for the record.

A (Witness Barber) Jamie Barber, the Georgia Public Service Commission. I'm the director of the Energy Efficiency and Renewable Energy Unit.

Q Mr. Deitchman, same question.

A (Witness Deitchman) I am Benjamin Deitchman. I work for the Georgia Public Service Commission. I am a utilities analyst in the electric unit.

MADAM CHAIR PRIDEMORE: Benjamin, pronounce your last name.

MR. DEITCHMAN: Deitchman.

MADAM CHAIR PRIDEMORE: Deitchman. I want to do a better job. Thank you.

BY MR. THOMAS:

Q Mr. Watkins, same question.

A (Witness Watkins) Yes. My name is Glenn Watkins. I am president and senior economist of Technical Associates, Incorporated, which is a consulting economics and finance firm.

Q Ms. Barber, on October 20th of this year, did you file or cause to be prefiled 103 pages of testimony in question-and-answer format, along with 21 exhibits marked as BBW 1 through 21, in both trade secret and public disclosure format?

A (Witness Barber) Yes.

Q Do you have any corrections you need to make to your testimony at this time?

A (Witness Watkins) Yes. We have one typographical error I would like to correct. And that's on page 60, line 6. And the first word "collected" should say "collective." That's the only correction we have.

Q Thank you, Mr. Watkins.

And with that correction, if I were to ask you the same questions today under oath, would your answers be the same as set forth in your prefiled testimony?

A (Witness Barber) Yes.

MR. THOMAS: Madam Chair, the court reporter has been provided with a copy of the prefiled direct testimony, and I would ask that the direct testimony

be copied into the record as if given here today. And I would ask that Exhibits BW 1 -- BW 1 through BD -- I'm sorry BDW 1 through BDW 21 be marked for identification purposes as Staff Exhibits 62 through 82, and that the trade secret testimony and trade secret exhibits be marked as one exhibit, Staff Exhibit 83.

MADAM CHAIR PRIDEMORE: So moved, so marked. So moved.

(Whereupon, the prefiled direct testimonies of Jamie Barber, Benjamin Deitchman, and Glenn A. Watkins follows:)

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the Matter of:** | **)** | |
| **GEORGIA POWER COMPANY'S** | **)** | **DOCKET NO. 44280** |
| **2022 RATE CASE** | **)** | |

# JOINT DIRECT TESTIMONY

# AND EXHIBITS

# OF

**JAMIE BARBER,**

**BENJAMIN DEITCHMAN,**

**AND**

**GLENN A. WATKINS**

**ON BEHALF OF THE**

**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

## PUBLIC DISCLOSURE

**OCTOBER 20, 2022**

**PUBLIC DISCLOSURE**

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## LIST OF EXHIBITS

| Staff Exhibit # | | Description |
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| Staff Exhibit __ (BDW-1) | – | Resume of Jamie Barber |
| Staff Exhibit __ (BDW-2) | – | Resume of Benjamin Deitchman |
| Staff Exhibit __ (BDW-3) | – | Resume of Glenn A. Watkins |
| Staff Exhibit __ (BDW-4) | – | Base-Intermediate-Peak Classification – Trade Secret |
| Staff Exhibit __ (BDW-5) | – | Base-Intermediate-Peak CCOSS Summary w/Vogtle 3 |
| Staff Exhibit __ (BDW-6) | – | Base-Intermediate-Peak CCOSS Summary w/o Vogtle 3 |
| Staff Exhibit __ (BDW-7) | – | Probability of Dispatch CCOSS Summary w/Vogtle 3 |
| Staff Exhibit __ (BDW-8) | – | Probability of Dispatch CCOSS Summary w/o Vogtle 3 |
| Staff Exhibit __ (BDW-9) | – | Staff Direct Customer Cost Analysis |
| Staff Exhibit __ (BDW-10) | – | Georgia Power Exhibit ___ (AF-2) from 2019 Rate Case |
| Staff Exhibit __ (BDW-11) | – | Typical Weekday & Weekend Hourly Loads (January) |
| Staff Exhibit __ (BDW-12) | – | Typical Weekday & Weekend Hourly Loads (July) |
| Staff Exhibit __ (BDW-13) | – | Income Qualified Report |
| Staff Exhibit __ (BDW-14) | – | Current Renewable and Non-Renewable Tariff |
| Staff Exhibit __ (BDW-15) | – | Community Solar Participation Chart |
| Staff Exhibit __ (BDW-16) | – | Company Response to STF-DEA-2-11 |
| Staff Exhibit __ (BDW-17) | – | Company Response to STF-PIA-6-44 |
| Staff Exhibit __ (BDW-18) | – | Company Response to STF-TAI-1-46 |
| Staff Exhibit __ (BDW-19) | – | Company Response to STF-TAI-1-47 |
| Staff Exhibit __ (BDW-20) | – | Company Response to STF-PIA-6-40 |
| Staff Exhibit __ (BDW-21) | – | Company Response to STF-TAI-1-40 |

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.**

A. Our names are Jamie Barber and Benjamin Deitchman, 244 Washington, Street, SW, Atlanta, Georgia 30334 and Glenn A. Watkins, 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

**Q. MS. BARBER PLEASE STATE YOUR TITLE, EMPLOYER, EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. I am the Director of the Energy Efficiency and Renewable Energy Unit for the Georgia Public Service Commission ("Commission"). My educational background and work experience are provided in my resume, which is attached as Staff Exhibit __ (BDW-1).

**Q. MR. DEITCHMAN PLEASE STATE YOUR TITLE, EMPLOYER, EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. I am a Utilities Analyst for the Commission. My educational background and work experience are provided in my resume, which is attached as Staff Exhibit __ (BDW-2).

**Q. MR. WATKINS WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?**

A. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by

Technical Associates continuously since 1980. During my 42-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of my education and experience is provided in Staff Exhibit __ (BDW-3).

**Q. MS. BARBER, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Yes. I testified in each of the 1998 through 2009 United Cities Gas Company (now known as Atmos Energy Corporation) Gas Supply Plan Proceedings. I also testified in Docket No. 10270, GPSC Determination of Lack of Market Constraints on Atlanta Gas Light Company's Commodity Sales; Docket No. 11114, Rule Nisi Against United Gas Management of Georgia, Inc.; Docket No. 14311, Earnings Review to Establish Just and Reasonable Rates for Atlanta Gas Light Company; Docket No. 15296 Service Quality Standards for Certified Marketers and Regulated Provider; Docket No. 18638-Atlanta Gas Light Company's 2004/2005 Rate Case; Docket No. 20298 Atmos Energy Corporation's 2005 Rate Case; Docket No. 27163 Atmos Energy Corporation's 2008 Rate Case; Docket No. 30442 Atmos Energy's 2010 Rate Case; Docket No. 36498 Georgia Power Company's

2013 IRP Filing; Docket No. 36499 Georgia Power Company's 2013 Demand Side Program Certification; Docket No. 37854, Georgia Power Company's Application for the Certification of the Power Purchase Agreements for Wind Resources from the Blue Canyon II and Blue Canyon VI Wind Farms; Docket No. 38877, Georgia Power Company's Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements, Docket No. 36989 Georgia Power Company's 2013 Rate Case, Docket No. 40161 Georgia Power Company's 2016 IRP Filing, 40162 Georgia Power Company's 2016 Demand Side Program Certification, Docket No. 41596, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements, Docket No. 41734, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements for the Commercial and Industrial Program, Docket No. 43210 Georgia Power Company's 2019 IRP Filing, Docket No. 43211 Georgia Power Company's 2019 Application for the Certification, Decertification, and Amended Demand-Side Management Plan, Docket No. 42516 Georgia Power Company's 2019 Rate Case, Docket No. 44160 Georgia Power Company's 2022 Integrated Resource Plan and Docket No. 44161 Georgia Power Company's Application for the Certification, Decertification and Amended Demand Side Plan.

**Q. MR. DEITCHMAN, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Yes. I testified in the 2019 Georgia Power Company Rate Case, Docket No. 42516.

**Q. MR. WATKINS, HAVE YOU APPEARED BEFORE THIS COMMISSION ON PREVIOUS OCCASIONS?**

A. Yes. I appeared as a witness on behalf of the Commission Public Interest Advocacy ("PIA") Staff ("Staff") in Georgia Power Company's ("Georgia Power" or "Company") general rate cases during 2007, 2010, and 2013. Furthermore, I provided testimony on behalf of the Staff many years ago in a Savannah Gas and Electric case.

**Q. PLEASE DESCRIBE THE ISSUES THAT EACH WITNESS WILL BE RESPONSIBLE FOR ADDRESSING.**

A. Mr. Watkins will address class cost of service study ("CCOSS"), revenue allocations and specific rate design issues. Ms. Barber will address proposed changes to the Community Solar "CS"), Renewable and Non-Renewable ("RNR"), and Simple Solar ("SS") tariffs, and the panel will address the Company's request for modifications to existing tariffs, request to eliminate tariffs, approval of a new tariff, proposed changes to its Rules and Regulations, and other tariff-related issues.

## II. CLASS COST OF SERVICE

**Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CCOSS AND ITS PURPOSE IN A RATE PROCEEDING.**

A. Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of this Commission, Georgia Power has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Most of the costs are jointly incurred to serve all or most customers; therefore, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent

practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy usage, number of customers, etc.

**Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?**

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to some costs.

**Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?**

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to the Federal Energy Regulatory Commission ("FERC")), the United States ("US") Supreme Court stated:

> "But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

**Q. DOES YOUR OPINION AND THE FINDINGS OF THE U.S. SUPREME COURT IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?**

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of cost allocation approaches show dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

[1] 324 U.S. 581, 65 S. Ct. 829.

**Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF GEORGIA POWER'S CCOSS.**

A. In conducting Staff's independent analysis, Mr. Watkins reviewed the structure and organization of the Company's revised CCOSS[2] and reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, Georgia Power's selection of allocators to specific rate base, revenue, and expense accounts was examined. Finally, the accuracy of Georgia Power's revised CCOSS model was verified by replicating its results using Mr. Watkins' own computer model.

**Q. DID YOU FIND THE COMPANY'S REVISED STUDY TO BE MATHEMATICALLY ACCURATE?**

A. Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, Company Witness Lee Evans' revised CCOSS was found to be mathematically accurate and was replicated with Mr. Watkins' computer model.

[2] On September 28, 2022, the Company provided notice that it had discovered a minor error in its original CCOSS relating to the assignment of revenues across rate schedules. Subsequently, on October 4, 2022, the Company provided its revised CCOSS to Staff.

## A. Allocation of Generation Plant

**Q. BEFORE YOU DISCUSS THE SPECIFICS OF THE COMPANY'S PROPOSED METHOD TO ALLOCATE GENERATION RELATED COSTS, PLEASE EXPLAIN THE COST CAUSATION CONCEPTS RELATING TO THESE RESOURCES.**

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (load) throughout the year, there would be no disagreement as to the proper assignment of generation related costs. All analysts would agree that energy usage in terms of kilowatt-hour ("kWh") would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that Georgia Power experiences periods (hours) of higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system.

To further complicate matters, the electric utility industry is somewhat unique in that there is a distinct energy (variable cost)/capacity (fixed cost) trade-off relating to production costs. That is, utilities design their mix of production facilities to minimize the total costs of variable energy and fixed capacity, while also ensuring there is enough available capacity to meet peak demand requirements. The trade-off occurs between the level of fixed investment per unit of capacity kilowatt ("kW") and the variable cost of producing a unit of output (kWh). Nuclear and coal units require high capital expenditures resulting in large investments per kW of capacity but operate very efficiently such that their variable running costs per kWh are very low. Conversely, combustion turbine units are relatively inexpensive to build per kW of capacity but are much less efficient and incur significantly higher variable running costs per kWh of output. Due to varying levels of demand placed on a utility's system over the course of each day, month, and year, there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its total cost of service.

The investment (capacity) costs of generation facilities are fixed in nature and are considered sunk investment costs. At the same time, the energy cost of running generation plants tends to be almost all variable in nature such that base load units tend to have low variable running costs whereas peaking units tend to have much higher variable running costs per kWh. As a result, generation assets tend to be dispatched based upon the variable running costs of each unit wherein lower variable cost units are dispatched before higher cost units. As such, total system production costs vary each hour of the year.

**Q. APPROXIMATELY HOW MANY COST ALLOCATION METHODOLOGIES EXIST RELATING TO THE ALLOCATION OF GENERATION PLANT?**

A. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[3]

**Q. BRIEFLY DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON GENERATION COST ALLOCATION METHODOLOGIES.**

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

**Single Coincident Peak ("1-CP")[4] --** The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

[3] Principles of Public Utility Rates, Second Edition, page 495.
[4] Coincident Peak is defined as each class's contribution to peak demand at the time (coincident) of the system peak.

However, the 1-CP method has several shortcomings. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, under this method, the sole criterion for assigning one hundred percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as Georgia Power had a peak load of 14,000 megawatts ("MW") and its actual optimal generation mix included an assortment of nuclear, coal, combined cycle, combustion turbine natural gas units, hydro, and solar, the total cost of capacity is significantly higher than if the utility only had to consider meeting 14,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year. This major shortcoming of the 1-CP method is readily apparent for Georgia Power.

Georgia Power is currently constructing two new nuclear units (Vogtle Units 3 and 4) wherein the capital (rate base) cost associated with these two units are the highest of any generation units ever built (in terms of cost per kW of capacity), these two units were planned, designed, and are being built to provide very low cost energy throughout the year for decades into the future. Clearly, Vogtle 3 and 4 are not being built simply to meet peak load, but rather, to serve energy needs throughout the year due to their expected low

variable running costs. Under the 1-CP method, the cost of Vogtle 3 and 4 would be allocated across classes based only on peak demand with no recognition of the reality that these units are not being built to meet peak load requirements but rather serve energy loads throughout the year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because streetlights are not on at this time of day, this class will not be assigned any capacity costs and will, therefore, enjoy a “free ride” on the assignment of generation costs that this class requires.

**4-CP** -- The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

**Summer and Winter Coincident Peak (“S/W Peak”)** -- The S/W Peak method was developed because some utilities’ annual peak loads occur in the summer during some years and in the winter during others. Because customers' usage and load characteristics

may vary by season, the S/W Peak attempts to recognize this. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method and is no more reasonable than the 1-CP or 4-CP methods.

**12-CP --** Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities than does the 1-CP or 4-CP methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

**Peak and Average ("P&A")** -- The various P&A methodologies rest on the premise that a utility's generation facilities are designed and placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between peak and average demands should be performed, most electric P&A studies use class contributions to coincident-peak demand for the "peak" portion, and weight the peak and average loads based on some arbitrary factor such as system coincident load factor.

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the P&A method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly

by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

**Average and Excess ("A&E")** -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak ("NCP") demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under the 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a "free-ride" under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods.

**Base/Intermediate/Peak ("BIP")** -- The BIP method is also known as a production stacking method that explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility's resources used to serve the varying demands throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors tend to run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy related (e.g., run of the river), peak related (e.g., pumped storage) or a combination of energy and demand related (traditional reservoir storage).

Finally, wind and solar generating facilities may only produce energy when environmental conditions are present; i.e., wind or sunshine. As a result, their reliability factors are such that they may not be relied upon to meet peak loads at all times. For example, many utilities experience peak demands in the early morning and evening hours when there is either no sunlight present or minimal sunlight available for solar generation. While wind and solar provides capacity during the middle of the day when system loads tend to be increasing, it is reasonable to classify these generation resources as partially demand related and partially capacity related. As such, wind and solar generating units are classified as 50% energy related and 50% demand related.

The potential weakness of the BIP method is the same as under other methods where no recognition is given to lower variable fuel costs during off-peak periods. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the BIP method will produce fair and reasonable results.

**Probability of Dispatch** -- The Probability of Dispatch method is the most theoretically correct as well as the most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year (8,760 hours). Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units

which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only those few peak hours. The hourly capacity costs for each generating asset are summed to develop hourly investment cost responsibilities. These hourly investments are then assigned to individual rate classes based on class contributions to system load for each hour of the year. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed load studies encompassing each hour of the year (8,760 hours).

**Q. YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?**

A. Yes. The 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than

in reality, but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

**Q. CAN YOU PROVIDE EXAMPLES OF THE ENERGY/CAPACITY TRADEOFF SPECIFIC TO GEORGIA POWER?**

A. Yes. Consider Vogtle Units 1 and 2 which are base load units that run almost continuously throughout the year and have a combined Georgia Power owned capacity of 1,110.5 MW[5]: the Company's gross investment in these units is $3.580 billion, which equates to a capacity cost of $3,224 per kW.[6] However, these generating units operate very efficiently with a forecasted fuel cost of [redacted] per kWh of output.[7] At the other extreme, consider McIntosh Combustion Turbine Unit 1 which is a peaker unit that only operates a few hours a year and has a capacity of 101 MW[8]: the Company's gross investment in this unit is $34.797 million, which equates to a capacity cost of only $343 per kW.[9] This unit is much less efficient and operates with an average forecasted fuel cost of [redacted] per kWh of output.[10]

[5] Per response to STF-TAI-1-5.
[6] *Id.*
[7] Per Confidential response to STF-TAI-1-14.
[8] Per response to STF-TAI-1-5.
[9] *Id*.
[10] Per Confidential response to STF-TAI-1-14.

**Q. PLEASE EXPLAIN WHY THE ENERGY/CAPACITY TRADEOFF OF GENERATION RESOURCES IS PARTICULARLY IMPORTANT AS IT RELATES TO THE PROPER ALLOCATION OF GEORGIA POWER'S PORTFOLIO OF GENERATION ASSETS.**

A. Georgia Power has a large and diverse portfolio of generation assets including base load nuclear and natural gas combined cycle units, large coal units, pumped storage units, hydro facilities, solar facilities, and gas/oil peaker units. As shown in the following table, the vast majority of Georgia Power's net investment in generation plant is associated with large nuclear, natural gas, and coal generating units that have high fixed investment costs and relatively low variable operating costs and operate to serve load throughout the year (85.61%). At the other extreme, Georgia Power's portfolio of peaker units that only operate a few hours of the year to meet peak load is very small in terms of its overall net investment in generation plant (0.99%).

TABLE 1
Georgia Power Portfolio of Generating Assets
($ Millions) [11]

| Type | Net Investment | % of Total |
|---|---|---|
| Nuclear[12] | $1,959.3 | 20.05% |
| Natural Gas Combined Cycle | $2,467.6 | 25.25% |
| Coal | $3,938.5 | 40.31% |
| Natural Gas Intermediate | $168.7 | 1.73% |
| Oil/Gas Peakers | $203.2 | 2.08% |
| Hydro | $360.0 | 3.68% |
| Pumped Storage | $96.5 | 0.99% |
| Solar | $577.9 | 5.91% |
| Total | $9,771.7 | 100.00% |

[11] Per response to STF-TAI-1-5.
[12] Excludes $4.4 billion of estimated Vogtle Unit 3 investment. Per response to STF-TAI-1-5.

**Q. WHAT GENERATION COST ALLOCATION METHODOLOGY DID MR. EVANS UTILIZE WITHIN HIS RECOMMENDED CCOSS?**

A. Mr. Evans' recommended CCOSS employs the 12-CP method to allocate generation plant costs.

**Q. DID MR. EVANS ALSO CONDUCT A CCOSS UTILIZING AN ALTERNATIVE METHODOLOGY TO ALLOCATE GENERATION PLANT?**

A. Yes. Mr. Evans also conducted a CCOSS utilizing the 4-CP approach to allocate generation plant. However, as noted on page 4, lines 9 through 11 of his Direct Testimony, Mr. Evans specifically indicates that he does not recommend this study or approach.

**Q. PLEASE PROVIDE A SUMMARY OF THE RESULTS OBTAINED UNDER MR. EVANS' 12-CP AND 4-CP GENERATION ALLOCATION METHODS.**

A. The following table provides a summary of each rate schedule's rate of return ("ROR") and indexed ROR[13] under the 12-CP and 4-CP methods:

[13] Indexed RORs measure a rate schedule's profitability relative to the system average ROR. For example, if a class has an absolute ROR of 6.00% and the system average ROR is 6.25%, that class's indexed ROR is 96%.

TABLE 2
Rate Schedule RORs & Indexed RORs at Current Rates
(12-CP & 4-CP Methods)

| | | ROR | | Indexed RORs | |
|---|---|---|---|---|---|
| Rate | Class | 12-CP | 4-CP | 12-CP | 4-CP |
| R, RM | DOM | 5.26% | 5.11% | 83% | 81% |
| TOU-RD | DOM | 7.76% | 7.93% | 123% | 126% |
| PRE-PAY | DOM | 2.21% | 2.72% | 35% | 43% |
| TOU-REO | DOM | 4.93% | 5.13% | 78% | 81% |
| TOU-PEV | DOM | 4.83% | 3.00% | 77% | 48% |
| GS | SM. BUS. | 3.67% | 3.24% | 58% | 51% |
| PLS | SM. BUS. | 10.15% | 9.40% | 161% | 149% |
| TOU-EO | SM. BUS. | 7.94% | 7.52% | 126% | 119% |
| UD | SM. BUS. | 8.01% | 8.50% | 127% | 135% |
| OGS | SM. BUS. | 19.76% | 22.00% | 313% | 349% |
| PLM | MD. BUS. | 9.12% | 8.87% | 145% | 141% |
| TOU-GSD | MD. BUS. | 11.71% | 12.49% | 186% | 198% |
| TOU-FD | MD. BUS. | 7.27% | 6.68% | 115% | 106% |
| PLL | LG. BUS. | 9.53% | 10.18% | 151% | 161% |
| TOU-HLF | LG. BUS. | 6.92% | 7.64% | 110% | 121% |
| TOU-RN | LG. BUS. | 6.40% | 6.60% | 101% | 105% |
| G | GOV'T | 8.36% | 7.36% | 132% | 117% |
| SCH | GOV'T | 11.08% | 11.44% | 176% | 181% |
| SLM | GOV'T | 3.28% | 3.58% | 52% | 57% |
| TC | GOV'T | -16.52% | -16.59% | -262% | -263% |
| TOU-SC | MARGINAL | -1.82% | -1.89% | -29% | -30% |
| RTP-DA | MARGINAL | 8.25% | 8.71% | 131% | 138% |
| RTP-HA | MARGINAL | 6.56% | 7.88% | 104% | 125% |
| FPA | MARGINAL | 2.44% | 3.53% | 39% | 56% |
| APS, FS, IOP | AGRIC. | 6.52% | 9.78% | 103% | 155% |
| SAS | AGRIC. | 0.79% | 1.37% | 13% | 22% |
| OL GOV | LIGHTING | 6.24% | 6.67% | 99% | 106% |
| OL NON-GOV | LIGHTING | 7.58% | 8.25% | 120% | 131% |
| EOL | LIGHTING | 17.07% | 21.57% | 270% | 342% |
| TOTAL RETAIL | | 6.31% | 6.31% | 100% | 100% |

**Q. HAS STAFF CONDUCTED ALTERNATIVE CCOSS THAT MORE ACCURATELY REPRESENTS THE CAPACITY AND ENERGY TRADE-OFF EXHIBITED IN GEORGIA POWER'S GENERATION PLANT INVESTMENT?**

A. Yes, Mr. Watkins has. As discussed earlier, the BIP and Probability of Dispatch methods better reflect the capacity/energy tradeoff that exists within an electric utility's generation related costs. As such, two alternative CCOSS utilizing the BIP method and Probability of Dispatch methods were conducted.

### 1. Base-Intermediate-Peak ("BIP") Method

**Q. PLEASE EXPLAIN HOW THE CCOSS UTILIZING THE BIP METHOD WAS CONDUCTED.**

A. In order to reflect the capacity/energy trade-off inherent in the Company's mix of generating resources, each plant's owned capacity (MW) and output (megawatt-hours "MWh") is required. The BIP method evaluates each plant based on its variable fuel costs as well as the extent to which each unit is utilized throughout the year (capacity factor) to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements.

Confidential Staff Exhibit __ (BDW-4) provides the classification between energy and demand for the Company's combined generation plant under the BIP method. In conducting this analysis, the classification between demand and energy was calculated in two ways: one that includes Vogtle 3 and another that excludes Vogtle 3. In the Company's response to STF-TAI-1-5, relevant information for each generating unit was included in the Company's Period II (12-months ending July 31, 2023). In this response, Georgia

Power provided Vogtle 3's nameplate capacity, investment data, and energy output for this unit. Furthermore, in the Company's response to STF-TAI-1-9, the Company provided each generating unit's hourly output during the forecasted test year in which Vogtle 3 was included. While the investment associated with Vogtle 3 is not included in the Company's rate application, these analyses were conducted with and without Vogtle 3.

**Q. DOES STAFF EXHIBIT __ (BDW-4) HELP EXPLAIN THE CAPACITY/ENERGY TRADE-OFF CONSIDERATION USED BY ELECTRIC UTILITIES IN DEVELOPING A PARTICULAR MIX OF GENERATING FACILITIES?**

A. Yes. As can be seen in Confidential Staff Exhibit __ (BDW-4), Georgia Power's larger, more expensive generating plants have high capacity factors and lower fuel costs. These large units run most hours of the year supplying energy to all customers. In contrast, the smaller, high operating (fuel) cost plants tend to have lower capacity factors meaning they are primarily used to meet peak loads. Because the vast preponderance of Georgia Power's investment in generation plant is associated with its base load units, a very large percentage of generation plant is classified as energy related under the BIP method. Specifically, when Vogtle 3 is included, the energy classification is 74.27% and 62.69% without Vogtle 3.

**Q. PLEASE PROVIDE A SUMMARY OF RESULTS OBTAINED UTILIZING THE BIP METHOD.**

A. The following table provides a summary of each rate schedule's ROR and indexed ROR under the BIP method:

TABLE 3
Rate Schedule RORs & Indexed RORs at Current Rates
(BIP Method)

| | | ROR | | Indexed RORs | |
|---|---|---|---|---|---|
| Rate | Class | w/ Vogtle 3 | w/o Vogtle 3 | w/ Vogtle 3 | w/o Vogtle 3 |
| R, RM | DOM | 6.17% | 5.99% | 98% | 95% |
| TOU-RD | DOM | 8.65% | 8.53% | 137% | 135% |
| PRE-PAY | DOM | 2.74% | 2.74% | 43% | 43% |
| TOU-REO | DOM | 5.72% | 5.63% | 91% | 89% |
| TOU-PEV | DOM | 4.67% | 4.40% | 74% | 70% |
| GS | SM. BUS. | 4.21% | 4.05% | 67% | 64% |
| PLS | SM. BUS. | 9.73% | 9.68% | 154% | 153% |
| TOU-EO | SM. BUS. | 8.90% | 8.67% | 140% | 137% |
| UD | SM. BUS. | 6.28% | 6.60% | 100% | 105% |
| OGS | SM. BUS. | 17.29% | 17.93% | 274% | 284% |
| PLM | MD. BUS. | 8.85% | 8.86% | 140% | 140% |
| TOU-GSD | MD. BUS. | 11.20% | 11.39% | 177% | 180% |
| TOU-FD | MD. BUS. | 6.47% | 6.50% | 103% | 103% |
| PLL | LG. BUS. | 8.15% | 8.44% | 129% | 134% |
| TOU-HLF | LG. BUS. | 4.94% | 5.31% | 78% | 84% |
| TOU-RN | LG. BUS. | 3.92% | 4.29% | 62% | 68% |
| G | GOV'T | 5.70% | 5.94% | 90% | 94% |
| SCH | GOV'T | 11.63% | 11.59% | 184% | 184% |
| SLM | GOV'T | 3.41% | 3.44% | 54% | 55% |
| TC | GOV'T | -16.23% | -16.28% | -257% | -258% |
| TOU-SC | MARGINAL | -3.07% | -2.91% | -49% | -46% |
| RTP-DA | MARGINAL | 6.34% | 6.68% | 100% | 106% |
| RTP-HA | MARGINAL | 3.65% | 4.22% | 58% | 67% |
| FPA | MARGINAL | 1.20% | 1.52% | 19% | 24% |
| APS, FS, IOP | AGRIC. | 5.43% | 5.99% | 86% | 95% |
| SAS | AGRIC. | 0.18% | 0.35% | 3% | 6% |
| OL GOV | LIGHTING | 4.49% | 4.80% | 71% | 76% |
| OL NON-GOV | LIGHTING | 4.95% | 5.40% | 78% | 86% |
| EOL | LIGHTING | 5.62% | 7.09% | 89% | 112% |
| TOTAL RETAIL | | 6.31% | 6.31% | 100% | 100% |

Staff has included a summary of the BIP method results with and without Vogtle as provided in Staff Exhibit __ (BDW-5) and Staff Exhibit __ (BDW-6), respectively.

**2. Probability of Dispatch Method**

**Q. PLEASE EXPLAIN HOW STAFF CONDUCTED THE CCOSS UTILIZING THE PROBABILITY OF DISPATCH METHOD.**

A. As discussed earlier, the Probability of Dispatch method is the most theoretically correct methodology to assign embedded (historical) generation plant investment. However, the data required to utilize this methodology is often not available because this approach requires detailed hourly output data for each generating facility as well as hourly class loads. In this case, Georgia Power provided both of these critical data sets. As such, it was possible for Mr. Watkins to conduct a CCOSS utilizing the Probability of Dispatch method. Similar to the BIP method, the Probability of Dispatch generation allocation factors were calculated with and without Vogtle 3.

The first step in conducting the Probability of Dispatch method was to assign individual generating plant investments to specific hours. In accordance with the procedures set forth in the NARUC: Electric Utility Cost Allocation Manual,[14] each plant's total gross investment was assigned pro-ratably to each hour of the year based on each respective unit's load (output) in that hour.[15]

Once the total hourly gross investment for each unit was determined, these costs were assigned to individual rate schedules on an hour-by-hour basis. As indicated earlier, the Company provided individual class loads for each hour of the forecasted test year. Each

[14] 1992 Edition, page 62.
[15] It should be noted that this exercise actually assigns costs to every hour of the year.

rate schedule's hourly percentage contributions (adjusted for line losses) were multiplied by the hourly generation investment cost for each hour of the year.[16]

**Q. PLEASE PROVIDE A SUMMARY OF RESULTS OBTAINED UTILIZING THE PROBABILITY OF DISPATCH METHOD.**

A. The following table provides a comparison of each rate schedule's ROR and indexed ROR at current rates with and without Vogtle 3:

[16] Class hourly loads for the margin rate schedules only include CBL load and exclude incremental RTP hourly loads.

TABLE 4
Rate Schedule RORs & Indexed RORs at Current Rates
(Probability of Dispatch Method)

| | | ROR | | Indexed RORs | |
|---|---|---|---|---|---|
| Rate | Class | w/ Vogtle 3 | w/o Vogtle 3 | w/ Vogtle 3 | w/o Vogtle 3 |
| R, RM | DOM | 6.63% | 6.60% | 105% | 105% |
| TOU-RD | DOM | 9.04% | 9.04% | 143% | 143% |
| PRE-PAY | DOM | 2.75% | 2.73% | 44% | 43% |
| TOU-REO | DOM | 5.99% | 5.96% | 95% | 94% |
| TOU-PEV | DOM | 5.20% | 5.15% | 82% | 82% |
| GS | SM. BUS. | 4.54% | 4.52% | 72% | 72% |
| PLS | SM. BUS. | 9.75% | 9.75% | 154% | 154% |
| TOU-EO | SM. BUS. | 9.50% | 9.48% | 151% | 150% |
| UD | SM. BUS. | 5.55% | 5.61% | 88% | 89% |
| OGS | SM. BUS. | 15.82% | 15.83% | 251% | 251% |
| PLM | MD. BUS. | 8.83% | 8.83% | 140% | 140% |
| TOU-GSD | MD. BUS. | 10.70% | 10.72% | 170% | 170% |
| TOU-FD | MD. BUS. | 8.89% | 8.87% | 141% | 141% |
| PLL | LG. BUS. | 7.40% | 7.45% | 117% | 118% |
| TOU-HLF | LG. BUS. | 4.12% | 4.21% | 65% | 67% |
| TOU-RN | LG. BUS. | 2.98% | 3.05% | 47% | 48% |
| G | GOV'T | 4.94% | 4.98% | 78% | 79% |
| SCH | GOV'T | 11.58% | 11.55% | 183% | 183% |
| SLM | GOV'T | 3.21% | 3.19% | 51% | 51% |
| TC | GOV'T | -16.22% | -16.22% | -257% | -257% |
| TOU-SC | MARGINAL | -3.54% | -3.50% | -56% | -55% |
| RTP-DA | MARGINAL | 5.51% | 5.56% | 87% | 88% |
| RTP-HA | MARGINAL | 2.33% | 2.42% | 37% | 38% |
| FPA | MARGINAL | 0.42% | 0.47% | 7% | 7% |
| APS, FS, IOP | AGRIC. | 4.38% | 4.44% | 69% | 70% |
| SAS | AGRIC. | -0.23% | -0.20% | -4% | -3% |
| OL GOV | LIGHTING | 3.56% | 3.59% | 56% | 57% |
| OL NON-GOV | LIGHTING | 3.72% | 3.77% | 59% | 60% |
| EOL | LIGHTING | 2.19% | 2.30% | 35% | 36% |
| TOTAL RETAIL | | 6.31% | 6.31% | 100% | 100% |

A summary of the Probability of Dispatch method results with and without Vogtle is provided in Staff Exhibit __ (BDW-7) and Staff Exhibit __ (BDW-8), respectively.

**Q. EARLIER IN THIS TESTIMONY, YOU INDICATED THAT THE BIP AND PROBABILITY OF DISPATCH METHODS MAY NOT PROPERLY RECOGNIZE CLASS VARIANCES IN VARIABLE FUEL COSTS. HAS STAFF EXAMINED IF THERE ARE MATERIAL DIFFERENCES IN CLASS FUEL COSTS WHEN ANALYZED ON AN HOURLY (TIME DIFFERENTIATED) BASIS?**

A. Yes. As discussed earlier, the Company provided each generation plant's hourly output for the forecasted test year. In addition, in Confidential response to STF-TAI-1-14, the Company provided monthly fuel costs (per kWh) for each plant. With this data, hourly fuel costs by individual generating plant based on each unit's hourly output was calculated. These hourly fuel costs to individual rate schedules were then assigned on an hour-by-hour basis based on individual rate schedule hourly loads previously discussed.[17] The results of this analysis yielded similar hourly fuel costs for all classes. Because hourly fuel costs were assigned to each rate schedule based on hourly loads at generation (in order to reflect line losses), each rate schedule's average fuel cost per kWh at the meter was then calculated. The table below provides each class's time differentiated fuel cost (per kWh) at the meter.

[17] Class hourly loads were measured at the generation level in order to reflect losses by voltage level.

TABLE 5
Time Differentiated Fuel Costs
Per kWh at Meter

| Class | Fuel Cost Per kWh | Percent of Total Retail Cost per kWh |
|---|---|---|
| Domestic | $0.02093 | 100.8% |
| Small Business | $0.02074 | 99.9% |
| Medium Business | $0.02069 | 99.6% |
| Large Business | $0.02065 | 99.5% |
| Agriculture | $0.02056 | 99.0% |
| Government | $0.02079 | 100.1% |
| Lighting | $0.02174 | 104.7% |
| Marginal | $0.02051 | 98.8% |
| Total Retail | $0.02076 | 100.0% |

In examining these time differentiated fuel costs by class and voltage level, the results are fairly similar across classes. It is observed that the Lighting class's time differentiated fuel costs are somewhat greater than the system average, which was further investigated. It was determined that there are two reasons why the Lighting class's fuel costs were higher than the system average. First, Georgia Power loses solar generation during the nighttime hours (when outdoor lighting is operated), and second, the Company's pumped storage facilities incur fuel costs during the nighttime hours with no generation, which somewhat skews these results for Lighting. It was also observed that the time differentiated fuel costs for the Marginal class are somewhat lower than the system average. However, it should be remembered that the current Fuel Cost Recovery mechanism (FCR-25) is both seasonally differentiated and voltage differentiated such that the Marginal class pays lower fuel costs per kWh than do other customers.

In conclusion, there is no material difference in per unit fuel costs on a time differentiated basis when all factors are considered.

### B. Allocation of Transmission Plant

**Q. PLEASE EXPLAIN HOW MR. EVANS ALLOCATED TRANSMISSION RELATED COSTS.**

A. Mr. Evans provides a complete description of the methods and procedures he used to allocate transmission related costs on pages 16 through 18 of his Direct Testimony. With regard to step-up substations from the generator, Mr. Evans allocated these costs based on 12-CP demands. For high voltage (bulk power) transmission related costs, Mr. Evans used a blended approach that considers both 12-CP and 4-CP demands. Specifically, Mr. Evans' blended high voltage transmission method utilizes a weighting of 20% 12-CP and 80% 4-CP. Lower voltage facility accounts are allocated based on either the 4-CP or class NCP methods.

**Q. DO YOU AGREE WITH MR. EVANS' APPROACHES TO ALLOCATE TRANSMISSION RELATED COSTS?**

A. Yes. Each sub-category of transmission plant was evaluated wherein we conclude that Mr. Evans' approach is reasonable and appropriate.

## C. Classification & Allocation of Distribution Plant

**Q. PLEASE EXPLAIN THE PHRASE "CLASSIFICATION OF DISTRIBUTION PLANT."**

A. It is generally recognized that there are no energy related costs associated with distribution plant. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, some electric utility distribution plant accounts are sometimes classified as partially demand related and partially customer related.[18]

**Q. PLEASE EXPLAIN WHY DIFFERENCES IN CUSTOMER DENSITIES THROUGHOUT A UTILITY'S SERVICE AREA ARE IMPORTANT IN DETERMINING WHETHER A PORTION OF DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS PARTIALLY CUSTOMER RELATED AND PARTIALLY DEMAND RELATED.**

A. Even though investments are made in distribution plant and related equipment in order to meet the power requirements of its collective customers, there may be considerable differences in both customer densities and the mix of customers throughout a utility's service area. As a hypothetical, suppose a utility serves both an urban area and a rural area. In this situation, many customers' loads are served with relatively few miles of poles and conductors in the urban area, while many more miles of poles and conductors are

[18] Traditionally, customer/demand splits relate to Accounts 364 (Poles), 365 (Overhead Conductors), 366 (Underground Conduit), 367 (Underground Conductors), and 368 (Line Transformers).

required to serve the requirements of relatively few customers in the rural area. If the distribution of classes of customers (class customer mix) is relatively similar in both the rural and urban areas, there is no need to consider customer counts (number of customers) within the allocation process, because all classes use the utility's joint distribution facilities proportionately across the service area. However, if the customer mix is such that commercial and industrial customers are predominately clustered in the urban area, while the rural portion of the service territory consists almost entirely of residential customers, it may be unreasonable to allocate the total Company's investment based only on demand; i.e., a large investment in many miles of poles and conductors are required to serve predominately Residential customers in the rural area while the commercial and industrial power needs are met with much fewer miles of poles and conductors in the urban area. Under this circumstance, an allocation method that considers number of customers can be considered equitable and appropriate.

Because of the diverse geographic and demographic characteristics of Georgia Power's service area, a classification of distribution poles, conductors, and line transformers is appropriate.

**Q. HOW DID MR. EVANS CLASSIFY DISTRIBUTION PLANT RELATED COSTS?**

A. Mr. Evans utilized what is known as the Zero-Intercept method to separately classify distribution poles, conductors, and transformers. Under the Zero-Intercept method, statistical linear regression techniques are used to estimate the cost of a theoretical "zero-size" pole, conductor, or transformer.

**Q. WHAT ARE THE RESULTS OF MR. EVANS' DISTRIBUTION PLANT CLASSIFICATIONS BETWEEN CUSTOMER AND DEMAND?**

A. The following table presents Mr. Evans' distribution classification results for each plant account:

TABLE 6
Georgia Power Classification of Distribution Plant

| Account | | Percent Customer |
|---|---|---|
| 364 - Poles | Primary & Secondary | 39.2% |
| 365 – OH Conductors | Primary & Secondary | 43.4% |
| 366 – UG Conduit | Primary | 11.7% |
| | Secondary | 26.3% |
| 367 – UG Conductors | Primary & Secondary | 11.7% |
| 368 – Line Transformers | | 53.7% |
| Total Accts. 364-368 | | 32.8% |

**Q. WHAT ARE YOUR FINDINGS REGARDING MR. EVANS' CLASSIFICATION OF DISTRIBUTION PLANT BETWEEN CUSTOMER AND DEMAND?**

A. While classification studies of distribution plant involve considerable judgment and can be controversial, based on the geography and demographics of Georgia Power's service area, we find that Mr. Evans' classification of distribution plant is reasonable.

**Q. EARLIER IN THIS TESTIMONY YOU EXPLAINED HOW GEORGIA POWER CLASSIFIED DISTRIBUTION PLANT BETWEEN CUSTOMER AND DEMAND. HOW WERE THESE CLASSIFIED DISTRIBUTION COSTS THEN ALLOCATED ACROSS RATE SCHEDULES?**

A. The above-referenced plant accounts classified as "customer-related" were allocated based on number of customers (primary and/or secondary). Demand-related costs were allocated utilizing class NCPs (primary and/or secondary). This is an accepted industry approach and we agree with Mr. Evans' allocation of distribution plant.

### D. CCOSS Conclusions

**Q. PLEASE PROVIDE YOUR CONCLUSIONS REGARDING CCOSS FOR THIS CASE.**

A. While no class cost allocation study (CCOSS) can be considered surgically precise as they require a myriad of subjective judgments and approximations, some allocation methodologies are better than others in reflecting cost causation and are fairer and more equitable across all classes. In this regard, there are never-ending debates on whether one particular method is superior to all others. As a result, Staff considered all CCOSS presented in this testimony while evaluating individual rate schedule revenue responsibility which will be discussed in the next section of this testimony.

## III. CLASS AND RATE SCHEDULE REVENUE RESPONSIBILITY

**Q. PLEASE EXPLAIN HOW THE COMPANY'S OVERALL REQUESTED INCREASE IN REVENUES IS STRUCTURED.**

A. As set forth in the Direct Testimony of Abramovitz, Adams, Houston, and Robinson, Georgia Power proposes a three-year Alternative Rate Plan ("ARP") wherein the revenue

requirement for each of the three years is first established and is generally composed of its requested increases to: traditional base rates; Environmental Compliance Cost Recovery ("ECCR"), Demand Side Management ("DSM"), and Municipal Franchise Fee ("MFF").

With regard to traditional base rates and the traditional (legacy) ECCR rider, the Company's initial revenue requirement filing proposed a three-year "levelized" increase of $738.7 million and -$1.2 million, respectively, that will be realized each year of the ARP; i.e., these increases would be implemented incrementally each year such that over the three-year rate plan, base rate revenues would increase by a total of $2,216.0 million over current base rate levels and the traditional ECCR rider would decrease by a total of $3.6 million over current rider revenue levels.[19]

With regard to the Coal Combustion Residual Asset Retirement Obligation ("CCR ARO") component of ECCR, DSM, and MFF revenue increases, the Company proposes varying increases each year of the proposed ARP.

For rate design purposes, the Company's as filed class and rate schedule revenue allocations, rate designs, and proposed tariffs were based only on the Company's "test year" requested increase and not those actually proposed under its "levelized" approach.[20] However, in the Company's response to STF-BAI-1-1 (Legg), the Company provided its

[19] The "levelized" increase represents the annual incremental increases on a levelized basis and was calculated based on the present value of each of the three-year proposed revenue deficiencies.
[20] The test year increases should not be confused with Rate Year 1 increases. The Company's as -filed tariffs reflecting the test year proposed increases are contained in MFR F-1 while the revenue proof relating to its proposed increases is contained in MFR F-4.

actual proposed revenue allocations and rate designs for Rate Year 1 of the ARP based on its requested "levelized" increases for base rates and traditional ECCR, as well as its requested Rate Year 1 CCR ARO, ECCR, DSM, and MFF riders. To further explain, in the Company's filing, its proposed rates and tariffs do not reflect the increases the Company is actually requesting in its rate application wherein the following table provides a comparison of the Company's as filed proposed increases to those it is actually requesting in this case[21]:

TABLE 7
Comparison of Georgia Power's Proposed Revenue Increases
As Filed Tariff Changes & Those Actually Proposed
($ Millions) [22]

| | As Filed Tariff Changes | Actually Proposed Year 1 | Year 2 | Year 3 | Cumulative |
|---|---|---|---|---|---|
| Base Rates (Levelized) | $312.2 | $738.7 | $738.7 | $738.7 | $2,216.0 |
| ECCR | | | | | |
| Traditional (Levelized) | $45.6 | ($1.2) | ($1.2) | ($1.2) | ($3.6) |
| CCR ARO | $60.0 | $64.5 | $142.5 | $189.2 | $396.2 |
| Total ECCR | $105.6 | $63.3 | $141.3 | $188.0 | $392.6 |
| DSM | $29.6 | $29.7 | $56.5 | $54.0 | $140.2 |
| MFF | $11.1 | $20.2 | $22.6 | $23.6 | $66.4 |
| Total | $458.5 | $851.9 | $959.1 | $1,004.3 | $2,815.3 |

**Q. WHAT ARE THE GENERAL CRITERIA THAT SHOULD BE CONSIDERED IN ESTABLISHING CLASS REVENUE RESPONSIBILITY FOR ELECTRIC UTILITY RATES?**

[21] It is understood that the Company made a Supplemental Filing on August 22, 2022, wherein its requested levelized base rate and traditional ECCR revenues were adjusted to $761.9 million and $5.0 million, respectively. In addition, the Company adjusted its DSM revenue increase to $36.9 million in Year 1.
[22] Per APA-SPA-ADH-MBR-1 (Schedules 2-5).

A. There are several criteria that should be considered in evaluating rate schedule revenue responsibility. First, cost allocation results should be considered, but as discussed in detail earlier in our testimony, CCOSS results are not surgically precise. They should only be used as a guide and as one of many tools in evaluating revenue responsibility. Other criteria that should be considered include: gradualism, wherein rates should not drastically change instantaneously; rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure; affordability of electricity across various classes as well as a relative comparison of electricity prices across classes; and, public policy concerning current economic conditions as well as economic development.

**Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO SPREAD ITS VARIOUS REQUESTED REVENUE INCREASES ACROSS INDIVIDUAL RATE SCHEDULES.**

A. As discussed on page 5, lines 6 through 12 of his Direct Testimony, Georgia Power witness Legg proposes (with minor exceptions) to increase all rate schedules' revenues and rate elements on an equal percentage basis. Specifically, and based on the Company's initial filing, for Year 2023, Mr. Legg proposes an approximate 16.0% increase to base tariff rates (excluding Real Time Pricing ("RTP") incremental rates), an approximate 7.6% increase to ECCR rates and revenues, an approximate 73.1% increase to Residential DSM rider rates and revenues, an approximate 56.4% increase to Commercial DSM rider rates and revenues, and an approximate 10.5% increase to MFF revenues. In this regard, Georgia

Power proposes no increase to RTP incremental rates and revenues and that the various riders are collected as a percentage of base rate revenues.

With regard to ECCR and DSM rider revenues, these riders are collected as a percentage of base rate revenues and therefore, follow Mr. Legg's increases to base rates. With regard to MFF rider revenues, these revenues are collected as a percentage of usage and bifurcated between those customers inside city limits and those outside city limits.

### A. Traditional Base Rates

**Q. DOES STAFF RECOMMEND AN ALTERNATIVE BASE RATE REVENUE DISTRIBUTION ACROSS INDIVIDUAL RATE SCHEDULES?**

A. Yes. While the Company has given no consideration to cost of service as it relates to individual rate schedules, Staff observed that many rate schedules are reasonably close to parity (i.e., RORs at current rates are close to the system average). As shown in the following tables, several rate schedules are either significantly above or significantly below the system average ROR under every CCOSS evaluated.

TABLE 8
Class & Rate Schedule RORs at Current Rates

| | | | Base-Intermediate-Peak | | Probability of Dispatch | |
|---|---|---|---|---|---|---|
| Rate Schedule | 12-CP | 4-CP | w/ Vogtle 3 | w/o Vogtle 3 | w/ Vogtle 3 | w/o Vogtle 3 |
| R, RM | 5.26% | 5.11% | 6.17% | 5.99% | 6.63% | 6.60% |
| TOU-RD | 7.76% | 7.93% | 8.65% | 8.53% | 9.04% | 9.04% |
| PRE-PAY | 2.21% | 2.72% | 2.74% | 2.74% | 2.75% | 2.73% |
| TOU-REO | 4.93% | 5.13% | 5.72% | 5.63% | 5.99% | 5.96% |
| TOU-PEV | 4.83% | 3.00% | 4.67% | 4.40% | 5.20% | 5.15% |
| TOTAL DOMESTIC | 5.21% | 5.09% | 6.09% | 5.93% | 6.53% | 6.50% |
| GS | 3.67% | 3.24% | 4.21% | 4.05% | 4.54% | 4.52% |
| PLS | 10.15% | 9.40% | 9.73% | 9.68% | 9.75% | 9.75% |
| TOU-EO | 7.94% | 7.52% | 8.90% | 8.67% | 9.50% | 9.48% |
| UD | 8.01% | 8.50% | 6.28% | 6.60% | 5.55% | 5.61% |
| OGS | 19.76% | 22.00% | 17.29% | 17.93% | 15.82% | 15.83% |
| TOTAL SM. BUS. | 7.29% | 6.73% | 7.42% | 7.31% | 7.62% | 7.61% |
| PLM | 9.12% | 8.87% | 8.85% | 8.86% | 8.83% | 8.83% |
| TOU-GSD | 11.71% | 12.49% | 11.20% | 11.39% | 10.70% | 10.72% |
| TOU-FD | 7.27% | 6.68% | 6.47% | 6.50% | 8.89% | 8.87% |
| TOTAL MED. BUS. | 9.07% | 8.84% | 8.77% | 8.78% | 8.86% | 8.87% |
| PLL | 9.53% | 10.18% | 8.15% | 8.44% | 7.40% | 7.45% |
| TOU-HLF | 6.92% | 7.64% | 4.94% | 5.31% | 4.12% | 4.21% |
| TOU-RN | 6.40% | 6.60% | 3.92% | 4.29% | 2.98% | 3.05% |
| TOTAL LG. BUS. | 8.66% | 9.19% | 6.94% | 7.26% | 6.12% | 6.18% |
| G | 8.36% | 7.36% | 5.70% | 5.94% | 4.94% | 4.98% |
| SCH | 11.08% | 11.44% | 11.63% | 11.59% | 11.58% | 11.55% |
| SLM | 3.28% | 3.58% | 3.41% | 3.44% | 3.21% | 3.19% |
| TC | -16.52% | -16.59% | -16.23% | -16.28% | -16.22% | -16.22% |
| TOTAL GOV'T | 3.72% | 3.98% | 3.70% | 3.74% | 3.48% | 3.47% |
| TOU-SC | -1.82% | -1.89% | -3.07% | -2.91% | -3.54% | -3.50% |
| RTP-DA | 8.25% | 8.71% | 6.34% | 6.68% | 5.51% | 5.56% |
| RTP-HA | 6.56% | 7.88% | 3.65% | 4.22% | 2.33% | 2.42% |
| FPA | 2.44% | 3.53% | 1.20% | 1.52% | 0.42% | 0.47% |
| TOTAL MARGIN | 6.61% | 7.42% | 4.51% | 4.92% | 3.53% | 3.59% |
| APS, FS, IOP | 6.52% | 9.78% | 5.43% | 5.99% | 4.38% | 4.44% |
| SAS | 0.79% | 1.37% | 0.18% | 0.35% | -0.23% | -0.20% |
| TOTAL AGRI. | 6.32% | 9.24% | 5.22% | 5.74% | 4.21% | 4.27% |
| GOV | 6.24% | 6.67% | 4.49% | 4.80% | 3.56% | 3.59% |
| NON-GOV | 7.58% | 8.25% | 4.95% | 5.40% | 3.72% | 3.77% |
| EOL | 17.07% | 21.57% | 5.62% | 7.09% | 2.19% | 2.30% |
| TOTAL LIGHT. | 7.96% | 8.80% | 4.77% | 5.30% | 3.30% | 3.35% |
| TOTAL RETAIL | 6.31% | 6.31% | 6.31% | 6.31% | 6.31% | 6.31% |

TABLE 9
Class & Rate Schedule Indexed RORs at Current Rates

| | | | Base-Intermediate-Peak | | Probability of Dispatch | |
|---|---|---|---|---|---|---|
| Rate Schedule | 12-CP | 4-CP | w/ Vogtle 3 | w/o Vogtle 3 | w/ Vogtle 3 | w/o Vogtle 3 |
| R, RM | 83% | 81% | 98% | 95% | 105% | 105% |
| TOU-RD | 123% | 126% | 137% | 135% | 143% | 143% |
| PRE-PAY | 35% | 43% | 43% | 43% | 44% | 43% |
| TOU-REO | 78% | 81% | 91% | 89% | 95% | 94% |
| TOU-PEV | 77% | 48% | 74% | 70% | 82% | 82% |
| TOTAL DOMESTIC | 83% | 81% | 97% | 94% | 104% | 103% |
| | | | | | | |
| GS | 58% | 51% | 67% | 64% | 72% | 72% |
| PLS | 161% | 149% | 154% | 153% | 154% | 154% |
| TOU-EO | 126% | 119% | 140% | 137% | 151% | 150% |
| UD | 127% | 135% | 100% | 105% | 88% | 89% |
| OGS | 313% | 349% | 274% | 284% | 251% | 251% |
| TOTAL SM. BUS. | 116% | 107% | 118% | 116% | 121% | 121% |
| | | | | | | |
| PLM | 145% | 141% | 140% | 140% | 140% | 140% |
| TOU-GSD | 186% | 198% | 177% | 180% | 170% | 170% |
| TOU-FD | 115% | 106% | 103% | 103% | 141% | 141% |
| TOTAL MED. BUS. | 144% | 140% | 139% | 139% | 140% | 141% |
| | | | | | | |
| PLL | 151% | 161% | 129% | 134% | 117% | 118% |
| TOU-HLF | 110% | 121% | 78% | 84% | 65% | 67% |
| TOU-RN | 101% | 105% | 62% | 68% | 47% | 48% |
| TOTAL LG. BUS. | 137% | 146% | 110% | 115% | 97% | 98% |
| | | | | | | |
| G | 132% | 117% | 90% | 94% | 78% | 79% |
| SCH | 176% | 181% | 184% | 184% | 183% | 183% |
| SLM | 52% | 57% | 54% | 55% | 51% | 51% |
| TC | -262% | -263% | -257% | -258% | -257% | -257% |
| TOTAL GOV'T | 59% | 63% | 59% | 59% | 55% | 55% |
| | | | | | | |
| TOU-SC | -29% | -30% | -49% | -46% | -56% | -55% |
| RTP-DA | 131% | 138% | 100% | 106% | 87% | 88% |
| RTP-HA | 104% | 125% | 58% | 67% | 37% | 38% |
| FPA | 39% | 56% | 19% | 24% | 7% | 7% |
| TOTAL MARGIN | 100% | 118% | 71% | 78% | 52% | 53% |
| | | | | | | |
| APS, FS, IOP | 103% | 155% | 86% | 95% | 69% | 70% |
| SAS | 13% | 22% | 3% | 6% | -4% | -3% |
| TOTAL AGRI. | 100% | 146% | 83% | 91% | 67% | 68% |
| | | | | | | |
| GOV | 99% | 106% | 71% | 76% | 56% | 57% |
| NON-GOV | 120% | 131% | 78% | 86% | 59% | 60% |
| EOL | 270% | 342% | 89% | 112% | 35% | 36% |
| TOTAL LIGHT. | 126% | 139% | 76% | 84% | 52% | 53% |
| | | | | | | |
| TOTAL RETAIL | 100% | 100% | 100% | 100% | 100% | 100% |

As discussed earlier, when every cost allocation approach produces a situation of consistently high RORs (consistently low RORs), there is a strong basis to assign less than (more than) the system average percentage increase to a particular class or rate schedule. As a result, a very gradual movement of certain rate schedules toward parity is recommended.

**Q. PLEASE EXPLAIN HOW STAFF DEVELOPED ITS RECOMMENDED BASE RATE REVENUE ALLOCATION ACROSS INDIVIDUAL RATE SCHEDULES.**

A. For those rate schedules whose indexed RORs are greater than approximately 125% under every CCOSS evaluated, a somewhat smaller percentage increase than the system average percentage increase was assigned to base rates. Conversely, for those rate schedules whose indexed RORs are less than approximately 75% under every CCOSS evaluated, a somewhat greater percentage increase than the system average percentage increase was assigned to base rates. Specifically, for those rate schedules that receive a smaller percentage increase, constraints of 75.0% and 87.5% of the system average were utilized. For those rate schedules that receive a larger percentage increase, constraints of 112 % and 125% of the system average were employed. All other rate schedules receive an equal percentage increase of the remaining base rate revenue requirement. The following table provides those rate schedules that receive less than or greater than the remaining average percentage increase:

TABLE 10
Staff's Proposed Base Rate Revenue Allocation

| Rate Schedule | Class | Pct. of System Avg. Increase |
|---|---|---|
| Less Than the System Average: | | |
| TOU-RD | Domestic | 87.5% |
| OGS | Small Business | 75.0% |
| PLS | Small Business | 87.5% |
| TOU-EO | Small Business | 87.5% |
| PLM | Medium Business | 87.5% |
| TOU-GSD | Medium Business | 75.0% |
| PLL | Large Business | 87.5% |
| SCH | Government | 75.0% |
| More Than the System Average: | | |
| GS | Small Business | 112.5% |
| SAS ND | Agriculture | 125.0% |
| SAS | Agriculture | 125.0% |
| SLM | Government | 112.5% |
| TC-M | Government | 125.0% |
| TC-U | Government | 125.0% |
| FPA | Marginal | 125.0% |
| TOU-SC | Marginal | 125.0% |
| All Other Rate Schedules: | | |
| Equal Percentage of Remaining Increase | | |

**Q. WHAT IS THE BASIS FOR ASSIGNING 87.5% OF THE SYSTEM AVERAGE TO SOME RATE SCHEDULES AND 75.0% OF THE SYSTEM AVERAGE TO OTHER RATE SCHEDULES?**

A. Individual rate schedules were delineated between those rate schedules whose indexed RORs are more than 125% and those that are somewhat more than 100% and those whose indexed RORs are significantly above 125%. To illustrate, and as shown in Table 9, the TOU-RD's indexed RORs are at, or somewhat greater than 125% under all CCOSS such that this rate schedule was assigned 87.5% of the system average percentage increase. With

regards to OGS, this rate schedule's indexed ROR is significantly above 125% under all CCOSS such that this rate schedule was assigned only 75% of the system average percentage increase.

**Q. WAS THE SAME LOGIC USED FOR THOSE CLASSES THAT WERE ASSIGNED 112.5% OR 125% OF THE SYSTEM AVERAGE PERCENTAGE INCREASE?**

A. Yes.

**Q. PLEASE PROVIDE A SUMMARY OF STAFF'S PROPOSED BASE RATE REVENUE INCREASES BY RATE SCHEDULE.**

A. In order to provide an apples-to-apples comparison to Georgia Power's proposed base rate revenue increases, the following table shows Staff's recommended revenue increases by rate schedule utilizing the Company's originally filed $738.77 million overall base rate increase:[23]

[23] It is understood that Georgia Power provided a Supplemental Filing on August 22, 2022, that requests a levelized base rate increase of $761.9 million. However, the Supplemental Filing did not provide a revenue allocation or rate design associated with this supplemental overall revenue increase to base rates.

TABLE 11
Summary of Staff Proposed Base Rate Revenues
Under Georgia Power's Original Proposed Increase
($ Thousands)

| | | | Staff Proposed | | |
|---|---|---|---|---|---|
| Rate | Class | Current Base Rate Revenue [24] | Pct. of System Avg. | $ Increase | % Increase Excluding Incremental |
| R, RM, SCD, OPT | DOM | $2,099,712 | 104.0% | $350,589 | 16.70% |
| FlatBill Risk Premium | DOM | $36,483 | | $3,764 | 10.32% |
| TOU-REO | DOM | $6,674 | 104.0% | $1,114 | 16.70% |
| TOU-PEV | DOM | $7,722 | 104.0% | $1,289 | 16.70% |
| PPS | DOM | $93,384 | 104.0% | $15,592 | 16.70% |
| PBD Risk Premium | DOM | $862 | | $97 | 11.29% |
| TOU-RD | DOM | $72,597 | 87.5% | $10,194 | 14.04% |
| GS | SM. BUS. | $185,508 | 112.5% | $33,491 | 18.05% |
| FlatBill GS Risk Premium | SM. BUS. | $574 | | $61 | 10.70% |
| OGS | SM. BUS. | $1,367 | 75.0% | $164 | 12.04% |
| PLS | SM. BUS. | $262,853 | 87.5% | $36,909 | 14.04% |
| TOU-EO | SM. BUS. | $47,834 | 87.5% | $6,717 | 14.04% |
| UD | SM. BUS. | $11,583 | 104.0% | $1,934 | 16.70% |
| PLM | MD. BUS. | $696,530 | 87.5% | $97,804 | 14.04% |
| TOU-GSD | MD. BUS. | $31,408 | 75.0% | $3,780 | 12.04% |
| TOU-FD | MD. BUS. | $39,164 | 104.0% | $6,539 | 16.70% |
| PLL | LG. BUS. | $128,575 | 87.5% | $18,054 | 14.04% |
| TOU-HLF | LG. BUS. | $2,703 | 104.0% | $451 | 16.70% |
| TOU-RN | LG. BUS. | $39,534 | 104.0% | $6,601 | 16.70% |
| APS | AGRIC. | $2,549 | 104.0% | $426 | 16.70% |
| IOP | AGRIC. | $3,088 | 104.0% | $516 | 16.70% |
| SAS-ND | AGRIC. | $132 | 125.0% | $26 | 20.06% |
| SAS | AGRIC. | $1,400 | 125.0% | $281 | 20.06% |
| TOU-FS | AGRIC. | $4,090 | 104.0% | $683 | 16.70% |
| G | GOV'T | $4,917 | 104.0% | $821 | 16.70% |
| SCH | GOV'T | $12,657 | 75.0% | $1,523 | 12.04% |
| SLM | GOV'T | $73,226 | 112.5% | $13,220 | 18.05% |
| TC-M | GOV'T | $167 | 125.0% | $34 | 20.06% |
| TC-U | GOV'T | $689 | 125.0% | $138 | 20.06% |
| EOL | LIGHTING | $18,584 | 104.0% | $3,103 | 16.70% |
| OLG | LIGHTING | $19,068 | 104.0% | $3,184 | 16.70% |
| OLNG | LIGHTING | $21,423 | 104.0% | $3,577 | 16.70% |
| RLG | LIGHTING | $35,958 | 104.0% | $6,004 | 16.70% |
| FPA | MARGINAL | $78,216 | 125.0% | $15,690 | 20.06% |
| RTP-DA (Excl. Increm.) | MARGINAL | $358,566 | 104.0% | $59,870 | 16.70% |
| RTP-HA (Excl. Increm.) | MARGINAL | $188,292 | 104.0% | $31,439 | 16.70% |
| TOU-SC | MARGINAL | $6,407 | 125.0% | $1,285 | 20.06% |
| TOU-SC Fixed | MARGINAL | $1,515 | 125.0% | $304 | 20.06% |
| EAF | MARGINAL | $6,971 | 125.0% | $1,398 | 20.06% |
| TOTAL | | $4,602,983 | | $738,667 | 16.05% |

[24] Includes Back-Up and excludes Incremental RTP.

**Q. TABLE 9 INDICATES THAT THE RESIDENTIAL PRE-PAY INDEXED RORs ARE SIGNIFICANTLY BELOW 100% FOR EVERY CCOSS EVALUATED. PLEASE EXPLAIN WHY STAFF DOES NOT RECOMMEND A LARGER PERCENTAGE INCREASE TO THIS RATE SCHEDULE.**

A. The only reason that the residential Pre-Pay RORs are significantly deficient is due to the fact that $21.8 million of pre-pay program expenses (Account 903) are directly assigned to this rate schedule. If these program costs are socialized across the entire residential class, the Pre-Pay rate schedule's RORs increase substantially to levels close to the system average ROR; i.e., indexed RORs of 100%. Furthermore, this rate schedule's basic service charge and weighted average energy charge is already higher than on the R rate. This rate schedule has been very effective in reducing uncollectibles such that Staff recommends that this rate schedule incur the same level of increase as all other residential rates and that the Pre-Pay program costs be socialized across all residential rate schedules.

**Q. PLEASE PROVIDE A COMPARISON OF THE COMPANY'S AND STAFF'S RECOMMENDED BASE RATE INCREASES UTILIZING GEORGIA POWER'S PROPOSED BASE RATE INCREASE OF $739 MILLION.**

A. As shown in the table 12 below, Staff recognized that some rate schedules are either consistently above or below the allocated cost of service and, therefore, recommends that these rate schedules receive somewhat less (somewhat more) of the system average increase as shown in the table below. Staff's recommendation provides some movement towards cost of service.

TABLE 12
Comparison of Georgia Power and Staff Base Rate Increases
At Georgia Power's Proposed $739 million Increase [25]
($ Thousands)

| Rate | Class | Current Base Rate Revenue [26] | $ Increase Georgia Power | $ Increase Staff | % Increase Georgia Power | % Increase Staff |
|---|---|---|---|---|---|---|
| R, RM, SCD, OPT | DOM | $2,099,712 | $336,095 | $350,589 | 16.01% | 16.70% |
| FlatBill Risk Premium | DOM | $36,483 | $3,764 | $3,764 | 10.32% | 10.32% |
| TOU-REO | DOM | $6,674 | $1,080 | $1,114 | 16.19% | 16.70% |
| TOU-PEV | DOM | $7,722 | $1,250 | $1,289 | 16.19% | 16.70% |
| PPS | DOM | $93,384 | $15,019 | $15,592 | 16.08% | 16.70% |
| PBD Risk Premium | DOM | $862 | $97 | $97 | 11.29% | 11.29% |
| TOU-RD | DOM | $72,597 | $11,751 | $10,194 | 16.19% | 14.04% |
| GS | SM. BUS. | $185,508 | $29,965 | $33,491 | 16.15% | 18.05% |
| FlatBill GS Risk Premium | SM. BUS. | $574 | $61 | $61 | 10.70% | 10.70% |
| OGS | SM. BUS. | $1,367 | $221 | $164 | 16.19% | 12.04% |
| PLS | SM. BUS. | $262,853 | $42,534 | $36,909 | 16.18% | 14.04% |
| TOU-EO | SM. BUS. | $47,834 | $7,711 | $6,717 | 16.12% | 14.04% |
| UD | SM. BUS. | $11,583 | $1,875 | $1,934 | 16.19% | 16.70% |
| PLM | MD. BUS. | $696,530 | $112,195 | $97,804 | 16.11% | 14.04% |
| TOU-GSD | MD. BUS. | $31,408 | $5,046 | $3,780 | 16.06% | 12.04% |
| TOU-FD | MD. BUS. | $39,164 | $6,339 | $6,539 | 16.19% | 16.70% |
| PLL | LG. BUS. | $128,575 | $20,692 | $18,054 | 16.09% | 14.04% |
| TOU-HLF | LG. BUS. | $2,703 | $436 | $451 | 16.13% | 16.70% |
| TOU-RN | LG. BUS. | $39,534 | $6,305 | $6,601 | 15.95% | 16.70% |
| APS | AGRIC. | $2,549 | $413 | $426 | 16.18% | 16.70% |
| IOP | AGRIC. | $3,088 | $500 | $516 | 16.19% | 16.70% |
| SAS-ND | AGRIC. | $132 | $21 | $26 | 16.19% | 20.06% |
| SAS | AGRIC. | $1,400 | $227 | $281 | 16.19% | 20.06% |
| TOU-FS | AGRIC. | $4,090 | $662 | $683 | 16.19% | 16.70% |
| G | GOV'T | $4,917 | $792 | $821 | 16.11% | 16.70% |
| SCH | GOV'T | $12,657 | $2,047 | $1,523 | 16.18% | 12.04% |
| SLM | GOV'T | $73,226 | $11,831 | $13,220 | 16.16% | 18.05% |
| TC-M | GOV'T | $167 | $27 | $34 | 16.19% | 20.06% |
| TC-U | GOV'T | $689 | $112 | $138 | 16.19% | 20.06% |
| EOL | LIGHTING | $18,584 | $3,009 | $3,103 | 16.19% | 16.70% |
| OLG | LIGHTING | $19,068 | $3,085 | $3,184 | 16.18% | 16.70% |
| OLNG | LIGHTING | $21,423 | $3,471 | $3,577 | 16.20% | 16.70% |
| RLG | LIGHTING | $35,958 | $5,814 | $6,004 | 16.17% | 16.70% |
| FPA | MARGINAL | $78,216 | $12,644 | $15,690 | 16.17% | 20.06% |
| RTP-DA | MARGINAL | $358,566 | $58,715 | $59,870 | 16.38% | 16.70% |
| RTP-HA | MARGINAL | $188,292 | $30,695 | $31,439 | 16.30% | 16.70% |
| TOU-SC | MARGINAL | $6,407 | $1,037 | $1,285 | 16.19% | 20.06% |
| TOU-SC Fixed | MARGINAL | $1,515 | $0 | $304 | 0.00% | 20.06% |
| EAF | MARGINAL | $6,971 | $1,128 | $1,398 | 16.19% | 20.06% |
| TOTAL | | $4,602,983 | $738,667 | $738,667 | 16.05% | 16.05% |

[25] Reflects Georgia Power's revised revenues provided to Staff on October 4, 2022.
[26] Includes Back-Up and excludes Incremental RTP.

**Q. IF THE COMMISSION WERE TO AUTHORIZE AN OVERALL BASE RATE INCREASE LESS THAN THE $739 MILLION REQUESTED BY GEORGIA POWER, HOW SHOULD THE REVENUE INCREASE BE ASSIGNED TO INDIVIDUAL RATE SCHEDULES?**

A. Staff designed its base rate revenue distribution method in a way that can be applied to any revenue increase authorized by the Commission. That is, the methodology described earlier can (and should) be applied regardless of the revenue increase that is authorized by the Commission.

**Q. STAFF RECOMMENDS THAT THE COMPANY'S PROPOSED THREE-YEAR LEVELIZED ANNUAL INCREASES BE REJECTED AND THAT THERE BE SEPARATE ANNUAL INCREASES DURING EACH YEAR OF THE THREE-YEAR RATE PLAN. HOW SHOULD BASE RATE INCREASES BE ASSIGNED TO INDIVIDUAL RATE SCHEDULES IN RATE YEAR 2 (2024) AND RATE YEAR 3 (2025)?**

A. Staff recommends that annual increases to base rates in Rate Years 2024 and 2025 be assigned to rate schedules based on revenues in Rate Year 2023.

## B. ECCR

**Q. PLEASE EXPLAIN HOW THE ECCR REVENUE REQUIREMENT IS COLLECTED ACROSS INDIVIDUAL RATE SCHEDULES.**

A. Currently, RTP incremental usage is exempt from the ECCR rider. Additionally, Rate Fixed Price Alternative ("FPA") and Rate Electric Arc Furnace ("EAF") only pay 65% of its base billed revenue. All other rate schedules are subject to a fixed percentage of base rate revenues.

**Q. IS THE CURRENT METHOD IN WHICH ECCR REVENUES ARE COLLECTED CONSISTENT WITH COST CAUSATION AND ARE THEY FAIR AND REASONABLE?**

A. No. The ECCR rider recovers costs associated with environmental compliance resulting from the burning of fuel for generation. These costs are the result of both decades of prior fuel burning as well as the environmental compliance with the current burning of fuel. Because the amount of fuel burned is 100% variable in nature and is therefore a function of the production of energy (kWh), ECCR costs are unquestionably a function of kWh. The current method to recover ECCR costs is based on base rate revenues. However, base rates for several rate schedules are comprised of a much higher percentage of distribution and transmission related costs (and a much lower percentage of generation related costs) than other rate schedules. To illustrate, outdoor and street lighting's total base rates are comprised largely of distribution related costs (that include dedicated street lighting poles, lamp fixtures, etc.) with a relatively small percentage relating to generation costs. At the other extreme, large industrial customers' total base rates reflect a much higher percentage of generation related costs and a much smaller percentage of distribution related costs. As

such, the current ECCR cost recovery method is contrary to cost causation and inequitable across rate schedules.

**Q. PLEASE PROVIDE SPECIFIC EXAMPLES OF THE INEQUITABLE RECOVERY OF ECCR COSTS ACROSS RATE SCHEDULES.**

A. The following provides examples of the effective ECCR rate per kWh:

TABLE 13
Examples of Present ECCR Rate per kWh

| Rate | MWh | Present ECCR Revenue ($000) | ECCR Rate Per kWh |
|---|---|---|---|
| Residential (Rate R) | 26,872,898 | $387,498 | 1.442¢ |
| General Service (Rate GS) | 1,331,927 | $33,912 | 2.546¢ |
| Large Power & Light (Rate PLL) | 2,396,081 | $23,496 | 0.981¢ |
| Gov't Road Lighting (Rate RLG) | 110,284 | $6,659 | 6.038¢ |
| Fixed Price Alternative (Rate FPA) | 2,220,132 | $9,148 | 0.412¢ |
| RTP-Day Ahead CBL | 7,465,547 | $65,598 | 0.879¢ |
| RTP-Day Ahead Incremental | 6,375,584 | $0 | 0.000¢ |
| RTP-Hour Ahead CBL | 5,709,811 | $33,528 | 0.587¢ |
| RTP-Hour Ahead Incremental | 9,996,539 | $0 | 0.000¢ |
| Electric Arc Furnace (Rate EAF) | 310,811 | $692 | 0.223¢ |

As can be seen above, Governmental Road Lighting's effective ECCR rate is more than 6¢ per kWh while the Large Power & Light effective ECCR rate is less than 1¢ per kWh.

**Q. IS IT APPROPRIATE TO EXCLUDE RTP INCREMENTAL USAGE FROM ECCR COSTS?**

A. No. While the base incremental rates for RTP (Day Ahead and Hour Ahead) are characterized as being priced on marginal production costs, these incremental rates do not

reflect the cost of environmental compliance. To be clear, the costs associated with ECCR are not forward looking and not included in marginal production costs (which is the basis for the incremental RTP rates), but rather, reflect the costs associated with decades of prior energy production by the Company's coal-fired generators. As a result, RTP incremental usage should not be exempt from ECCR cost recovery.

**Q. IS IT APPROPRIATE TO PROVIDE AN ECCR DISCOUNT FOR RATES FPA AND EAF?**

A. No. Customers using energy under these rate schedules have and continue to use kWh energy produced by Georgia Power's generators just like every other rate schedule.

**Q. DOES STAFF RECOMMEND A CHANGE IN THE METHOD IN WHICH ECCR COSTS ARE RECOVERED ACROSS RATE SCHEDULES?**

A. Yes. Unquestionably, ECCR costs are the result and function of kWh energy produced by Georgia Power's generators. As such, these costs should be recovered on a per kWh basis. However, if all rate schedules become subject to a constant ECCR rate per kWh in this rate case, some rate schedules would experience an unreasonable overall rate increase. Therefore, as an interim step towards moving to a consistent ECCR rate per kWh, Staff recommends a mitigation approach wherein the ECCR rate per kWh reflects 50% of the kWh for RTP incremental (Day Ahead and Hour Ahead), FPA, EAF, and TOU-SC. The following table provides a comparison of current, Georgia Power proposed, and Staff recommended ECCR revenues by rate schedule:

TABLE 14
Georgia Power & Staff Recommended ECCR Revenue
($ Thousands)

| | | Current | Proposed ECCR Revenue | | ECCR $ Increase (Decrease) | |
|---|---|---|---|---|---|---|
| Rate | Class | ECCR Revenue | Georgia Power | Staff | Georgia Power | Staff |
| R, RM, SCD, OPT | DOM | $387,498 | $416,834 | $321,311 | $29,336 | ($66,187) |
| TOU-REO | DOM | $1,242 | $1,338 | $1,083 | $96 | ($159) |
| TOU-PEV | DOM | $1,413 | $1,523 | $1,297 | $110 | ($116) |
| PPS | DOM | $17,123 | $18,437 | $13,395 | $1,313 | ($3,728) |
| TOU-RD | DOM | $13,311 | $14,345 | $9,129 | $1,034 | ($4,182) |
| GS | SM. BUS. | $33,912 | $36,540 | $15,925 | $2,628 | ($17,987) |
| OGS | SM. BUS. | $250 | $269 | $99 | $19 | ($151) |
| PLS | SM. BUS. | $48,052 | $51,788 | $36,414 | $3,736 | ($11,638) |
| TOU-EO | SM. BUS. | $8,744 | $9,419 | $6,931 | $675 | ($1,813) |
| UD | SM. BUS. | $2,117 | $2,282 | $1,102 | $165 | ($1,016) |
| PLM | MD. BUS. | $127,330 | $137,283 | $125,216 | $9,952 | ($2,115) |
| TOU-GSD | MD. BUS. | $5,739 | $6,180 | $5,520 | $440 | ($219) |
| TOU-FD | MD. BUS. | $7,159 | $7,716 | $8,134 | $557 | $975 |
| PLL | LG. BUS. | $23,496 | $25,305 | $28,649 | $1,809 | $5,153 |
| TOU-HLF | LG. BUS. | $494 | $532 | $746 | $38 | $252 |
| TOU-RN | LG. BUS. | $7,177 | $7,728 | $12,240 | $550 | $5,062 |
| APS | AGRIC. | $466 | $502 | $718 | $36 | $252 |
| IOP | AGRIC. | $564 | $608 | $421 | $44 | ($143) |
| SAS-ND | AGRIC. | $24 | $26 | $17 | $2 | ($7) |
| SAS | AGRIC. | $256 | $276 | $329 | $20 | $73 |
| TOU-FS | AGRIC. | $748 | $806 | $732 | $58 | ($15) |
| G | GOV'T | $899 | $968 | $1,263 | $69 | $364 |
| SCH | GOV'T | $2,314 | $2,494 | $1,876 | $180 | ($438) |
| SLM | GOV'T | $13,386 | $14,424 | $19,794 | $1,038 | $6,408 |
| TC-M | GOV'T | $31 | $33 | $32 | $2 | $1 |
| TC-U | GOV'T | $128 | $136 | $455 | $8 | $327 |
| EOL | LIGHTING | $3,441 | $3,662 | $4,102 | $220 | $661 |
| OLG | LIGHTING | $3,531 | $3,757 | $1,868 | $226 | ($1,663) |
| OLNG | LIGHTING | $3,967 | $4,222 | $1,663 | $254 | ($2,304) |
| RLG | LIGHTING | $6,659 | $7,084 | $1,319 | $425 | ($5,340) |
| FPA | MARGINAL | $9,148 | $9,959 | $13,273 | $811 | $4,125 |
| RTP-DA CBL | MARGINAL | $65,598 | $69,962 | $89,263 | $4,364 | $23,665 |
| RTP-DA Increm. | MARGINAL | $0 | $0 | $38,115 | $0 | $38,115 |
| RTP-HA CBL | MARGINAL | $33,528 | $35,856 | $68,270 | $2,328 | $34,743 |
| RTP-HA Increm. | MARGINAL | $0 | $0 | $59,763 | $0 | $59,763 |
| TOU-SC | MARGINAL | $1,171 | $1,262 | $1,256 | $91 | $85 |
| TOU-SC Fixed | MARGINAL | $277 | $257 | $1,007 | ($20) | $730 |
| EAF | MARGINAL | $692 | $773 | $1,858 | $81 | $1,166 |
| TOTAL | | $831,887 | $894,585 | $894,585 | $62,698 | $62,698 |

## C. DEMAND SIDE MANAGEMENT TARIFFS

**Q. HOW ARE GEORGIA POWER'S DSM COSTS RECOVERED FROM CUSTOMERS?**

A. DSM costs are recovered from customers through a rider which is added to the bills of residential and commercial customers to cover the costs of all demand side program activities including the Company's additional sum. DSM costs are recovered based on a percentage of base rate revenues for the specific rate schedules. Each customer class pays only for the program costs and associated additional sum for their respective class. The DSM tariffs are updated annually to reflect the actual spending and revenues as determined through the yearly True-Up process.

**Q. DOES STAFF AGREE WITH THE METHOD IN WHICH DSM COSTS ARE RECOVERED FROM RATEPAYERS?**

A. Yes. The structure in which the DSM costs are recovered is reasonable.

## D. MUNICIPAL FRANCHISE FEE RIDER

**Q. HOW ARE GEORGIA POWER'S MUNICIPAL FRANCHISE FEES RECOVERED FROM CUSTOMERS?**

A. The MFF rider is bifurcated between those customers located inside city limits with municipal franchise fees and those located outside city limits with municipal franchise fees. These bifurcated rates are based on kWh usage.

**Q. DOES STAFF AGREE WITH THE METHOD IN WHICH MFF COSTS ARE RECOVERED FROM RATEPAYERS?**

A. Yes. The structure in which the MFF costs are recovered is reasonable.

**Q. PLEASE PROVIDE A COMPARISON OF THE COMPANY'S AND STAFF'S RECOMMENDED TOTAL ("ALL-IN") REVENUE INCREASES BY RATE SCHEDULE.**

A. The following table provides a comparison of Georgia Power's and Staff's recommended all-in revenue increases utilizing the Company's proposed levelized increase for 2023:

TABLE 15
Comparison of Georgia Power & Staff "All-In" Revenue Increases
($ Thousands)

| Rate Schedule | | Current Revenue [27] | Total Increase GPC Proposed | Total Increase Staff Proposed | Percent Increase GPC Proposed | Percent Increase Staff Proposed |
|---|---|---|---|---|---|---|
| R | DOM | $3,442,399 | $389,894 | $308,864 | 11.32% | 8.97% |
| FlatBill Risk Premium | DOM | $37,343 | $3,855 | $3,855 | 10.32% | 10.32% |
| TOU-REO | DOM | $11,106 | $1,253 | $1,032 | 11.28% | 9.29% |
| TOU-PEV | DOM | $12,936 | $1,450 | $1,263 | 11.21% | 9.77% |
| PPS | DOM | $150,738 | $17,414 | $12,946 | 11.55% | 8.59% |
| PBD Risk Prem. | DOM | $882 | $100 | $100 | 11.30% | 11.30% |
| TOU-RD | DOM | $113,865 | $13,628 | $6,855 | 11.97% | 6.02% |
| GS | SM. BUS | $274,013 | $34,771 | $17,681 | 12.69% | 6.45% |
| FlatBill GS Risk Prem. | SM. BUS | $588 | $63 | $63 | 10.71% | 10.71% |
| OGS | SM. BUS | $1,966 | $251 | $24 | 12.76% | 1.21% |
| PLS | SM. BUS | $422,630 | $49,368 | $28,368 | 11.68% | 6.71% |
| TOU-EO | SM. BUS | $77,689 | $8,930 | $5,446 | 11.49% | 7.01% |
| UD | SM. BUS | $17,370 | $2,178 | $1,056 | 12.54% | 6.08% |
| PLM | MED. BUS. | $1,191,490 | $130,513 | $104,055 | 10.95% | 8.73% |
| TOU-GSD | MED. BUS. | $53,435 | $5,758 | $3,833 | 10.78% | 7.17% |
| TOU-FD | MED. BUS. | $69,698 | $7,363 | $7,981 | 10.56% | 11.45% |
| PLL | LG. BUS. | $233,971 | $23,787 | $24,494 | 10.17% | 10.47% |
| TOU-HLF | LG. BUS. | $5,272 | $507 | $736 | 9.61% | 13.95% |
| TOU-RN | LG. BUS. | $80,547 | $7,118 | $11,926 | 8.84% | 14.81% |
| APS | AGRIC. | $5,198 | $463 | $692 | 8.91% | 13.31% |
| IOP | AGRIC. | $4,938 | $580 | $408 | 11.74% | 8.27% |
| SAS-ND | AGRIC. | $211 | $24 | $21 | 11.59% | 10.00% |
| SAS | AGRIC. | $2,606 | $261 | $368 | 10.00% | 14.13% |
| TOU-FS | AGRIC. | $6,984 | $769 | $716 | 11.01% | 10.26% |
| G | GOV'T | $9,358 | $920 | $1,244 | 9.83% | 13.29% |
| SCH | GOV'T | $20,671 | $2,378 | $1,236 | 11.51% | 5.98% |
| SLM | GOV'T | $141,858 | $13,743 | $20,502 | 9.69% | 14.45% |
| TC-M | GOV'T | $293 | $31 | $37 | 10.60% | 12.60% |
| TC-U | GOV'T | $2,007 | $128 | $473 | 6.36% | 23.58% |
| EOL | LIGHTING | $33,721 | $3,441 | $3,975 | 10.21% | 11.79% |
| OLG | LIGHTING | $28,801 | $3,533 | $1,742 | 12.27% | 6.05% |
| OLNG | LIGHTING | $31,202 | $3,970 | $1,518 | 12.72% | 4.87% |
| RLG | LIGHTING | $48,811 | $6,658 | $1,082 | 13.64% | 2.22% |
| FPA | MARGINAL | $156,614 | $13,533 | $19,892 | 8.64% | 12.70% |
| RTP-DA | MARGINAL | $901,730 | $66,016 | $124,587 | 7.32% | 13.82% |
| RTP-HA | MARGINAL | $740,579 | $34,162 | $127,083 | 4.61% | 17.16% |
| TOU-SC | MARGINAL | $14,471 | $1,165 | $1,407 | 8.05% | 9.72% |
| TOU-SC Fixed | MARGINAL | $7,056 | ($17) | $1,037 | -0.24% | 14.69% |
| EAF | MARGINAL | $17,177 | $1,239 | $2,594 | 7.21% | 15.10% |
| **TOTAL** | | $8,372,625 | $851,195 | $851,195 | 10.17% | 10.17% |

[27] All-in revenue. Includes base rates, RTP incremental, DSM, ILR, ECCR, NCCR, MFF, and Fuel.

# IV. RATE DESIGN AND OTHER TARIFF ISSUES

## A. Proposed Changes to Existing Tariffs

**Q. DOES GEORGIA POWER PROPOSE INCREASES TO THE RESIDENTIAL AND SMALL BUSINESS BASIC SERVICE (CUSTOMER) CHARGES?**

A. Yes. Except for one Small Business rate schedule (TOU-EO),[28] the Company proposes increases to all residential and small business basic service charges. The following table provides Georgia Power's current and proposed basic service charges based on its requested $739 million base rate increase:

TABLE 16
Georgia Power Current and Proposed Basic Service Charges

| | Current | | Proposed | | Monthly Increase | |
|---|---|---|---|---|---|---|
| Tariff | Daily | Monthly | Daily | Monthly | $ | % |
| Residential | | | | | | |
| R, Flat, TOU-REO, TOU-RD, & TOU-PEV | $0.4603 | $14.00 | $0.5350 | $16.27 | $2.27 | 16.23% |
| Pre-Pay & Pay-By-Day | $0.6600 | $20.08 | $0.7300 | $22.20 | $2.13 | 10.61% |
| Small Business | | | | | | |
| GS | -- | $36.00 | -- | $42.00 | $6.00 | 16.67% |
| PLS | -- | $38.00 | -- | $44.00 | $6.00 | 15.79% |
| OGS | -- | $50.00 | -- | $58.00 | $8.00 | 16.00% |
| UD | -- | $18.00 | -- | $21.00 | $3.00 | 16.67% |
| TOU-EO | -- | $96.00 | -- | $96.00 | $0.00 | 0.00% |

**Q. DOES COMPANY WITNESS LEGG PROVIDE ANY SUPPORT FOR HIS PROPOSED INCREASES TO THE BASIC SERVICE CHARGES?**

[28] On page 5 of his Direct Testimony, Mr. Legg indicates that this rate's basic service charge was not increased because this charge was adjusted to the "full amount of the customer -related costs in the 2019 base rate case."

A. No, not directly. Mr. Legg indicates that under his proposal all traditional base rates are increased on an equal percentage basis including rate elements.[29] However, in the CCOSS model provided in the Company's response to STF-TAI-1-1, there is a column entitled "Residential Customer Component" in which Company Witness Evans classified all costs as customer, demand, and energy. The residential customer related costs then reflect all costs allocated based on number of customers as well as numerous overhead and administrative & general costs allocated on internally generated allocators.

**Q. SHOULD ALL COSTS CLASSIFIED AS "CUSTOMER RELATED" INCLUDING THOSE OVERHEAD AND ADMINISTRATIVE & GENERAL COSTS BE CONSIDERED IN THE DEVELOPMENT AND DESIGN OF RESIDENTIAL AND SMALL BUSINESS BASIC SERVICE CHARGES?**

A. No. Basic service (customer) charges should only reflect those direct costs required to connect and maintain a customer's account. In comparison, the Company's residential customer cost analysis includes the following distribution plant amounts that were classified and allocated based on number of customers:

| | |
|---|---|
| Substations – Land | $68.9 million |
| Poles | $465.5 million |
| Overhead Conductors | $614.7 million |
| Underground Conduit & Conductors | $309.4 million |
| Transformers | $485.8 million |

[29] Direct Testimony of Legg, page 5, lines 6 through 9.

While these plant amounts may be appropriately allocated across classes based on number of customers, it is not appropriate to include these costs in evaluating or designing fixed monthly customer charges. Georgia Power does not incur additional investment associated with the above plant accounts to serve new customers since the Company's distribution system is fully developed such the above-related costs are placed in-service to serve the collected needs of all customers on the distribution system.

Furthermore, Georgia Power's residential customer cost analysis includes a multitude of overhead and administrative costs including:

| | |
|---|---|
| General Plant | $520.6 million |
| Intangible Plant | $171.2 million |
| Materials & Supplies | $158.2 million |
| Pre-Paid Pensions | $481.5 million |
| Uncollectibles (100%) | $12.3 million |
| Customer Assistance Expenses | $55.9 million |
| Sales Expenses | $9.7 million |
| Administrative & General Expenses | $59.8 million |

**Q. WHY IS IT INAPPROPRIATE TO CONSIDER OVERHEAD AND ADMINISTRATIVE COSTS IN THE DEVELOPMENT OF THE BASIC SERVICE (CUSTOMER) CHARGES?**

A. Like all businesses, Georgia Power incurs overhead costs in providing service to its customers. These overhead costs are simply a cost of doing business. In competitive markets, these overhead costs are invariably recovered on a volumetric basis. It is often

said that regulation should serve as a surrogate for competition such that Georgia Power's basic service charges should not incorporate various overhead costs.

**Q. IS THERE ACADEMIC SUPPORT FOR YOUR OPINION THAT FIXED MONTHLY CUSTOMER CHARGES SHOULD ONLY REFLECT THE DIRECT COSTS REQUIRED TO CONNECT AND MAINTAIN A CUSTOMER'S ACCOUNT?**

A. Yes. In his well-known treatise Principles of Public Utility Rates, Professor James C. Bonbright states:

> But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customers costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories. (Second Edition, page 492)

**Q. HAS STAFF CONDUCTED A CUSTOMER COST ANALYSIS FOR THE RESIDENTIAL AND SMALL BUSINESS CLASSES TO EVALUATE THE REASONABLE LEVEL OF FIXED MONTHLY CUSTOMER CHARGES?**

A. Yes. As indicated earlier, customer costs should only reflect those costs that are required to connect a new customer and maintain that customer's account. The approach used and which is widely-used in the industry is often referred to as a modified "Direct Customer Cost" analysis. Specifically, in addition to those direct costs required to connect and maintain a customer's account, Staff's analysis also includes certain indirect costs such as General Plant, Intangible plant, and Administrative & General expenses associated with

customer accounting. This analysis produces the following range of reasonable customer costs that should be reflected in basic service charges:

TABLE 17
Staff Monthly Customer Cost & Current Charge

| | Cost of Capital | | | Current Monthly Basic Service Charge |
|---|---|---|---|---|
| | Staff | | Company | |
| Total Residential | $12.09 | - | $12.59 | $14.00 [30] |
| Small Business: | | | | |
| GS | $16.61 | - | $17.31 | $36.00 |
| PLS | $22.05 | - | $23.00 | $38.00 |
| OGS | $27.22 | - | $28.32 | $50.00 |
| UD | $7.56 | - | $7.84 | $18.00 |
| TOU-EO | $26.50 | - | $27.64 | $96.00 |

The details supporting Staff's Direct Customer Cost analysis are provided in Staff Exhibit __ (BDW-9).

**Q. WHAT ARE STAFF'S RECOMMENDATIONS REGARDING RESIDENTIAL AND SMALL BUSINESS MONTHLY CUSTOMER (BASIC SERVICE) CHARGES?**

A. Considering that the current basic service charges are higher than a reasonable level of customer costs, and in the interest of rate continuity, Staff recommends no increases to the residential and small business basic service charges.

[30] The basic service charge for Residential Pre-Pay and Pay-By-Day is currently $20.08 per month ($0.66 per day).

**Q. PLEASE EXPLAIN HOW THE ENERGY RATE FOR THE RESIDENTIAL SERVICE TARIFF IS STRUCTURED.**

A. For several years, Georgia Power's residential energy rates have been seasonally differentiated with an inverted-block rate structure during the summer months of June through September and a declining-block rate structure during the non-summer months. A comparison of the current residential Service Schedule ("R-25") energy charges is provided below:

TABLE 18
Current R-25 Energy Charges

| Season | Rate | Percentage of First Block |
|---|---|---|
| Summer | | |
| First 650 kWh | 5.8366¢ | 100% |
| 651 to 1,000 kWh | 9.6943¢ | 166% |
| All Over 1,000 kWh | 10.0336¢ | 172% |
| Non-Summer | | |
| First 650 kWh | 5.8366¢ | 100% |
| 651 to 1,000 kWh | 5.0062¢ | 86% |
| All Over 1,000 kWh | 4.9143¢ | 84% |

As shown above, the energy charge for the first 650 kWh of usage is the same for both the summer and non-summer periods. During the four summer months of June through September, the residential energy charge increases as usage increases such that the second usage block (651 to 1,000 kWh) is priced at 66% more than the first 650 kWh of usage. Similarly, the summer tail block is priced at a graduated rate of 72% greater than the first block. Conversely, during the non-summer months (October through May), the residential energy charge decreases as usage increases such that the second usage block (651 to 1,000

kWh) is priced at 14% less than that for the first 650 kWh of usage. In addition, the non-summer tail block is priced at an even lower rate of 16% less than the first block.

**Q. HAS GEORGIA POWER'S LOAD PATTERNS AND SEASONAL GENERATION PLANNING CHANGED OVER THE LAST SEVERAL DECADES?**

A. Yes. In the past, Georgia Power was predominately concerned with summer loads for its reliability planning. However, over the years, the Company's load profiles have changed such that for planning purposes, much more consideration is given to winter loads and energy requirements. To illustrate, the 2022 Georgia Power Integrated Resource Plan ("IRP") notes and emphasizes the changing seasonal dynamics confronted by Georgia Power. Specifically, with respect to generation reserve margins, the IRP states:

> In order to effectuate seasonal planning, the Company must also establish seasonal Target Reserve Margins. The Reserve Margin Study evaluated the need for these seasonal Target Reserve Margins. Notably, the results of the most recent Reserve Margin Study continue to reflect the significant increase in winter reliability risks. These risks are associated with the following drivers: (1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) cold-weather-related unit outages; (4) the penetration of solar resources; (5) increased reliance on natural gas; and (6) market purchase availability. Given the difference in customer load response as well as differences in both the availability and dependability of resources in the summer and winter peak periods, it remains necessary to independently evaluate Resource Adequacy in both the summer and winter peak periods to ensure that System reliability has been appropriate evaluated.[31]

**Q. ARE GEORGIA POWER'S PEAK LOADS AND ENERGY USAGE RELATIVELY HIGH IN THE WINTER MONTHS?**

[31] 2022 IRP, page 5-26.

A. Yes. While Georgia Power continues to incur its annual peak load in the summer, loads and energy usage are also relatively high during the cold winter months as shown in the tables below:

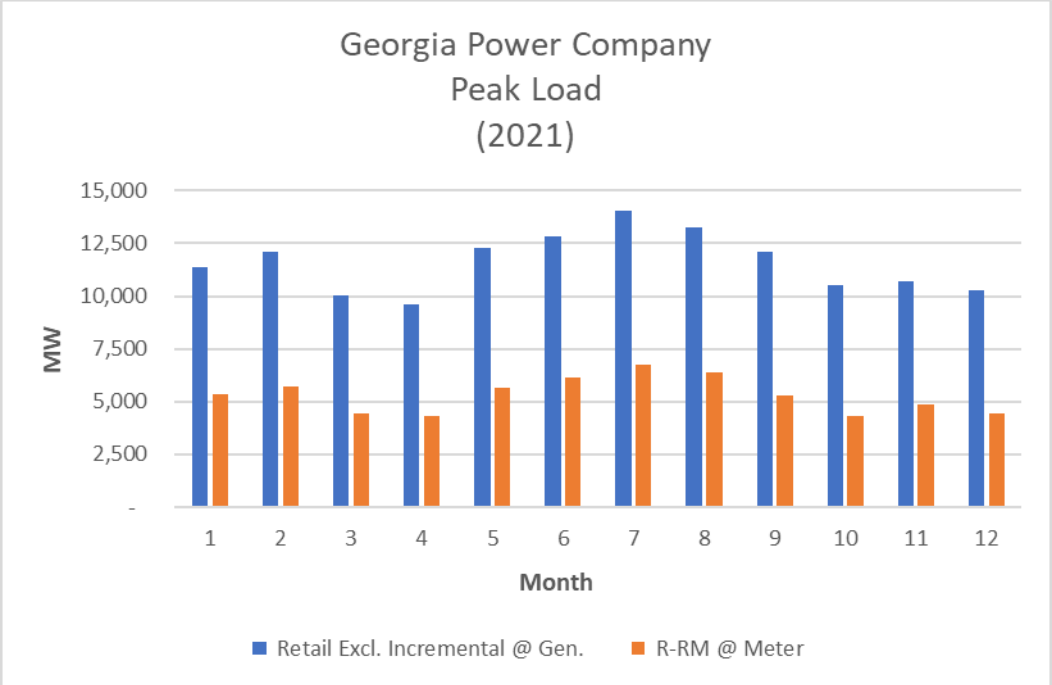
TABLE 19
Georgia Power
Monthly Peak Loads (MW)
2021

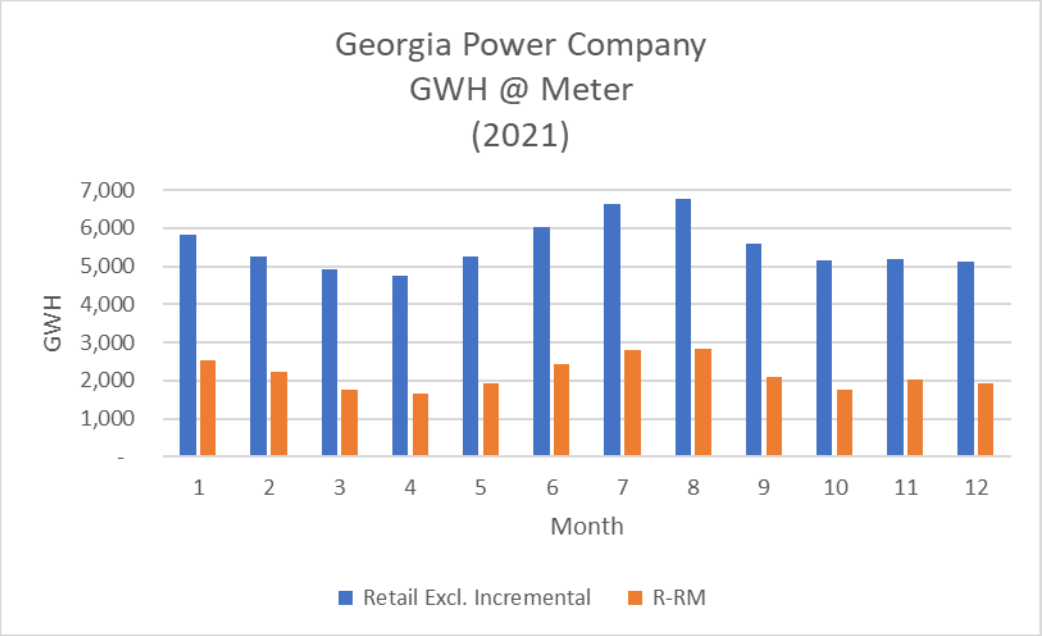
| Month | Retail (Excl. RTP Incremental) @ Gen. | Rate R-RM @ Meter |
|---|---|---|
| 1 | 11,347 | 5,362 |
| 2 | 12,123 | 5,707 |
| 3 | 10,034 | 4,466 |
| 4 | 9,614 | 4,301 |
| 5 | 12,260 | 5,656 |
| 6 | 12,804 | 6,113 |
| 7 | 14,068 | 6,746 |
| 8 | 13,263 | 6,411 |
| 9 | 12,097 | 5,309 |
| 10 | 10,520 | 4,325 |
| 11 | 10,673 | 4,877 |
| 12 | 10,246 | 4,463 |

TABLE 20
Georgia Power
Monthly Energy (GWH)
2021

| Month | Retail (Excl. RTP Incremental) @ Meter | Rate R-RM @ Meter |
|---|---|---|
| 1 | 5,813 | 2,524 |
| 2 | 5,246 | 2,218 |
| 3 | 4,932 | 1,767 |
| 4 | 4,750 | 1,669 |
| 5 | 5,260 | 1,923 |
| 6 | 6,041 | 2,431 |
| 7 | 6,631 | 2,790 |
| 8 | 6,774 | 2,833 |
| 9 | 5,592 | 2,079 |
| 10 | 5,146 | 1,765 |
| 11 | 5,170 | 2,027 |
| 12 | 5,128 | 1,935 |

The tables provided above are provided graphically below:






As indicated in the above tables and graphs, both the system (retail) and the residential customers receiving service on the R-25 tariff have considerably high loads and energy requirements during the traditional winter months.

**Q. DOES STAFF RECOMMEND ANY CHANGES TO THIS RESIDENTIAL SERVICE ("R") RATE STRUCTURE?**

A. Yes. While Staff concurs with the concept of an inverted-block rate during the high cost summer months since it will provide customers a proper price signal during this high cost period, we recommend the elimination of the declining-block rates during the non-summer months to a flat rate for all kWh usage. Specifically, Staff recommends that the relationship between the summer and non-summer base rate energy charge revenues be maintained.

**Q. DOES THE COMPANY PROPOSE ANY OTHER CHANGES TO THE R TARIFF?**

A. Yes. The Company proposes to make the R tariff unavailable to newly constructed premises that are established on Georgia Power's system after December 31, 2022.

**Q. DOES THE COMPANY PROPOSE TO ALSO MAKE OTHER RESIDENTIAL TARIFF OPTIONS UNAVAILABLE TO ALL CUSTOMERS BEGINNING JANUARY 1, 2023?**

A. Yes. While the Company proposes to continue its residential Time-of-Use Residential Energy Only (TOU-REO) for those customers already subscribed under this optional rate, under the Company's proposal, this tariff option will not be available to new or existing customers after January 1, 2023.

**Q. WHAT ARE THE RAMIFICATIONS OF THE COMPANY'S PROPOSALS TO ELIMINATE THE R RATE FOR NEW CUSTOMERS AND TO ELIMINATE THE TOU-REO FOR EXISTING AND NEW CUSTOMERS THAT MAY WANT TO RECEIVE SERVICE UNDER THIS RATE OPTION AFTER JANUARY 1, 2023?**

A. Although the Company will continue to offer a flat bill Pre-Pay option to residential customers as well as the TOU-PEV rate targeted for those customers with plug-in electric vehicles, the Company is clearly attempting to move to a demand-based rate for most residential customers. To be clear, approximately 74.7% of current residential customers are on energy-based rates (R, TOU-REO, and TOU-PEV), approximately 21.4% of current residential customers are on either the Flat rate or Pre-pay rates, and approximately 3.4% of current residential customers are on a demand-based rate (TOU-RD). In this regard,

there has been significant growth in TOU-RD since the 2019 rate case because it became the default rate for customers in new premises such that if an eligible customer is unaware or does not select another tariff when signing up for service, they are automatically placed on TOU-RD.

**Q. WHY DOES THE COMPANY PROPOSE TO MAKE THE R TARIFF UNAVAILABLE TO NEW PREMISES THAT ARE CONNECTED TO THE COMPANY'S SYSTEM AFTER DECEMBER 31, 2022?**

A. In the Direct Testimony of Larry Legg page 8 lines 21-26, he states that "the Company's proposal is the logical next step in the Company's ongoing efforts to encourage residential customers to move toward more modern rate structures. As initially discussed in the Company's 2019 base rate case, utilities across the country are proactively moving away from more antiquated volumetric rate designs (such as the R tariff) and toward more modern rate designs that send price signals that more appropriately reflect the cost of service."

**Q. ARE DEMAND-BASED RATES A NEW FEATURE OF "MODERN" RATE STRUCTURES?**

A. No. While two-part electric rates (customer charge plus energy charge) have been in place since the 1880s, three-part rates (customer, energy, and demand) were first introduced by Henry L. Doherty as early as 1900.[32] However, three-part rates have historically been

[32] Per James C. Bonbright, Principles of Public Utility Rates, Second Edition, page 401. In this regard, Samuel Insull, a colleague of Thomas Edison is also given credit for the invention of three-part rates (customer, energy, and demand) at the turn of the 20th Century.

utilized for larger commercial and industrial customers such that the two-part rate for residential customers has been tried and true for over a century.

**Q. IS COMPANY WITNESS LEGG'S STATEMENT THAT UTILITIES ACROSS THE COUNTRY ARE MOVING AWAY FROM VOLUMETRIC RATE DESIGNS CORRECT?**

A. No. As will be discussed below, there is not a single investor-owned utility ("IOU") in the country that has mandatory residential demand charge rates. In STF-PIA-2-5, the Company was asked to "Please provide any research or analysis of the Company related to demand charges in other jurisdictions." The Company's response was as follows:

> Georgia Power is generally aware of the residential demand rate options that are available through regulated electric utilities across the country. However, the Company does not have an internally developed analysis or summary of these programs.
>
> In the 2019 base rate case filing, Georgia Power witness Dr. Ahmad Faruqui included exhibit AF-2 in support of his testimony that highlighted 62 residential three-part tariffs from across the country that his firm, The Brattle Group, had identified.

Similarly, in STF-TAI-1-29, the Company was asked the following:

> Based on the Company's research and analysis or a consultant on its behalf, please provide all examples of jurisdictions or utilities who are eliminating or reducing standard volumetric rate options for residential customers?

The Company's response was:

> The Company has not performed a specific analysis of which utilities or jurisdictions are eliminating standard volumetric rate options for residential customers. However, as noted in the Company's testimony, utilities across the country are moving away from more antiquated volumetric rate designs (such as the R tariff) and toward more modern rate designs that send price

> signals that more appropriately reflect the cost of service. This trend has been well documented throughout industry press, highlighted at utility conferences, and advanced through regulatory filings for many years. This transition is not isolated to regulated electric utilities but is also prevalent in cooperatives and municipal providers. The Company's expert witness in the 2019 base rate case, Dr. Ahmad Faruqui, identified utilities that are making this transition and he explained the appropriateness for these new modern rate designs that send more accurate price signals and help achieve the goals of promoting economic efficiency and equity. His testimony goes further to identify different types of modern rate designs and gives specific examples in Table 2 of his testimony of utilities that have experienced success with moving to these improved options. Dr. Faruqui's testimony remains relevant today and supports the Company's position of encouraging customers to move to more modern rate structures.

As indicated in these two data request responses, even though the Company has not conducted its own investigation, it relies upon a 2019 Rate Case exhibit provided by Georgia Power's expert, Dr. Ahmad Faruqui. The referenced exhibit prepared by Dr. Faruqui is provided as Staff Exhibit __ (BDW-10).[33]

A careful review of Dr. Faruqui's exhibit shows that there are nine utilities located in six states with mandatory demand charges.[34] Each of these utilities are either cooperatives or municipals that are self-regulated and not regulated by a state regulatory commission. In fact, there is not a single IOU in the country regulated by a state regulatory commission that has mandatory residential demand charges.

[33] While Dr. Faruqui's Exhibit AF-2 is captioned as confidential, this exhibit was obtained on the Georgia Public Service Commission website for Docket No. 42156.

[34] Butler Rural Electric Cooperative (KS), City of Templeton (MA), Flathead Electric Cooperative (MT), Mid-Carolina Electric Cooperative (SC), Platte-Clay Electric Cooperative (MO), Santee Cooper Electric Cooperative (SC), Sun River Electric Cooperative (MT), Swanton Village Electric Department (VT), and Vigilante Electric Cooperative (MT).

**Q. HAS ANY OTHER IOU REGULATED BY A STATE REGULATORY COMMISSION PROPOSED MANDATORY RESIDENTIAL DEMAND CHARGES FOR ALL RESIDENTIAL CUSTOMERS?**

A. Yes. Staff is aware of one instance. Arizona Public Service Company in a 2016 rate case. In that case, the Commission rejected the Company's proposal for mandatory residential demand charges.[35]

**Q. HAS STAFF INVESTIGATED THE NEED OR REASONABLENESS OF HAVING A RESIDENTIAL DEMAND CHARGE AS EITHER THE DEFAULT RATE OR THE ONLY MONTHLY VARIABLE USAGE-BASED RATE AVAILABLE TO NEW RESIDENTIAL CUSTOMERS?**

A. Yes. We have conducted three separate quantitative analyses. Under the current and proposed residential demand-based rate (TOU-RD), a customer would be subject to a demand charge based on the highest level of power (kW) during any 60-minute period of each billing cycle. While some residential customers may incur their peak load during the morning, others may incur their peak load during the evening hours. Furthermore, one residential customer may reach their peak load on one day of the month while their neighbor's peak load occurs during a different day of the month. This load diversity across customers within the residential class, in and of itself, indicates that a demand charge based on whenever an individual customer's peak occurs is not a reflection of cost causation, nor does it promote the efficient utilization of Georgia Power's total resources. As important

[35] Arizona Corporation Commission, Docket No. E-01345A-16-0036.

is the fact that even though Georgia Power's total system load and energy requirements are greater on weekdays than weekends, the opposite is true for the residential class.

In the Company's response to STF-TAI-1-12, the Company provided hourly loads for the residential class during calendar year 2021. With this data, Staff evaluated typical residential and non-residential hourly loads during weekdays and weekends for the months of January and July 2021.[36] Staff Exhibit __ (BDW-11) and Staff Exhibit __ (BDW-12) compare typical weekday and weekend hourly loads for the residential and non-residential classes during January and July, respectively.

As indicated in these exhibits, the non-residential load tends to be considerably lower on weekends/holidays than during weekdays. Conversely, residential loads tend to be greater on weekends/holidays than during weekdays. The importance of this as it relates to Georgia Power's residential demand charge is that many (if not most) residential customers will peak on a weekend (and thus will be the basis for their monthly demand charge) even though the system load tends to be considerably lower during the weekend. This diversity in the timing of class loads tends to benefit the entire system by flattening the diurnal system load curve.

[36] Typical hourly loads were calculated as the average hourly load for each day in a given month separated between weekdays and weekends/holidays. The months of January and July were evaluated because these represent the peak winter and summer months.

**Q. PLEASE DISCUSS THE SECOND ANALYSIS STAFF CONDUCTED CONCERNING GEORGIA POWER'S RESIDENTIAL DEMAND-BASED RATES.**

A. As a result of the hourly data provided in the Company's response to STF-TAI-1-12, Staff was able to calculate and compare monthly load factors between the R Rate (energy only rate) to those for TOU-RD (demand charge rate).[37] The following table provides a comparison of monthly load factors between the energy only rate (R Service) and the demand-based rate (TOU-RD):

TABLE 21
Monthly Class Load Factor

| | Rate | |
|---|---|---|
| Month | R Service | TOU-RD |
| January | 63% | 50% |
| February | 58% | 54% |
| March | 53% | 56% |
| April | 54% | 42% |
| May | 46% | 44% |
| June | 55% | 52% |
| July | 56% | 56% |
| August | 59% | 55% |
| September | 54% | 51% |
| October | 55% | 39% |
| November | 58% | 50% |
| December | 58% | 52% |

Although the monthly load factors tend to be fairly similar between the R Rate and TOU-RD, it is observed that energy only rate customers' (R Rate) load factors are actually higher

[37] Load factors measure the relative relationship between energy usage and peak load wherein the formula is: [(Total Energy Usage ÷ Hours) ÷ Peak Load]. A higher load factor indicates that energy is used more uniformly across hours of the day; i.e., load does not vary as much as with a lower load factor.

than the demand-based rate customers' (TOU-RD) load factors for every month except for March. This analysis indicates that first, those customers receiving service under demand-based rates have not improved their load factor relative to energy only rate customers such that they have not reduced their peak demands relative to their energy usages. Furthermore, we see that for all months except for March, demand-based customers' relationship between energy and peak demand is even worse than those of the energy only rate customers. This finding is of course contrary to any claimed objectives of demand-based rates for the residential class. In other words, residential customers on TOU-RD have not responded or reduced their peak load relative to their energy usage by being on a demand-based rate.

**Q. PLEASE EXPLAIN THE THIRD ANALYSIS STAFF CONDUCTED CONCERNING GEORGIA POWER'S RESIDENTIAL DEMAND-BASED RATES.**

A. It has often been said that the energy charges a residential customer pays serve as a good surrogate for that customer's level of peak demand. In other words, there tends to be a strong correlation between peak demand and energy usage; i.e., customers with high peak demands tend to also utilize high levels of energy, and therefore, reasonably pay for demand costs and vice versa. In STF-TAI-2-2, the Company was requested to provide a database that provided every residential customers' bill during 2021 that included the specific rate schedule, billing date, number of days in bill, billed kW, maximum kW and date and time of maximum kW. The Company provided the data that it does maintain;

however, the Company indicated that monthly peak demands are not recorded for residential customers except for those taking service under the TOU-RD rate schedule.

Regarding individual bills for TOU-RD that did include demand data, Staff was able to evaluate the correlation between these customers' monthly energy usage and peak demands. Georgia Power provided 339,200 records for these TOU-RD customers. In evaluating the relationship between energy usage and peak demand, 99,835 records were eliminated due to anomalies or potentially misleading results leaving a database for evaluation 239,365 observations.[38] The analysis showed that there is a 77% correlation between a customer's energy usage and peak demand.[39] This analysis supports the contention that there is a strong relationship between the level of energy a customer uses and the customer's peak demand such that a two-part (energy only) rate serves as a good surrogate, or proxy, for the level of the customer's maximum demand.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S REQUEST TO NOT ALLOW NEW PREMISES ON THE R RATE AFTER JANUARY 1, 2023?**

A. Staff does not support the R tariff being unavailable to new premises after January 1, 2023 as customers should continue to be allowed to choose a two-part rate option (basic service

[38] Records eliminated include: bills less than 25 days (49,041), bills greater than 35 days (424), billed kW less than 100 (12,477), billed kW less than or equal to 0 (458), monthly load factor greater than 100% (117), and load factor less than 10% (37,318).

[39] Specifically, the correlation coefficient for all bills evaluated is 76.62% and for those customers using less than 5,000 kWh coefficient is 77.03%.

plus energy charge). Therefore, Staff recommends that the Company's request to not allow new premises after January 1, 2023 to receive service on the R tariff be denied.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO NOT ALLOW EXISTING OR NEW CUSTOMERS THE OPTION OF TAKING SERVICE USING TOU-REO?**

A. Staff recommends that TOU-REO continue to be an optional tariff for all residential customers as this rate provides a viable option for customers to shift their load and usage patterns from on-peak (high cost) hours to off-peak (low cost) hours thereby benefiting the entire Georgia Power system. Indeed, and as stated in Mr. Legg's Direct Testimony, page 2, lines 23 and 24, "Georgia Power takes pride in being an industry leader that offers an innovative and robust portfolio of rate options that meet our customers' evolving energy needs."

**Q. IN ADDITION TO THE PROPOSED CHANGES TO THE R TARIFF, HAS THE COMPANY PROPOSED CHANGES TO ANY OF ITS OTHER TARIFFS?**

A. Yes. In the Direct Testimony of Larry Legg, the Company proposed changes to the following tariffs and programs: FlatBill, FlatBill General Service, Income-Qualified Senior Citizen Discount program, Roadway Lighting Governmental ("RLG"), Demand Plus Energy Credit ("DPEC"), RNR, CS, and SS.

**Q. PLEASE DESCRIBE THE CHANGES THAT THE COMPANY IS PROPOSING TO FLAT BILL AND FLAT BILL GENERAL SERVICE.**

A. The Company is proposing a minimum monthly offer of $50 per month for Flat Bill customers. This proposed change does not impact current Flat Bill customers and as provided in the Company's response to STF-TAI-1-18, currently fewer than 2 percent of Flat Bill customers pay less than $50 per month. Based on the Company's proposal, customers who do not qualify with the increased minimum amount will not be offered the Flat Bill option.

**Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S PROPOSED CHANGES TO THE FLAT BILL TARIFFS?**

A. Yes. Staff recommends approval of the Company's proposed changes to the Flat Bill tariffs. In addition, Staff recommends that the Company be required to increase the availability and awareness of seasonally smoothed Budget Billing to its customers. Budget Billing serves a customer's interest by providing more consistent billing amounts while still reflecting the customer's most recent usage and conservation.

**Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE INCOME QUALIFIED SENIOR CITIZENS DISCOUNT?**

A. Yes. The Company is proposing to increase the income qualified senior citizens discount to reflect its proposed increase to the Basic Service Charge. As noted earlier, Staff is not recommending an increase to the residential Basic Service Charge; however, in the event the Commission was to approve an increase in the Basic Service Charge for residential

customers, Staff would support an increase to the Income Qualified Senior Citizens discount.

**Q. HAS THE COMPANY ANALYZED THE EXPANSION OF INCOME QUALIFIED DISCOUNTS BEYOND SENIOR CITIZENS?**

A. Yes. As a requirement from the Final Order in Docket No. 42516 which states that, "the Company, Georgia Watch, and Commission Staff shall collaborate on a process to consider potential options for the expansion of income qualified discount opportunities to assist customers." After the parties met on April 28, 2020 and August 18, 2020, the Company analyzed two possible programs. One of the policy options would have expanded the current Senior Citizen Discount to all qualified customers regardless of age, while the other option targeted customers with high energy burdens to attempt to bring their cost to below the 6 percent of income threshold. After soliciting comments from stipulating parties from the previous rate case, the Company filed a report on November 2, 2020 which is being provided as Staff Exhibit __ (BDW-13). This report recommended no further action on an expanded discount program at that time.

**Q. DOES STAFF HAVE A RECOMMENDATION REGARDING THE EXPANSION OF INCOME QUALIFIED DISCOUNT OPTIONS?**

A. Yes. Staff recommends that the analysis and discussion of policy options regarding the expansion of income qualified discounts continue between the parties including the Company, Staff, and other interested parties. These discussions should take place within 3

months following the Final Order in this docket. The Company should be required to file a report that provides the details of its analysis and recommendations for Commission consideration.

**Q. WHAT IS THE CURRENT DEFAULT TARIFF FOR RESIDENTIAL CUSTOMERS WHEN SIGNING UP FOR SERVICE?**

A. Residential customers default to one of two rates if the customer does not select a rate when signing up for service. For customers in residential premises that were constructed before January 1, 2021, the default rate is R. For customers in residential premises constructed after January 1, 2021, the default rate is TOU-RD.

**Q. WHEN DID THE TOU-RD BECOME THE DEFAULT RATE FOR PREMISES CONSTRUCTED AFTER JANUARY 1, 2021?**

A. As part of the Order adopting Stipulation during the 2019 Georgia Power Rate Case, TOU-RD became the default rate for premises constructed after January 1, 2021 for customers that don't choose a tariff when establishing service.

**Q. IN THE 2019 RATE CASE, DID THE COMMISSION REQUIRE THE COMPANY TO INCREASE ITS MARKETING FOR THE TOU-RD RATE?**

A. Yes. The Final Order in Docket No. 42516 stated that "The Proposed Agreement also provides that the Company and Commission Staff shall collaborate in 2020 to increase marketing of the TOU-RD rate." The Company and Staff met on September 10, 2020 to discuss the marketing of this tariff throughout 2020.

**Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION ORDER TO PROVIDE EDUCATIONAL MATERIALS TO CUSTOMERS DEFAULTED ON TO THE TOU-RD RATE?**

A. Yes. As provided in the Company's response to STF-PIA-2-3, "New customers to the Smart Usage rate (TOU-RD) receive a welcome letter that confirms their enrollment and provides helpful information to educate them on how to take advantage of the rate's design." Customers on TOU-RD also receive seasonal postcards with information about the rate and there is material on the Georgia Power website.

**Q. WHAT HAS BEEN THE BILL IMPACT FOR CUSTOMERS ON TOU-RD?**

A. As shown in the table below, using data from the Company's response to STF-PIA-2-1, customers on the TOU-RD rate pay on average approximately $200 more per year than if they were receiving service on the R tariff.

TABLE 22

| Month | Average Actual Smart Usage Bill for Individual TOU-RD Customers | Average Residential Bill for Individual TOU-RD Customers if they were on the R Rate | Increased Cost to Average Customer on TOU-RD |
|---|---|---|---|
| **Jun-21** | $89.70 | $82.73 | $6.98 |
| **Jul-21** | $113.13 | $106.22 | $6.91 |
| **Aug-21** | $125.77 | $125.83 | -$0.07 |
| **Sep-21** | $122.60 | $119.47 | $3.13 |
| **Oct-21** | $101.56 | $78.25 | $23.31 |
| **Nov-21** | $102.02 | $77.97 | $24.06 |
| **Dec-21** | $117.60 | $95.59 | $22.02 |
| **Jan-22** | $129.82 | $109.59 | $20.23 |
| **Feb-22** | $138.24 | $120.62 | $17.61 |
| **Mar-22** | $118.52 | $91.35 | $27.17 |
| **Apr-22** | $110.31 | $83.51 | $26.80 |
| **May-22** | $108.30 | $88.28 | $20.02 |
| **TOTAL** | $1,377.56 | $1,179.41 | $198.15 |

These higher bills result for customers even as the TOU-RD customer peak demands are slightly lower than for all residential customers, based on the data provided in the Company's response to STF-PIA-2-1 (see table 23 below).

TABLE 23

| Month | Average Peak Demand Individual TOU-RD Customers in kW | Average Peak Demand All Individual Residential Customers in kW | Amount Lower of Average Demand for TOU-RD Customers in kW |
|---|---|---|---|
| **Jun-21** | 5.4108 | 7.151 | 1.7406 |
| **Jul-21** | 5.7368 | 7.049 | 1.3121 |
| **Aug-21** | 5.9531 | 7.203 | 1.2496 |
| **Sep-21** | 5.8477 | 7.143 | 1.2949 |
| **Oct-21** | 5.5896 | 6.657 | 1.0675 |
| **Nov-21** | 6.4205 | 7.036 | 0.6151 |
| **Dec-21** | 7.2439 | 7.610 | 0.3664 |
| **Jan-22** | 7.6274 | 7.996 | 0.3687 |
| **Feb-22** | 7.9401 | 8.168 | 0.2274 |
| **Mar-22** | 7.2502 | 7.453 | 0.2032 |
| **Apr-22** | 6.7073 | 6.950 | 0.2427 |
| **May-22** | 6.2016 | 6.677 | 0.4750 |
| **AVERAGE** | 6.4941 | 7.2577 | 0.7636 |

**Q. BEYOND HIGHER BILLS FOR CUSTOMERS, WHAT OTHER CONCERNS DOES STAFF HAVE REGARDING THE TOU-RD RATE BEING THE DEFAULT RATE FOR NEW RESIDENTIAL PREMISES?**

A. In addition to higher bills, Staff has concerns as to whether customers understand how demand and related demand charges are determined. Staff also has concerns because the rate, as currently constructed, does not have significant system benefits due to customers bill being determined based on a noncoincident peak demand. As an optional rate, TOU-RD might be a good rate option for more sophisticated customers, but as a default rate TOU-RD does not best serve the interests of most new customers. As previously discussed, customers' bills are, on average, higher than they would be under the R rate.

**Q. DOES THE COMPANY CURRENTLY PROVIDE ANY TOOLS TO ASSIST CUSTOMERS IN VERIFYING THEIR BILL OR ALLOWS FOR A COMPARISON OF DIFFERENT RATE OPTIONS?**

A. No. The Company does not currently offer any tools for residential customers to export or input their usage data in order to calculate their bill or allows the customer to calculate their bill under different rate options. The Commission's website hosts a bill calculator for customers receiving service on the R tariff and Company's website does have a link to the Commission's Bill Calculator.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE USE OF TOU-RD AS THE DEFAULT RATE FOR PREMISES CONSTRUCTED AFTER JANUARY 1, 2021?**

A. Staff recommends that the R rate become the default tariff for all residential premises regardless of when the premise was constructed and added to the Company's system. In addition, Staff recommends that the Company be required to provide further tools to assist residential customers in understanding and choosing a tariff that best suits their needs.

**Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE UNDERGROUND SERVICE CUSTOMER CHARGE?**

A. The Company is proposing an underground service tariff that reflects cost of service. The one-time $1,000 payment for each underground service point connection would increase to $1,200 effective January 1, 2024.

**Q. DOES STAFF RECOMMEND APPROVAL OF THE PROPOSED INCREASE TO THE UNDERGROUND SERVICE CUSTOMER CHARGE?**

A. Yes. It is Staff's position that the customer requesting underground service should be responsible for the cost associated with providing that service. Therefore, Staff recommends approval of the Company's proposed increase to $1,200 for each underground service point interconnection.

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE RLG TARIFF.**

A. In the Direct Testimony of Larry Legg, pg. 11 lines 1-3, the Company is proposing several changes to the RLG tariff in order to clarify the existing fixture options, expand and clarify the available pole options, and close one fixture to future customer enrollments. The Company states that these changes will enable it to continue offering an array of LED options for roadway lighting requirements that helps to serve the needs of Governmental customers.

**Q. DOES STAFF RECOMMEND APPROVAL OF THE PROPOSED CHANGES TO THE RLG TARIFF?**

A. Yes. Staff recommends approval of the Company's proposed changes to the RLG tariff in order to continue serving the roadway lighting needs of its Governmental customers.

**Q. PLEASE DESCRIBE THE DPEC PROGRAM AND THE COMPANY'S PROPOSED CHANGES TO THIS PROGRAM.**

A. DPEC is a voluntary program for large customers who provide at least 200 kW of demand reduction during extreme supply and demand conditions on the Company's system. The Company is proposing to modify the DPEC rider by updating the energy credits and demand values in Part I of the rider to reflect updated costs.

**Q. DOES STAFF RECOMMEND APPROVAL OF THE PROPOSED CHANGES TO DPEC?**

A. Yes. Staff recommends approval of the modified Demand and Energy Credit for customers who contract for DPEC on or after July 1, 2013.

**Q. DOES THE COMPANY PROPOSE TO ELIMINATE ANY OF ITS TARIFFS?**

A. Yes. The Company is proposing to eliminate the Power & Light High Load Factor **(**"PLH") and Solar Purchase ("SP") tariffs.

**Q. PLEASE DESCRIBE THE PLH AND SP TARIFFS.**

A. The PLH tariff has a very narrow applicability to large customers with steady demand and previously had only one customer taking service on this rate. Currently, there are no customers receiving service on this tariff. The PLH tariff is only available to industrial customers contracting for not less than 10,000 kW and with an annual billing load factor of not less than 75 percent.

The SP tariff was approved by the Commission on October 14, 2010 in Docket No. 16573 and was used to procure additional solar capacity at a premium above avoided cost. The

Company provided several reasons for making its request to add more solar purchases at the time including: procuring additional resources that would allow the Company's customers to take advantage of federal and state incentives, requiring customers to file project cost and operational data to gain cost, and operational knowledge of solar electricity generation. The Commission approved the closure of the SP tariff as part of the 2016 IRP. As provided in the Direct Testimony of Larry Legg, pg. 16 lines 11-13, all customers who participated in the SP tariff have transitioned off the program to other programs or tariffs.

**Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S REQUEST TO ELIMINATE THE PLH AND SP TARIFFS?**

A. Yes. Since there are no customers receiving service on either of these tariffs and there will not be any impacts to customers, Staff recommends approval of the Company's request to eliminate these tariffs.

**Q. PLEASE DESCRIBE THE MODIFICATIONS THAT THE COMPANY IS PROPOSING TO MAKE TO THE RNR TARIFF.**

A. The Company is proposing two modifications to the RNR tariff. The first proposed modification is the addition of language that would prohibit customers that receive service on RTP tariffs from participating in RNR-Monthly Netting. However, these customers would be able to participate in RNR-Instantaneous Netting.

The Company's second proposed change to the RNR tariff is the elimination of the Witness Testing cost of $5/kW AC and the inclusion of a one-time Interconnection Fee. The specific

Interconnection Fee amount is a proposed modification that was made in the Company's Rules and Regulations.

**Q. ARE THERE CURRENTLY OTHER CUSTOMERS THAT ARE NOT ALLOWED TO PARTICIPATE IN RNR-MONTHLY NETTING?**

A. Yes. As provided in the current RNR tariff and provided as Staff Exhibit __ (BDW-14), the RNR-Monthly Netting option is not available to customers receiving service under the FlatBill, Pre-Pay or CS tariffs.

**Q. DOES STAFF RECOMMEND APPROVAL OF THE COMPANY'S REQUEST TO EXEMPT RTP CUSTOMERS FROM BEING ABLE TO PARTICIPATE IN RNR-MONTHLY NETTING?**

A. Yes. Staff recommends approval of the request to exempt RTP customers from participating in RNR Monthly Netting.

**Q. PLEASE DESCRIBE THE COMPANY'S CURRENT CS PROGRAM.**

A. The Company's CS program was first approved during the 2016 IRP for 3 MW. As part of the Company's 17th Vogtle Construction Monitoring ("VCM") proceeding, the program was expanded by an additional 5 MW for a total of 8 MW of projects. To meet this capacity need, the Company procured the 2 MW Comer facility, the 3.6 MW Solar Savannah facility, and the 2.4 MW Solar Vogtle facility. Originally available only to Georgia Power's residential customers, the Community Solar program was modified recently in the Company's 2022 IRP to provide for a commercial customer offering for customers on the

General Service tariff. The CS program was also modified to include an Income-Qualified Pilot. This pilot will provide discounted community solar subscriptions to up to 5,000 residential customers below 200% of the current federal annual poverty level. This program would be supported by corporate sponsorships covering 75% of the subscription cost for those income-qualified customers. On August 23, 2022, as part of the Supplemental filing, the Company filed a tariff to reflect modifications to the CS program that were approved as part of the IRP Order.

**Q. PLEASE DESCRIBE THE PURPOSE OF CS PROGRAMS.**

A. The purpose of many CS programs is to provide an opportunity for customers to realize the benefits of rooftop solar that are unable due to financial or for other reasons unable to add a rooftop solar system to their home. Most CS programs are designed to pass along the savings realized from the solar system through bill credits and renewable energy credits "RECs" to customer participants.

**Q. HOW IS THE COMPANY'S CS PROGRAM STRUCTURED?**

A. The CS program allows customers to purchase a monthly subscription to 1 kW blocks of solar energy from a portfolio of Company-owned solar facilities. The participating customer pays a fixed monthly CS charge on the customer's normal electricity bill for each block subscribed; however, the monthly production of energy from the customer's solar subscription is credited to offset the customer's energy usage (virtual net metering). The customer pays only for their total energy used, minus the solar production. If the solar

subscription's monthly production is greater than the customer's monthly electric usage, then any production in excess is credited at the solar avoided cost rate as filed in Docket No. 16573. As part of the current CS tariff, it states that a customer should anticipate that the fixed CS charges to participate in the program will exceed any bill credits received. Therefore, there is a premium for customers to participate currently in the CS program.

**Q. HAS THE COMPANY PROPOSED REVISIONS TO THE CS TARIFFS?**

A. Yes. The Company is requesting approval to increase the monthly price per kW block from $24.99 to $27.99 for residential customers and approval of a commercial rate of $29.99 per block.

**Q. HAS THE CS PROGRAM BEEN WELL RECEIVED BY GEORGIA POWER CUSTOMERS?**

A. No. Since its inception, participation in the CS program by residential customers has been very low. After several years of the program being offered to customers, still over 5 MW of CS blocks remain unsubscribed as shown in Staff Exhibit __ (BDW-15).

**Q. WHAT IS THE COMPANY'S RATIONALE FOR ITS PROPOSED INCREASE TO THE RESIDENTIAL CS TARIFF RATE?**

A. As provided in the Company's response to STF-TAI-1-36, Attachment C, the Company calculates the block cost for the CS tariff to cover lost revenue from the crediting of solar generation to program participants. Participants in the program are credited at the retail rate for each kWh that their block of community solar generates. For the typical Georgia Power

customer, one kW CS block will generate $321 annually in credits on their bill over the next 3 years, or roughly $27 per month. Georgia Power rounded this amount up to $27.99 as the proposed monthly block rate. Also included in the Company's response to STF-TAI-1-36, a similar calculation was provided for commercial customers in order to justify the proposed $29.99 per month subscription price.

**Q. IS THERE ANOTHER OPTION FOR THE COMMISSION TO CONSIDER WHEN DETERMINING THE PRICING FOR THE CS PROGRAM?**

A. Yes. During the recent 2022 IRP, there was a lot of discussion surrounding the pricing for the CS program and how the current design of the program places an approximate $5 premium per month for participating customers. Under the current CS program design, customers do not realize any savings associated with subscribing to the CS program.

Another option for the Commission to consider when determining the per kW block price is to determine the revenue requirement associated with the net book value of the CS solar facilities along with the associated O&M on the facilities and administrative costs to run the program.

**Q. HAS STAFF CALCULATED AN ALTERNATIVE COMMUNITY SOLAR MONTHLY BLOCK RATE?**

A. Yes. Staff has calculated an alternative per kW monthly block rate which is based on allowing the Company to earn a return on and recovery of the book value of the CS solar facilities as well as recovery of associated O&M on the facilities and Administrative fees.

The block rates as calculated by Staff are $20 for residential customers and $22 for commercial customers.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE APPROPRIATE PRICING FOR THE CS PROGRAM?**

A. The basic question from a policy perspective to answer is, what is the purpose of the Company's CS program? If the Commission determines that the purpose of the program is to allow participating customers the opportunity to support the development of clean energy as well as the opportunity to realize bill savings, then Staff recommends approval of the block charges as determined by Staff. If the Commission determines that the purpose of the CS program is to allow participating customers the opportunity to support the development of clean energy but not the opportunity to realize any bill savings, then Staff recommends approval of the Company's proposed rates of $27.99 for residential and $29.99 for commercial.

**Q. PLEASE DESCRIBE THE COMPANY'S SIMPLE SOLAR PROGRAM.**

A. The Company's Simple Solar program was first approved as part of the Company's 2016 IRP as a replacement for the Green Energy Program. The Green Energy Program first began in 2003 with customer enrollments starting in 2006. However, the cost of the Green Energy Program exceeded the revenues received by the program due to lower-than-projected avoided energy costs, higher long-term contracted prices for the renewable energy to supply the program, as well as lower than expected customer participation.

Georgia Power proposed the Simple Solar Program to replace the current structure of the Green Energy Program.

The Company's Simple Solar program enables retail customers to purchase and retire RECs generated from solar resources for either 50% or 100% of the customer's monthly energy usage. The per kWh REC charge is in addition to the customer's normal electricity bill. Also available was a Large Volume Purchase Option for customers who purchase a monthly minimum of 50,000 kWh of RECs to receive a lower REC charge for the RECs purchased above 50,000 kWh.

**Q. WERE REVISIONS TO THE SIMPLE SOLAR TARIFF APPROVED IN THE COMPANY'S 2022 IRP?**

A. Yes. The Commission approved changes to the Simple Solar program in its Order Adopting Stipulation in Docket No. 44160, dated July 29, 2022, but deferred the consideration of modifying the REC pricing to this rate case. The approved revisions to the Simple Solar tariff include the removal of the Large Volume Purchase Option, which was replaced with a separate Flex REC program for large customers. The Flex REC program includes both a tiered pricing structure from the Simple Solar Large Volume program, as well as an economic development option with negotiated rates for new customers that qualify for the large load exception of the Georgia Territorial Electric Service Act.

**Q. PLEASE DESCRIBE THE PROPOSED REVISION TO THE REC PRICING IN THE MODIFIED SIMPLE SOLAR TARIFF.**

A. The Company is requesting to raise the price of RECs under the Simple Solar Program from 1¢ to 1.25¢ per kWh. The Company responded that the proposed price is reflective of increases in recent market prices for RECs (Docket No. 44160, Georgia Power's 2022 IRP Company Response to STF-DEA-2-11 and is provided as Staff Exhibit __ (BDW-16). Similarly, pricing for the Flex REC tiers will also start at 1.25¢ per kWh for the first tier, stepping down eventually to market rate for all RECs in excess of one million kWh per month.

**Q. DOES STAFF AGREE THAT RECENT AND FUTURE REC PRICING HAS INCREASED?**

A. Yes. Staff agrees that the cost of RECs purchased by the Company for the Simple Solar Program has increased. The Company provided support in its Confidential response to STF-TAI-1-42. While Staff cannot predict future REC prices, recent trends indicate that increased REC pricing might continue.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING PRICING CHANGES TO THE SIMPLE SOLAR PROGRAM?**

A. Staff recommends approval of the Company's request to increase REC pricing from 1¢ to 1.25¢ per kWh.

## V. PROPOSED NEW TARIFFS AND REQUIREMENTS

**Q. PLEASE DESCRIBE THE PROPOSED CHARGE IT–ELECTRIC VEHICLE RIDER.**

A. The Company is requesting approval for a new rider called Charge It – Electric Vehicle ("CIEV"). According to the Company, the CIEV rider is meant to support public commercial EV charging expansion by offering reduced billing demand costs to new, separately metered charging loads for up to 48 months (Company Witness Legg Direct Testimony, pg. 17, lines 1-8). On August 22, 2022, the Company filed a corrected CIEV tariff as part of the Errata-Supplemental filing.

**Q. IS THE CIEV RIDER A MANDATORY TARIFF FOR ALL NEW ELECTRIC VEHICLE CHARGERS?**

A. No. The CIEV is an optional rider that can be used by customers as a modification of the Power and Light ("PL") tariff schedules (PLS, PLM, and PLL) if they want to separately meter the load for a new electric vehicle charger. Customers will also be able to add the new electric vehicle charger load to its existing tariff but they will not get the demand discount that is provided under the CIEV rider. As proposed, the CIEV rider may not be used with the Real Time Pricing – Day Ahead (RTP-DA), or Real Time Pricing – Hour Ahead (RTP-HA) tariffs.

**Q. WILL THE PROPOSED CIEV RIDER SHIFT COSTS TO OTHER CUSTOMERS AS A RESULT OF DISCOUNTING BILLING DEMAND?**

A. No. The CIEV tariff is only for new charging loads, so there are no existing revenues that would be foregone with the reduction of the billing demand. Although the program will initially discount the billing demand for the first four years after a customer enrolls, Company Witness Legg testified that the program would pass the ratepayer impact measure test and put downward pressure on ratepayers' rates over time (Transcript at 939, lines 4-20). According to the Company's response to Staff's data request STF-PIA-10-6, the Company has not performed a forecast of the number of new customers who may enroll on the CIEV-1 rider and so does not have an estimate of the reduction in revenue from customer bills resulting from participation on the rider.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE PROPOSED CIEV TARIFF?**

A. Staff recommends approval of the tariff as filed in the Company's Errata-Supplemental filing. As commercial entities seek to install chargers to meet the growing need for EV infrastructure across the state, a rate structure using billing demand can be a short-term barrier to deployment. As usage of chargers ramps up, charging station providers should be able to serve their customers while receiving electric service with appropriate price signals. In order to monitor the adoption of this tariff, Staff recommends quarterly reporting regarding the location, peak demand, usage, and revenue received from CIEV customers.

**Q. IS STAFF PROPOSING ANY ADDITIONAL CHANGES TO THE COMPANY'S EXISTING TARIFFS?**

A. Yes. Staff recommends a change to the FPA and Price Protection Products ("PPP") tariffs. Both of these tariffs state that they are offered "periodically, as determined by the Company, to eligible customers." This determination is made in consideration of "uncertainty around environmental regulation or fuel markets that could impact the forecasted prices used in the development of FPA offers." (Company Response to STF-PIA-6-44 and provided as Staff Exhibit __ (BDW-17)).

**Q. WHAT IS STAFF'S RECOMMENDED CHANGE TO THE FPA AND PPP TARIFFS?**

A. Staff recommends that the determination of whether to offer these tariffs to eligible customers is not made solely by the Company but made in coordination and with the support of the Commission. Specifically, Staff recommends deleting the language "as determined by the Company" from the FPA and PPP tariffs.

**Q. IN ADDITION TO THE PROPOSED REVISIONS TO ITS TARIFFS, DID THE COMPANY ALSO PROPOSE REVISIONS TO THE RULES AND REGULATIONS?**

A. Yes. The Company proposes modifications to several sections of its Rules and Regulations including Section F (Contract and Enforcement Regulations) and Section G (Customer

Generation). The Company's proposed changes to Section G are related to the Company's proposed modifications to the RNR tariff.

**Q. PLEASE DISCUSS THE PROPOSED CHANGES TO SECTION F OF THE COMPANY'S RULES AND REGULATIONS.**

A. The Company is proposing to modify Section F.2 to clarify that all charges paid to Georgia Power by its customers must be in U.S. dollars.

The Company is also proposing to add Section F.9 to help protect its customers from higher costs by limiting damages in connection with any outage, surge, voltage fluctuation, disturbance or other variation or failure of electric service, or the Company's equipment. In its response to STF-TAI-1-46 which is provided as Staff Exhibit __ (BDW-18), the Company stated that the proposed language represents a clarification of current policy and not a change in the current limitation on liability that applies to customer accounts. As proposed, the new section will limit Georgia Power's liability to only direct damages and that personal property liability will only be limited to the depreciated value.

The Company is also proposing to add Section F.10 to prohibit out of state litigation. In response to a Staff data request, the Company stated that a customer should only initiate litigation in the state of Georgia concerning service with Georgia Power because the Company provides electric service to customers and premises within Georgia, consistent with the requirements of Georgia law (Company Response to STF-TAI-1-47; Staff Exhibit __ (BDW-19)).

**Q. DOES STAFF RECOMMEND APPROVAL OF THE PROPOSED CHANGES TO SECTION F OF THE RULES AND REGULATIONS?**

A. Yes. Staff recommends approval of the proposed changes to Section F of the Company's Rules and Regulations.

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISIONS TO SECTION G OF THE COMPANY'S RULES AND REGULATIONS.**

A. Georgia Power is proposing to modify Section G.3 such that customer generators 250 kW and above are responsible for all fees associated with a system impact study and witness testing. The proposed revisions also require these customers to install a local communications interface that supports information exchange with, and control by, the Company. Customer-owned generators less than 250 kW may also be required to undergo witness testing if the Company deems that the generator poses a safety or reliability risk. Additionally, Georgia Power is proposing to modify Section G.4 such that all customers proposing to interconnect customer generation must pay a one-time interconnection fee of $200.

**Q. WHAT JUSTIFICATION DID THE COMPANY PROVIDE FOR ITS REQUEST TO COMMUNICATE WITH AND CONTROL ALL CUSTOMER GENERATORS LARGER THAN 250 kW?**

A. In response to STF-PIA-6-40, provided as Staff Exhibit __ (BDW-20), the Company asserts that communication and control of large customer generators is supportive of the

proposed DERMS, and improves the company's planning and operation of the electric system. The Company clarified that the required control capabilities were established in Section A13.3 of its Operation of DER in Parallel with the Distribution System Policy, provided as an attachment to the Company's response to STF-PIA-6-40. These capabilities are also defined in IEEE 1547-2018 and are limited to the ability to remotely shut off all energy conversion equipment of the DER and remotely change the reactive power control setting of the DER. The Company's proposal would require all customer generators larger than 250 kW, both existing and future, to comply with this requirement.

**Q. DOES STAFF SUPPORT THE COMPANY'S REQUEST TO COMMUNICATE WITH AND CONTROL CUSTOMER GENERATORS?**

A. No. Staff has significant concern with giving the Company unconditional access and control of customer generators. First, the Company's communication and control of customer generators should be explicitly limited to those capabilities provided in IEEE 1547-2018. In addition, the proposed communication and control requirement should not be applied retroactively, as requiring existing customer generators to upgrade to meet changing requirements could be seen as punitive.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE LOCAL COMMUNICATION INTERFACE?**

A. Staff recommends the Company's proposed modification to the language in Section G.3 to explicitly limit the Company's communication with and control of the customer's

generator to those capabilities provided in IEEE 1547-2018 and to require only new interconnecting customer generators to comply with the proposed communication and control requirements.

**Q. WHAT IS THE COMPANY'S RATIONALE FOR THE NEW INTERCONNECTION FEE?**

A. The Company stated that its proposed interconnection fee is to cover the costs of interconnection review, meter installation and programming, witness testing for generators under 250 kW, and the costs associated with processing interconnection applications (Legg Direct Testimony, pg. 11, lines 15-20). It is Staff's understanding from meetings with the Company that interconnections of such facility size do not always warrant witness testing but all incur certain costs. The Company has indicated that it will not require witness testing for the majority of residential systems going forward. Georgia Power's calculation of its proposed $200 interconnection fee reflects this plan by reducing the percentage of planned residential witness testing events to only 50% of all such installations in 2023 and only 25% thereafter. As interconnecting customers currently only pay a witness testing fee, these other interconnection costs are currently recovered from all retail customers and not directly from interconnecting customers.

**Q. WOULD THE PROPOSED $200 INTERCONNECTION FEE COVER THE KNOWN COSTS FOR INTERCONNECTIONS?**

A. As provided in the Company's response to STF-TAI-1-40, the $200 interconnection fee would cover the interconnection costs projected for the next three years. The number of projects interconnecting is projected by the Company to increase each year by 15%.

Not only will this proposed interconnection fee apply to customer generators on the RNR tariff, but to all customers on the Company's distribution circuit who intend to install a customer generation facility, including those generators larger than 250 kW.

**Q. DOES STAFF HAVE CONCERNS REGARDING THE COMPANY'S PROPOSED $200 INTERCONNECTION FEE AND ITS IMPACT TO RESIDENTIAL CUSTOMERS?**

A. Yes. Staff has concerns regarding the significant increase in fees related to the interconnection of a residential solar rooftop project. Currently, a residential customer pays on average $35 based on the $5 per kW witness testing fee with the average residential rooftop system size of 6.9 kW (Response to STF-TAI 3.9).

**Q. HAS THE COMPANY PROVIDED CALCULATIONS REGARDING HOW THE $200 INTERCONNECTION FEE WAS DETERMINED?**

A. Yes. In the Company's response to STF-TAI-1-40, the Company provided its calculations of the proposed interconnection fee. This data request response is being provided as Staff Exhibit __ (BDW-21). In Georgia Power's calculations, the calculated interconnection fee averages $190 per application during the next regulatory cycle, with the remaining $10 of the $200 fee being added as an estimate to account for costs not easily quantifiable or

attributable on an average per project basis. Georgia Power listed such added costs as: labor associated with program and project inquiries, multiple "truck rolls" for failed witness tests, and additional technology and/or software investments.

**Q. DOES STAFF SUPPORT THE COMPANY'S REQUEST TO INCREASE THE INTERCONNECTION FEE FOR RESIDENTIAL CUSTOMER GENERATORS TO $200?**

A. No. It is Staff's position that increasing the interconnection cost by a factor of five is a significant increase for residential customers. The Company's proposed fee is based on the inclusion of commercial and industrial interconnections, including generators larger than 250 kW, which have significantly higher costs to interconnect. Residential customer generators would subsidize commercial generators, who would recognize a significant decrease in fees associated with interconnecting a solar system.

**Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE INTERCONNECTION FEE?**

A. Staff recommends that the interconnection fee for residential customers be set at $100 and the interconnection fee for commercial customer generators under 250 kW be set at the proposed $200.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

(The documents referred to were marked for identification as Staff Exhibits 62 through 83.)

MR. THOMAS: Thank you. And, Madam Chair, with your permission, Mr. Watkins and Mr. Deitchman would like --

MADAM CHAIR PRIDEMORE: Deitchman.

MR. THOMAS: Deitchman.

MADAM CHAIR PRIDEMORE: Deitchman. We got it. You got it, Preston. Deitchman.

MR. THOMAS: Thank you.

-- would like to split their 15 minutes and both give a brief summary of their testimony.

MADAM CHAIR PRIDEMORE: They are both giving 15-minute summaries?

MR. THOMAS: No. They would like to split their 15 minutes.

MR. WATKINS: It will be limited to.

MADAM CHAIR PRIDEMORE: Oh, that's fine. Go ahead. Please summarize your testimony.

MR. WATKINS: Thank you, Your Honor.

Although the company did not rely upon any individual class cost of service study results in evaluating class or individual rate revenue responsibility, it did conduct such studies for this case.

**Specifically, the company supports what is known as a 12CP method to allocate generation plant and other generation-related demand costs. In addition, and as a result of the settlement in the 2019 case, Company Witness Evans also conducted a 4CP study to allocate the above-referenced generation costs.**

**Now, there are a myriad of accepted cost allocation methods and approaches in the industry. This is largely due to the fact that there are differences of opinion on how costs are incurred, as well as who imposes costs on a utility system since generation plant is commonly used by all customers.**

**Indeed, and as opined by the U.S. Supreme Court, cost allocation studies cannot be considered surgically precise. With this in mind, staff also conducted class cost of service studies using alternative methods to allocate generation-related costs. A summary of results under each allocation approach evaluated -- that being the company's two studies and two alternative studies that we conducted -- can be seen in our panel testimony on pages 42 and 43, which are Tables 8 and 9 of our testimony.**

**As can be seen in these tables, for some**

**classes and rate schedules, different accepted methods produce significantly different results. As a result, staff did not rely on any one particular cost-of-service study but -- result, but rather evaluated and gave some weight to every cost of service study.**

**That is, each of the four.**

**For all intents and purposes, the company proposes to assign any overall increase authorized in this case on an equal percentage basis across classes and rate schedules.**

**Staff has taken a somewhat different approach in that some consideration should be given to cost of service.**

**As a result of the imprecise nature of any cost allocation study, the results should only be used as a guide in evaluating class or rate schedule revenue responsibility.**

**In evaluating the revenue responsibility for individual rate schedules, staff found that some rate schedules are overcontributing to costs under every cost study evaluated, while a few others are consistently undercontributing to costs under every cost study evaluated.**

**With this in mind, staff proposes somewhat**

larger percentage increases to those rate schedules whose results; i.e., index rates of return, are significantly deficient under every cost study and proposes somewhat smaller percentage increases to those rate schedules whose results are significantly above parity under every cost study.

All other rate schedules were increased at an equal percentage basis because they were either close to parity under every cost study or there were mixed results, depending on the methodology.

A comparison of companies and staff's proposed base-rate increases by individual rate schedule are provided on page 49 of our testimony, which is Table 12.

In this regard, staff has utilized the company's proposed overall base-rate increase of 739,000,000 in order to provide an apples-to-apples comparison of the company's proposal to staff's recommendation.

However, should the Commission authorize an overall base-rate increase less than that requested by Georgia Power, staff's methodology can and should be utilized.

Moving on to ECCR, the recovery of ECCR costs, generally, ECCR costs are currently recovered from

customers as a percentage of total base revenues. ECCR costs are clearly energy related as these costs are incurred as a result of the burning of fuel, which is 100 percent energy related.

However, the current mechanism to recover ECCR costs is extremely unfair to certain rate schedules and does not reflect cost causation in any way, shape, or form.

To illustrate, a streetlighting customer's total base revenues are largely related to distribution costs and that these customers use little -- relatively little energy or generation-related costs in relation to the distribution costs required to serve that customer.

At the other extreme, very large industrial customers have very few distribution costs embedded within its base rates, wherein the majority of these customers' base rates are generation -- are related to generation.

As shown on page 52 of our testimony, Table 13, we see that there is a huge and inequitable disparity in the manner in which current ECCR costs are collected and recovered.

As an example, government road lighting's rate schedule effective ECCR rate is more than six cents

per kilowatt hour, while the effective ECCR rate for large power and light is less than one penny.

Furthermore, the incremental usage associated with the realtime pricing rate schedules are exempt from any ECCR cost responsibility, even though these customers' incremental usage add to the company's environmental compliance requirements.

Similarly, customers under the FPA, fixed-price alternative, and electric arc furnace rate schedules currently receive a special deal in that these customers' ECCR rates are based on only 65 percent of their base rate revenues.

Staff recommends that costs should be recovered on a per-kilowatt-hour basis. However, immediate movement to a total kilowatt hour usage would result in a very -- in very large increases to certain rate schedules.

As a result, staff recommends an interim step towards a consistent ECCR rate per kilowatt hour. Staff has developed a mitigation approach wherein the ECCR rate per kilowatt hour reflects 50 percent of the kilowatt hours for RTP incremental, FPA, fixed price alternative, electric arc furnace, and TOU supplier choice.

A comparison of the company's and staff's ECCR

proposal by rate schedule is provided on page 54 of our testimony, which is Table 14.

With respect to DSM and MFF cost recovery, these ride -- these rider costs are generally recovered on base revenues and staff agrees with the current approach.

In order to provide an apples-to-apples comparison of the company's proposed increases, Table 15 on page 57 of our testimony provides a comparison of the company's and staff's overall, quote/unquote "all-in" revenues and revenue increases by individual rate schedule.

Moving on to rate design, as mentioned earlier, Georgia Power proposes equal percentage increases to most rate schedules, as well as individual rate elements. As a result, if the Commission does authorize an overall increase in base rates for this case, the company proposes to increase residential in all but one small business basic service charge by the same percentage as the overall increase authorized by the Commission.

To illustrate, under the company's proposed levelized approach, the residential customer charge would be increased by 16.23 percent, from $14 to $16.27 per month.

**In this regard, it should be understood that the basic service charges are actually based on a daily basis, which equates to the monthly amounts I just noted.**

**Staff has undertaken an analysis of the reasonableness of fixed basic service charges for the residential and small business classes. Staff's approach utilized what is known as a modified direct customer cost analysis in which only those costs required to connect and maintain a customer's account are evaluated.**

**The result of our analysis are provided in Table 17 on page 62 of our testimony, while the details of this study are provided in Staff Exhibit BDW-9.**

**As indicated in Table 17, each rate schedule's, quote/unquote "customer cost" are significantly below the current basic service charge. As such, staff recommends no increase in basic service charges to the residential or small business rate schedules.**

**With regard to the design of rates, currently the residential rate R energy charges are seasonally differentiated between summer and non-summer months.**

**For the summer months, there is an inverted 3-block rate structure per kilowatt hour. For the**

non-summer months, there is a declining 3-block rate structure per kilowatt hour. A comparison of Rate R's current energy charges is provided in Table 18 on page 63 of our testimony.

While staff agrees with the current inverted block rate structure during the summer months, we disagree with the continuation of a declining block rate structure in the non-summer months. Indeed, and as discussed on page 64 of our testimony, the company itself has acknowledged that it has changed its integrated resource planning that once emphasized only summer loads and reserve margins to one that now is considered -- to one that now considers both summer and winter periods due to what the company has characterized as, quote/unquote "changing seasonal dynamics confronted by Georgia Power," unquote.

While Georgia Power's annual peak does occur during the summer, its winter loads and corresponding energy requirements are relatively high as well. The tables and charts -- the tables and charts on pages 65 through 67 of our testimony provide peak load and energy requirements for each month of the year.

As a result, staff recommends the elimination of the declining block rate structure in the

non-summer months and switching to a flat energy rate -- flat energy charge rate structure.

MR. DEITCHMAN: Georgia Power is proposing to make the standard R-tariff unavailable to newly constructed premises that are established on Georgia Power's system effective January 1st, 2023.

The company is also proposing to continue to use the time-of-use residential demand tariff as the default tariff for newly-constructed premises. Fewer than 3-1/2 percent of current residential customers are on a demand-based rate. Most of those customers having defaulted onto the TOU-RD after the previous rate case.

Staff analysis has shown that customers on the TOU-RD pay significantly more than they would on the standard tariff and that the demand rate does not send an actionable price signal to customers.

In addition, staff has found that no other investor-owned utilities require residential customers to take service under a three-part rate design.

Staff is recommending that the Commission reject the company's proposal to limit the R-tariff to existing premises and to make the R-tariff the default option for all residential premises.

**Staff recommends that the company continue to offer TOU-RD as an optional tariff and be required to provide further tools to assist residential customers in choosing a tariff that best suits their needs.**

**The company also proposes to discontinue its residential time-of-use residential energy-only tariff for new sign-ups. Staff recommends that the Commission reject this proposal and to require the company to retain all current tariff options for residential customers. The time-of-use residential energy-only tariff provides a viable option for customers to shift their use of patterns, from on-peak to off-peak hours, thereby benefiting the entire Georgia Power system.**

**Staff recommends approval of the company's change to the FlatBill tariff, doubling the minimum offered of $50 per month. And staff recommends that the company be required to increase the availability and awareness of seasonally smooth budget billing to its customers.**

**Staff recommends approval of the company's proposed increase to $1,200 for each underground service -- underground service point interconnection to reflect those costs and that the Commission approve the proposed changes to the roadway lighting**

governmental tariff and the DPEC rider to serve the needs of those customers.

The company is also proposing to eliminate power and light high-load factor and solar purchase tariffs; and since no customers are taking service under those tariffs, staff recommends approval.

For solar power-related tariffs, staff recommends approval of their request to exempt realtime pricing customers from participating in RNR monthly netting. For the Community Solar program, the Commission must determine the purpose of the program.

If the Commission determines that the purpose of the program is to allow participating customers the opportunity to support the development of clean energy as well as the opportunity to realize bill savings, then staff recommends approval of the block charges as determined by staff of $20 per block to residential customers and $22 per block to commercial customers.

If the Commission determines that the purpose of the program is to allow participating customers the opportunity to support the development of clean energy but not the opportunity to realize any bill savings, then staff recommends approval of the

company's proposed rates.

Regarding the Simple Solar program, staff recommends approval of the company's request to raise the price of renewable energy credits.

The company is requesting approval of a new rider called Charge It Electric Vehicle, CIEV, which is meant to support public-commercial electric vehicle charging expansion by offering reduced billing demand cost to new charging loads for up to 48 months.

The CIEV is an optional rider for new loads on power and light tariff schedules for customers who want to separately meter the load for a new electric vehicle charger. As commercial entities seek to install chargers to meet the growing need for EV infrastructure across the state, a rate structure using billing demand can be a short-term barrier to deployment. Staff recommends approval of this rider with quarterly reporting requirements.

Regarding the fixed-price alternative and price protection product tariffs, staff recommends that the determination of whether to offer these tariffs to eligible customers not be made solely by the company but made in coordination and with the support of the Commission.

Regarding changes to the company's rules and regulations, staff recommends approval of the Section F contract and enforcement regulations changes. Georgia Power's also proposing to modify Section G.3, such that customer generators 250 kilowatts and above are responsible for all fees associated with a system impact study and witness testing and require these customers to install a local communications interface that supports information exchange with and controlled by the company.

Customer-owned generators less than 250 kilowatts may also be required to undergo witness testing if the company determines that the generator poses a risk.

Staff recommends changing the company's proposed modification to the language in Section G-3 to explicitly limit the company's communication with and control of the customer's generator to those capabilities provided in IEEE regulations and to require only new interconnecting customer generators to comply with the proposed requirements.

Regarding interconnection fees, it is staff's position that increasing the interconnection costs by a factor of five is a significant increase for

residential customers. Staff recommends that the interconnection fee for residential customers be set at $100, and $200 for commercial customer generators under 250 kilowatts.

Thank you.

MR. THOMAS: Madam Chair, the witnesses are available for questions from the Commissioners and cross-examination.

MADAM CHAIR PRIDEMORE: Questions from Commissioners?

Okay. Commissioner Echols.

VICE CHAIRMAN ECHOLS: Madam Chair, thank you.

Mr. Watkins, it's days like today that I wish I had not been an English major at the University of Georgia.

You know, your testimony, you know, is a primer on formulas and methodology. It's over my head. But on page 13, you are discussing the I-CP methodology about allocating Vogtle 3 and 4 for peak demand instead of base load power.

Do you remember that?

MR. WATKINS: Yes, sir.

VICE CHAIRMAN ECHOLS: So what is the -- I mean, you mentioned 739,000,000. I don't think that's the financial impact of that. But what is the

impact -- financial impact? As you know, I am hunting for money here. So what is the financial impact of doing it the way that you suggest? For -- is there a benefit to ratepayers?

MR. WATKINS: No, sir. So what our panel does is we accept the overall increase, if any, to Georgia Power. And then we say, how are we going to divvy those revenues up across classes. Okay?

So there is no revenue savings or whatever. It is what you tell us it is, you know, in the final result when the company and we review, with our compliance filings, to how we spread that revenue requirement across the classes.

What this is referring to is how you assign cost responsibility between, say, residential, commercial, that kind of thing

VICE CHAIRMAN ECHOLS: I see.

MR. WATKINS: Does that help you?

VICE CHAIRMAN ECHOLS: It's only going to make a difference for residential customers is if we approve the shift; right? If we approve a different type of allocation?

MR. WATKINS: Right. And I -- I can't remember -- I believe it was Dr. Blank, and I agreed with him wholeheartedly in his testimony. I am not

aware of any requirement that you have to approve any specific cost allocation methodology. Now, in a few jurisdictions, they do. But in most jurisdictions, they understand that there is -- it is kind of muddy with --

VICE CHAIRMAN ECHOLS: Yeah, okay. I'm good. I'm good.

MR. WATKINS: There is no right or wrong answer.

VICE CHAIRMAN ECHOLS: I'm good. I can't handle any more of that.

Let me move to Ben. Ben, the standard R-tariff, and moving to the -- you know, moving to TOU-RD, have you ever been on a time-of-use rate in your residence?

MR. DEITCHMAN: I have, yes.

VICE CHAIRMAN ECHOLS: Okay. So, you know, the clock is your price signal. Right? At 2:00, you know, I know things are going up and I can make adjustments. I can precool my house. I can shut everything down, you know. Threaten my children, you know, with, you know, with things to get them to go outside or sit by a box fan or, you know, things like that.

But with this smart usage rate, I really -- I

am not smart enough -- I am not smart enough to be able to figure out how to avoid the -- the unintended impact of increasing -- you know, increasing my demand or the formula. It's too complicated. And I'm -- you mentioned no price signal.

And I'm wondering, you know, if we could -- and obviously the Commissioners would have to agree on this, but I am wondering if we could delay for three years the defaulting to this TOU-RD rate until we -- until we can allow Georgia Power to come up with better signals to warn me that, you know, maybe an hourly text -- I start getting an hourly text that tells me: You are -- you know, you are approaching a cliff, you know. And if you don't take evasive action in your home, you're going to impact your -- your rate.

Tell me, what do you think about delaying this for three years until we can -- until the company can figure out the best way to signal people?

MR. DEITCHMAN: So, yes, with the demand charge, what we are finding, customers are not understanding how that works. So the straight time-of-use, which is the TOU-REO, which is just basically there's on peak and off peak. On peak only being summer afternoons 2:00 to 7:00, is clear to

customers. You know, turn down the AC in the afternoon. Don't do laundry at that time. Don't wash the dishes at that time.

When you start dealing with this demand charge that, you know, your highest -- your peak charge each month, your peak usage each month affects your rate for the whole month, it's not even a matter of anybody necessarily knowing how to do it. The way your AC may be cycling, your refrigerator may be cycling, may contribute to that.

So certainly there are customers who are in smart homes who can understand and benefit. But for the general customer, for a broad swath of customers, having them default onto that rate we see as...

VICE CHAIRMAN ECHOLS: So, you're familiar with the prepay rate that we have, aren't you?

MR. DEITCHMAN: Absolutely.

VICE CHAIRMAN ECHOLS: So it's not a clock signal but it's a text signal; right?

MR. DEITCHMAN: Yes.

VICE CHAIRMAN ECHOLS: And we have helped low-income ratepayers become very geeky. Low-income ratepayers get this text, they know that, hey, it costs $6 for me to run my house today and I've got $18 in this account and I am going to have to put

some more money in there in three days if I'm going to keep my power on.

So this -- this is why people are saving 11 percent on that rate. This is a -- you know, this is -- this has been something that has been tremendously successful, wouldn't you say?

MR. DEITCHMAN: Yes. Yes. We support continuing the prepay rate. And certainly, yes, sending those regular text messages and, you know, one thing to motivate somebody is letting them know that power is about to be shut off because you are running down to zero. Absolutely.

VICE CHAIRMAN ECHOLS: So the elimination of one of the time-of-use rates moving to just, I guess, the EV time-of-use rate, which is, I guess, what they are proposing, it seems confusing to me, that if I don't have an EV, and you've heard -- you have heard a lot of nasty things about EVs during, you know, the last couple days. But if I don't have an EV, why would I want to go on an EV rate? I mean, that seems counterintuitive. And I don't know that customers are going to be able to go, well, you know, this is the only time-of-use rate available really that I have control over that runs by a clock. I mean, it seems -- it seems like it's going to be hard to

market that. Do you think?

MR. DEITCHMAN: Yes.

VICE CHAIRMAN ECHOLS: Yes? Okay.

A question about the solar. I hate to say don't get me started about the solar, but -- but, you know, I'm wondering, you know -- I'll start with the community -- the Community Solar; right? It was my amendment in '16 that created these things. It has not been successful. We haven't had the, you know, the take rate on this. It hasn't been marketed that much. And I am wondering about, you know, the theory that you all have about reducing it, what, to $20? Is that --

MS. BARBER: That's correct. $20 per block.

VICE CHAIRMAN ECHOLS: I wonder if we could -- obviously the Commissioners would have to approve this, but I wonder -- and if we tried that for three years; right? I mean, we are -- we try things all the time. We do pilot things. We are testing. We're trying to figure out how to make it work. I wonder if we did that and Georgia Power did some additional marketing, do you feel like we are going to get a full subscription on these rates that we have?

MS. BARBER: I think it will help, definitely.

You know, as you know, in our testimony we left it a policy decision, if the Commission wants to reduce the rate to $20, which is basically a calculation allowing the company to earn a return on their undepreciated investment, O&M, and admin cost. And then the company has proposed to increase the rate up to 27.99 per block.

We do feel it's in the right direction. This program's been in effect for many years and only 3 megawatts out of the 8 have been subscribed. So definitely customers are not interested in paying the current rates for this program

VICE CHAIRMAN ECHOLS: Okay. So let's just say we don't -- we don't do anything. We raise the rates, we get less subscribers. Those panels are still out there producing energy, aren't they?

MS. BARBER: They are.

VICE CHAIRMAN ECHOLS: Yes. Who is --

MS. BARBER: Well, they are going to the -- they are part of the company's portfolio. But as you remember, as part of the IRP, some of the megawatts are going to be corporate sponsorships. So they are going to cover 75 percent of the subscription price. So there's intent that those will be subscribed by, you know, corporate or customers for their behalf.

**VICE CHAIRMAN ECHOLS: Yes, that's the theory; right?**

**MS. BARBER: Yes.**

**VICE CHAIRMAN ECHOLS: But the other remaining part is what you are trying to get folks to take; right?**

**MS. BARBER: Yes. And so staff has given commissioners an option, because we have heard -- we've heard it for years. As you know, I was involved in the beginning on the design of this original Community Solar, which does virtual net metering, but also -- but on the other side, the block price includes the full recovery of the lost revenue by the company.**

**So, in essence, customers are not really getting a benefit or any savings as if -- as they would if the rooftop system was on their home. So this is just giving you an option for you to consider.**

**VICE CHAIRMAN ECHOLS: I mean, normally, Georgia Power's leading the way and the EMCs follow. I mean, that's a pattern we have seen for years. Georgia Power -- they've got the horsepower to be able to develop these things and produce it.**

**But in this case, Walton EMC and some of these**

other EMCs, and GreenPower EMC, they have figured out the secret sauce. They are fully subscribing their systems. Why are they having success at smaller utilities? Why are they having success and why are -- why is Georgia Power failing with Community Solar?

MS. BARBER: Well, we've been trying to figure that out, just like you have. But it has to be the price. It just has to be -- and there's other programs, too. I mean, Georgia Power has other programs that some customers are just not taking advantage of. But it has to be advertising and the price of the program.

VICE CHAIRMAN ECHOLS: All right. Last line of questions. About the rooftop solar.

You know, I'm -- you have heard me say -- you have heard me talk about congested circuits. The value of solar. You know, I have talked about this for -- you know, for almost a decade now. And we are still -- we are still kind of struggling with this. These changes that you are recommending, that they are recommending that you are, you know, modifying, how do you think it's going to benefit rooftop -- current rooftop solar customers and, you know, customers that would like to participate?

**MS. BARBER: Now, are you being specific about the interconnection cost? Fee?**

**VICE CHAIRMAN ECHOLS: Yes.**

**MS. BARBER: I am not really sure. You know, the company's recommending $200 interconnection fee. Staff is recommending $100 for residential. That is quite an increase compared to an average size of 7 kW times the $5. So $35 is what a current customer would pay.**

**I am not really sure what impact it would have. I mean, I -- I think at the end of the day, it's probably going to depend on what happens with the monthly netting issue, too, about, you know, the customers. But I tend to think customers would continue to pay the $100 to interconnect.**

**VICE CHAIRMAN ECHOLS: Did y'all consider, as you deliberated, any idea of, like, about a rebate? Like, Jackson EMC has done per kilowatt, $450 rebate? Did you look at that as a possible option, or no?**

**MS. BARBER: Are you -- no. But, you know, our net metering testimony is due in a couple weeks.**

**VICE CHAIRMAN ECHOLS: Okay. I will save that for then. All right. Thank you so much.**

**MADAM CHAIR PRIDEMORE: Any other commissioner questions?**

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Start with the list.

Americans for Affordable Clean Energy?

MR. GALLOWAY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: ChargePoint?

MR. FYKES: No questions.

MADAM CHAIR PRIDEMORE: Commercial Group?

I see Mr. Jenkins has questions.

MR. JENKINS: I do.

MADAM CHAIR PRIDEMORE: Welcome.

MR. JENKINS: Thank you. May I approach?

MADAM CHAIR PRIDEMORE: You may.

MR. JENKINS: Thank you.

CROSS-EXAMINATION

BY MR. JENKINS:

Q Good afternoon. Alan Jenkins for the Commercial Group.

A (Witness Watkins) Good afternoon. Good to see you again.

Q Thank you.

Now, Ms. Barber, it seems the two of us have been sitting in rate hearings for a long time over the years; isn't that right?

A (Witness Barber) That's correct.

Q Now, isn't it true that the ECCR collection mechanism was first approved in 2007?

A (Witness Barber) That sounds familiar.

Q Yes. The first -- refresh your memory. The first -- look at the first document I gave you, which is a copy of that settlement.

Do you see paragraph 4?

A (Witness Watkins) I'm sorry. What page are you on?

A (Witness Barber) It is right here.

Q Doesn't that say, "The parties agree that the Commission should approve an ECCR tariff"?

A (Witness Barber) Yes, it does.

Q And could you kindly read aloud paragraph 6?

A (Witness Barber) "The ECCR tariff shall be allocated to all customer groups, but not the incremental portion of the RTP tariffs, as closely as practical to an equal percentage basis."

Q Thank you. And isn't it true that that collection mechanism largely has remained in place as it was approved in 2007?

A (Witness Barber) That's correct.

Q And staff was a party to the 2007 settlement; right?

A (Witness Barber) I'm not sure. I think that

actually predates me in this current role.

Q Imagine. Thank you. The record will speak for itself on that.

Now, Mr. Watkins, I notice that you now state that the ECCR collection mechanism is unfair.

Isn't it true your ECCR proposals would shift about $150 million to RTP customers each year?

A (Witness Watkins) Is there a question?

Q Isn't that true?

A (Witness Watkins) Let's see.

Q And you might look at Table 14.

A (Witness Watkins) That's exactly where I'm going.

Q Page 54 of your testimony.

A (Witness Watkins) Let's see. For RTP Day Ahead, my proposal is an increase of 23.7, RTP Day Ahead. And for the CBL and for the incremental, another 38 million. For Hour Ahead, 34.7 million. And for the incremental portion, 59.8 million.

Q And roughly that equates to a total increase of 156 million for RTP?

A (Witness Watkins) I will accept your arithmetic.

Q Thanks.

Now, at page 53, line 16, you state there that

this huge revenue shift to RTP would just be an interim step; right?

A (Witness Watkins) That is correct.

Q And presumably you would have other increases down the line?

A (Witness Watkins) Yes. It would be my recommendation for staff to recommend it, assuming we do a three-year rate plan, to make further modifications to a full kilowatt-hour-based cost recovery.

Q In fact, in each Georgia Power rate case in which you've testified, you have proposed substantial increases to the RTP rates; right?

A (Witness Watkins) Yes. Particularly as it related to the incremental portion.

Q Yeah. And as one example, in the -- 2010, you proposed to substantially increase the RTP capacity charge?

A (Witness Watkins) I did. Not -- but -- you may characterize it as substantial, but in terms of the RTP bill, total revenue, it was de minimis, quite frankly.

Q All right. Please -- one of the excerpts I provided was your -- in case you need to refresh your memory -- was page 8 of your 2010 testimony.

Do you see that?

A (Witness Watkins) 2010?

Q Yes.

A (Witness Watkins) On page 8?

Q Yes.

A (Witness Watkins) Correct.

Q Lines 14 to 16, you -- there you say that your proposed $23 million increase to RTP incremental rates would be the first of, quote, "A plan of gradual increases over several years," end quote; is that right?

A (Witness Watkins) I apologize. The reference again?

Q It's the 2010 testimony.

A (Witness Watkins) Yes, sir.

Q Page 8, line 14.

A (Witness Watkins) Page 8, line 14. "I recommend a plan of gradual increases to the efficient -- full marginal cost is" -- that is correct. And as you -- I am sure you well know, reading my testimony, I did not address that issue in this case.

Q And the -- part of the proposal to have increases over a number of years was to avoid rate shock; right?

A (Witness Watkins) That's right.

Q Now, when the Commission did not approve your 2010 proposal, in 2013 you again proposed to increase the RTP reliability charge; right?

A (Witness Watkins) Right. And so it's clear,

that was not a litigated case, so it was settled. The 2010. I'm pretty sure the 2013, if memory serves me, as well.

Q Yeah. In 2010, staff agreed to that settlement as well; right?

A (Witness Watkins) They did. Well, I don't know that staff did. I do know that it was a result of a settlement. And I'm almost sure that staff did not object to the settlement. Whether they were signatory or not, I don't know.

Q Ms. Barber, do you know? Staff agreed to the 2010 --

A (Witness Barber) I'm pretty sure. I'm pretty sure. Yes.

A (Witness Watkins) It's give and take, like any settlement.

Q Now, at page 42, line 23 of your 2013 testimony, another excerpt I gave you.

A (Witness Watkins) I'm sorry. What page are we at?

Q 42, Line 23.

A (Witness Watkins) Of my 2013?

Q Yes, sir.

A (Witness Watkins) Okay, I'm here.

Q There you say that the reliability charge proposal would raise an additional 32-1/2 million per year

from RTP customers; right?

A (Witness Watkins) That's correct.

Q And again, that would be the first of a number of such increases that you proposed in that case?

A (Witness Watkins) That's correct.

Q And the Commission did not adopt those two '13 -- 2013 proposals, did they?

A (Witness Watkins) Right. Again, that case was a result of the settlement. Give and take on all issues.

Q And, Ms. Barber, staff agreed to that settlement; right?

A (Witness Barber) Yes, I'm pretty sure we did.

Q Thank you.

MR. JENKINS: Nothing further.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Jenkins.

MR. JENKINS: Yes.

MADAM CHAIR PRIDEMORE: EVgo Services?

MR. VIJAYKAR: No questions.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers?

MR. CLAY JONES: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. CLAY JONES:

Q Good afternoon, panel. How are you?

A (Witness Watkins) Doing well.

Q That is good.

My name is Clay Jones. I represent the Georgia Association of Manufacturers and I will be asking my questions directly to Mr. Watkins. If I ask a question that's really in the purview of someone else's testimony on the panel, then please feel free to answer, but I believe these will be directed to Mr. Watkins.

Mr. Watkins, as we just went through, this isn't your first time testifying here before the Commission.

A (Witness Watkins) Not my first rodeo, sir.

Q No, sir. And you've have testified in the 2007, '10, and '13 rate cases?

A (Witness Watkins) That is correct.

Q Okay. And would you agree with me that the decisions of this Commission can and do have a major impact on our state economically in terms of economic development, job creation and retention? Would you agree that?

A (Witness Watkins) I think -- yeah, their decisions have long-arching impacts on the economy, social aspects, affordability of electricity. That's why this is such a very important Commission.

Q Thank you. And Georgia Power is a large -- very large electric utility. Would you agree with me? And its rates and terms of service can have a significant influence on the state's economy?

A (Witness Watkins) In fact, I believe this is the biggest utility that I have ever practiced in. If not the biggest, the second.

Q Okay. And would you agree with me also that manufacturing plays an important role in our economy here in Georgia?

A (Witness Watkins) Yes, as it does in most every state.

Q Are you aware that manufacturing provides over 400,000 jobs to Georgians, including in many of the more rural areas of our state?

A (Witness Watkins) I don't know the number, but I know there's a large manufacturing base in the state of Georgia.

Q And you would agree with me that as in other states, manufacturing creates wealth for its local communities in which it's located?

A (Witness Watkins) Yes.

Q Supports other related industries and other jobs in other sectors of the economy?

A (Witness Watkins) Absolutely, as does small businesses.

Q And you would agree with me that energy costs are particularly important for manufacturers because they complete with others across state lines and internationally.

Would you agree?

A (Witness Watkins) Absolutely. Yes.

Q Now, let's talk a little bit about RTP.

You -- since it seems to be the focus of much of this. Is it your understanding that manufacturers and many of the large commercial classes represented by Mr. Jenkins take service under the RTP tariffs?

A (Witness Watkins) Yes, sir.

Q Okay. And you understand the design of the RTP tariff is that there is a CBL, or a customer baseline, below which you are charged a tariff rate, for example, PLO; right? And then above the CBL is marginally-priced power. Do you understand that?

A (Witness Watkins) Yes. I'm familiar -- very familiar with it, yes.

Q You understand that there are fixed costs that are also paid by RTP customers based on certain riders or adders that are included in that?

A (Witness Watkins) Very few, but a tiny bit.

Q Well, it's interesting you say "very few."

Have you read Mr. Pollock's testimony?

A (Witness Watkins) Yes, but, quite frankly, not in great detail. I've known Mr. Pollock for years and pretty familiar with his standard testimony.

Q Okay. Well, this might not be a standard point

because it's more recent.

Are you familiar with RTP prices during 2022? Have you tracked any of those?

A (Witness Watkins) No, sir. And -- part of my scope of work in this engagement was not to get involved in the RTP issue.

Q Really?

A (Witness Watkins) Yes.

Q Well, that's very strange because your testimony seems to be largely about RTP and trying to put more cost onto RTP.

A (Witness Watkins) We're are not trying to put costs on any particular class. And, in fact, when it comes to RTP Day Ahead and Hour Ahead, when you look at the base-rate increases, they have the equal percentage of everybody. I think the issue that you guys might have is the relationship of how I recommend the collection of ECCR cost, which is a specific cost associated with the burning of fuel and environmental compliance.

Q Okay. Well, wouldn't --

A (Witness Watkins) It has nothing to do with the CBL or incremental or the loads that are placed on the incremental piece.

Q Well, let's talk about that a little bit. I'm not sure we agree there. Are you -- would it surprise you

to know that in many cases RTP rates tripled this year for manufacturers?

A (Witness Watkins) I have no idea.

Q Okay. Well, if you read Mr. Pollack's testimony or if you have read it or do read it, would you find in there that RTP customers have contributed $565,000,000 to fixed costs through July of this year, in 2022? Did you know that?

A (Witness Watkins) I don't know. But with fuel costs going up for everybody -- industrials, residential, governmental -- it's not surprising to me that the incremental lambdas have gone up substantially.

Q Right. And so the way RTP works with commodity prices at very high rates, natural gas prices, that affects that lambda and the marginal price of power in real time, that manufacturers pay on RTP; is that right?

A (Witness Watkins) That's right. And that's exactly why we have such an under-recovery on the fuel balance as well. The same exact thing.

Q Except that the under-recovery on the fuel balance is to be paid when the Commission holds a fuel hearing and adjusts that rate; right?

A (Witness Watkins) Yes. Eventually consumers are going to pay it. They may not have paid it yet, but they will eventually.

Q RTP customers are paying it right now, aren't they?

A (Witness Watkins) I would imagine so, yes.

Q All right. Do you understand that RTP has been an essential rate to keeping manufacturers rates competitive here in the state of Georgia?

A (Witness Watkins) I don't know if I would agree or disagree with that. I know it's been in place for quite a while.

Q Are you familiar with the fact that Georgia Power often uses RTP as an economic development tool to attract customers when there's a competitive choice load?

A (Witness Watkins) Yes, I do know that. But I work around the country and, for example, South Carolina, some of those utilities don't have it. They are butting heads with Georgia every day on competing for manufacturing.

Theoretically, I'm not here to testify bad against RTP. Don't get me wrong. That's not my issue at all.

Q Gotcha. Customers on the RTP rates take a significant amount of risk, would you agree, when they agree to sign up and have a significant portion of their rates priced at marginally-priced real-time prices, don't they?

A (Witness Watkins) That's not in my testimony. I really don't want to go there because I was asked not to

get involved in that in this case.

Q Okay.

A (Witness Watkins) And my testimony does not address any of that.

Q All right. So you were asked not to get involved in RTP in this case?

A (Witness Watkins) Correct.

Q That's what you were asked to do? Okay.

MADAM CHAIR PRIDEMORE: That was asked and answered by the way. So...

MR. CLAY JONES: It was. I wasn't asking him again. I think he had said that before.

MADAM CHAIR PRIDEMORE: I know. Sometimes we tend to answer over and over to the same thing.

MR. CLAY JONES: I'm moving on.

MADAM CHAIR PRIDEMORE: Mr. Watkins, do me a favor, too, straighten the neck of your mic.

MR. WATKINS: I'm sorry?

MADAM CHAIR PRIDEMORE: Straighten the neck of your mic.

MR. WATKINS: Like this?

MADAM CHAIR PRIDEMORE: Help him, Jamie.

MR. WATKINS: Is that better?

MADAM CHAIR PRIDEMORE: Yes. Thank you, sir.

BY MR. CLAY JONES:

Q Now, you've testified that you weren't asked to address RTP issues, but you do make several proposals in this case that would impact RTP rates; right?

A (Witness Watkins) Yes. Just due to the aspect of rate design, it's going to impact every rate schedule.

Q And as Mr. Jenkins pointed out, back in 2013 you made several proposals that would have increased RTP rates; correct?

A (Witness Watkins) That's right. Because my engagement in that case was to investigate the RTP program.

Q Right.

A (Witness Watkins) But it was not in this case.

Q And he mentioned the reliability capacity charge, but you also wanted to allocate costs on primarily an energy basis or allocate fixed production and transmission costs to RTP incremental loads in that case, didn't you?

A (Witness Watkins) I don't understand your question, or I don't follow what you're saying.

Q All right. Did you also propose in that case that all customer baselines, regardless of individual characteristics, be raised to reduce the amount of marginally-priced power available to RTP customers?

MR. THOMAS: Madam Chair, I would just object

to the extent that -- I would ask the questioner to ask Mr. Watkins about his testimony and his recommendations for this case and not the previous case. He is not making those recommendations in this case.

MR. CLAY JONES: Madam Chair, he has opened the door. He has talked about how he didn't testify. Now he's talking -- he has already been answering questions on the 2013 case, and I'm almost done with that anyway.

MADAM CHAIR PRIDEMORE: He has. Overruled. Stay within the guardrails, please.

MR. CLAY JONES: I will.

BY MR. CLAY JONES:

Q Do you understand the question?

A (Witness Watkins) No. Could you repeat it, please?

Q So you also proposed in that case that if all customer baselines, regardless of individual circumstances, be increased across the board that would then reduce the amount of marginally-priced power available to RTP customers, didn't you?

A (Witness Watkins) I'm going to be perfectly honest with you, I frankly don't remember, sir.

I do 20 cases a year. That was nine years ago.

I'm sorry, I just don't recall.

Q All right.

Now, the Commission didn't adopt any of those proposals, did they?

A (Witness Watkins) Again, as we noted before, the case was settled.

Q Yeah. Did any commissioner offer an amendment to modify the settlement to adopt one of your proposals about RTP?

A (Witness Watkins) I don't know if they did or not.

Q All right. And in 2016, we didn't have a rate case, did we?

A (Witness Watkins) No, sir.

Q And in 2019, you weren't able to testify here in the rate case; is that right?

A (Witness Watkins) Correct. I had a scheduling conflict.

Q And in that case, we didn't have any issue. The staff didn't propose any increases to RTP in 2019, did it?

A (Witness Watkins) I have no idea.

Q All right. Let's examine some of your recommendations in this case.

So, first of all, you make recommendations with

regard to class cost of service studies; correct?

A (Witness Watkins) I do.

Q And you would agree with me that the purpose of a class cost of service study is to determine whether rates reflect the cost of providing service to each customer class. Is that fair?

A (Witness Watkins) With the big caveat, in that no cost of service study is surgically precise and that that's why economics is the dismal science. It's more social science. There's a -- because of the commonality of all of the plant and equipment, there is no engineering or physical way to say: This customer used this energy -- this electron. That customer used another electron.

So it's imprecise, but at the same time, cost of service should play a role. It's just that you need to be careful in evaluating cost-of-service studies in that there is no precise answer such that if -- every way which you look at it, one class is undercontributing -- well, maybe we should give them a little bit more of an increase; or if every time you look at it, no matter how you look at it, they are overcontributing -- there's good reason to pause and say, maybe I ought to give them a break. If that makes sense.

Q My question was, what the purpose of a class cost of service study is.

Admitting that it's an imprecise science, would you agree that the purpose is to determine whether rates reflect the cost of providing service to each customer class; yes or no?

A (Witness Watkins) I think the best way to answer it is to say it should serve as a guide in evaluating class revenue responsibility.

Q Okay. Should it reflect cost causation? Is that part of the --

A (Witness Watkins) Yes. However, that is the number one question. I truly respect all of my fellow experts in this room, but we have different opinions. And we are all very qualified. We are all very confident, but -- competent. But we have different views on what causes cost to be incurred.

Q Okay. Now, in this case, Georgia Power, as it has done in almost every rate case that I think most people in the room can remember, has proposed a 12-CP cost of service methodology. Would you agree?

A (Witness Watkins) As I recall, at least since 2007 when I have been involved.

Q Right. And they have also filed a 4-CP -- the 12-CP looks at 12 coincident peaks across the year in order to allocate cost; correct?

A (Witness Watkins) That's right.

Q And the 4-CP looks at the four summer months in the same way?

A (Witness Watkins) Correct.

Q All right. Now, you've proposed looking at two additional proposals, the base intermediate peak method; correct?

A (Witness Watkins) Yes, sir.

Q And that one you also proposed in the 2013 rate case?

A (Witness Watkins) Did I? Okay. I typically do.

Q Okay. You proposed a peak-and-average method back in the 2013 case.

A (Witness Watkins) I did.

Q But in this case, you have replaced that with the probability of dispatch method; right?

A (Witness Watkins) Yes. Because the probability of dispatch is much more granular in detail. Back in 2013, we didn't have realtime data. We didn't have all the EMR hourly data necessary to fully, and in a granular method, look at every hour of the year how costs were being incurred.

Q Now, there's going to be plenty of cost-of-service testimony in this case. People can look through and understand all the nuances of these. And I'm

not going to waste the Commission's time trying to ask you about all of those, because I know you've put it in your testimony and others will too.

But I will just ask: Would you agree with me that in contrast to Georgia Power's cost-of-service studies, your methodologies allocate substantially more production-fixed costs to customer classes based on energy, or year-round energy; is that right?

A (Witness Watkins) As it turns out, it does. And that's exactly why, in evaluating these cost-of-service studies, we all have different opinions.

Over there on one side is the 4-CP that tends to favor industrial customers. On the other end of the spectrum is the probability of dispatch that tends to -- and they are not biased. It is just the way the arithmetic -- tends to benefit residential customers.

That's exactly why I didn't say: Oh, this is -- you know, this is the best thing since sliced bread. I have evaluated every single cost of service study.

Q Now, I want it refer you to page 43 of the testimony. I believe that's where Table 9 -- I will give you a minute to get there. Just let me know when you are ready.

A (Witness Watkins) Thank you.

Yes, sir. I'm there.

Q Okay. So this provides a summary of the results of Georgia Power's and your recommended class cost of service study based on index rates of return; right?

A (Witness Watkins) Yes, sir.

Q That's another name for parity ratio. Is that fair?

A (Witness Watkins) I think that's fair.

Q Okay. And all other things being equal, a parity ratio above 100 percent means a class is above cost while one below 100 percent means a class is below cost. Would you agree?

A (Witness Watkins) That's reasonable.

Q So if you read these results, reading across the table, some classes, when we get to your base intermediate peak and probability of dispatch, sometimes the parity ratios go up and sometimes they go down.

A (Witness Watkins) Okay.

Q From what Georgia Power's proposed; correct?

A (Witness Watkins) Right. That's correct.

Q And when they go down, that means that a cost of service study is shifting more costs to a specific class or rate. Would you agree?

A (Witness Watkins) Yes. And shifting fewer costs to other classes.

Q Right. So, for example, the PLL, or Power,

Large and Light, which many manufacturers pay on their CBL, between 151 and 161 percent under the ones that have always been filed here before the Commission, but they go down substantially under your proposals; is that right?

A (Witness Watkins) Under the probability of dispatch, they go down from roughly 100 to 135 percent to roughly 117, 118 percent.

Q And that's the same for -- if you go down to the marginal class, the same for RTP-DA, RTP-HA, FPA. All those.

A (Witness Watkins) Yes. That's correct.

Q Now, I don't want to get into the details of the methodology because I think, again, we can all read about it, but have you cited -- for probability of dispatch, have you cited anywhere in your testimony a list of regulatory commissions that have approved that method in past litigated rate cases?

A (Witness Watkins) No. In fact, there has not been a single commission that has either accepted or rejected, and as much wisdom as commissions have around the country, I'm not sure they fully understand the details of the mathematics. But I can tell you I have never had it accepted, and there's not been a single commission that I have testified before that has rejected it.

Q So you would agree with me that no state

regulatory commission in the 21st century has adopted this method. Would you agree?

A (Witness Watkins) Correct. And again, I would like to say that most commissions around the country do not adopt a particular cost of service study. They recognize that this is a lot of judgment and a lot of imprecision. And they simply use that, as I do, as a tool in evaluating class revenue responsibility.

Q Are you familiar with the study of production cost allocation methods published by Duke Energy in January of this year? Are you familiar with that study?

A (Witness Watkins) I'm sorry?

Q Are you familiar with a study of production cost allocation methods published by Duke Energy in January of 2022?

A (Witness Watkins) I believe -- is that the one in North Carolina?

Q That's correct.

A (Witness Watkins) In fact, I am, yes.

Q Yeah. Would it surprise you to learn that probability of dispatch is not even mentioned in that very comprehensive study? Would that surprise you?

A (Witness Watkins) It's not a very comprehensive study, sir. I was involved in that, and I'm involved right now on behalf of the South Carolina

Commission staff, in which we were a party to that.

What that is, was a workshop in seeing if they could stop the bickering, for lack of a better word, on cost allocation studies. So various parties proposed their various allocation methods, and that's the only ones in there.

Q And the report didn't mention probability of dispatch at all, did it?

A (Witness Watkins) No. Because in that case, the public staff of North Carolina doesn't have the data yet for it. Here in Georgia, we now have smart meters and we have the data to do the probability of dispatch.

However, I will add that the regulatory assistance project, they have put out a new cost allocation manual and they specifically say that the probability of dispatch is the most preferred embedded cost-of-service method.

Q But no commission has adopted it in the 21st century?

A (Witness Watkins) Again, this is becoming fairly new because the data has not been out there very long.

Q Okay.

A (Witness Watkins) Again, no commission has ever rejected it either.

Q Well, speaking about accurate data, let's look at page 14 of your testimony.

A (Witness Watkins) Page 14, sir?

Q Yes, sir.

A (Witness Watkins) Okay. I'm there.

Q Okay. So toward the bottom -- this is in a section of your testimony where you identify the strengths and weaknesses of each of the methods that you talk about in your testimony. Would you agree?

A (Witness Watkins) Yes, sir.

Q Under the 12-CP method, you identify one major shortcoming, and that is that accurate load data is required by class throughout the year. This generally requires the utility to maintain ongoing load studies.

A (Witness Watkins) That's correct.

Q But Georgia Power has the necessary load data. Would you agree?

A (Witness Watkins) I'm sorry?

Q Would you agree that Georgia Power has access to that data?

A (Witness Watkins) Has?

Q Access to the data that you say is a major shortcoming.

A (Witness Watkins) Oh, in fact, they provided me with the 8,760 hours -- individual hours for every rate

schedule. They have very good, detailed data.

Q So that's not really a shortcoming here in Georgia, is it, the 12-CP method, because they've got the access to that data?

A (Witness Watkins) No. I'm just saying potentially that is a shortcoming, if the utility does not have that. Of course, yes, Georgia Power does have that.

Q All right. Let's go a little bit over to page 40. And let me know when you are there.

A (Witness Watkins) I'm getting there. Yes, sir.

Q All right. So, there, you recommend -- on page 40, you recommend at the top there, determining -- in determining the spread of a base rate increase, cost of service studies results should be considered, but that there are other factors as well; right? And list some of those there?

A (Witness Watkins) Yes, sir.

Q And some of those include gradualism and rate stability; correct?

A (Witness Watkins) That's correct.

Q And you talk about that in your summary as well?

A (Witness Watkins) That's correct.

Q And as was previously -- as you testified to,

you are proposing to replace the current structure of the ECCR rate with a kilowatt energy charge. Is that fair?

A (Witness Watkins) I am, yes.

Q And your proposed kilowatt charge would apply not only to coal ash removal cost, but to all the entirety of the environmental costs that are recovered under that rider; is that correct?

A (Witness Watkins) Yes, sir.

Q All right. So when -- and the ECCR rate was first adopted in the 2007 rate case, as Mr. Jenkins mentioned to you; correct? And at that time, the Commission ruled that the ECCR tariff would not be applied to incremental portions of RTP tariffs; right? That was the settlement agreement approved by the Commission?

A (Witness Watkins) That's what I understand.

Q Nobody proposed, to your knowledge, a modification to that on the Commission?

A (Witness Watkins) I don't know.

Q And it's not been changed since then, has it, to your knowledge?

A (Witness Watkins) Not to my knowledge.

Q All right. So when the Commission first adopted the ECCR in its current form, do you think it was likely that the Commission could have chosen to implement a kilowatt charge if it thought it was a cost-based charge at

that time?

A (Witness Watkins) I have no idea. I guess they could have. If -- I'm not sure the issue was brought up, but at that time, the ECCR was a fairly small component. Now it is almost a billion dollars, as I recall.

Q It's not your testimony the Commission was wrong in the way that it established the ECCR, is it?

A (Witness Watkins) I don't know that the Commission came up with this. I -- I don't know how -- I don't know how that was -- how that -- the current rate structure was brought about. Did the company propose it? Did an industrial? I have no earthly idea.

Q You were in the case; right?

A (Witness Watkins) But I wasn't involved in that issue.

Q Okay. But the parties agreed to a settlement -- you understand that the parties can't just agree to a settlement and that's it?

The Commission has to review that settlement, and they have to decide if they think it's good, and they can even make modifications to that settlement?

A (Witness Watkins) I'm well aware of that, yes.

Q Okay. So they approved it; right? I mean, we're dancing --

A (Witness Watkins) Yeah, yeah, it was

definitely approved. Right.

Q Thank you.

All right. Let's look at page 57 of your testimony. It's Table 15.

A (Witness Watkins) Yes, sir. I'm there.

Q Okay. Now, here, you measure the percentage increases on current revenues based on Georgia Power's proposal, the staff's proposal, and then the percentage increases. Those are the two columns on the right; correct?

A (Witness Watkins) Yes, sir.

Q And you have a footnote here that says this is all in revenue. Includes base rates, RTP incremental, DSM, ILR, ECCR, NCCR, MFF, and then fuel. Right?

A (Witness Watkins) Yes, sir.

Q This is not a fuel case.

A (Witness Watkins) No. But I wanted to give the Commission information as to what is the impact on a customer's bill. What is the total bottom line. Because there's so many pieces parts, sometimes it's hard to put them all together. So I wanted to give information to the Commission as to this is what the impact will be all-in.

Q Sure. But at the end of the day, the Commission is going to pass an order, and that order is not going to impact the FCR rate; correct? The order will not impact the FCR rate in this case?

A (Witness Watkins) Oh. No, sir, not immediately, no.

MR. CLAY JONES: Madam Chair, may I approach the witness?

MADAM CHAIR PRIDEMORE: You may approach.

BY MR. CLAY JONES:

Q Okay. Mr. Watkins, I'm handing you what I'm going to mark as GAM Exhibit 1, with the Chair's permission.

MADAM CHAIR PRIDEMORE: So marked.

MR. CLAY JONES: Thank you.

(The document referred to was marked for identification as GAM Exhibit 1.)

BY MR. CLAY JONES:

Q And I will represent to you that this is an exhibit that is identical to your Table 15 except for two things: One, it removes fuel revenues from the current revenue column; and, two, it highlights some rates that I would like to talk about. And in the bottom it says -- you will notice fuel is not listed in the footnote.

A (Witness Watkins) I'm not going to accept a single number on this exhibit.

Q That's fine. You don't have to accept the numbers. You can accept them subject to check. They're in the case. It's a simple mathematical equation. This is without fuel.

A (Witness Watkins) Who prepared this document?

Q I did. We did.

A (Witness Watkins) There is no way I'm going to --

Q I'm not asking you to verify the numbers.

A (Witness Watkins) Okay. We can talk about it for illustrative purposes.

Q Sure. Illustrative purposes. You are exactly right. So if these numbers are correct -- and that can be mathematically verified, but we will leave that -- I'm not going to ask you to do that.

But if those numbers can be verified, can you take a look at the right column of the staff proposal on the percentage increases on the rates that I have highlighted?

A (Witness Watkins) Okay.

Q The TCU rate for government, 52.66 percent. Do you see that?

A (Witness Watkins) I'm sorry. Could you repeat the question?

Q The -- do you see where I have highlighted the TCU government rate with an increase of 52 percent, greater than 52 percent?

A (Witness Watkins) I see that number.

Q That's off the base rates.

A (Witness Watkins) I have no idea what it's

from.

Q That's what the exhibit represents. That's what I am saying, 25.8 -- point 08 for --

A (Witness Watkins) With all due respect, it looks like you're testifying, not me.

Q Well, I'm asking you a question, but you keep interrupting me. So if you'll let me ask the question, I'll ask the question.

A Please do.

MADAM CHAIR PRIDEMORE: Mr. Watkins, hang with us now. Okay?

MR. WATKINS: I will try. Yes, ma'am.

BY MR. CLAY JONES:

Q FPA, it says 25.08 percent. Do you see that?

A (Witness Watkins) Yes, sir.

Q RTP-DA, it says 22.05 percent?

A (Witness Watkins) I see that number.

Q RTP-HA 32.72 percent?

A (Witness Watkins) Yes, sir.

Q TOU-SC fixed, 51.33 percent?

A (Witness Watkins) Yes, sir.

Q The electric arc furnace rate, which, by the way, supports one of the largest customers on the system, 32.79 percent?

A (Witness Watkins) I see that number.

MR. THOMAS: Madam Chair, I'm just going to object in that I don't think a proper foundation has been laid for this document. I don't think we can authenticate the numbers. I don't know where this chart exactly is coming from. So I would just object to this chart.

COMMISSIONER MCDONALD: Mr. Jones, are you comparing your information here against what is on the testimony? Is that what you are doing?

MR. CLAY JONES: That's correct, sir. All we have done is taken out the fuel -- he included the fuel revenue so that the percentages, if you increase, would be a smaller percentage.

And I'm just pointing out that if you take the fuel out, what we are deciding in this case, the base rates and these other tariffs, the percentages are substantially higher than that.

Now, he doesn't have to accept the numbers for him to accept the principle that that's what would happen, and I'm providing this as an illustrative exhibit.

And Mr. Thomas, with all due respect, I haven't moved it into evidence yet, so I don't know what he's objecting to.

MR. THOMAS: Well, I'm objecting to questions

based on this chart that hasn't -- I don't think the foundation has been properly laid.

So did you add any numbers or did you just subtract --

MR. CLAY JONES: No. I said on the record what I did. I represented it. I took the fuel revenues out of the current revenue column. That's it.

MADAM CHAIR PRIDEMORE: Mr. Thomas, I'm going to allow it. His questions are not outside of anything that hasn't been previously asked by an intervenor attorney. So I'm going to allow it.

And, Mr. Jones, you have been here a long time. You know the guardrails.

MR. CLAY JONES: Yes, ma'am. I'm almost through with this part, so we can move on in just a moment.

BY MR. CLAY JONES:

Q But, Mr. Watkins, I just want to -- I just want to ask you whether you think that, for example, a 32 percent increase or a 51 percent increase represents gradualism, which you have said is an important factor to consider?

Do you think that's a gradual increase?

A (Witness Watkins) Well, your chart -- your chart is clever.

Q Thank you.

A (Witness Watkins) It is clever for an attorney.

Q I will let Mr. Pollock know.

A (Witness Watkins) And he is indeed clever. I've known him for 35 years.

Q He's much cleverer than I am. I will say that.

A (Witness Watkins) What I have done, to answer your question, I -- I have shown the pieces parts of my recommended increases.

In other words, I have showed my recommended increase, limited to just base rates. I have showed the increases limited to just the ECCR. We have no difference of opinion or disagreements on the NCCR or the DSM tariff. And then -- in this particular exhibit, I provided information, what is the impact on a total customer's bill. Everybody has to pay fuel. We all know that fuel case is not involved here, but we -- everybody has to pay fuel. So it was to provide information to that.

So again, a very clever representation that you make because everybody has to pay fuel. I don't care if we have a case or not. We are paying for fuel today.

Q Mr. Watkins, I appreciate the compliment, but isn't it true that we often ask questions around here about whether something is an increase based on total bill or based on base rates, excluding fuel or including fuel?

A (Witness Watkins) Yes. But, again, the individual components, we -- we can talk about anything you want, but that's why -- exactly why I did what I did, is so I could show the pieces parts of our recommendation as well as the composite of what all of this means.

Q Did you -- Mr. Watkins, did you conduct a study or determine what the economic impact of your proposals would be on manufacturers that rely on the RTP rate?

A (Witness Watkins) No. Nor did I take into account what the requested increase would be on any individual small business or low-income customers or anybody.

My assignment, and as an economist in there, is to reasonably assign cost responsibility across individual classes and rate schedules.

MR. CLAY JONES: Madam Chair, I think that's all I have for the witness.

Thank you, Mr. Watkins.

MR. WATKINS: Thank you, Mr. Jones.

MR. CLAY JONES: I will move my exhibit into evidence.

MR. THOMAS: I would just note my objection for having it moved into evidence today. Again, there is just no foundation or authentication that's been provided for this document. So I would object to it

being moved into evidence.

MR. CLAY JONES: Do you want me to respond?

MADAM CHAIR PRIDEMORE: You are welcome to respond, Mr. Jones.

MR. CLAY JONES: I don't need to respond.

MADAM CHAIR PRIDEMORE: No response? Okay. Your objection is on the record.

Mr. Jones, your document, did you mark it as an exhibit?

MR. CHARLES JONES: I did. I marked it as GAM 1. The Commission can give it the weight it wants to afford it.

MADAM CHAIR PRIDEMORE: It is marked.

MR. CLAY JONES: Thank you.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?

CROSS-EXAMINATION

BY MS. BROWN:

Q Good afternoon, panel. Alicia Brown on behalf of the Georgia Coalition of Local Governments.

If I can direct you to page 92 of your testimony, and I will just be directing to the panel at large. Feel free to answer as you feel appropriate.

It was established in the IRP and elsewhere in this proceeding that the Community Solar program is

currently a premium program that's intended to be revenue neutral relative to the R-tariff.

Has the staff calculated what the cost would be if we looked at the cost of the program as opposed to the lost revenues approach?

A (Witness Barber) Yes. That's what our calculation is based on.

Q Can you please give us the cost that you calculated?

A (Witness Barber) $20 for residential.

Q And for general service?

A (Witness Barber) It would also be $20, but we added $2 additional because that was kind of what the company has proposed in their -- in their request.

Q Okay. For the residential program, what portion of that is dedicated to administrative costs?

A (Witness Barber) Let me see. I think I have that with me here.

I would say roughly 20 percent.

Q Roughly 20 percent. So that's about $2 on the subscription price?

A (Witness Barber) We will confirm in just a second, but, yes, that's correct.

Q Okay. Now, in response to some criticism -- I'm sorry.

A (Witness Barber) Well, 8 percent.

Q Eight percent? Okay.

So in response to some criticism about the premium nature of the program, the company has provided a income-qualified pilot that's based on corporate sponsorship.

Are the administrative costs for the income-qualified pilot larger than those for the standard program?

A (Witness Barber) No, they are not. We didn't -- we didn't include all of the -- those costs.

Q Okay. So the cost in staff TAI3, you did not allow some of those?

A (Witness Barber) That's correct.

Q Okay. So if the Commission adopted your proposal, would there be as much need for an income-qualified program because there would be a savings opportunity for customers?

A (Witness Barber) I'm not really sure. I mean, it's already been approved as part of the IRP. I mean, I'm assuming still the corporate sponsors are going to buy down the subscription price. I'm not really sure that's a bad thing. But is it going to be as needed as much? No.

Q Okay. So on page 92, beginning at line 5, you essentially frame this as a policy decision for the

Commission. But based on the data we have from the, I believe six years of the program, has there been any benefit to the broader customer base from these solar resources?

A (Witness Barber) Well, they have supported the development of these projects, so I would say yes, in that regard. And they were done at -- they were done below avoided cost. So I think they were a good thing, but as in has customers wanted to participate and subscribe, no. They have not wanted to.

Q You said that they were done below avoided cost. So does that mean that there is downward pressure on rates as a result of these resources?

A (Witness Barber) Well, at or below -- that was a requirement, so yes. I mean, customers have not been harmed by the development of these projects.

Q And given the way that fuel prices have increased, they may perhaps even be benefiting? Is that --

A (Witness Barber) Yes, that's correct.

Q Okay. If we can shift gears to page 79 of your testimony. In the final order from the 2019 rate case, the company and Georgia Watch staff were to collaborate on a report or study of expanding income-qualified discount opportunities.

What resulted from that requirement?

A (Witness Deitchman) So the report was included

in our exhibits. It's Exhibit BDW 13. So it was -- we -- staff, Georgia Watch, and the company worked on that report. Georgia Watch had a specific proposal related to reducing customer energy burden.

So that was analyzed, and also what was analyzed was expanding the income-qualified discount that's currently only offered to senior citizens across -- across customers. So regardless of age.

Q So was any recommendation made to change or expand the program as a result of that study?

A (Witness Deitchman) That did not come out of that report, no.

Q In the section I referenced, staff is recommending, specifically in line 18, that this discussion continue.

Do you think that the outcome will be different in this case in that the discussions will result in some kind of recommendation?

A (Witness Deitchman) I don't know at this point. We would have to have those discussions and see what's going forward. And obviously circumstances change, times change. But certainly keeping -- working with the company and keeping the Commission informed on possible options to help income-qualified customers certainly has benefits and something for us to keep looking at going

forward.

Q But to be clear, the staff is saying that the company should come forward with the recommendation, not the collective or the staff?

A (Witness Deitchman) So, I mean, in the -- the previous proposed program was really Georgia Watch's proposal, so we're not saying that the company is the only entity that might have a strong idea for a potential income-qualified program and, you know, we -- you know, certainly as a staff we pay attention to what's going on around the country and what other groups are looking at.

So we are always welcome to listen to and analyze and understand potential ideas for programs that benefit the public interest and Georgia Power's customers.

Q But the staff will not be making the final recommendation?

A (Witness Deitchman) At this point, our recommendation is to continue to look at, explore the issue.

Q Okay. And then if I can direct -- were you going to say something?

A (Witness Barber) I was going to say our recommendation doesn't preclude staff from -- I mean, it does specifically say "the company," but we are part -- we would be part of the discussions and we would -- we could come before the Commission as well with a recommendation if

we felt that it was needed or justified.

Q Okay. Understood.

And finally, if I can direct you to page 74 of your testimony. Looking at Table 21.

So it's already been established by several counselors up here that the company wants to maintain the smart usage as the default residential tariff for newly constructed premises.

In the Coalition's initial cross of Witness Legg, we raised some concerns that consumers would not be able to understand any price signals embedded in the demand charge. Has that assertion been proven in the data?

A (Witness Watkins) Yes. Indeed it has. Quite frankly, the demand for electricity is very inelastic. And the theoretical purpose of a demand charge, particularly for residential, is to increase their load factor. In other words, decrease their demand relative to their energy usage. Use energy more efficiently.

There is not a heck of a lot of difference, but in fact, the exact opposite is true, in that the customers that are under the demand rate -- residential customers under the demand rate actually have a slightly lower load factor than people that are on the energy only.

And this is consistent with my experience around the country. I am an economist. This is how I make

my living. But the truth be known, American families have a lot more to worry about than just their electric bill. They've got children to feed. They've got children to bathe. They've got dinner to cook. It just doesn't work very well for residential customers, plain and simple.

Q And what information do customers have to control their demand? In your opinion, do they have enough information to do so?

A (Witness Watkins) Although I haven't conducted a specific survey, I talk to intelligent, well-educated people all the time. They have no idea what a kilowatt is relative to a kilowatt hour. They don't know that, oh, my goodness, I can't give the kids a bath the same time I'm cooking supper, the same time I've got the dishwasher running. Moreover, they don't really care.

Q To ask a more specific question, does the company's billing system record the date and time that a customer's peak demand is set?

A (Witness Watkins) For -- I'm trying to remember, I have a data request on this. For the -- for the non-demand residential customers, they do not keep track of that. At least, you know, for historical purposes.

For the RD class, I stand to be corrected, but I'm pretty sure I'm right, that they don't know the date and time, they just know the maximum load each month.

A (Witness Deitchman) So customers have access to hourly data and they can look at that and figure out which hour they perhaps set their highest hourly demand.

Q But it is not easily accessible?

A (Witness Deitchman) No.

MADAM CHAIR PRIDEMORE: I would just like -- this is an interesting line of questioning, but this was covered just -- we covered the tar out of it in that IRP. So I just want to remind us this is a rate case. So I look forward to the rate-related questions on demand usage.

MS. BROWN: Yes, ma'am.

BY MS. BROWN:

Q So just one other question. You did an additional analysis on this rate and you looked at when different customer classes peaked. What did you find out with the residential rate class?

A (Witness Watkins) As indicated in our testimony, typically, the residential class peaks on weekends, whereas the system peaks during weekdays.

Q So residential customers are not contributing to system peaks?

A (Witness Watkins) Oh, they certainly are.

Q On this rate. This rate does not control those peaks?

A (Witness Watkins) Correct. What -- the purpose of the analysis I did was to find out when residential customers peak. And, in fact, they peak on the weekend. But at the same time, the commercial load is considerably lower, so that -- I don't want to say it's unfair, but the residential class is peaking on the weekend while the commercial load and governmental load peaks during the week. So that tends to help level out our system load, our load duration curve and everything, makes things look a little bit better.

Furthermore, the residential class tends to peak at a later time of day on the weekends. It's common sense. People sleep in on the weekends than they do during the weekday. So I don't know if that answers your question or not.

Q It does.

So just a final question. Does the smart usage rate, in your opinion, reduce system costs in any way or send a good price signal?

A (Witness Watkins) In theory, it might; but in practicality and reality, it hasn't done a doggone thing.

Q All right. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Brown.

Georgia Conservation Voters?

MS. OPIE: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA?

CROSS-EXAMINATION

BY MR. THOMASSON:

Q Gentlemen, I'm going to pick up on where she left off on demand charges, but specifically on page 70 of your testimony.

You talk about this question that was raised with Witness Legg's testimony on direct about whether other utilities around the country have imposed a mandatory residential demand rate. And there was a little back-and-forth about that during direct, but it sounds like y'all have kind of put that to bed in your testimony.

Could you explain your findings on how many other investor-owned utilities have done this around the country?

A (Witness Watkins) Zero.

Q And how many have even proposed it?

A (Witness Watkins) I'm only aware of one, and that was Arizona Public Service, I think around 2016 or so.

Q So just to clarify, there's not a trend forming of utilities moving residential customers to demand-based rates? Is that accurate to say?

A (Witness Watkins) Not investor-owned. There are a handful of electric co-ops and municipals that are self-regulated.

Q Do you have -- I think you may have sort of answered this already. But do you have an opinion as to why that's not happening? I mean, is that consistent with the discussion you just had about the price signals?

A (Witness Watkins) The two-part rate, that is a basic customer charge, service charge, and an energy charge. It's been tried and true for well over a century.

Studies -- I have conducted my own study in this case, which is consistent with every other study I have seen, and that is an energy-only rate for a residential customer reasonably reflects cost causation because customers that have higher demands tend to have also higher energy usage and they pay for that. A fundamental aspect in economics is you should pay for what you use.

In this study, we found that there's a 77 percent correlation -- which is a very high correlation -- between peak demand and energy usage. And other commissions have recognized that. That, and the fact that residential customers typically don't understand power versus energy. And they've got more important things to worry about in their life. It's that simple.

Q And I'm going to skip to page 84 of your

testimony where I think you've got a recommendation that sort of relates back to this for a customer tool to compare the different residential rates.

You note the company doesn't have a customer tool currently; correct?

A (Witness Watkins) I'm sorry. Could you repeat the question?

A (Witness Barber) That's correct. They don't.

Q Okay. Thanks.

And then you recommend that they impose one or that they establish a customer tool but you don't provide a lot of detail. What are you envisioning as a customer tool?

A (Witness Deitchman) So currently, yeah, the company does not host a rate calculator on its own website. On the Commission's site, which I think the company links to, we do have, for the standard R-tariff, an opportunity for customers to plug in their usage and see how much their bill should be.

But there -- there's a lack of an easy way for customers to understand how much different rate plans would cost them, what the bill impacts of choosing each of these different rates would be for a customer who uses, you know, a certain number of kilowatt hours, has a certain demand, if they are on a demand rate.

So we certainly would hope to work with the

company as, you know, they seek to market various modern rates and find ways to make it easy for customers to understand the impacts these different rates might have on them.

Q And so to clarify what you just said, you envision and support -- would you support a customer rate calculator tool that used a specific customer's historical usage data for that calculator?

MADAM CHAIR PRIDEMORE: Can I ask you -- before you answer that -- Mr. Thomasson, it's in the -- it's on page 84 of the prefiled direct testimony that you are referencing. I mean, you are asking them things directly from their testimony. Do you have follow-on?

MR. THOMASSON: I'm only asking them details about this. I mean, they say they recommend a tool, but they don't -- they don't mention any details about it. We've got a similar recommendation. I just want to know if we are on the same page as staff.

MADAM CHAIR PRIDEMORE: All right.

MR. THOMASSON: I'm winding it up.

MADAM CHAIR PRIDEMORE: It's not just a time consideration, it's that if it's in the prefiled direct testimony that they recommend a tool that has

historical data and that's just what you asked them, it's redundant. Read the testimony. We all have to do it.

MR. THOMASSON: Okay. Well, I will ask a different clarification that is not in the testimony, but that I think Mr. Deitchman just said.

MADAM CHAIR PRIDEMORE: Go forward.

BY MR. THOMASSON:

Q Would you support including a customer's demand data to the extent that it's available, which it sounds like it is, hourly demand data -- or it is not -- I'm getting a head shake.

A (Witness Barber) Yeah. My understanding is the company does not have demand data for customers that are not on those tariffs. If you're just on a standard tariff, they don't have demand data.

A (Witness Watkins) At least they don't retain that data in any reasonable or accessible form is my understanding.

Q Is it your understanding that their advanced metering technology would allow them to do that if they were to...

A (Witness Watkins) I know the hardware will. They may not have implemented all the software to maintain that. But I don't know for sure.

Q Okay. That's why I was asking.

A (Witness Barber) That's correct.

MADAM CHAIR PRIDEMORE: I mean, there's so many considerations to that. How long do they store the data? What capital expenditures would need to be deployed to be able to purchase enough data storage? What is the -- what is the customer's expectation of how long that data should be available?

MR. THOMASSON: And I --

MADAM CHAIR PRIDEMORE: These are IRP questions, Mr. Thomasson.

MR. THOMASSON: I was just asking if it was even a reasonable thing to discuss, whether that capability was there. So I'm moving on.

BY MR. THOMASSON:

Q Couple quick questions about the interconnection fee, which is on page 102 of your testimony. Begins on that page.

You already mentioned staff is recommending a reduced fee for residential from the proposed $200 to $100; correct?

A (Witness Barber) Yes, that's correct.

Q In preparing that recommendation, did staff have sufficient information from the company to specifically land on that number as a -- based on cost justification or

was it more a judgment call based on other considerations for system size and customer class?

A (Witness Barber) We did have a DR response, which I have here somewhere, that justified the -- I think it was $190. It was a policy decision. It was -- I'm not sure that we agreed with some of the costs or that, you know, that some of these costs shouldn't be socialized. But for us, it was a policy decision of just the increase from $35 to $200, and to charge residential the same as commercial. We don't support that as a policy.

Q Okay. That answers my question.

Did staff review interconnection fees for other neighboring IOU's for comparison --

A (Witness Barber) No, we didn't.

Q -- in making that policy decision?

A (Witness Barber) We didn't.

MR. THOMASSON: Okay. That's all the questions I have.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch? She's in the other room. We're going to give her a minute.

MS. COYLE: No. I'm right here.

MADAM CHAIR PRIDEMORE: Right there?

MS. COYLE: I just wanted to make sure I didn't

drop my glasses. I might need them. Thank you.

Like you, I've been waiting patiently for my opportunity to ask this panel just a few questions, and I will try very hard not to ask any that they have already answered, because they have been answering a lot of the same questions.

MADAM CHAIR PRIDEMORE: You can put your purse by Mr. Thomas. Just watch your wallet.

CROSS-EXAMINATION

BY MS. COYLE:

Q Good to see you all again.

Actually, Mr. Watkins, I think this is the first rate case you and I have done together -- or maybe -- 2013, anyway.

So you have had a number of questions about the demand charge itself and the structure, and I don't want to get into that part of it. But I'm interested in the -- in your testimony. You conducted research about what other investor-owned utilities were or were not doing in this space and you analyzed various aspects of the impact that TOU-RD has on both the system load and impact on customers' energy usage and bills; is that correct?

A (Witness Watkins) Yes, ma'am.

Q And did one of the analyses that you did show that customers on the demand charge plan compared to

customers on the standard residential plan could be paying as much as $200 -- thank you. Mr. Deitchman?

A (Witness Deitchman) Yeah. So, yes, this was one of the tables in our report, but we had, you know, put in data requests to the companies to -- to the company to see, you know, what the average customer cost was for customers on TOU-RD and then what the costs would have been for those customers if they were on the standard rate. And we found that, yeah, they were paying more than they otherwise would just based on which rate plan they were on.

Q And is it your -- would it be -- that would have been something the company could have done; is that correct?

A (Witness Deitchman) Yes. So they provided us the data and we did the subtraction.

Q But the company has been recommending this rate plan not only to this Commission but to their customers, have they not?

A (Witness Deitchman) Correct.

Q And has -- would you say that your findings directly counter some of the language the company has been using to suggest that this rate plan is actually better for customers?

A (Witness Deitchman) So there may be customers who could save money on this rate plan. I'm not going to

discount that idea. But what we are finding is impracticality out in the field -- out in the real world. Customers either don't understand. These are customers moving into new premises. They don't necessarily have a sense of what their electric bill should be.

Q Right. No, you -- I have long -- yes. Thank you.

Back in the 2019 rate case, PIA staff and the intervenors like Georgia Watch raised concerns about this rate plan.

Since 2020, customers moving into new premises have been defaulted onto this rate plan.

A (Witness Deitchman) Since 2021, yes.

Q 2021. Yes. 2021, yes.

So is it possible that -- so then your analysis was based on actual customers' bills --

A (Witness Deitchman) Correct.

Q -- who were on this plan. Some of them would be these customers who were defaulted onto it without necessarily knowing that they were going onto this new plan; right?

A (Witness Deitchman) Many of the them -- many of the new customers going on TOU-RD are customers who defaulted onto it, if not most.

Q And those customers may have paid an additional

$200 a year for their electric service, per your analysis?

A (Witness Deitchman) That's what our analysis shows.

Q Okay.

A (Witness Watkins) By the way, currently 75 percent of the new customers go on the TOU-RD. And it's increased. But right -- for the last several months, it's been right at 77, 75 percent. So that tends to be the trend right about now.

Q So now that staff has performed this analysis, should the Commission order the company to perform this and validate this analysis? And if it's shown that the customers put on this rate plan have paid $200 more a year or a substantial amount more a year, should they be required to notify those customers that they have been put on a plan that may very well have cost them more money?

A (Witness Deitchman) That would be a policy decision for the Commission.

A (Witness Watkins) I will say that in addition to Dr. Deitchman's analysis -- Deitchman's analysis, in the company's own cost of service study where we look at rates of return by individual rate schedules, the TOU-RD is well above parity while the regular rate R is slightly below parity. So, I mean, it's apparent from -- and obviously if you are paying more, they are making more profits. So --

so, you know, I mean, that's apparent to the company.

MADAM CHAIR PRIDEMORE: I'm just impressed that Ben is now a doctor. I'm going with that.

MR. WATKINS: He is a doctor. He's a smart cookie.

MR. DEITCHMAN: From Georgia Tech. Go Jackets.

MADAM CHAIR PRIDEMORE: Are you really a doctor?

MR. DEITCHMAN: Yes.

MADAM CHAIR PRIDEMORE: Oh, my gosh. That's fantastic. You're now Dr. Ben in my world. That's good.

BY MS. COYLE:

Q Dr. Deitchman, back to that question.

You said it's a policy decision. Would you recommend this Commission require the company to at least perform the analysis, and should they, at a minimum, put on the website where their customers might go to select a rate plan, a cautionary statement that some people going on this rate plan end up paying a lot more money?

A (Witness Deitchman) I think the company should definitely, you know, warn customers and help them to understand what they are -- I mean, frankly, they should do that with every rate plan to make sure their customers are well-informed and understand the potential costs of the

plan.

Q And Commissioner Echols asked if you want to perhaps slow this down by about three years in terms of having the TOU-RD, the demand rate plan, supplant residential -- the standard residential tariff.

Instead of that, I have a couple of questions. One, should this Commission require the company to stop putting people moving into newly-constructed properties on this plan?

MR. HEWITSON: Madam Chair, I'm just going to have to object because the way the question is worded, it makes it look like it's mandatory that the -- you know, the TOU-RD rate is not mandatory for any new premises or any new customer or a new premises. It's the default rate. Customers can choose whatever rate they want to go on.

Ms. Coyle is making it sound as if it's a mandatory rate. It is not.

MADAM CHAIR PRIDEMORE: Ms. Coyle, have you said it's a mandatory rate?

MS. COYLE: It is a default rate that a customer is now put on if they move into a new premises; whereas, someone who is just starting up service, the default rate has always been the standard residential plan, something that people are

typically used to because that's what most customers are on.

What the company is doing now, since 2021, if you move into a newly-constructed premises, you are defaulted on that rate. You can ask to get off of it, but you are put on that. And so I'm just suggesting that maybe there needs to be a disclaimer for customers that this is coming.

MADAM CHAIR PRIDEMORE: Well, then, perhaps that should be your question.

MS. COYLE: Should there be a disclaimer?

MADAM CHAIR PRIDEMORE: Okay. Because default and mandatory are two different things.

BY MS. COYLE:

Q Should there be a disclaimer for customers who are being put on this default rate that that is the case and that there are some of the potential pitfalls, including higher bills?

A (Witness Watkins) Well, first of all, remember it's our recommendation that the rate TOU-RD, as the default rate, should not continue.

Q Thank you. That was a more direct answer to my question. Thank you. That was my --

MADAM CHAIR PRIDEMORE: Which is in their prefiled written testimony.

A And should the customers who are on that -- have already been defaulted onto that be given additional information that they may be paying more money?

MR. HEWITSON: It has been asked and answered multiple times.

MADAM CHAIR PRIDEMORE: Asked and answered.

BY MS. COYLE:

Q And so back to the -- so Commissioner Echols, your question about delaying this by three years, would you recommend instead that this Commission do what the Arizona Public Service Commission did in 2016 and disallow the company from making this a default plan for any of their customers.

A (Witness Watkins) Yes. That's absolutely what we're saying.

Q Okay. And then off of that subject. And you had some questions about the meetings that we had after the last rate case and the resulting recommendations from the company to the Commission.

Would you agree that the intent of an expanded income discount program directly relates to the higher energy burden that people are feeling if they have a lower income?

A (Witness Deitchman) So, I mean, really it was your proposal that was the main one analyzed, and it was

definitely addressing the higher-energy-burdened customers.

And, Dr. Deitchman, would you agree that if the Commission -- would you agree that we have heard a lot of testimony over the last couple of days about how much people's power bills were going to be going up from the rate case and other things, other factors that have intentionally caused their bills to go up, the average residential customer 45 to $60?

A (Witness Deitchman) Correct.

Q And would you agree that Georgia Power's customers, whether they're seniors or otherwise income-qualified customers, are going to really feel that pinch if that goes into effect?

A (Witness Deitchman) Correct?

Q So would you also perhaps recommend that not only Commission staff and intervenors and the company do an analysis of the potential to expand this that perhaps we invite a commissioner or two to participate in those discussions?

A (Witness Deitchman) I'm always happy to have commissioners participate in every discussion we have. So...

MS. COYLE: No further questions.

MADAM CHAIR PRIDEMORE: The Kroger Company? He had a flight to catch.

MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. DOWDY: No questions.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association is still gone. Probably not coming back.

Ms. Medlyn? She represents United States Department of Defense and all other Federal Executive Agencies, but it's just faster for me to say.

MS. MEDLYN: Yes. Thank you. I appreciate that.

CROSS-EXAMINATION

BY MS. MEDLYN:

Q Good afternoon.

A (Witness Watkins) Good afternoon.

Q On page 51, lines 8 to 13 of your testimony, you say that the ECCR rider recovers costs associated with environmental compliance for both decades of prior fuel burning and the current burning of fuel; correct?

A (Witness Watkins) Yes, ma'am.

Q Okay. Is it safe to say that most of the ECCR is for recovery of costs related to the decades of past energy usage and prior fuel burning?

A (Witness Watkins) I'm not sure of the breakdown. I know a large amount of it is due to coal ash. But as far as the percentage breakdown, between that and S02 and all of that, I don't know.

Q Okay. But you would agree that there is a portion of it that is allocated to past fuel -- prior fuel burning; correct?

A (Witness Watkins) Oh, absolutely. Yes.

Q Okay. And would you agree that the costs created by decades of prior fuel burning are not caused by current burning of fuel or current kilowatt hours of production of energy?

A (Witness Watkins) Yes, obviously.

Q And would you agree that there are current Georgia Power customers who were not customers during the past when these costs created by the decades of prior fuel burning were occurring?

A (Witness Watkins) Sure.

Q Okay. And conversely, would you agree that there are current Georgia Power customers who were customers during the past when these costs created by the decades of

the prior fuel burning were occurring?

A (Witness Watkins) Yes, ma'am.

Q And would you agree that some of these decades-long customers may have significantly increased their annual energy usage?

A (Witness Watkins) Yes. And some may have significantly decreased.

Q Okay. And one example of an increase would be if a customer expands operations at its sites; correct?

A (Witness Watkins) Correct. Or reduction, if they reduce their operations. That's correct.

Q Okay. And would you agree that the ECCR cost created by the decades of prior fuel burning are not caused by the current kilowatt energy usage?

A (Witness Watkins) No. It's -- the question that we have to all wrestle around with with this -- with this coal ash and environmental cost compliance is a lot of that has been -- is a result of burning of fuel in the past.

We need -- we need to come up with mechanisms to recover those required compliance costs. How should we do that? It's -- you can't go back and bill somebody who has been in the grave for five years, you know. It not a perfect world. What we are trying to do is come up with the most fair and reasonable method to collect those costs that must be paid for compliance.

Q Okay. But you are asking the Commission that recovery for these costs should be based on current kilowatt hour energy usage; correct?

A (Witness Watkins) I'm not asking the Commission to do anything. I'm recommending that that's what they do.

Q Are you familiar with the terms "embedded cost" and "marginal cost"?

A (Witness Watkins) I'm afraid so.

Q Okay. And is there a difference between those two?

A (Witness Watkins) Absolutely.

Q Can you briefly explain the difference?

A (Witness Watkins) That takes about three semesters of microeconomics, but embedded cost, in lay terms, is fully-allocated costs, which are accounting costs. Marginal costs are defined as the incremental change in costs with an incremental change in output.

At the same time, you have the short run marginal cost, long run marginal cost. One must understand that you have no excess capacity or if you do have excess capacity. But, in short -- and this isn't technically correct -- you can think of incremental cost as the variable cost that's on the top, if you will. And that's not totally correct; whereas, embedded costs are an average of all

costs.

Q And are ECCR costs created by decades of prior fuel burning currently embedded costs or current marginal costs?

A (Witness Watkins) Neither one. Neither one. It is -- think of it like a superfund, if you will. I mean, the utility is responsible to pay that, to pay those compliance costs recovered. It has nothing to do with marginal costs or embedded cost.

The question becomes, is: How are they most fairly recovered. Those that are -- who pay for a portion of their bill based on incremental or marginal cost, well, they have contributed proportionally to that coal ash, just like everybody else.

So, you know, clearly your position is, no, we should -- the Defense Department should not be responsible for the incremental portion. You guys have been using fuel just like everybody else for decades. In my opinion, the most fair and equitable way to do that is based on energy because that's how those costs were incurred, by the burning of fuel. It's that simple.

Q Okay. Thank you. That's all I have.

A (Witness Watkins) Yes, ma'am. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Medlyn.

Georgia Power?

MR. HEWITSON: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Panel. How are you? I know you've been up there a little while and I've been trying to cross off a bunch of questions for you. So hopefully I got rid of a bunch of them.

A (Witness Watkins) Thanks.

A (Witness Deitchman) Thanks.

Q You are welcome, Dr. Ben.

A (Witness Deitchman) Thank you.

Q All right. Starting real quick on the cost of service study. You indicated on page 48, lines 1 through 13 of your testimony, that the residential prepay rate is significantly below parity. And you noted in your testimony there was an assignment of expenses in account 903 that may have contributed to the lower ROR for prepay.

And so, Mr. Watkins, was the company able to provide you information to clear up this accounting issue?

A (Witness Watkins) Yes. Indeed they had. We had a conference call, I believe it was Monday of this week. And as a result of a review of my testimony, the company found actually a small error in their accounting as it relates to this. And we discussed it. And the long and short of it is, whereas in their original cost study, as

well as mine, they had directly assigned approximately $21.8 million to the prepaid program when, in fact, there was a small error in which there should have been about 14 million of that that should have been booked to customer records and collections such that only about $7.6 million should have been directly assigned to the prepaid program.

By doing that, the rate of return for the prepay class, rates schedule customer, about 2.2 to 5.2 percent. And I truly appreciate the company's being up-front. It was an inadvertent error, you know, with all of the millions of records.

So with that being said, I guess I was right for the wrong reasons. So it would be my recommendation on page 48 to strike from my testimony lines 1 through 13 because they are no longer relevant as a result of that error that the company acknowledged.

Q I very much appreciate that, Mr. Watkins. Thank you.

A (Witness Watkins) Thank you for all your help on that.

VICE CHAIRMAN ECHOLS: Can you give us that site one more time for our stenographer.

WITNESS WATKINS: Page 48, line 1 through line 13 should be stricken.

VICE CHAIRMAN ECHOLS: All right. Thank you.

BY MR. HEWITSON:

Q Now, you've already answered a bunch of questions on ECCR, so after playing nice there, I'm not going to try and get you riled up. But I do want to ask just a couple questions I don't think did get asked yet.

Ms. Medlyn was asking you about the fact that ECCR recovers more -- ECCR -- EECCR recovers more than just the CCR ARO cost. And it also recovers cost of pollution control equipment; right?

A (Witness Watkins) Correct.

Q Okay. And do you agree that the cost of pollution control equipment does not necessarily vary with the amount of fuel burned?

A (Witness Watkins) Not necessarily vary, but it is in there in size based on the amounts of fuel it has -- fuel that -- well, it is size based on the amount of kilowatt hours that it's going to produce, which is based on the amounts of fuel that's going to be burned in there.

Q There is some pollution control equipment, though, that is not necessarily sized for the volume, like wastewater control equipment, that has to be either implemented or not implemented. Is that your understanding?

A (Witness Watkins) I don't know if that's true or not. And I don't mean to be argumentative. Common sense goes if you got a thousand megawatt coal plant, you're going

to have a bigger wastewater treatment than if you have a little distributed energy, even though there's not such a thing, but a very small plant. But as far as the proportionality, I don't know.

Q Fair enough.

Ms. Medlyn also asked you about the embedded costs versus marginal cost. Let me ask you this question. CCR costs will still be there even if Georgia Power does not sell a single kilowatt hour of electricity in 2023. Right?

A (Witness Watkins) Yes.

Q And the amount of electricity sold in 2023 through 2025 will not alter in any way the CCR ARO costs to be recovered in rates over the next three years. Is that your understanding?

A (Witness Watkins) Probably so. I would agree with that.

Q All right. Let me turn -- well, given that, do you agree that the RTP rate is designed to represent the hour marginal cost of electricity for kilowatt hours?

A (Witness Watkins) Again, I didn't get into that in my testimony and I would rather not now.

Q All right. Fair enough.

Let me ask you some questions about Community Solar. The panel's recommendation on Community Solar is that the company's proposed rate adjustment hinges on a

policy decision. Is that your testimony?

A (Witness Barber) That's correct. Yes.

Q And your testimony states that if the purpose of the Community Solar program is to let customers participate in the development of clean energy and give them the opportunity to realize bill savings, and the staff recommends, if lower blocks be approved; right?

A (Witness Barber) Right.

Q But if the only purpose of the Community Solar program is to allow customers to participate in the development of clean energy, then the staff recommends approval of the company's proposed rates; right?

A (Witness Barber) Yes.

Q Well, hasn't the Commission already spoken to this issue?

A (Witness Barber) They have, but they can always change their position on that.

Q Okay. So it's your understanding when they approved the Community Solar program, they specifically noted in the order that the Community Solar program is not designed to produce credits in excess of the customer's usage and a customer should anticipate the Community Solar program charges will exceed the value of any bill credits received.

A (Witness Barber) Can you repeat that.

Q Yes. It might be easier for me to just give you an exhibit.

A (Witness Barber) Yes.

MR. HEWITSON: May I approach?

MADAM CHAIR PRIDEMORE: You may approach.

BY MR. HEWITSON:

Q All right. Mr. Marzo is handing out the Order Approving Georgia Power Company's Community Solar Program and Related Tariff, dated June 7, 2017, in docket No. 40161. I won't mark this as an exhibit since it is an order of this Commission. I have highlighted two sections for you, Ms. Barber.

The first page, the order states that "The CS program will provide residential customers with an opportunity to support the development of solar power in Georgia by purchasing a monthly subscription. With this subscription, the customer will receive a bill credit based on the production of the company-owned solar facilities that will be used to support the CS program."

Do you see that?

A (Witness Barber) Yes.

Q Okay. And on the second page, it says, "The CS program is not designed to produce credits in excess of a customer's usage and a customer should anticipate the CS program charges will exceed the value of any bill credits

received."

Did I read that correctly?

A (Witness Barber) Yes.

Q So it seems the Commission has already decided that policy question that you have asked in your testimony; right?

A (Witness Barber) Well, at this particular time they have.

Q All right. Thank you.

That's all I have for you today. I appreciate your time.

A (Witness Watkins) Thank you.

MADAM CHAIR PRIDEMORE: Redirect?

REDIRECT EXAMINATION

BY MR. THOMAS:

Q Mr. Watkins, am I correct to say that your recommendations are based on the 2022 filing and the specifics of that filing means that your recommendations might be different than they had been in the previous case?

A (Witness Watkins) Well, of course that -- every case that I have I looked at the facts and the record as they appear. But I will say doing this for 42 years, you wouldn't last very long if you weren't consistent on your philosophies and positions methodologically anyway.

Q And your recommendations might impact the RTP

tariff, but they aren't targeting that tariff; correct?

A (Witness Watkins) I did not address the RTP components of the tariff as it relates to CBL incremental, whether it's appropriate, inappropriate, or anything.

Q Right. But you got a lot of questions surrounding those -- the RTP tariff, and I think you acknowledged that it had an impact on that tariff, but you weren't targeting that tariff over any other.

A (Witness Watkins) No. It has an impact on every single tariff, whether it's a 40 or 42. It has an impact on every single tariff.

Q Ms. Barber, you got some questions surrounding the Community Solar program. Do you consider this an appropriate forum to -- for the Commission to possibly reconsider what the purposes of that program are policy-wise?

A (Witness Barber) Yes. Most definitely. The company is requesting an increase in their block charge from 24.99 to 27.99, and so this is a time for the Commission to reconsider the policy and the purpose of this program.

Q Thank you.

MR. THOMAS: Madam Chair, that's all I have for redirect. I would ask that the panel be excused and the exhibits be entered into the record.

MADAM CHAIR PRIDEMORE: Staff's exhibits are in

the record. Panel is excused. Thank you, Ms. Barber, Mr. Watkins, Dr. Deitchman.

WITNESS DEITCHMAN: Thank you.

(Staff Exhibits 62 through 83 were admitted into evidence.)

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy, please present your panel.

Mr. Galloway, you can swear in your witnesses.

MR. GALLOWAY: Yes, ma'am.

Madam Chair, Commissioners, Newton Galloway on behalf of Americans for Affordable Clean Energy. At this time we would like to call our witness panel, consisting of Mr. Joe Akers, Mr. Ron Nelson, and Mr. Barry Selvidge.

And if I could get the members of the panel to please stand, please, so I can swear you in. If you would raise your right hand.

Thereupon,

JOSEPH AKERS,
RON NELSON,
BARRY SELVIDGE,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. GALLOWAY:

Q You may be seated. Would each of you please state your name and business address, starting with

Mr. Akers.

A (Witness Akers) Joe Akers, RaceTrac, Inc., 200 Galleria Parkway, Atlanta, Georgia 30339.

A (Witness Nelson) Ron Nelson, 1131 Portland, Oregon 97215.

A (Witness Selvidge) Barry Selvidge, 3334 Peachtree Road Northeast, Atlanta, 30326.

Q And if I could ask each of you to be cognizant of speaking into the microphone so that you can be heard.

Are you the same members of the panel and persons that prepared and prefiled testimony consisting of 47 pages in this docket?

A (Witness Akers) Yes.

A (Witness Selvidge) Yes.

Q And if you were asked the same questions today, would your answers be the same?

A (Witness Akers) Yes.

A (Witness Selvidge) Yes.

Q Do you have any additions or corrections to your testimony?

A (Witness Akers) Yes. One. On page 4, footnote 1, it should read, known as, quote, as COCOTs, closed quote.

Q Mr. Akers, does that conclude any corrections to the testimony?

**A (Witness Akers) Yes, it does.**

**Q Okay. Did your testimony also include six exhibits which were attached thereto?**

**A (Witness Akers) Yes.**

**MR. GALLOWAY: Madam Chair, I would ask that the prefiled direct testimony of the panel and the accompanying exhibits -- six exhibits be entered into the record as if stated from the stand, please.**

**MADAM CHAIR PRIDEMORE: So moved, so marked.**

**(Whereupon, the prefiled direct testimonies of Joseph Akers, Ron Nelson and Barry E. Selvidge follows:)**

BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

| | | |
|---|---|---|
| In re: | : | |
| GEORGIA POWER COMPANY'S 2022 RATE CASE | : | DOCKET NO.: 44280 |
| | : | |
| | : | |

**TESTIMONY OF**
**JOSEPH AKERS, RON NELSON AND BARRY E. SELVIDGE**

Presented as a panel on behalf of
Americans for Affordable Clean Energy

October 20, 2022

**Q. State your names, business titles and business addresses.**

A. (Mr. Akers) Joseph Akers. I am Chief Legal Officer and General Counsel of RaceTrac, Inc. My business address is 200 Galleria Parkway, SE, Suite 900, Atlanta, Georgia 30339.

(Mr. Nelson) Ron Nelson. I am a Senior Director at Strategen Consulting located at 10265 Rockingham Dr., Suite #100-4061 Sacramento, California 95827.

(Mr. Selvidge) Barry E. Selvidge. I am the President and owner of Selvidge Strategic Consulting, Inc. My business address is 3334 Peachtree Road, No. 613, Atlanta, Georgia 30326.

**Q. State your business experience and educational background.**

A. (Mr. Akers) I have served as Chief Legal Officer and General Counsel for RaceTrac, Inc. ("RaceTrac") since 2012. Prior thereto, I was Corporate Counsel from 2005-2012. RaceTrac is a $10+ billion privately - held retail convenience store company with over 9,000 employees working in over 700 stores. Our seventeen (17) affiliates and subsidiaries provide wholesale fuel and energy, logistics, real estate, and transportation services. As Chief Legal Officer and General Counsel, I am responsible for all aspects of RaceTrac's legal, risk management, and compliance functions. My work includes enterprise risk management, data privacy, safety, environmental, licensing, asset protection, and public policy. I also serve as Corporate Secretary to RaceTrac's Board of Directors and all its subsidiaries and affiliates.

Among other accomplishments, I led our M&A team in RaceTrac's largest asset sale (~$125MM), created enterprise risk management policies and procedures and reduced total legal and risk management spending by approximately 20%. In 2013, I received the Association of Corporate Counsel Value Champion Award, which recognizes the General Counsel's role in

improving costs, predictability, and business outcomes. Prior to RaceTrac, I worked in private law practice. I received a Bachelor of Arts degree from Tulane in 1994 and my Juris Doctor degree from the University of Georgia in 1997. In 2017, I received a Certificate in Fundamentals of Accounting from the Northwestern University School of Professional Studies. My resume is attached as Exhibit 1.

(Mr. Nelson) Currently, I am a Senior Director at Strategen Consulting. Strategen is nationally recognized for its work in regulatory innovation, performance-based regulation, rate design, renewable program development, grid modernization, and new grid technologies including distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. At Strategen, I have worked with consumer advocates, non-governmental organizations, utilities, and state regulatory commissions on issues related to cost-of-service modeling, rate design, demand response, grid modernization, distributed energy resource ("DER") valuation and integration, and performance-based regulation.

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led that office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics and a Bachelor of Arts in Environmental Economics from Western Washington University where I minored in Mathematics. My resume is attached as Exhibit 2.

(Mr. Selvidge) From 1991 to 1998, I served as Vice President, Regulatory Affairs and General Counsel of Communications Central, Inc. ("CCI"), a publicly held independent payphone

provider ("IPP")[1] based in Roswell, Georgia. CCI owned and operated payphones in forty-two (42) states in competition with payphones installed by incumbent local exchange carriers ("LEC") in their respective geographic monopoly service territories. I was responsible for CCI's legal and regulatory matters, including regulatory compliance in each state in which it provided payphone service. I negotiated with major telecommunications companies, often Regional Bell Operating Companies ("RBOC"), including BellSouth Telecommunications, Inc. ("BellSouth") to achieve reasonable rates, terms and conditions for IPPs to install phones within their monopoly service territories, and I also advocated for regulatory initiatives before the Federal Communications Commission ("FCC") and numerous state public utility commissions to promote greater availability of payphone service through competition across the country.

During my tenure at CCI, I was elected Chairman of the American Public Communications Council ("APCC"), the national trade association representing IPPs nationwide promoting the widespread deployment of public phones. I worked with RBOCs to develop and pass Section 276 of the Telecommunications Act of 1996 ("TA 1996") (47 U.S.C. § 276 – Provision of Payphone Service) which required the FCC to implement nondiscrimination safeguards to prevent RBOCs from subsidizing their payphone service directly or indirectly out of regulated telephone exchange service or exchange access revenues and to prevent them from providing necessary services for their own payphone operations that were not offered to competitors.

I also served as Executive Director of the Georgia Public Communications Association, Inc. ("GPCA") for more than a decade. In that role, I actively participated in the development and implementation of strategic positions to advance public communications issues before this Commission. During that time, GPCA successfully negotiated rate reductions and argued for

[1] IPPs were also referred to a COCOTs (Customer Owned Coin Operated Telephone) and PSPs (Payphone Service Providers).

"same terms and conditions" treatment for IPPs payphone services by incumbent LECs whose public phones (paid by ratepayers) directly competed with those owned and operated by IPPs. My resume is attached as Exhibit 3.

**Q. Have you previously testified before this Commission?**

A. (Mr. Akers) No.

(Mr. Nelson) No.

(Mr. Selvidge) Yes. I pre-filed testimony in a docket styled: *In re: Petition of the Georgia Public Communications Association, Inc. for the Implementation of LEC Pay Telephone Services to Competitors under the "Same Terms, Same Conditions" and for the Investigation of LEC Pricing and Service Offering Practices under the Telecommunications and Competition Development Act of 1995*; Docket 5876 (October 2, 1995) (the "Same Terms, Same Conditions Docket").

**Q. On whose behalf is the panel testifying in this docket?**

A. We are testifying on behalf of Americans for Affordable Clean Energy ("AACE").

**Q. Summarize your professional experience with electric vehicle ("EV") programs and policy.**

A. (Mr. Nelson) Most recently, I testified before the Massachusetts Department of Public Utilities on behalf of the state Office of the Attorney General with recommendations on three electric utilities' comprehensive EV planning proposals, addressing topics including EV market development, rate design, and load management (DPU 21-90, 21-91, and 21-92). I served as the technical expert to the Hawai'i Public Utilities Commission ("PUC") on advanced rate design,

including EV rates and DER compensation in Docket No. 2019-0323. I also work as stakeholders' expert in advanced rate design proceedings in Minnesota and Utah. In Docket No. 20-86, the Minnesota PUC recently adopted my proposed time-of-use ("TOU") with critical peak pricing ("CPP") rate design for large commercial and industrial ("C&I") customers, including large EV charging facilities as a pilot the PUC will later consider using as a default rate. I also recently testified on behalf of the Pennsylvania Office of the Consumer Advocate in the areas of EV pilots and EV rate design in Docket No. R-2021-3024759 10 and R-2021-3024601 and have been the lead or assisted on EV rate design and infrastructure proposals in Massachusetts, Illinois, and Washington, DC.

(Mr. Selvidge) I am not directly involved with EV deployment. When I was asked to review regulatory EV charging issues in Georgia, it was clear that EV charging issues are virtually identical to those that arose in the provision of public telecommunications services and were resolved by this Commission years ago. I was an active participant in the regulatory battles that raged for more than a decade seeking a level-playing field between IPPs and monopoly utilities' payphones operations. The same issues are presented by EV charging, and I apply my telecommunications regulatory experience and precedents established by the FCC and this Commission to them. Ultimately, I recommend that this Commission apply these telecommunications precedents to EV charging and establish a fair, level playing field now.

**Q. What is AACE?**

A. (Mr. Akers). AACE is a non-profit organization, organized pursuant to the Internal Revenue Code, Section 501(c)(4), whose members own and operate convenience stores, public travel facilities and truck stops that provide fuel, goods and services to the traveling public at locations throughout Georgia and across the United States. AACE members operate 784 stores in

Georgia. AACE's principal office is located at 1330 Braddock Place, Suite 501, Alexandria, Virginia 22314.

**Q. What are AACE's interests in this docket?**

A. (Mr. Akers) As business operators and property owners of sites at which electric vehicle EV charging stations will be deployed, AACE members are uniquely situated to play a critical role in the deployment of EV charging stations to advance the public policy goal of developing electricity fueled transportation. We already provide fuel for all shapes, forms and types of vehicles on the nation's roads today. Electricity provided to operate an EV is just another type of transportation fuel. To deploy EV charging stations, our members will predominantly rely on private investment, rather than ratepayer subsidies.

Pursuant to tariffs approved by the Commission, our members will purchase electricity from Georgia Power Company ("Georgia Power" or the "Company") (and other electric suppliers) to provide EV charging at our numerous business locations. However, Georgia Power will also provide EV charging at its own locations in direct competition with us. Georgia Power will not charge itself the commercial tariffed rate that we will have to pay nor (absent direction from this Commission) is it likely to provide services to us on the same tariff terms and conditions as it does to its EV charging service. The differential between the tariffed rates, terms and conditions that we will pay the Company to provide electricity to us and the Company's costs to provide the same electricity to its own EV charging stations increases our costs to provide the same EV charging services and gives Georgia Power significant competitive advantage.

**Q. How is your testimony organized?**

A. Our testimony covers three primary topics:

1. We state our business goals to provide EV charging services to motorists at our publicly accessible business locations, and we define the role that we will play in providing EV charging to customers throughout the state, with limited ratepayer support. We also state our support for a Make-Ready type program, with targeted goals, objectives and guardrails subject to Commission review.

2. We analyze the Company's Charge-It Electric Vehicle-1 ("CIEV") tariff, and we propose an alternative volumetric tariff that is better suited to provide electricity to EV chargers.

3. We show that the CIEV-1 tariff discriminates between EV charging providers, imposing rates, terms and conditions on our EV charging service that the Company will not charge or impute to its own EV charging service. To that reality, we apply FCC and Commission regulatory precedents, as both agencies dealt with similar issues that arose in public telecommunications services. We show that such discrimination between EV providers deters development of a robust private sector to meet consumer demand for EV changing. We urge the Commission to secure a level-playing field now, not ten (10) years down the road.

## I.

## PROVISION OF EV CHARGING

**Q. What are the business goals of AACE members related to EV charging?**

A. (Mr. Akers) The future is clear: electricity will be an important source of transportation fuel in the future. AACE members (along with other gas stations, convenience stores, truck stops, grocery stores and retailers) already offer fuel (e.g., diesel, gasoline, etc.) for internal combustion engines now used in commerce by the traveling public. We can provide electricity to EVs in the exact same way we provide gasoline and diesel to most vehicles on the road today. EV charging simply expands the services we offer to the traveling public.

**Q. Why should AACE members, rather than the Company alone, provide EV charging to the public?**

A. We hold a key asset that will be required to deploy reliable EV charging in Georgia: existing business locations that already dispense transportation fuel and that the traveling public deems safe and convenient. We also believe that private investment can deploy EV charging stations faster and with better amenities for customers than a regulated utility dependent on long-term ratepayer subsidy. The faster the EV charging market can grow through private investment, rather than ratepayer funds, the better.

**Q. Why are your existing business locations a key asset for EV charging?**

A. We already provide fuel to the traveling public at numerous business locations along every thoroughfare and rural byway in Georgia. Our locations are conveniently located for urban, suburban, rural and traveling customers. Our locations are found in virtually every town in Georgia and in some of the most rural areas of the state. We provide motorists with convenience, offering fuel, amenities and the security of on-site personnel and good lighting on a 24/7 basis. We provide products and services that the traveling public wants and needs at locations with which they are already familiar.

**Q. Does Georgia Department of Transportation ("GDOT") recognize the importance of our existing business locations to provide EV charging?**

A. Yes. In August 2022, GDOT released its "Georgia Electric Vehicle Infrastructure Deployment Plan" which it submitted to secure funding through the National Electric Vehicle

Infrastructure Program ("NEVI") to deploy EV charging infrastructure and stations.[2] Therein, GDOT found:

> Convenience store and gas station operators are logical candidates to offer charging services for EVs given that they currently provide fueling services to the nation's drivers.[3]

GDOT recognized the value of placing EV charging stations at our existing business locations where the traveling public already purchases gasoline and diesel. GDOT's plan was approved on September 14, 2022.[4]

**Q. Will our customers and the traveling public benefit by having access to EV chargers at our existing business locations?**

A. Yes. The traveling public already obtains transportation fuel and other services at our locations. Providing EV charging at the same place gasoline and diesel are already purchased makes sense, particularly since electricity is just another form of transportation fuel. Commerce and travel require a reliable EV charging infrastructure so that EVs can travel long distances with assurance that fast charging is available. Drivers will not experience "range anxiety" -- concern about: "Where am I going to charge?" or "Will the charger work when I get there?" While there is no difference between EV range anxiety and a driver's concern about running out of gas, EV chargers are not yet as commonplace as fuel pumps, and drivers' range anxiety is greater for EVs. Our members' locations are already etched in the minds of the traveling public and knowing that EV charging is available at our locations will assure drivers that their EV will reach the intended destination because an EV charging station can be found in time to recharge. As EVs proliferate,

[2] Guidance from the Joint Office of Energy and Transportation (Feb. 10, 2022).
[3] Georgia Electric Vehicle Infrastructure Deployment Plan, p. 47 (August 2022).
[4] https://www.fhwa.dot.gov/environment/nevi/ev_deployment_plans/ga_approval_letter.pdf

our locations can provide drivers with access to an EV charging network that will be as familiar, reliable and ubiquitous as the gasoline and diesel we provide now.

**Q. But, can't EV owners charge their vehicles at home?**

A. Many EV drivers will be able to charge at home. The availability of home charging is important, and EV owners can charge at home using relatively inexpensive, slower chargers and pay lower off-peak electric rates. However, those who live in multi-unit dwellings ("MUD") or do not have a detached garage where home charging can be installed will most likely need to rely on public chargers to fuel their EVs. For those with home charging, it can take 8-10 hours to charge up an EV at home, and the ability to charge an EV at home at night does not eliminate the driver's range anxiety when the EV must travel long distances the next day. Home charging may be sufficient for daily commuters, but it does not cure long distance range anxiety.

**Q. What type of charging will be required for long-distance travel?**

A. High speed chargers, commonly referred to as Direct Current Fast Chargers ("DCFC"), are required for business and long-distance travel. The time to recharge must be as comparable as possible to the amount of time required to fill a gas tank and pay. Currently, Level 2 chargers cannot satisfy that need because they take too long to charge while traveling on the road. Over time, chargers will become more powerful, and the time to recharge will be reduced.

**Q. Are AACE members willing to invest funds to provide EV charging services?**

A. Yes. We are prepared to make significant capital investment to develop EV charging services supported by a reliable EV charging infrastructure. However, our capital investment

cannot succeed unless our members can deploy EV chargers and provide EV charging service to customers on a level playing field with those deployed by the Company.

**Q. Does the current market structure deter AACE members' investment to provide EV charging?**

A. Yes. We face two primary barriers to our ability to provide EV charging:

1. We will provide EV charging in direct competition with monopoly electric suppliers, like Georgia Power, whose costs to provide the same EV charging equipment and the electricity required to provide electric service will be paid by ratepayers; and

2. We will obtain electricity to provide EV charging pursuant to tariffs, riders, terms and conditions that the Company will not charge or impute to itself to provide its own EV charging stations with which we must compete.

As a result, our costs to provide EV charging will always exceed those of Georgia Power, and our EV charging service will always be provided at competitive disadvantage. As retailers in private enterprise, we do not earn a higher return because we incur more costs. Instead, we have to cover increased costs by charging our customer a higher rate for EV charging than the Company, and we risk losing customers as a result.

**Q. How should EV charging services be defined?**

A. The Commission has already determined that the owner of the EV charging station is Georgia Power's customer and that the retail sale of electricity occurs between Georgia Power and

the EV charging provider.[5] Before the Joint Study Committee on the Electrification of Transportation ("Joint Committee"),[6] Madame Chair Pridemore's presentation noted that:

> … because **EV charging service** is not provided to a **Premises**, but rather, to a transient motor vehicle, EV charging service does not constitute the provision of **retail electric service**." (Emphasis in original)[7]

She also noted that no court has ever found that EV charging constitutes retail electric service. We agree with both the Commission's decision and Madame Chair's comments before the Joint Committee. Not being a retail electric service, EV charging does not fall within the Georgia Territorial Electric Service Act, O.C.G.A. § 46-3-1, et seq. (the "Territorial Act"). To date, we know that our members, as EV charging providers, are the Company's customers and that providing our EV charging service does not constitute a retail sale of electricity.

**Q. How should our EV charging service be defined?**

A. (Mr. Nelson, Mr. Selvidge) The provision of EV charging to the public is probably most closely associated with the term "resale." This is consistent with the Commission's telecommunications precedent and the exclusion of "resale" from the Territorial Act.[8] Though the Territorial Act does not apply to "resale," "resale" is prohibited by Georgia Power's rules and regulations.[9]

**Q. How are EV charging providers currently compensated for electricity they provide EVs?**

[5] "Order Affirming and Adopting Hearing Officer's Initial Decision;" *Sawnee EMC v. Georgia Power Company*; Docket 43899 (August 23, 2022).
[6] Senate Resolution 463 (March 20, 2022).
[7] "Georgia Public Service Commission Electric Vehicles and the Territorial Act;" Joint Committee (August 24, 2022) (p. 5).
[8] O.C.G.A. § 46-3-3(9).
[9] Georgia Power Company Rules and Regulations and Rate Schedules for Electric Service, Section A(6) (p. 1.11).

A. Currently in Georgia, most EV charging providers charge for the amount of time by the hour or minute the EV charger is used. If an EV charging provider wants to continue to charge on that basis (or some other) they should have the right to do so, so long as the EV charging customer is made aware of the fee they are paying.

**Q. Does AACE recommend a better means of compensation?**

A. (Mr. Akers, Mr. Nelson) We believe that a volumetric charge to the EV owner based on the amount of electricity in kWh being provided to the EV by the EV charger is the best and most appropriate way to compensate the EV charging provider. This is permitted in over twenty (20) states, and it is more transparent to the EV owner. The average EV owner that pulls into a parking space to charge expects to get electricity from the charger, not rent the charger over time or rent the parking space in which the EV is located. Customers buy gas and diesel by the gallon, and electricity from the charger should be provided by kWh. There is no substantive difference between how they are dispensed.

The EV charging provider pays for the electricity on a per kWh basis. EV drivers obtain a commodity – electricity – whose units are measured in kWh, and the EV charging provider should be compensated on the same basis. Per-kWh pricing allows for that granular price signal. It is also simpler to set per kWh costs for drivers. Finally, it is easy for drivers to estimate the cost of charging based on $/kWh pricing, particularly when they travel across state lines. They simply need to know the total kWh of their EV battery and multiply it by the $/kWh pricing to find the total cost of charging.

**Q. What is your concern with pricing EV charging service on a per minute or hour basis?**

A. (Mr. Nelson) Dollar-per-minute or hour pricing does not account for the different power levels of EV chargers. A 50-kW station does not provide the kWh delivered as a 100-kW station in the same amount of time. Under dollar-per-minute or hour pricing, the EV owner must know the charging power of the station (in kW), the total kWh of their EV battery, the charging rate of the vehicle's battery at different states of charges and the dollar-per-minute pricing, then (using that information) calculate the total cost to charge up their EV. This is much more complex, and it makes it very difficult to compare the cost of charging between different stations. For example: is a 150-kW station priced at $3/minute more or less expensive than a 75-kW station priced at $2/minute? $/kWh pricing is not dependent upon the charging power of the EV charging station. With $/kWh pricing, EV chargers with higher charging power can charge the EV faster but the total kWh delivered – and therefore the total cost -- would be the same for the EV.

**Q. Is the Territorial Act implicated at all if EV charging providers charge by the kWh?**

A. (Mr. Nelson, Mr. Selvidge) It does not appear that a kWh charge conflicts with the Territorial Act.

**Q. Has Federal Highway Administration ("FHWA") proposed regulations that suggest per kWh pricing is preferred?**

A. FHWA's proposed regulations[10] implementing NEVI include a requirement that chargers "display and base the price of electrical charge in $/kWh," signaling that this is the most driver-friendly pricing structure and should be the standard around the country. FHWA acknowledged that "several states restrict the ability to display charge in $/kWh."

**Q. Is AACE familiar with Georgia Power's Make Ready program?**

A. Generally, yes. The Commission approved Georgia Power's Make Ready program to fund EV infrastructure improvements in the Company's 2019 rate case.[11] It authorized $6 million per year for three (3) years to install EV infrastructure upon application by a commercial or industrial customer that wants an EV charging station installed on their property. The Commission approved the program as a policy decision, advancing public policy goals that extend beyond cost considerations. The Make Ready and Community Charging programs fall within this authority, and the costs for both are paid by ratepayers.

**Q. Does Georgia Power seek to enlarge the infrastructure program in this rate case?**

A. Though the Company's direct pre-filed testimony did not request an extension of the Make Ready and Community Charging programs, its response to STF PIA 3-5 identified a requirement of $90 million in EV infrastructure upgrades from 2023-2025. The Abramowitz panel and Mr. Legg[12] testified in the Company's direct case that Georgia Power is requesting $90 million

[10] https://www.federalregister.gov/documents/2022/06/22/2022-12704/national-electric-vehicle-infrastructure-formula-program.
[11] "Order Adopting Settlement Agreement;" *In re: Georgia Power Company's 2019 Rate Case*; Docket 42516 (February 6, 2020) (p. 18-19).
[12] Testimony of Abramowitz Panel, T. 405:13-25; Testimony of Larry Legg, T. 949:11-20.

for EV infrastructure deployment, with 90% of the funds to go to the Make Ready program.[13] The remaining 10% is proposed for the Community Charging program.

**Q. How does the Make Ready program work?**

A. Based on public information, a commercial or industrial customer applies to the Company to install an EV charger on the customer's property. Georgia Power reviews the application, notifies the customer that their site has been selected and then installs the infrastructure from the customer's meter to the EV charger. The customer selects the EV charger, pays for it, installs it and collects revenue from charging. Georgia Power maintains the infrastructure for the life of the EV charger. The customer owns, operates and maintains the charger.

**Q. Are there guidelines for participation in the Make Ready program?**

A. The Company's rules and regulations for the Make Ready program are publicly available. (Exhibit 4). The Make Ready program standard contract between the Company and the customer is not publicly available to our knowledge. Pursuant to a number of Georgia Open Records Act requests, we obtained the Make Ready contract between Georgia Power and the City of Augusta, Georgia to install an EV charger at 535 Telfair Street. (Exhibit 5).

We do not believe that the Make Ready program guidelines, criteria and standard contracts were reviewed or approved by the Commission. It appears that participation in the Make Ready program rests largely in Georgia Power's discretion. Also, the Make Ready program's terms and conditions do not set priorities based on a strategic plan to deploy EV charging stations.

[13] *Id.*, T: 405:7-19.

**Q. How many EV chargers have been deployed in the Make Ready program?**

A. Based on its public disclosure response to STF PIA 1-1, the Company received approximately 616 location applications to deploy approximately 3100 Level 2 chargers and 100 DCFCs. Some were not installed because the program funds ran out. Georgia Power reports that there is a waiting list for the Make Ready program.

**Q. Does AACE support continuation of a Make Ready program?**

A. Provided the goals and requirements of the program are clearly defined, there is a role for a program like Make Ready until the EV market is more developed. We support it and would participate in it. But, the Commission should require clearly stated priorities for the use of ratepayer funds to deploy the infrastructure from the customer's meter to the EV charging station, and continue the customer's obligation to pay for the charger, its installation and maintenance. All EV commercial and industrial customers will be eligible to apply and qualify, as the Abramowitz panel testified.[14]

**Q. What priorities should the Commission set for the Make Ready program?**

A. Priority for deployment in the Make Ready program should be based on the proposed location and the nature of the site, as follows:

1. Charging infrastructure located at public locations (gas stations, downtown areas, shopping malls, community centers, gas stations, grocery stores, etc.) which will provide EV charging service to the public, including those without access to home charging, for both long-

[14] Testimony of Abramowitz Panel, T. 427:3-428:11.

distance and daily travels. Sites that offer24/7 amenities (employees on site, restrooms, food etc.) should be given the same priority as in the NEVI grant program administered by GDOT.

2. Charging infrastructure serving public transit fleets which provide the benefits of EVs to all residents, including low-income residents and residents who do not own EVs. Electrifying Medium- and heavy-duty vehicles ("MHDV"). used by public transit fleets also reduces air pollution.

3. Charging infrastructure at workplaces and multi-unit dwellings ("MUD") which are shared among many EV drivers but may have limited accessibility to the public.

4. Charging infrastructure serving other non-transit fleets which primarily serve private companies and not the general public but help electrify MHDVs; and

5. Within these categories, charging infrastructure sites located in rural and economically challenged communities which are expected to have lower EV adoption rates in the near term.[15]

**Q. Based on these priorities, what do you recommend?**

A. To support these priorities, we recommend that the Company through the Make Ready program offer to cover a percentage of the total make-ready costs as follows:

- Public transit fleets and public charging sites: 70% of make-ready costs
- Workplace and MUD sites: 50% of make-ready costs
- Other fleets: 30% of make-ready costs
- Bonus 20% of make-ready costs if the EV charging site is located in a rural or economically distressed community.

[15] The Georgia Department of Transportation has already identified populations – based on minority, elderly, and low-income status – for its Statewide Transportation Improvement Program (STIP). Environmental Justice Identification and Proposed Outreach Report. FY 2015-2018. https://www.dot.ga.gov/BuildSmart/Programs/Documents/STIP/EnvironmentalJustice/EJ-OutreachReport.pdf.

**Q. Do you have additional recommendations for the Make Ready program?**

A. We also recommend that the Commission:

1. review and approve requirements, terms, conditions and contracts used by the Company in the Make Ready program; and

2. review the benefits and costs of the Make Ready program triennially in the Company's Integrated Resources Plan.

3. require that the property owner own the EV charging station and charge for the service provided.

**Q. What is the difference between the Company's Make Ready program and its Community Charging Program?**

A. In the Community Charging program, the Company incurs the cost to install the infrastructure from the customer's meter to the EV charger, and it also owns, operates and maintains the EV charger and gets the revenue generated from its use over the life of the charger. All of the costs of the Community Charging program are borne by ratepayers.

**Q. How many EV chargers have been deployed in the Community Charging program?**

A. Based on the Company's response to STF PIA 1-8, the Company deployed approximately 50 chargers at 25 Community Charging sites as of July 2021. Of these, approximately 90% are DCFCs (45) and 10% (5) are Level 2. The Company contends that

Community Charging chargers serve charging deserts – locations at which private investment will not deploy an EV charger.[16]

**Q. Do you agree with the Company's contention?**

A. No. Investigation of the Community Charging locations identified in response to STF PIA 1-8 showed that most EV chargers in the Community Charging program are actually located along commercial strip thoroughfares, near interstate interchanges, in central downtowns and near college campuses. In these areas, it is likely that private investment would support EV charging without ratepayer subsidy.

**Q. Should DCFCs be deployed in the Community Charging program?**

A. No. EV chargers deployed with ratepayer funds in the Community Charging program should provide basic, Level 2 charging service. The costs to deploy Level 2 charging in rural locations is substantially less than that required for DCFCs.

**Q. Are there other issues with the Community Charging program?**

A. Yes. Like its Make Ready program, the Company has not (to our knowledge) developed objective or identifiable criteria to determine the need for the charger at any proposed Community Charging location. Again, deployment rests largely within the discretion of the Company.

[16] In response to STF 19-1 (Docket 42516), the Company identified 51 DCFCs that it owns. It is not clear whether these were deployed in the Community Charging program. Mr. Legg testified that the Company now owns 59 DCFCs. (Testimony of Larry Legg, T. 950:1-9).

**Q. What does AACE recommend?**

A. Over a period of time as the EV market develops, a community charger may be needed to serve a specific location that private enterprise cannot. To serve those locations, Community Charging guidelines should be developed that include specific objective criteria by which the need for a community charger (placed in service and operated at ratepayer expense) can be identified. Before the costs of the community charger are imposed on ratepayers, however, private enterprise should be given the opportunity to serve the proposed EV charge location through private investment. But, these locations will prove to be few and far between.

**Q. Is there a telecommunications precedent applicable to the deployment of EV chargers to serve charging deserts, particularly in truly rural locations?**

A. (Mr. Selvidge) Yes. The FCC found that payphones "unquestionably serve critical public interests in health, safety and welfare" and that a competitive market may fail to adequately provide payphones in locations serving important public needs because the payphones "may not be economically self-supporting."[17] The FCC cited "payphones…along deserted stretches of highway [that] can be essential for public safety but fail to be [sufficiently] revenue-generating for various reasons, including lack of sufficient traffic, damage from extreme weather conditions, or high maintenance costs." The FCC established criteria by which individual states could maintain and fund "public interest payphones in locations serving health, safety, and welfare goals, where they would not otherwise exist as a result of the operation of the market."[18]

[17] "Report and Order;" *In the Matter of Implementation of the Pay Telephone Reclassification and Compensation Provisions of the Telecommunications Act of 1996*; CC Docket 96-128 (September 20, 1996)(¶ 13).
[18] *Id.*

The FCC defined a "public interest payphone" as a payphone which (1) fulfills a public policy objective in health, safety, or public welfare, (2) is not provided for a location provider with an existing contract for the provision of a payphone, and (3) would not otherwise exist as a result of the operation of the competitive marketplace. However, the FCC added a caveat that "while we grant the states broad discretion in administering and funding public interest payphone programs, we also require that they do so in a manner which does not upset the competitive balance of the payphone market (i.e., competitively neutral), and that fairly and equitably compensates those entities providing public interest payphones."[19]

**Q. Should the Commission apply this precedent to Georgia Power's Community Charging program?**

A. Yes. The Commission should recognize that an EV charger deployed in the Community Charging program is the equivalent of a public interest phone and develop equivalent rules governing their deployment. This Commission should establish criteria for the deployment of EV charging stations that are truly required in the public interest, while being cognizant of the FCC's caveat that the Community Charging program not upset the competitive balance in the provision of EV charging service.

## II.

## EV CHARGING TARIFFS

### A. Georgia Power's Proposed Rider CIEV-1 (Charge It – Electric Vehicle)

**Q. Is the Company proposing any new riders in this proceeding?**

[19] "Report and Order;" CC Docket 96-128 (¶ 264).

A. (Mr. Nelson) Yes, the Company is proposing a new rider, Charge It – Electric Vehicle - 1 ("CIEV"), to support public commercial EV charging.

**Q. Please describe Rider CIEV-1.**

A. CIEV-1 is a rider to the Power and Light (PL) Small (PLS-14), Medium (PLM-14), and Large (PLL-14) tariffs, available to new premises dedicated to EV charging, served behind a dedicated meter, and starting service on or after January 1, 2023.[20] Under Rider CIEV-1, the customer's billing demand under tariff PLS/PLM/PLL is adjusted by the Billing Demand Adjustment Factor (BDAF) following this schedule:[21]

- Year 1 (bills 1-12) BDAF = 0.20
- Year 2 (bills 13-24) BDAF = 0.40
- Year 3 (bills 25-36) BDAF = 0.60
- Year 4 (bills 37-48) BDAF = 0.80

The adjustment amounts to a billing demand discount of 80% in Year 1, 60% in Year 2, 40% in Year 3, and 20% in Year 4. The reduction in a customer's billing demand ultimately reduces the customer's minimum monthly bill. This adjustment is only available for customers with a 12-month load factor of 15% or less,[22] which the Company measures by dividing that month's total energy by that month's peak demand divided by the hours in the billing month.

**Q. What are the underlying tariffs to which Rider CIEV-1 is attached?**

[20] CIEV-1 may not be used in combination with other tariffs such as the Real Time Pricing – Day Ahead (RTP-DA) or Real Time Pricing – Hour Ahead (RTP-HA) tariffs. EV load does not have to take service under CIEV-1, and can take service under other optional tariffs, such as RTP-HA.

[21] Correction to CIEV-1 Rider. Rate Case Supplemental Filing (August 23, 2022).

[22] It is unclear how the Company will determine load factor for customers without 12 months of billing history. This eligibility requirement may restrict new DCFC and all EV charging for one year.

A. PLS, PLM, and PLL are three similar tariffs that consist of three key elements. Each tariff has a basic serve charge, an energy charge ($/kWh), and a demand charge. The energy charge decreases as consumption increases. The demand charge is calculated using a billing demand based on the highest 30-minute kW measurement during the current month and the preceding 11 months.[23] This is also referred to as a demand "ratchet".[24]

## B. Analysis of Georgia Power's Proposed CIEV -1 Tariff

**Q. Provide an overview of your analysis and recommendations regarding the Company's rate design.**

A. The Company's proposed CIEV-1 rider and the existing tariffs that accompany it do not reflect the importance of rate modernization in the context of an evolving power grid. Specifically, the Company's proposed tariff does not encourage load flexibility, even though EV demand can be aligned with changing grid conditions for cost-effective EV integration, if given the right price signals. To better reflect cost causation, I recommend an alternative rate design that encourages EV adoption while providing meaningful price signals for grid-efficient charging.

### 1. Background: Impact of an Evolving Power Grid for Rate Design Processes

**Q. How is the power grid evolving in Georgia?**

A. It is important to provide context about Georgia's evolving power grid and how it impacts the rate design process, including EV rates. The penetration of variable renewable energy in Georgia Power's resource mix has increased and is projected to accelerate in the future. While

[23] Georgia Power Electric Service Tariff: Power and Light Medium. Schedule: "PLM-14". At 2.
[24] https://feds.pnnl.gov/faq/what-demand-ratchet

renewables comprised only 3% of the Company's generation in 2020,[25] the Company has plans to add 6,000 MW of renewable generation by 2035, doubling its renewable generation.[26] Renewable resources are cost effective, and consumers are demanding them.

**Q. Do changes in the power system impact the rate design process, generally?**

A. Yes. The evolution of the power grid toward increasing renewable resources is beneficial from a public interest perspective and requires cost-effectively integrating those resources. The increase in variable renewable resources makes the timing of grid services and the availability of grid flexibility (i.e., the ability to shape demand side load, such as EV charging load) increasingly important. From a ratemaking perspective, flexible demand can be treated like a system resource. The ability to shape demand makes it important to recover generation and transmission costs through dynamic, time-varying volumetric rates and to closely examine distribution-related demand charges.[27]

**Q. How are changes on the power grid relevant to EV rate design?**

A. EV rates are no exception to the rate design evolution—and are arguably more important to treat dynamically due to EVs' high potential for flexibility and equally high potential

[25] https://www.georgiapower.com/company/about-us/facts-and-financials.html

[26] The Company also plans to own 1,000 MW of energy storage by 2030. *See:* https://www.georgiapower.com/company/news-center/2022-articles/georgia-power-files-plan-preparing-for-future-energy-landscape-building-upon-solid-foundation-to-meet-needs-of-customers-and-state.html

[27] Traditionally, utilities determine which customer classes cause the various costs associated with providing service through a cost of service study. As part of that process, costs are functionalized and levelized into categories like primary distribution, secondary distribution, and billing. Costs are then classified as energy costs, demand/capacity costs, or customer costs and further categorized based on cost causation; that is, whether costs are caused by meeting energy or demand requirement or caused by the number of customers. Lastly, the costs are allocated to the various customer classes using allocators. During the classification and allocation process, system costs are used to inform energy, demand, and customer-related rate components, such as volumetric ($/kWh), demand ($/kW), and customer ($/customer) charges.

to charge out-of-sync with variable supply and incur high grid costs in the absence of proper price signals and program options. Time-varying volumetric cost recovery that incentivizes load flexibility will become increasingly important, such as from EV users. The Company's rate design should reflect the actual value of load flexibility by creating and improving temporal cost allocations that can be used to inform more granular, dynamic rate designs and demand response programs. For example, supply and transmission costs can be analyzed and translated into more granular TOU rates. It is important that a utility have a suite of rate options that incent multiple types of load flexibility. EV load can be throttled, curtailed, increased to build load during low net load, scheduled, and managed in numerous other ways.

2. Concerns with the CIEV-1 Rider

**Q. Describe your concerns with the CIEV-1 Rider**

A. I have several. My primary concern is that the rider does not improve upon the underlying tariffs, which are not conducive to EV adoption or cost-effective EV charging. My secondary concern is that the rider itself may not efficiently achieve the intended goal of EV adoption.

**Q. Explain how the CIEV-1 Rider fails to improve upon the underlying tariffs.**

A. Rather than proposing a holistic EV rate, the Company proposed a rider that layers on top of existing PL rates – rates that themselves present significant barriers to EV adoption and grid-efficient EV charging. Even when combined, the CIEV-1 rider and underlying tariffs do not reflect the importance of rate modernization and the evolving power grid that I highlighted above.

Specifically, the proposed rate structure maintains a ratcheted demand charge and does not time-differentiate energy costs.

**Q. How does the ratcheted demand charge on tariffs PLS, PLM, and PLL hinder EV adoption?**

A. The ratchet locks in a higher bill for charging stations by setting monthly billing demand at the greatest of:

1) current actual demand,
2) 95% of the highest actual previous summer demand, or
3) 60% of the highest actual previous winter demand.[28]

Thus, rather than paying monthly demand charges based on individual monthly demand, an EV charging station would likely pay monthly demand charges based on the highest demand over the entire previous year. For example, a station with multiple charging ports might usually only have one customer at a time, but one day, it has three simultaneous charging customers. Under CIEV-1, it may be billed based on the abnormally higher demand level resulting from this single event for the following year.

High demand charges make the economics of EV station ownership particularly challenging because at low charger utilization, EV stations are usually unable to collect the amount of revenue necessary from drivers to cover the high demand charges. Indeed, the demand ratchet is the reason the Company's CIEV-1 discount on billed demand is necessary in the first place.

**Q. Why is a ratcheted demand charge inappropriate for EV customers?**

[28] Georgia Power Electric Service Tariff: Power and Light Medium. Schedule: "PLM-14". At 2.

A. Although the CIEV-1 rider attempts to address the issue that high demand charges pose to low load factor EV station hosts,[29] the ratchet itself is inappropriate for EV customers. The ratchet is an outdated rate design intended for high load factor customers that does not reflect the costs caused by EV charging load. Specifically, at low load factors, EV charging stations do not use generation and transmission capacity the same way that a high load factor customer does. Their spiky load is less likely to occur during the system peak than is a high load factor customers' load. EV charging stations' load diversity means that they can more efficiently share system capacity, unlike customers whose load is more consistent across all hours – including during the coincident system peak.[30] But under GP's proposal, low load factor charging stations would be charged as though they cause generation capacity costs the same way as high load factor customers. If they have abnormally high charging for 30 minutes out of a full year, such as in the example above, it would be billed the same way as a high load factor customer. These customers utilize the system in significantly different ways, but the Company proposes to bill them similarly.

**Q. Have other jurisdictions started to retire the concept of ratcheted demand charges to move toward more modernized rate designs?**

A. Yes. In January 2020, Xcel Energy filed for a new general time-of-use service tariff in Minnesota.[31] This new rate consists of three time periods and includes new seasonally

[29] Load factor is an expression of how much energy was used in a time period, versus how much energy would have been used, if consumption remained at the maximum demand level throughout that time period. https://austinenergy.com/wcm/connect/8fe76160-0f73-4c44-a735-529e5c7bee61/understandingLoadFactor.pdf?MOD=AJPERES&CVID=kC1aR-I#:~:text=WHAT%20IS%20LOAD%20FACTOR%3F,over%20a%20period%20of%20time.

[30] Mark LeBel, Frederick Weston, Ronny Sandoval. Demand Charges: What Are They Good For? An Examination of Cost Causation (November 2020). Regulatory Assistance Project.

[31] In the Matter of the Petition of Northern States Power Company for Approval of General Time-of-Use Service Tariff, Docket No. E002/M-20-86 https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={3045B56F-0000-C717-8A47-BA1EBB6314F3}&documentTitle=20201-159322-01

differentiated demand charges that bill based on the highest monthly 15-minute load during the mid and on-peak times during any given month. Duke Energy has also investigated rate design alternatives to ratcheted demand charges.[32] It is clear that Duke Energy has determined that demand ratchets are not an appropriate rate design mechanism. Duke has proposed to transition away from their current two-part demand structure to a three-part demand charge consisting of a base, mid-peak, and peak period. The structure aligns to system costs and includes lower overall $/kW prices that are applied to different determinants. This proposed restructuring is indicative of Duke Energy recognizing that ratcheted demand charges are outdated and a rate structure that is not a good fit for many customers.

**Q. How do the non-time-differentiated energy charges on tariffs PLS, PLM, and PLL hinder cost-effective EV charging?**

A. As described above, EV charging has the potential to provide demand flexibility – in other words, to avoid charging during times of day that are costliest on the power system, and to instead target charging to low-cost hours. On the other hand, EVs could significantly increase system costs by charging during times of system stress. Whether or not EV charging causes system costs or works efficiently with the grid depends on whether EVs receive dynamic price signals via time-varying volumetric rates. The rates that Georgia Power proposes to underlie the CIEV-1 charging service (PLS/PLM/PLL) are not time-differentiated and therefore do not provide sufficiently granular price signals to encourage charging during system surplus and discourage charging during system stress. The PLS/PLM/PLL energy rates do not promote load flexibility.

[32] Duke Energy Comprehensive Rate Design Study Roadmap, Docket No. ND-2021-12-E, p. 11-14. https://dms.psc.sc.gov/Attachments/Matter/b9cc7976-5dac-4ec0-9b60-0d4ecbd0e574.

**Q. Regarding your secondary concern about the CIEV-1 Rider, explain how the rider structure may not efficiently achieve the intended goal of EV adoption.**

A. Under the Company's proposal, a customer's demand charge discount decreases annually. Annual decreases would result in customers who need the discount (i.e., those with low load factors) not receiving it. A demand charge discount should decrease based on load factor, not arbitrary time increments. Lowering a demand charge discount on a sliding scale as load factor increases (up to, say, 15%) would target the discounts to low load factor EV chargers who need it the most and ensure that potentially profitable chargers (i.e., those with high load factors) do not continue to receive a discount that they don't need.

3. Alternative EV Rate Recommendation

**Q. Do you recommend an alternative to Georgia Power's CIEV-1 Rider?**

A. Yes. Instead of the CIEV-1 rider, Georgia Power should develop a distinct and default rate (not a rider) available for EV charging[33] with the following features:

- A time-of-use energy rate with on-peak, mid-peak, and off-peak periods.
- The on-peak period should be narrow (e.g. five hours long, such as from 3pm-8pm.)[34]
- There should be a high price differential between the on- and off-peak periods (e.g. 3:1 or 4:1 on:off peak).[35]

[33] My rate recommendation is focused on EV charging here but could be opened to wider participation beyond EV applications because it fully reflects cost causation.

[34] For example, Xcel Energy in Minnesota has been directed to pilot two C&I rates (applicable to EVs) using a five-hour peak period from 3p-8pm. *See* Order to Conduct Pilot Programs for General Service Time-of-Use Rates, and Setting Procedural Schedule (July 16, 2021). Docket No. E002/M-20-86.

[35] For example, Xcel Energy in Minnesota has been directed to pilot two C&I rates (applicable to EVs) based on initial proposals of an on-peak rate more than four times and more than six times the off-peak rate. *See* Order to Conduct Pilot Programs for General Service Time-of-Use Rates and Setting Procedural Schedule (July 16, 2021). Docket No. E002/M-20-86.

- The rates should be seasonally differentiated to reflect the variations in system costs throughout the year.

- A demand charge that recovers only distribution costs. All generation and transmission costs should be recovered through the volumetric TOU charges, rather than demand charges.[36]

- No demand charge ratchet

This rate should be default for separately-metered EV customers. But, they should be able to select other rates if they choose. It is important to make a suite of options available to customers. If they want to meter separately under an EV rate or treat EV charging as native load under their pre-existing tariff, both should be permissible. In the future, the Commission should also require Georgia Power to develop and offer a suite of rate designs to maximize EV load flexibility, such as TOU with critical peak pricing[37] and active load management options that allow for capacity interruption.[38]

**Q. Why do you recommend a narrow on-peak period?**

A. The objective of an on-peak period should be to capture the highest average hourly system prices, while keeping the on-peak time period short enough to allow customers to react to

[36] For example, Xcel Energy in Minnesota has been directed to pilot a C&I rate (applicable to EVs) that collects generation and transmission costs through time-differentiated, volumetric TOU charges, rather than demand charges. *See*: Order to Conduct Pilot Programs for General Service Time-of-Use Rates, and Setting Procedural Schedule (July 16, 2021). Docket No. E002/M-20-86

[37] CPP is a rate design that designates a limited number of peak demand events (i.e., severe weather events, high pricing, etc.) that a utility can "call" or "dispatch" to dramatically reduce demand. For example, in the summer, a utility may announce a 5-hour CPP event that will charge $2/kWh for participating non-residential customers. Customers receive advanced notification that rates will be, for example, 10 times higher than normal, and they can reduce their consumption by lowering air conditioning requirements, altering manufacturing operations, or using a battery for backup power. During a CPP event, EV chargers could use energy management systems to decrease or curtail charging, among other means of energy savings.

[38] Passive managed charging programs focus on altering customer behavior to affect charging times, typically through rate design or other financial incentives. Unlike passive managed charging programs, active managed charging programs utilize communication/dispatch signals from a utility or aggregator to control EV charging in a predetermined manner, and thereby unlock a greater level of flexibility of EV load. *See* Smart Electric Power Alliance (SEPA), *Managed Charging Incentive Design: Guide to Utility Program Development,* (2021) https://sepapower.org/resource/managed-charging-incentive-design/.

the elevated price signal. Without hourly system energy and transmission data, I cannot recommend specific on- and off-peak periods for Georgia Power. However, best practices suggest that a short peak period more easily enables customers to shift energy, while a longer peak period limits customers' opportunities to respond to the TOU price signal, preventing behavioral change. At the same time, a shorter window allows the utility to more narrowly target the highest hours of system stress – achieving behavioral change precisely where it is needed.

**Q. Why do you recommend a high on:off peak price differential?**

A. Behavioral research and analysis on TOU rates demonstrate that utility customers shift their consumption when presented with highly differentiated peak and off-peak prices.[39]

**Q. Why is your EV rate recommendation superior to the Company's CIEV-1 Rider?**

A. I recommend a TOU rate structure that incentivizes managed charging and load flexibility, neither of which are incentivized by Georgia Power's proposed CIEV-1 Rider and underlying PLS/PLM/PLL rates. Load flexibility is critical to ensure cost-effective EV charging and avoid harmful grid impacts into the future as EV adoption increases. Indeed, my rate recommendation also supports increased EV adoption. My recommendation reduces the cost barrier for EV charging customers with low load factor, more effectively achieving the Company's

[39] While most studies have examined the response of residential EV customers to TOU price signals, EV drivers who charge at public charging stations can be expected to have similar responses to TOU price signals.
Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report 10th Report. March 31, 2022. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/10th-joint-iou-ev-load-report-mar-2022.pdf. *See* Table SCE-1b, pg. 46 and Charts SCE-7, pg. 60 and SCE-8, pg.61.
Schey, et al, A First Look at the Impact of Electric Vehicle Charging on the Electric Grid. May 2021., Available at https://www.energy.gov/sites/prod/files/2014/02/f8/evs26_charging_demand_manuscript.pdf
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stated goal to "encourage the growth of EVs" in Georgia.[40] My recommended rate addresses the same demand charge issue that the CIEV-1 Rider addresses, without the need for a discount. Instead, my rate recommendation lowers the demand charge by recovering only distribution costs via demand charge and not generation and transmission costs.

**Q. Could the Commission still apply a demand charge discount under your rate recommendation?**

A. If the Commission desires to further incentivize EV adoption, a demand charge discount based on EV station load factor could be applied to the distribution portion of the bill for a four-year period. However, the structure I have proposed should already alleviate the largest financial hurdle for EV charging (i.e., collecting generation and transmission costs through a demand charge) without any explicit subsidy.

**Q. Is your rate recommendation similar to EV rates offered elsewhere?**

A. Yes. Alabama Power offers Rate BEVT (Business Electric Vehicle – Time of Use), which includes seasonably differentiated, three-period TOU energy charges.[41] Rate BEVT also includes a $2.00/kWh demand charge that is **only assessed** based on the customer's demand during each billing period and applied as part of a minimum bill provision. Xcel Energy Minnesota will also be piloting a commercial and industrial rate, that is eligible for EV charging, with three-period TOU energy charges that collect generation and transmission costs via volumetric rates rather than demand charges.[42]

[40] Testimony of Larry Legg, T. 971:17-20.
[41] https://alabamapower.com/content/dam/alabama-power/pdfs-docs/Rates/BEVT.pdf
[42] Docket 20-86. Clean Energy Organizations Alternative Proposal (May 29, 2020).

**Q. How do you recommend that the Commission oversee Georgia Power's development and implementation of your recommended rate?**

A. The Commission should ensure that there is sufficient opportunity for stakeholder review prior to adoption.

## III.

## APPLICATION OF THE COMMISSION'S TELECOMMUNICATIONS PRECEDENTS TO ESTABLISH A LEVEL-PLAYING FIELD FOR EV CHARGING

**Q. Does the panel seriously suggest that the Commission should apply precedents to EV charging deployment that were intended to address issues pertinent to a now extinct telecommunications service – payphones?**

A. (Mr. Selvidge) Yes. History is an excellent teacher, and policies and precedents set by this Commission should be followed when similar facts are presented as a new service develops. To deploy a ubiquitous network of EV charging stations, Georgia needs AACE members to install public EV charging stations at their business locations. Nearly forty (40) years ago, when regulators determined that available LEC owned public communications facilities were insufficient to serve the traveling public, they authorized private ownership and investment to deploy public payphones to serve a similar public demand and fill a service void.

**Q. From a regulatory perspective, are public EV charging stations and public payphones essentially the same?**

A. Yes, they present the same market and regulatory issues. The only difference between them is the service that each provides. The EV charger provides electricity to the traveling public's

vehicles while the public phone provided communication access to the traveling public to make a telephone call while away from home or office. The similarities between public charging and public communications services are so striking that deployment of EV charging stations and development of a level-playing field between EV charging services provided by AACE members and the Company do not present novel regulatory issues of first impression. Application of the Commission's public communications precedent to EV charging will establish an appropriate policy for this new service.

**Q. Elaborate on the similarities between public charging and public communications.**

A. Before there was range anxiety, there was missed communication anxiety. Before cell phones, the traveling public needed access to communications while away from home or office at airports or on traveled highways. Payphones provided this important mobile telecommunications access. Payphone service was initially provided by incumbent LECs that (similarly to Georgia Power) were rate of return, regulated monopolies that furnished service in a specified geographic service territory.

Payphone service was also a component of universal service. The Commission's rules required that each incumbent LEC provide a single payphone in each exchange.[43] All costs incurred by the LEC to provide public communications were included in the incumbent LEC's ratebase and paid by its ratepayers. Obviously, this level of service was not sufficient to serve the traveling public's communications demand. To meet that need, the FCC and this Commission[44] allowed location owners and third parties to own and deploy payphones on their properties. The

[43] Commission Utility Rule 515-12-1-.17(4), *repealed* "Final Order Adopting Rule;" *In re: Notice of Proposed Rulemaking to Amend Rule 515-12-1-.17 Quality of Service – General*; Docket 44167 (January 19, 2022).
[44] "Order;" *In re: Customer Owned Coin/Coinless Operated Telephones (COCOT)*; Docket 3494-U (February 5, 1985, amended March 5, 1985, March 7, 1985).

authority was premised on the belief that private enterprise would deploy payphones to fill the unserved void in the monopoly, incumbent LECs' public communications service.

**Q. Continue.**

A. Unfortunately, the traditional regulatory environment was not welcoming to new IPP entrants to fill the public communications service void. The primary roadblock was the refusal of incumbent, monopoly LECs to allow property owners to deploy the same type of public phone that LECs operated which could access essential central office functions. As a result, a payphone manufacturing industry gradually developed that used computer technology to replicate central office functions in each individual payphone. Manufacturing rose to the challenge, providing IPPs the ability to navigate around incumbent LEC barriers. Today, these payphone manufacturers are personified by EV charging manufacturers, like ChargePoint, EV go and others, and the first IPPs that deployed the new payphones for public use are personified by AACE members.

**Q. Was service provided to IPPs pursuant to incumbent LEC tariffs?**

A. Yes. Incumbent LECs crafted special public payphone tariffs for IPPs. IPPs had to rely on the monopoly LECs to provide the basic telephone line required to provide payphone service and connect the IPP's phone to the network. Early LEC tariffs required the IPP to pay up to 75% of the revenue generated from the payphone for line charges. This imposed high costs on IPPs to deploy phones, and it limited the locations at which a profitable public phone could be deployed. While IPP's private investment eventually and significantly increased the overall number of public payphones in the United States, the incumbent LECs' tariffs dictated where a profitable phone could be located, and Georgia Power's proposed EV charging tariff may produce a similar result.

**Q. Did incumbent LECs, such as BellSouth, pay for the service to their own phones under the same tariff that was required of IPPs?**

A. No. Incumbent LECs' payphone line costs were expensed for accounting purposes in the same manner as the cost of providing telephone service to itself – an amount that was always lower than the tariff paid by IPPs for their payphone lines. This cost differential limited phone deployment and placed IPPs at competitive disadvantage.

Similarly, Georgia Power testified that it will not pay the tariffed rate it will charge AACE members to deploy their chargers. Like BellSouth, it will account for the cost of the electricity required to run its EV charger the same way it accounts for the cost of electricity that its facilities use.[45]

**Q. What was the relationship between the IPP and the incumbent LEC?**

A. The IPP was both the incumbent LEC's customer and its competitor. The incumbent LEC provided the basic telephone line to the IPP pursuant to tariff, and it also owned and operated (at ratepayer expense) the payphones against which the IPPs' phones had to compete. As the FCC noted years later, the incumbent LECs by furnishing the telephone line to the IPP pursuant to tariff as well as competing against the IPP for locations had both the incentive and ability to "unfairly act to the detriment of their…competitors and to act in other anti-competitive ways."[46]

**Q. Will the relationship between AACE members and Georgia Power be the same for EV charging services?**

A. Yes. To provide EV charging for the traveling public, AACE members must obtain electric service from Georgia Power pursuant to tariffed rates, terms and conditions. Then, they

[45] Testimony of Larry Legg, T. 965:2-15.
[46] "Report and Order;" CC Docket 96-128 (September 20, 1996) (¶ 13).

must deploy the EV charger in competition with the Company's own EV chargers. Just as with payphones, AACE members will deploy EV chargers predominately through private investment, and their EV chargers will directly compete against Georgia Power's EV chargers for which the costs will be paid by ratepayers.

**Q. Does the Company's CIEV-1 tariff (or any other Company tariff) and its provision of electricity service thereunder establish a level-playing field between Georgia Power and ACCE members in the EV charging market?**

A. No. Georgia Power's tariff (CIEV-1 or other) will only apply to service provided to EV chargers owned and operated by private enterprise. Tariff options still discriminate in favor of the Company's EV charging stations by increasing the private EV charging station provider's costs. Mr. Legg's testimony on behalf of the Company made this distinction very clear: electricity supplied to the Company's EV chargers will not be provided pursuant to any tariff.[47] Instead, Georgia Power (like BellSouth years ago) will use its internal accounting policies governing the cost to supply electricity at its properties to account for the cost of electricity provided to its EV chargers. This will either prevent the private EV charging provider from offering EV charging as a service or it will require the EV charging provider to charge its customers a higher price than the Company for the same service from the same EV chargers. Either result provides competitive advantage to the Company's EV chargers.

**Q. Will the tariffed rate revisions proposed by our panel eliminate this cost differential and the competitive advantage enjoyed by the Company?**

[47] Testimony of Larry Legg, T. 965:5-966:10.

A. No. The revised tariff rates proposed in our panel's testimony will still not be applied to Georgia Power's own EV chargers. The cost differential may be reduced somewhat by the tariff we propose, but the cost differential will continue to exist, and private EV chargers will remain at a competitive disadvantage.

**Q. What is the competitive significance of this distinction?**

A. This means that the tariffed rate for electricity provided to a privately owned EV charger will always exceed the cost that Georgia Power incurs to provide electricity to its own EV chargers. The privately-owned EV charging provider will always be at competitive disadvantage.

**Q. Is the tariffed rate the only cost differential?**

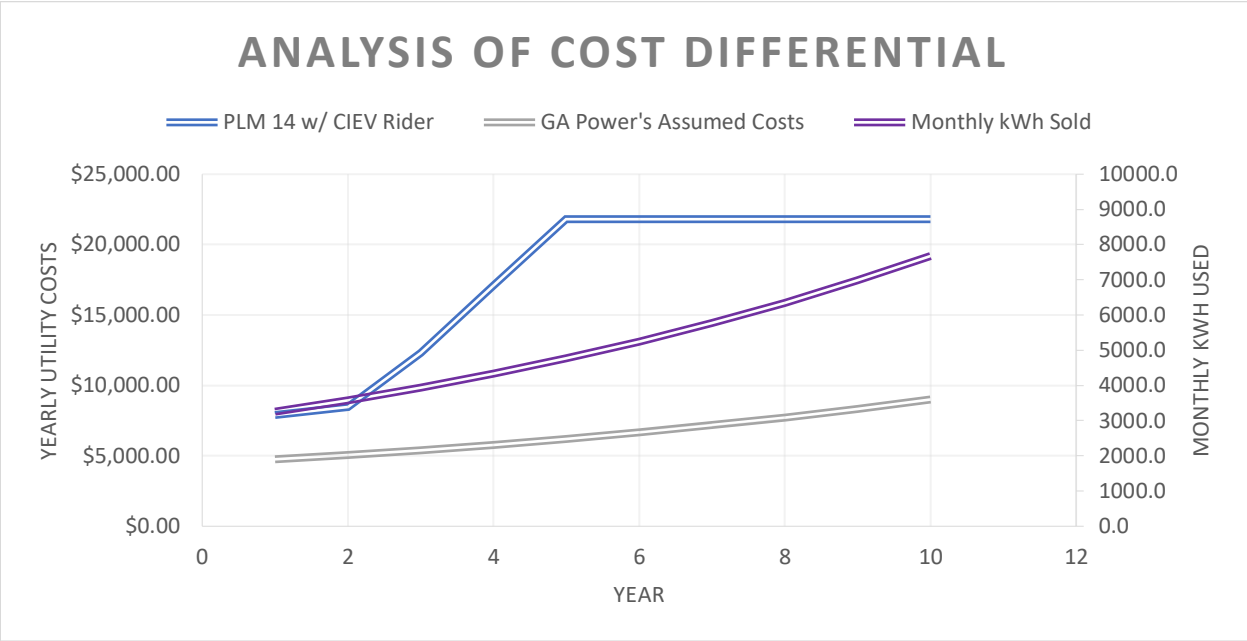
A. No. PLS, PLM and PLL are the tariffs onto which CIEV-1 is attached as a rider for new EV charging locations. The PL tariffs also charge customers the following riders which private EV chargers will have to pay, but the Company's chargers will not:

Environmental Compliance Cost Recovery (ECCR)
Nuclear Construction Cost Recovery (NCCR)
Demand Side Management Schedule (DSM)
Fuel Cost Recovery (FCR)
Municipal Franchise Fee (MFF)

These riders (which are paid in addition to tariffed rates) increase the private EV charging provider's costs significantly.

**Q. Can you quantify the differential increase in costs incurred by a privately-owned EV charge provider, given the Company's failure to pay/impute the tariffed rates and charges to its own EV chargers?**

A. Yes. The following graph quantifies the cost differential between the higher costs imposed on private EV charging providers:[48]




The back-up data supporting this graph is provided in Exhibit 6. As shown, the increased costs imposed on private EV charging providers exceeds $110,000.00 over the ten (10) year life of the EV charger.

**Q. Can the Company implement operational policies that will favor its EV charging business?**

A. Yes. BellSouth created a separate internal office to address all payphone issues and provide service to its own payphones as well as service to IPPs. As a result, BellSouth knew exactly where IPPs intended to place public phones based on receiving service orders in advance.

[48] Because the actual cost the Company charges to itself is unknown, this analysis assumes a cost of $.08/kW.

Often after placing a telephone line order and awaiting installation, the IPP found that BellSouth had already placed its own payphone at the desired location. This is just one example.

In direct testimony, the Company stated that it has created an EV charging team to handle all EV issues.[49] If so, private EV charging providers may encounter similar risks that Company policies may similarly advance its EV charging business. For example, Georgia Power's standard Make Ready contract requires the program participant to provide complete EV charger usage information and data to Georgia Power after the EV charger is operable.[50] No other entity will have access to or be able to use that information which over a large number of deployed EV chargers could be competitively valuable in understanding the developing EV charging market. Company policies, like tariffs, can negatively impact EV charging availability.

**Q. Is there also risk of cross-subsidy?**

A. Yes. Cross-subsidy occurs when the monopoly provider uses revenues from its regulated service to financially support its competitive service. Absent appropriate accounting separations, cross-subsidies can develop to benefit the Company's EV charging business. At a minimum, the Commission must prohibit cross-subsidy of its EV charging business from its regulated revenues.

**Q. How can a level-playing field be implemented in a market in which both the Company and private enterprise provide EV charging services?**

[49] Testimony of Abromowitz Pane, T. 404:13-405:5; Testimony of Larry Legg, T. 946:5-22.
[50] Georgia Power Company Electric Vehicle Charging Make Ready Program Agreement, Paragraph 5.

A. All EV charging providers, both Company and private enterprise, must be treated equally in application of tariffed rates, terms and conditions, as well as the Company's operational policies.

**Q. Did you work to establish a level-playing field between the incumbent LECs' payphone business and the businesses of IPPs?**

A. Yes, for more than a decade. Competitive issues were addressed piece meal and finally resolved shortly before the industry began to decline due to the proliferation of cell phones.

**Q. What action did you take?**

A. At the federal level, I was a member of the team that negotiated with most stakeholders to enact Section 276 of TA 1996 "to promote competition among payphone service providers and promote the widespread deployment of payphone services to the benefit of the general public" (Section 276 (b)(1)). Among other directives, Section 276 directed the FCC to:

1. discontinue all intrastate and interstate payphone subsidies from basic exchange and exchange access revenues; [51] and

2. prescribe a set of nonstructural safeguards for Bell operating company payphone service…;[52]

The legislation also directed the FCC to "… determine whether public interest payphones which are provided in the interest of public health, safety, and welfare, in locations where there would otherwise not be a payphone, should be maintained, and if so, ensure that such public interest payphones are supported fairly and equitably."

[51] 42 U.S.C. § 276(b)(1)(B).
[52] 42 U.S.C. § 276(b)(1)(C).

Finding that "regulatory restrictions on the placement of payphones, and existing subsidies from other telecommunications services available to certain competitors but not others are…examples of regulatory inefficiencies affecting competition and the widespread deployment of payphones," the FCC conditioned the competitive entry of monopoly telecommunications carriers into the unregulated activity of providing payphone services on the termination of any subsidies that were being received – essentially preventing the cross-subsidization of a monopoly's payphone operations from its local exchange services.[53]

**Q. What happened in Georgia?**

A. For nearly a decade, Georgia's payphone industry addressed discriminatory tariff provisions, policies and procedures in a piece meal fashion with the Commission. Numerous issues were presented when BellSouth provided a service to its own phones that it would not provide to IPPs. The BellSouth tariff rate to IPPs was reduced bit by bit, and in order to achieve some rate relief, IPPs actually agreed to pay measured service whereby the IPP paid for the use of its phone on a per minute basis. Finally, GPCA filed its Same Terms, Same Conditions petition asking the Commission to require BellSouth and other incumbent LECs to provide IPPs with the same services on the same terms they provided service to their own payphones. As a result, BellSouth entered a Stipulation by which it consented to the relief sought by GPCA, and it agreed to provide the same service to IPPs that it provided to its own payphones.

**Q. Did Section 276 and/or the Stipulation in the Same Terms, Same Conditions docket eliminate the incumbent LEC's competitive advantage?**

[53] "Report and Order;" CC Docket 96-128 (September 20, 1996)(¶ 5).

A. No. Though the competitive playing field improved, the non-structural safeguards did not level it, and the incumbent LEC's competitive advantage persisted. It became clear that structural separation between the incumbent LEC's regulated business and its competitive payphone business was required.

**Q. Has this Commission imposed structural and non-structural separations requirements to prevent competitive advantage between service providers?**

A. Yes. The Commission has addressed structural and non-structural separation and accounting safeguards between the competitive services provided by an entity (such as an incumbent monopoly provider, a municipality or electric membership corporation) that possesses the ability to utilize its position to cross-subsidize its competitive affiliate or gain competitive advantage by favoring its affiliate's competitive service. This issue has arisen in the provision of telecommunications, natural gas and broadband deployment.

**Q. What did BellSouth ultimately do?**

A. In 1996, BellSouth created a separate subsidiary to own and operate its payphone business: BellSouth Public Communications, Inc.[54] As a result, tariffed rates to IPPs were reduced and the market quickly equalized between BellSouth and IPPs. Achieving these necessary changes took more than a decade, and by then, the writing was on the wall for the limited remaining viability of public wireline communications, as payphones were being replaced by cellular phone service.

[54] BellSouth Public Communications, Inc.; Georgia Secretary of State Control No.: K626470 (August 23, 1996).

**Q. Should the Commission apply the lessons learned from these public communication precedents to EV charging?**

A. Yes. From this history, the similarities between public communications and public EV charging should be obvious. The Commission should carefully consider the lessons learned from years of regulatory battles fought over public phones as precedent to develop a fair, robust and competitive environment for providing an essential EV charging service to the traveling public.

We believe that the best policy is to direct the Company to create a separate subsidiary for its competitive EV charging business. The Company's current locations should be transferred to that entity, which will develop future locations and pay the same tariffed rates for electricity to the Company.

**Q. Why is it important for the Commission to address these issues now as Georgia's EV charging market is just beginning to develop?**

A. The implementation of policies to ensure that the EV charging market develops on a level-playing field from the very beginning will benefit Georgia's consumers and encourage a market driven, robust public charging market in the public interest. By applying the countless lessons learned over many years from the development and emergence of public phone competition, the Commission can avoid the considerable issues that required more than a decade to finally achieve a non-discriminatory regulatory regime that supported fair competition in Georgia's payphone industry. For public phones, the FCC's ultimate goal was to have a "competitive payphone industry that meets the needs of the public by a wide deployment of payphones…in our view, we can best facilitate this by putting in place rules and regulations that

provide incentives to all the players in the industry to eliminate, as soon as possible, all of the market distorting factors that exist today."[55]

In contrast to the public phone market that confronted the FCC and this Commission nearly forty (40) years ago, this Commission does not have to navigate any preexisting market conditions as it establishes the appropriate regulatory structure and policies for Georgia's new EV charging industry. It has a clean slate from which to work to promote robust competition for EV charging station deployment. Ultimately, developing a level playing field now will result in robust, market driven competition to provide ubiquitous EV charging by the Company and private enterprise all across Georgia for the traveling public.

**Q. Does this conclude the panel's testimony?**

A. Yes.

[55] "Report and Order;" CC Docket 96-128 (September 20, 1996)(¶ 15).

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were marked for identification as AACE Exhibits 15 through 20.)

MR. GALLOWAY: Thank you.

BY MR. GALLOWAY:

Q Has the panel prepared a summary of your testimony?

A (Witness Akers) Yes, we have.

Q Mr. Akers, would you please give it at this time?

A (Witness Akers) Yes. Madam Chair, Commissioners, thank you for having us today. Our panel appreciates the opportunity to present testimony on behalf of Americans for Affordable Clean Energy, AACE.

AACE is a nonprofit organization. Our members include RaceTrac, Inc., the Love's Family of Companies, QuikTrip Corporation, Travel Centers of America, the Pilot Company, and Circle K Stores, Inc. We own and operate convenience stores, public travel facilities and truck stops that provide fuel, goods and services to the traveling public at locations throughout Georgia and across the United States. AACE members operate 784 stores in Georgia. Our members are uniquely situated to play a critical role in the deployment of EV charging stations because electricity for an EV is just another type of transportation fuel.

**The future is clear: Electricity will be an important transportation fuel in the future. We hold a key asset required to deploy reliable EV charging in Georgia: Existing business locations that already dispense transportation fuel and that the traveling public deem safe and convenient.**

**Our locations are found in virtually every town in Georgia and in some of the most rural areas of the state. We provide motorists with convenience, offering fuel, amenities and the security of on-site personnel and good lighting on a 24/7 basis.**

**Our role was confirmed in G dot -- Georgia Electric Vehicle Infrastructure Deployment Plan which found, quote, "Convenience stores and gas station operators are logical candidates to offer charging services for EVs, given that they currently provide fueling services to the nation's drivers."**

**Commerce and travel require reliable EV charging infrastructure so that EVs can travel long distances with assurance that fast charging is available. Our locations assure drivers that their EV will reach their intended destination because an EV charging station can be found in time to recharge.**

**We help eliminate range anxiety. High-speed chargers, commonly referred to as direct current fast**

chargers, DCFC, are required for business and long-distance travel. The time to recharge must be as comparable as possible to the amount of time required to fill a gas tank and pay.

We face two market realities as we enter the EV charging market. One, our EV charging services will directly compete with Georgia Power's chargers, whose costs to provide the same EV charging equipment and the electricity required to provide electric charging service will be paid by ratepayers.

And, two, we must obtain electricity to provide EV charging pursuant to tariffs, riders, terms, and conditions that the company will not charge or impute to itself to provide its own EV charging stations with which we must compete.

As a result, our cost to provide EV charging will always exceed those of Georgia Power and our EV charging service will always be provided at competitive disadvantage.

We are prepared to make significant capital investment to develop and deploy EV charging services supported by a reliable EV charging infrastructure. However, our capital investment cannot succeed unless our members can deploy EV chargers and provide EV charging service to customers on a level playing field with those

deployed by the company.

To establish a level playing field, we urge the Commission to review the history of the telecommunications precedence set by the FCC and this Commission in a similar market, public communications pay phones, in which the independent provider was both the customer of the incumbent telephone company for service and its competitor. They present the same market and regulatory issues. The only difference is that the EV charger provides electricity to the traveling public's vehicles while the public phone provided communication access to the traveling public to make a telephone call while away from home or office.

A level playing field requires that all EV charging providers, both company and private enterprise, must be treated equally in application of tariff rates, terms and conditions, as well as the company's operational policies.

Cross-subsidies between the company's regulated and non-regulated services must be prohibited and experience has taught us that the best solution is to require the company to own and operate its EV chargers in a separate subsidiary.

However, the company has made it clear, electricity supplied to the company's EV chargers will not be provided pursuant to any tariff. Nor will its EV

charging service incur the costs of the riders that all customers pay.

Our testimony shows that the company's tariffs, riders, and policies will increase the cost of installing and operating a private charger by more than $100,000 over the ten-year life of the charger. This places our EV chargers at competitive disadvantage.

We believe that a volumetric charge to the EV owner based on the amount of electricity in kilowatt hours being provided to the EV by the EV charger is the best and most appropriate way to compensate the EV charging provider.

The average EV owner that pulls into a parking space to charge expects to get electricity from the charger, not rent the charger over time or rent the parking space in which the EV is located.

The EV charging provider pays for the electricity on a per kilowatt hour basis. EV drivers obtain a commodity, electricity, whose units are measured in kilowatt hours and the EV charging provider should be compensated on the same basis.

AACE supports continuation of the company's Make Ready Program provided the goals and requirements of the program are clearly defined and the Commission sets clear priorities for the use of ratepayer funds to deploy the infrastructure.

**In our testimony, we recommend priorities of deployment and we propose to step down program contribution based there on. The terms and conditions of the program requirements, terms, conditions, and contracts used by the company in the Make Ready Program should all be reviewed by the Commission. The benefits and costs of the Make Ready Program should be reviewed triennially in the company's integrated resources plan and we must make certain that the service is not provided for free.**

**We oppose the Community Charging program and our investigation does not confirm that EV chargers in the program are being located in so-called "charging deserts." Most appear to be located along commercial strip throughfares, near interstate interchanges in central downtowns and near college campuses, areas where private investment will likely support EV charging without ratepayer subsidy. Also, most chargers deployed are DCFC's, which are not compatible with basic charging service.**

**Over a period of time, as the EV market develops, a community charger may be needed to serve a specific location that private enterprise cannot. Guidelines should be developed that include specific objective criteria by which the need for a community charger placed in service and operated at ratepayer expense can be identified.**

**Before the cost of the community charger is imposed on ratepayers, however, private enterprise should be given the opportunity to serve the proposed EV charge location through private investment. This is consistent with precedence established by the FCC in public communications.**

**We oppose the company's CIEV-1 tariff. Primarily the rider does not improve upon the underlying tariffs, which are not conducive to EV adoption or cost effective EV charging.**

**We oppose the company's CIEV-1 tariff. Primarily, the rider does not improve upon the underlying tariffs, which are not conducive to EV adoption or cost-effective EV charging. Secondarily, the rider itself may not efficiently achieve the intended goal of EV adoption. The CIEV layers on top of existing PL rates maintains a ratcheted demand charge and does not time differentiate energy costs.**

**The ratchet locks in a higher bill for charging stations by setting monthly billing demand at the greatest of, one, current actual demand; two, 95 percent of the highest actual previous summer demand; or, three, 60 percent of the highest actual previous winter demand. Rather than paying monthly demand charges based on individual monthly demand, an EV charging station will likely pay monthly**

demand charges based on the highest demand over the entire previous year.

For example, a station with multiple charging ports might usually have only one customer at a time, but one day, it has three simultaneous charging customers. Under CIEV-1, the charger may be billed based on the abnormally higher demand level resulting from the single event for the following year.

High demand charges make the economics of EV station ownership particularly challenging because, at load charger utilization, EV stations are usually unable to collect the amount of revenue necessary from drivers to cover the high demand charges. Indeed, the demand ratchet is the reason the company's CIEV-1 discount on bill demand is necessary in the first place.

Under CIEV, low-load-factor charging stations would be charged as though they cause generation capacity costs the same way as high-load-factor customers. If they have abnormally high charging for 30 minutes out of a full year, such as in the example above, it would be billed the same way as a high-load-factor customer. These customers utilize the system in significantly different ways, but the company proposes to bill them similarly.

Instead of the CIEV-1 rider, Georgia Power should develop a distinct and default rate, not a rider,

available for EV charging with the following features: A time-of-use energy rate with on-peak, mid-peak, and off-peak periods. The on-peak period should be narrow. For example, five hours long, such as from 3:00 p.m. to 8:00 p.m. There should be a high price differential between the on- and off-peak periods. For example, three to one, or four to one on/off peak.

The rates should be seasonally differentiated to reflect the variations in systems costs throughout the year. A demand charge that recovers only distribution costs. All generation and transmission costs should be recovered through the volumetric time-of-use charges, rather than demand charges, no demand charge ratchet. This rate should be default for separately metered EV customers, but they should be able to select other rates if they choose.

It is important to make a suite of options available to customers. If they want to meter separately under an EV rate or treat EV charging as native load under their preexisting tariff, both should be permissible. We recommend the time-of-use rate structure that incentivizes managed charging and load flexibility, neither of which are incentivized by Georgia Power's proposed CIEV-1 rider and underlying PLS, PLM, PLL rates.

Load flexibility is critical to ensure cost-effective EV charging and avoid harmful grid impacts

into the future as EV adoption increases. Indeed, our rate recommendation also supports increased EV adoption and reduces the cost barrier for EV charging customers with low load factor, more effectively achieving the company's stated goal to, quote, "Encourage the growth of EVs," close quote, in Georgia.

Our recommended rate addresses the same demand charge issue that the CIEV-1 rider addresses without the need for a discount. Instead, our rate recommendation lowers the demand charge by recovering only distribution costs via demand charge and not generation and transmission costs. This concludes our summary.

MADAM CHAIR PRIDEMORE: Questions from Commissioners?

Commissioner Echols.

VICE CHAIRMAN ECHOLS: Panel, did you hear my earlier comments and questions to Representative Powell? Were you in the side room, or did you hear any of that?

MR. NELSON: Was that earlier today?

VICE CHAIRMAN ECHOLS: Yes, uh-huh.

MR. NELSON: I think I caught some of that.

VICE CHAIRMAN ECHOLS: All right. And I'm not being a smart aleck here, but do any of you own an electric vehicle?

MR. NELSON: I do not.

VICE CHAIRMAN ECHOLS: You do, sir?

MR. AKERS: No.

VICE CHAIRMAN ECHOLS: Have any of you ever personally charged an electric vehicle that didn't belong to you, plugged it in?

MR. AKERS: Yes, I have.

VICE CHAIRMAN ECHOLS: What kind?

MR. AKERS: I've test driven a Tesla, and I can't remember the other make of the car, but it was not a Tesla.

VICE CHAIRMAN ECHOLS: Okay.

COMMISSIONER MCDONALD: Did you charge it or did you just drive it?

MR. AKERS: I drove and charged multiple times.

VICE CHAIRMAN ECHOLS: All right. Good. Good.

Are you familiar with Parker's stores along the coast, those C stores that run from Charleston down to Jacksonville?

MR. AKERS: I am familiar with Parker's.

VICE CHAIRMAN ECHOLS: So Greg Parker was one of the first C stores, you know, to put chargers in, as well as Enmarket on the coast, and they both worked with Georgia Power to get community chargers there because there really wasn't -- other than Tesla

being at some places, there really -- there just wasn't any non-Tesla chargers anywhere.

Are you aware of just how scarce non-Tesla chargers are out there in the wild?

MR. AKERS: I'm not.

VICE CHAIRMAN ECHOLS: I'll take that as a yes.

MR. NELSON: I haven't seen any analysis in this record.

VICE CHAIRMAN ECHOLS: Yeah, I can tell you. I've had six EVs and I can tell you that these community chargers have been extremely valuable out there.

So how many chargers of any type are at the 784 stores that -- in the association, just approximately? Do you --

MR. AKERS: I don't know the number. RaceTrac has zero.

VICE CHAIRMAN ECHOLS: And how do you know that your chargers will be more expensive than Georgia Power's community chargers? What are you basing that on?

MR. AKERS: I don't think our testimony is that the charger itself is more expensive.

VICE CHAIRMAN ECHOLS: Not the charger, but the rate.

How do you know that, that what I'm going to pay at my RaceTrac in Braselton as I charge, how is -- how do I know that's going to be more expensive than a Georgia Power charger at Chateau Elan?

MR. AKERS: That also wasn't our testimony. Our testimony has to do with our costs as Georgia Power's customer, and we know that based upon their previous testimony, that they're not going to charge themselves the same cost. And so our cost structure is already higher, which means if we're in it for profit, we would have to charge more or lose.

VICE CHAIRMAN ECHOLS: Their chargers are expensive. Too expensive. Sorry, Georgia Power.

So you plan on making money with these DC fast chargers?

MR. AKERS: Yes, we do.

VICE CHAIRMAN ECHOLS: And I'm not telling you how to do your business, but you've done some research with California C stores and other places that have fast chargers to determine if you can actually make a profit with these things? You're sure you can do this?

MR. AKERS: We're sure that, with favorable rates, that we can. We have an opportunity to compete fairly, and then we'll let the chips fall

where they may, like we do currently with liquid fuels.

VICE CHAIRMAN ECHOLS: And you're planning on the chargers lasting ten years? Is that what I hear you say?

MR. AKERS: I believe that is someone else's testimony, that the average life of a charger is --

VICE CHAIRMAN ECHOLS: I thought I heard you say --

MR. NELSON: It's one of the assumptions we're looking at over a ten-year timeline.

VICE CHAIRMAN ECHOLS: Yeah, they don't last that long. Three, yeah, they're done. People are backing into them, tearing them up, pulling the hose off. It -- they wear out. The screen goes, you know, out. These chargers have not held up out there. So plan on -- plan on replacing them in three years. They will not last ten.

MR. AKERS: If I can offer any comfort, it's very rare that customers drive over dispensers, and we think that our location, with on-site access and attendants and well-lit lots and secure locations, will perhaps prevent that.

VICE CHAIRMAN ECHOLS: Yeah. Well, it's not the electric cars that really are messing them up.

It's the F-150s that are icing the chargers and backing into them with the tailgate down or things like that.

So, you know, I told Representative Powell I love the idea of you charging by the kilowatt. These chargers -- these batteries get hot, and they slow down, and customers wind up paying more for the last part of their charge than they do the first part. So that's -- you know, I'm with you all the way there.

I'm just concerned at this time, while we have so few chargers out there, barring the utility, you know, or making it -- you know, giving them a disincentive to do this, because they have kind of led the way in getting people to, you know, move to EVs. I mean, you may not be aware that they've done that, but they've led the way here in Georgia.

MR. AKERS: Yeah, with both the Make Ready and the Community Charging program, we're talking about a fledgling industry, and we believe that there is value right now with a fledgling industry like charging to promote infrastructure ratepayer spend, which is why we support the Make Ready.

We believe that the charger itself, however, is part of the transportation fuel infrastructure, and we believe that that should not be borne by

ratepayers. If, however, the committee -- the Commission has a different policy in mind, I think that it's important for both programs that clear direction, clear oversight, selection criteria, oversight and review should be implemented.

VICE CHAIRMAN ECHOLS: Well, great. Thank you. I'm a regular RaceTrac customer, so I appreciate the good job and the great, clean stores you have.

MR. AKERS: Thank you, Commissioner Echols.

MADAM CHAIR PRIDEMORE: Commissioner McDonald?

COMMISSIONER MCDONALD: In your stores, do you sell non-ethanol gas?

MR. AKERS: In some of our locations, we have E zero.

COMMISSIONER MCDONALD: When you convert a pump or tank or whatever to supply that item to a customer, are you subsidized by local governments, anybody to offset those costs to accommodate that non-ethanol?

MR. NELSON: More recently -- it is rare. But more recently, I can use an example in Florida where diesel tanks were showing higher levels of corrosion. There was a State-led environmental refund program that enabled us to access funds if we installed different types of tanks, but it is rare.

**COMMISSIONER MCDONALD: Was there a subsidy from the State to do that?**

**MR. NELSON: Yes. We had to apply for -- for it and meet certain criteria. But, yes, in that instance, we were given a refund for the cost of that.**

**COMMISSIONER MCDONALD: Would you be suggesting, in order to accommodate your facilities there with a charging station, that there would be some kind of subsidy to provide that?**

**MR. NELSON: Not from this Commission, we're not asking for a subsidy. We understand that there is a Make Ready Program, which we would apply for and take advantage of if it were appropriate and we met the criteria.**

**COMMISSIONER MCDONALD: But by the same token, you wouldn't want Georgia Power ratepayers to be subsiding their competitive program to you; is that correct?**

**MR. AKERS: I'm not sure I understand that question.**

**COMMISSIONER MCDONALD: In other words, in order for them to put in the infrastructure at a facility that's owned by Georgia Power --**

**MR. AKERS: Yes.**

**COMMISSIONER MCDONALD: -- you wouldn't want every other ratepayer to be paying for putting that program in when just a small amount of the consumers are going to be able to use it; is that correct? Or will use it?**

**MR. NELSON: I don't -- I don't know if that's corrected. I think what we've been asking for in our testimony is a level playing field. And so if our transmission and distribution infrastructure, the ET or EV infrastructure that's covered in the Make Ready Program is covered by ratepayers for an applied-for location, then that would be consistent with a Georgia Power charger at one of its current locations.**

**COMMISSIONER MCDONALD: When you build a facility, you have an interconnection fee to connect up. It goes to a particular pole, but you have to put in the infrastructure to from that pole from your facility; right?**

**MR. NELSON: I believe that's correct, yes.**

**COMMISSIONER MCDONALD: And that would do the same thing that would -- that's the same way it is with solar energy in Georgia today. There's an interconnection fee.**

**Anyway, I'm just saying that -- I'm really**

saying that I don't mind -- I like the kW cost, price. If the territorial rights applies to being able to do this is another item, but I don't want my ratepayers of Georgia, Mrs. Smith out there in the hinterlands, that's going to be paying for somebody with their Tesla to get their car charged. It's got to each -- it's got to stand on its own body.

MR. NELSON: Yeah, and I would just add, to just distinguish between the Community Charging and what we're proposing for Make Ready, customers would not get paid a hundred percent of Make Ready costs. They would get paid a proportion, and what that does is it incentivizes them to only upgrade what's needed and bear, you know, 80 percent to 30 percent of the costs, is what we're recommending.

That would be different in the Community program. The Community program would be a hundred percent funded by ratepayers. And I also will just note that, you know, we don't -- we're not proposing Make Ready rebates for single-family houses that would be charging a Tesla, for example. We're trying to prioritize areas that provide public benefits so those are publicly accessible chargers.

MADAM CHAIR PRIDEMORE: Any other questions from commissioners?

Okay. I just have one.

So thank you for stating, Mr. Akers, at the beginning of your testimony, your list of members.

You call yourself AACE?

MR. AKERS: Double AACE.

MADAM CHAIR PRIDEMORE: Double AACE. It sounds like Vegas.

Okay. RaceTrac, TA, Pilot, Circle K, QuikTrip, Love's, Flying J.

Did I miss anybody?

MR. AKERS: Circle K and Travel Centers of America.

MADAM CHAIR PRIDEMORE: TA.

MR. AKERS: Okay.

MADAM CHAIR PRIDEMORE: Pilot, RaceTrac, QuikTrip, Love's, and Flying J?

MR. AKERS: Correct.

MADAM CHAIR PRIDEMORE: I got everybody? Okay. All right.

So I've read your prefiled testimony. I understand your point of view, but my question really has to do with, like, your group of members, they believe that they're at a market disadvantage. I believe, Mr. Akers, you said that they want to, quote, "level the playing field."

**MR. NELSON: Yes.**

**MADAM CHAIR PRIDEMORE: Well, I guess you have two members that have this wide-scoping, coast-to-coast EV fast-charging effort going on right now with building over 200 fast chargers, including in Georgia, and that's Pilot and Flying J. They announced that back in July of this year.**

**So they don't see market conditions in Georgia, with Georgia utilities, the EMCs, the municipals as a barrier to the marketplace. Why do they not see it as a barrier to the market place, but you say other members do?**

**MR. NELSON: I won't pretend to speak for Pilot and Love's, but what I think you're referring to are public announcements of a partnership or a joint effort with car manufacturers and themselves to deploy the charging stations, and I think that's the what. What are they planning? What's the plan?**

**And then what I think they still believe there are barriers to, depending on the state, as they are members of Double AACE, is the how, the how, how can they deploy those effectively in a cost-effective way and in all likelihood make a return on their capital investments.**

**MADAM CHAIR PRIDEMORE: Well, they've committed**

to the 2,000 chargers, and that's been in their very public announcement that's on Pilot's website. You know, so they've committed to go forward and make this investment, and they have a pretty comprehensive plan for charging stations in Georgia.

I guess I just wondered -- and you could use Commissioner Echols' example with Parker's as well, where some C stores and truck stops, they don't see any barriers. They're just moving forward.

Why do some do and some don't?

MR. NELSON: A very limited number of those view what is sometimes referred to as lost leaders, and they're not concerned with making a return on the capital investment for the chargers themselves. They hope in the investment that they're making is that they will see greater lift on the inside of the store. Not all members of Double AACE or not all convenience stores agree with that approach.

MADAM CHAIR PRIDEMORE: So what you're saying is some believe that there is a more level playing field than others?

MR. NELSON: I don't think I'm saying that.

MADAM CHAIR PRIDEMORE: No?

MR. SELVIDGE: Madam Chair, if I could interject. I'm not -- I think we may be confusing

two things, and that is we talk about a level playing field in a regulatory scheme that is nondiscriminatory and has same rates, terms, and conditions across the board. That can be one thing.

But when you ask for a private enterprise to make decisions on partnerships or to do -- and make business decisions on how they're going to allocate their capital, that doesn't necessarily mean that there's automatically a level playing field.

I think that has to be adjusted and regulated by you, as the Commission, setting that scheme. And that's why we believe the telecommunications background with pay phones is a very good one to look at in terms of a precedent.

MADAM CHAIR PRIDEMORE: Well, I would love for to you find a pay phone. It would be good to talk on one again. I'll call my mother and ask her to pick me up from the roller rink.

Mr. Galloway?

MR. GALLOWAY: Madam Chair, the summary being concluded, I would like to go ahead -- excuse me -- before I forget it, go ahead and enter into evidence AACE exhibits, which are now number 15 through 20.

MADAM CHAIR PRIDEMORE: Talk into the mic, please.

MR. GALLOWAY: I would like to go ahead and introduce into evidence AACE exhibits 15 through 20, which were just identified in the record.

And, Madam Chair, the panel is available for cross.

MADAM CHAIR PRIDEMORE: So moved on your exhibits.

(AACE Exhibits 15 through 20 were admitted into evidence.)

MADAM CHAIR PRIDEMORE: ChargePoint?

MR. DUNBAR: No questions.

MADAM CHAIR PRIDEMORE: Commercial Group?

MR. WALSH: Madame Chair, I don't mean to interrupt. I just was going to say staff does have questions. Sometimes we go first, but we'll go whenever they --

MADAM CHAIR PRIDEMORE: Oh, I'm sorry. Of course. It's 5:00. Go ahead. Sorry. Sorry, Alan. Go ahead, staff.

MR. WALSH: Thank you, and it will be brief.

CROSS-EXAMINATION

BY MR. WALSH:

Q Good afternoon, panel. My name is Dan Walsh, and I represent the Public Interest Advocacy Staff.

A (Witness Nelson) Good afternoon.

Q On page 8 of your testimony, lines 22 through 24, you state, "We can provide electricity to EVs in the exact same way we provide gasoline and diesel to most vehicles on the road today. EV charging simply expands the services we offer to the traveling public."

Do you know what portion of Georgia Power Company's customers own electric vehicles?

A (Witness Nelson) I'm not aware.

Q Does 3 percent sound like a reasonable estimate?

A (Witness Nelson) Yeah, I remember that Georgia started pretty rapidly with EV growth in the beginning, and then rebates changed for EVs a while back.

Q An EV owner has the ability prior to making the purchase to investigate where chargers are located; correct?

A (Witness Nelson) Correct.

A (Witness Selvidge) Correct.

Q And an EV owner also has the ability to investigate what a long trip may require prior to making that purchase; correct?

A (Witness Nelson) As long as the information is available.

Q Would that -- say, if somebody was considering purchasing an EV, would they be able to go online and research what obstacles there would be?

A (Witness Nelson) What do you mean by "obstacles"?

Q Well, I mean, what would be involved with what a long trip might require?

A (Witness Nelson) Yeah, there's apps that have, you know, different EV charger locations on them, Chargeway being one of them.

Q On page 42 of your testimony, lines 13 through 14, you note that, "A cross-subsidy occurs when the monopoly provider uses revenues from its regulated service to financially support its competitive service."

Would you characterize the electric vehicle charging as a competitive service?

A (Witness Selvidge) It can grow into a competitive service depending on who is going to interact within the industry itself, and Georgia Power is currently, obviously, extending that and putting out chargers for public use.

Q And you also say that there's a risk of cross-subsidy related to EV charging.

If the company's request is approved, the Make Ready and Community Charging programs will be included in the rates of regulated customers.

Is that your understanding?

A (Witness Selvidge) Yes.

A (Witness Nelson) Yes.

Q Okay. So do you believe the more accurate characterization would be to say that there's a risk of cross-subsidy or that if the Make Ready Program and Community Charging is approved, that cross-subsidy would be a certainty?

A (Witness Selvidge) I would say there's a risk of cross-subsidy. There's no certainty that can be provided, and that's why we would say, at a minimum, there should be accounting separations to prevent that.

Q Wouldn't customers of Georgia Power Company's regulated service under the company's Make Ready Program, wouldn't they be contributing to funding the Make Ready Program?

A (Witness Selvidge) Yes, I believe they would. Yes.

Q You also referenced in your testimony that the FCC had defined the public interest pay phone, and you discussed that some in your testimony.

A (Witness Selvidge) Yes. That was part of the implementation of the Telecommunications Act of 1996 where the FCC implemented Congress's intent. And they defined -- the FCC actually defined the definition of a public interest pay phone at that time, stating that it was one that fulfills a public policy objective in health, safety, or

public welfare. It is not provided for a location provider with an existing contract with the provision of a pay phone, and, thirdly, would not otherwise exist as a result of the operation of the competitive marketplace.

Q Were public interest pay phones ever defined to include pay phones that were not available for use by the public?

A (Witness Selvidge) Not available for use by -- are you talking about in specific locations, like inside buildings that would not be accessible to the public?

Q I'm talking about comparing it to the proposals that are at issue in a case today where it wouldn't be generally available to the public, some of the services wouldn't be?

A (Witness Nelson) What wouldn't be?

Q Well, would community charging be available to every member of the public?

A (Witness Nelson) I don't believe that's clearly stated in the record.

Q How common will it be that the competitive marketplace would not be able to provide electric vehicle charging?

A (Witness Selvidge) I'm not sure we know at this stage, and that's why a regulatory scheme that's nondiscriminatory and that all users of the electricity for

the chargers pay the same rates, terms, under the same terms and conditions. It's very important to promote a competitive environment so that those chargers can get widely deployed.

Q Do all Georgia Power customers have an equal opportunity to benefit from the Make Ready Program if it's approved as proposed?

A (Witness Nelson) Are you speaking about how it's proposed by us?

Q By Georgia Power Company.

A (Witness Nelson) I didn't see any terms and conditions provided with Georgia Power's.

Q Are residential customers generally eligible to apply for the Make Ready Program?

A (Witness Nelson) I'm sorry. Can you -- if you could point me to a reference where -- are you referring to the record?

Q If you -- if you don't know, that's fine.

A (Witness Nelson) No, I don't know. I'm not -- I don't believe that's in the record. We tried to offer a framework for which we believed funds should be prioritized for.

Q Could I get you to turn to page 19 of your testimony.

Beginning on line 15, you recommend -- you --

you are recommending certain subsidizations of a percentage of the total Make Ready cost with different amounts based on the location type; is that correct?

A (Witness Nelson) Correct. Location accessibility.

Q Which of these categories that you detail in your testimony would apply to your members?

A (Witness Nelson) The first bullet point --

Q The first bullet point --

A (Witness Nelson) -- public charging sites.

Q -- the public transit fleets and public charging sites, which you recommend 70 percent of Make Ready costs; is that correct?

A (Witness Nelson) Correct.

Q Any of the others?

A (Witness Akers) I suppose the last bullet point where if the location might be if a member is in a rural community, perhaps.

Q And that's the bonus 20 percent?

A (Witness Nelson) Yes.

Q And so that's -- just to be clear, that would mean on top of the other subsidy that's identified in the individual line item; is that correct?

A (Witness Nelson) I think that's our initial proposal, yeah.

Q Okay. So your members would be located or -- the category that would apply to your members is the category that you're recommending the highest subsidy on; is that correct?

A (Witness Nelson) Yes. This is based off my experience designing or proposing programs in Massachusetts, review and participation in Illinois, as well as Maryland.

Q Thank you. Thank you very much.

MR. WALSH: Madam Chair, that's all the questions that I have.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Walsh. Commercial Group?

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: EVgo?

MR. VIJAYKAR: No questions.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Conservation Voters?

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Conservation

Voters?

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Conservation Voters?

(No response.)

MADAM CHAIR PRIDEMORE: She's gone for the day. Georgia Interfaith Power and Light?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA?

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch?

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: A few questions. Thank you.

CROSS-EXAMINATION

BY MS. ARIZA:

Q Good afternoon.

A (Witness Nelson) Good afternoon.

Q For the record, my name is Isabella Ariza, and I represent the Sierra Club in this proceeding. I have a few questions for you.

On page 10, lines 1 through 9, you discuss the role you'll play in the federal NEVI program deployment; right?

A (Witness Akers) That is correct.

Q Do you see that?

Thank you.

You cite to the Georgia Department of Transportation's EV deployment plan; is that right?

A (Witness Akers) Correct. Footnote 3.

Q So you read that document? You're familiar with it?

A (Witness Akers) Yes.

Q Do you recall that that document also describes what the role of the utilities should be?

A (Witness Akers) I don't recall.

Q I have that document with me. But I'll ask you some questions. If you don't recall, I'll show it to you.

But would you agree with GDOT that utilities should help assess grid upgrade costs per NEVI?

A (Witness Nelson) I apologize?

MADAM CHAIR PRIDEMORE: Grid upgrade costs for NEVI.

A (Witness Nelson) Should be Georgia Power fund that? Is that what --

Q Should they be involved in assessing?

A (Witness Nelson) Yeah, I think they have to be.

Q And do you agree with GDOT that utilities like Georgia Power should coordinate with other parties to optimize deployment?

A (Witness Nelson) I do.

Q And do you agree with GDOT that utilities like Georgia Power should help develop various approaches to Make Ready?

A (Witness Nelson) I do.

Q And, Mr. Nelson, on page 5, lines 21 through 23, you mention that recently you testified before the Massachusetts Department of Public Utilities, and you referenced that a minute ago as well.

A (Witness Nelson) Yes.

Q And there you testified and recommended -- commented on utilities' comprehensive EV planning proposals; is that right?

A (Witness Nelson) I did.

Q Was that docket similar to this one?

A (Witness Nelson) In some ways. That was six dockets broke into EV infrastructure spending for three and EV rate design for the other three, for all customer

classes.

Q So that was a more comprehensive docket, would you say?

A (Witness Nelson) I would say that -- yes, that was much more --

Q On the EV portion?

A (Witness Nelson) There was much more detail for the Make Ready terms and conditions. There were terms and conditions. There was discussions of how to prioritize funding for different areas and public policy goals, and there was additional conversation around appropriate rate design.

Q Given your expertise, do you see any benefit to this Public Service Commission opening a docket similar to that one?

A (Witness Nelson) I do think it -- there would be benefit from additional conversation on Make Ready and EV rate design. I think there could be progress made in the current docket as well, because I think there's going to be -- there's going to be -- things are going to start to move faster, I think, in the EV industry with many of the announcements that have been made.

And so trying to take a phased approach with how we deal with these programs is important.

Q Thank you.

Mr. Selvidge, just a couple questions for you.

You testified about the history of pay phones; is that right?

A (Witness Selvidge) That is correct.

Q And are you aware of the chicken and the egg problem in EV adoption?

A (Witness Selvidge) I'm sorry. Could you restate?

Q Are you aware of the chicken and the egg problem in EV adoption?

A (Witness Selvidge) Yes.

Q Okay. Is -- would you say that the history of pay phones had a similar chicken and the egg problem?

A (Witness Selvidge) Yes, it did.

Q Could you explain how?

A (Witness Selvidge) So from the standpoint of being able to place pay phones across the country in the widespread deployment, the way the system began was that BellSouth, who was the local exchange carrier, would not allow the independent pay phone providers to have access to the same access line. And so they had to come up with a different version of a pay phone to be able to replicate the central office functions.

So the way I see it is, from a chicken and egg standpoint, they had to find another way around the

roadblocks that were being provided by that local exchange company in order to even be able to provide pay telephone service. So that took a lot of investment for them to do that.

MADAM CHAIR PRIDEMORE: Mr. Selvidge, I'm not familiar with pay phone regulation, going back to my previous joke about the roller rink. But in this case, you've got a vertically integrated investor-owned electric utility that is perfectly satisfied with other people having charging stations. There's not a monopoly on charging stations in the state of Georgia.

So the example of BellSouth precluding others from owning pay phones, I don't -- where's the correlation?

MR. SELVIDGE: I was trying to answer the chicken and the egg issue.

But the issue, Madam Chair, is the fairness of the rates in terms and conditions. So if there's going to be a robust competitive market, and everybody wants a lot of EV chargers across the state of Georgia, then allowing that competitive market means that you've got to have the same terms and conditions for the participants to pay.

So in the pay phone arena, you're correct.

There was a difference in terms of the actual utility was not allowing in providing the service it was allowed. In this case, it's more of the rates, terms, and conditions being equal across the board and being treated the same operationally as well.

MADAM CHAIR PRIDEMORE: Do you have evidence that it's not right now, that it's not being treated equally?

MR. SELVIDGE: I don't have direct evidence except to say that, if you look out and you want to promote the competition in the market, then I think it's really important to learn from the past, and that's why my testimony states about the pay phone industry and the challenges over a decade.

And the good news here is there's not a lot of history in the EV market. You're in an early point in it, so you can set that regulatory regime to prevent, in my opinion, many of these challenges that came up similarly in the pay phone industry.

MR. NELSON: I would just add that the cost structure is also one example of being different in that level, right, because Georgia Power is not using a tariffed rate for the EV charging.

MADAM CHAIR PRIDEMORE: There's three separate tariffs for EVs in Georgia.

MR. NELSON: Yeah, but Georgia Power --

MADAM CHAIR PRIDEMORE: But only one that has a demand charge.

MR. NELSON: But Georgia Power doesn't use any of them.

MR. SELVIDGE: Georgia Power doesn't pay the same tariffed rate, nor do they impute the charges of the cost of that for -- to themselves.

MADAM CHAIR PRIDEMORE: Did you cover the difference in those rates in your testimony?

MR. NELSON: Yes, I believe that we did -- well, no, I don't know, because we don't know the rate that Georgia Power charges itself.

MADAM CHAIR PRIDEMORE: Okay. Go ahead.

BY MS. ARIZA:

Q Okay. Mr. Nelson, do you agree with Mr. Selvidge's depiction of what the chicken and the egg problem in the EV market is?

A (Witness Nelson) I will let his answer stand on that one. I could ask a follow-up -- or answer a follow-up question, I guess.

Q Would you briefly describe what, in your view, is the chicken and egg problem in the EV market.

A (Witness Nelson) Yeah. I think there's -- part of the problem is that there is not sufficient charging

available to give people confidence into entering the EV market is kind of the chicken and the egg issue here.

Q Thank you.

And I was going to ask Mr. Selvidge, there was no similar problem because, if you delayed pay phone deployment, pay phone adoption was not going to be delayed, was it?

A (Witness Selvidge) If you delayed deployment? I'm sorry.

Q Yeah, if you delayed deployment of pay phones, as if you delayed deployment of charging stations, pay phone adoption wouldn't be delayed as EV adoption would?

A (Witness Selvidge) That's probably correct, yes.

MS. ARIZA: Okay. Thank you. No further questions.

MR. NELSON: Thank you.

MADAM CHAIR PRIDEMORE: SACE?

MR. DOWDY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Ms. Medlyn?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Power?

MR. HEWITSON: Thank you, Madam Chair.

CROSS-EXAMINATION

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BY MR. HEWITSON:

Q Gentleman, good afternoon.

A (Witness Nelson) Good afternoon.

A (Witness Selvidge) Good afternoon.

Q My name is Steve Hewitson. I represent Georgia Power Company. A few question for you, and I'll try and tell you where I am. First, Community Charging.

Do you know how many public electric vehicle chargers are currently located in Georgia?

A (Witness Nelson) I've heard that Georgia Power has 3 percent, and you say 60, so that's about -- I don't know. We could do the math, I guess.

Q Really? Have you been here today about lawyers and math?

Mr. Akers, help us out.

A (Witness Nelson) I don't know off the top of my head. I'll put it that way.

Q Would it surprise you to learn that there are more than 3,600 chargers in the state of Georgia right now?

A (Witness Nelson) Is that in Georgia Power Company's territory or the state of Georgia?

Q In the state of Georgia, currently in Georgia.

A (Witness Nelson) I haven't seen --

Q I'm not talking about Georgia Power -- let me be clear. I'm sorry. I'm not talking about the number of

chargers Georgia Power has. I'm talking about the total number of chargers within the state of Georgia.

A (Witness Nelson) So that's not the charging locations or sites; that's the number of chargers?

Q Correct.

A (Witness Nelson) Yeah --

Q Would it surprise you to learn --

A (Witness Nelson) -- I haven't seen anything in the record.

Q Okay. Would it surprise you to learn it's 3,600 at 1,300 locations?

A (Witness Nelson) Like I said, I haven't seen anything in the record. It doesn't surprise me.

COMMISSIONER MCDONALD: Mr. Hewitson, does that include, like, Amazon that has their own station of chargers? Are those included in --

MR. HEWITSON: These are all the public electric vehicle chargers. They're not the chargers that are only for individual fleets.

BY MR. HEWITSON:

Q And but you are aware that Georgia Power owns fewer than 3 percent of those chargers; right?

A (Witness Nelson) That is what I've heard.

Q Okay. And do you understand -- well, did you -- did you watch, were you here when Georgia Power

testified on direct, or have you reviewed their testimony?

A (Witness Nelson) I've reviewed portions of their testimony.

Q Okay. And did you understand the company's witnesses to testify that Georgia Power intends only to be a charging service of last resort, meaning that Georgia Power only plans to locate chargers in areas not being served by private investment?

A (Witness Nelson) And, yeah, how did -- did they define that in their testimony?

Q Do you understand that their position is, going forward, Georgia Power wants to be the charger of last resort; right?

A (Witness Nelson) I didn't see that portion of their testimony.

Q You didn't read that portion of their testimony?

A (Witness Nelson) Oh, sorry. I thought you were referring to earlier this week's.

Q No, the direct testimony of Georgia Power's witnesses, Mr. Legg and --

A (Witness Nelson) The hearing structure is a little different here. I get a little confused. I understand what you're saying.

Q Okay. Well, let me cut to the chase.

If, going forward, Georgia Power only installed chargers in locations where private investment was not serving it, and Georgia Power gave private investment a right of first refusal on Community Charging locations, would that alleviate Double AACE's concerns with competition?

A (Witness Akers) I think we would be interested in the right of first refusal so long as there are other criteria, objective selection criteria and others that make up the Community Charging framework.

Q Okay. Thank you.

On page 11, lines 14 to 16, you note that DC fast chargers are needed to support public charging for business and long-distance travel purposes.

Do you see that testimony?

A (Witness Akers) What page?

Q 11, lines 14 to 16.

A (Witness Akers) Yes, I see it.

Q And that would be true in rural areas where people often pass through while on long distance trips; right?

A (Witness Akers) Perhaps, yes.

Q Okay. On page 21, lines 11 to 14, you recommend that Georgia Power's community chargers be limited to Level 2 chargers.

Is that your recommendation?

A Yes.

Q But that would not serve the need of -- the needs of business and long-distance travelers in those rural areas, would it?

A (Witness Akers) As a carrier of last resort, it would, you know. If it truly is a desert, then, yes, they would stop and drink water. But I think we don't need to have the Taj Mahal oasis in a charging desert.

Q So is it your testimony and your position or the position of Double AACE that rural customers aren't worthy of having access to DC fast chargers?

A (Witness Akers) That's not our position at all.

Q Okay. It's just that you're trying to handicap Georgia Power in that area?

A (Witness Akers) I don't think that's what we said, either.

Q Okay.

A (Witness Selvidge) Could I add a comment there? When you're looking at it from a regulatory standpoint from the history, it's more in the nature of the universal service, and so universal service would be -- as a carrier of last resort would be the basic level of service. That doesn't mean you're trying to discriminate against anyone in rural or you're trying to discriminate against a monopoly

provider.

Q Monopoly provider of what? Public community charging services? I think we've already established Georgia Power is not a monopoly provider; right?

A (Witness Selvidge) As of the electricity that's powering those stations.

MADAM CHAIR PRIDEMORE: Can I ask you a question on that, Mr. Selvidge?

Excuse me, Mr. Hewitson.

MR. SELVIDGE: Sure.

MADAM CHAIR PRIDEMORE: This difference continues to come up when we talk about EVs here, and you've got to realize that some folks -- like, who else is going provide the electricity? Where is the electricity going to come from if it's not coming from an electric utility?

MR. SELVIDGE: Well, it will, but the monopoly provider of the electric utility is Georgia Power. So as it evolved in the telecommunications business, right, you had others coming up who could provide those access lines.

So I was just suggesting, if it was at the rural location, there would likely be -- or at least now, one provider of that electricity to the EV charging station.

MADAM CHAIR PRIDEMORE: But you -- I mean, I think we're all on the same page when we say that you have -- you have an investor-owned electric utility in Georgia, you have 41 electric membership co-ops, you have the municipals, that they're going to provide the electricity under the ground that the charger sits on top of. There's no way around that.

I mean, wouldn't you agree with me? How do you get around that?

MR. NELSON: I don't think that we're debating that.

MADAM CHAIR PRIDEMORE: Okay. Okay.

BY MR. HEWITSON:

Q All right. Let's move onto Make Ready. And very quick, just wanted to clarify something in your testimony on page 20, lines 7 to 8. You recommend that the Commission require the property owner to own the EV charging station in the Make Ready Program.

Are you proposing to limit participation to only customers who own the property where the premises are located?

A (Witness Akers) Just to use as an example, if the -- instead of a property owner, they're leasing? Is that what you -- is that what you're saying?

Q Yeah. I mean, I'd want to know if you were

trying to exclude people with commercial leases.

A (Witness Akers) No.

Q Okay. Thank you.

All right. Onto the Charge It electric vehicle rider, your testimony recommends a different approach to designing a rate for EV charging; right?

A (Witness Nelson) Correct.

Q And I assume you're aware that none of the other have EV intervenors in this case have filed testimony opposed to that structure; right?

A (Witness Nelson) I'll take your word for that.

Q And you know that public interest advocacy staff recommends approval of the tariff without any modification; right?

A (Witness Nelson) I will also take your word on that.

Q Okay. Are you aware that Georgia Power has seen significant increase in private investment by EV charging providers over the last several years in Georgia?

A (Witness Nelson) Was that in Georgia Power's testimony?

Q I asked you are you aware that Georgia Power has seen a significant increase in investment by private charging companies in Georgia?

A (Witness Nelson) Yeah, I haven't seen anything

about that in the record.

Q So you're not aware of that?

A (Witness Nelson) No.

Q You're not aware of private investment building chargers within the state of Georgia over last several years?

A (Witness Nelson) I have not seen any data on that.

Q Okay. So if there's 3,600 public community chargers in the state of Georgia, and Georgia Power owns 3 percent of them, then there's probably a whole lot owned by private investment; right?

A (Witness Nelson) I guess it depends on how you view "a whole lot," which I would compare in different states and do a per capita.

Q 97 percent are owned by private investment --

A (Witness Nelson) I'm talking about the total number of chargers --

Q Right.

A (Witness Nelson) -- is what I was just -- the categorizing of the number of chargers. I don't know if that's a lot compared to other states.

Q Okay. Are you --

MADAM CHAIR PRIDEMORE: Based on your math, Mr. Hewitson, 108, which I believe that the record

actually shows there's 114 when I've looked back at all of the EV chargers in the state that are Georgia Power community -- publicly available community chargers. There's 114 of those.

So if you take that number -- there's 3,486 that are owned by somebody besides the investor-owned utility.

MR. HEWITSON: Thank you for the help on the math, Chair.

MADAM CHAIR PRIDEMORE: Doing my part.

MR. AKERS: And I think if you equate that to liquid fuel, I don't think anyone in this room would be comfortable with 3 percent of State-owned gas stations.

BY MR. HEWITSON:

Q I'm not sure I understand that statement.

A (Witness Akers) Well, I think you're making the point that it's only 3 percent. 3 percent is still a material amount.

Q No. If we go back to my question, it was: Are you aware that Georgia Power has seen a significant increase in private investment by EV charging providers over the last several years?

A (Witness Nelson) Yeah, I would just -- my response to that is I don't know what you mean by

"significant."

Q Okay. Well, given that there's investment by private investors in Georgia Power's territory, it appears these charging service providers have found the company's existing rates attractive enough to warrant their investment.

Would you agree with that?

A (Witness Nelson) I would disagree because you're looking -- would there have been ten times as many if your rate structures were different? Potentially. So you would want to compare -- you would want to do a comparison against different states with different rate structures to be able to say whether -- what's driving the changes, right.

Q Georgia Power's rate structures haven't prevented anyone else from coming in the market; right? There are other private -- there's private investment that has come into the Georgia Power territory.

Can we agree on that?

A (Witness Nelson) That there is private investment that's gone into Georgia Power's -- apparently so, yes.

Q Okay. And the Charge It rider enhances the current offerings by the company and provides another option for private investment; right?

A I'm sorry. Can you repeat that question?

Q It's just that the Charge It rider provides another option for people to use?

A (Witness Nelson) That is true. It's another optional tariff.

Q Okay. And a basis of your recommendation on the Charge It rider is that the EV rate should encourage charging during lower load periods, like overnight; is that correct?

A (Witness Nelson) Correct.

Q The Charge It rider is available to any commercial customer in one of the underlying rates, not just those seeking to electrify their fleet; right?

A (Witness Nelson) I apologize. You're speaking a little fast.

Would you mind repeating that?

Q Usually in the South, we don't have trouble with going too fast, but --

A (Witness Nelson) I'm from the Pacific Northwest, so we talk real slow.

Q All right.

MADAM CHAIR PRIDEMORE: Remember, he has a hard time doing math. That's why I had to get out the calculators.

BY MR. HEWITSON:

Q The Charge It rider is available to any

commercial customer on one of the underlying rates, not just those seeking to electrify their fleet; right? I think we established that.

A (Witness Nelson) Yes.

Q Okay. And Charge It rates can be used by employers who want to make charging available to their employees; right?

A (Witness Nelson) I believe so.

Q Okay. And with that use case, the charging is more likely to occur during the middle of the day when employees are at work or traveling to and from work; right?

A (Witness Nelson) Well, that's just one of many use cases.

Q And that's a fair point.

And Charge It is also available to the commercial public charging, like at a gas station; right?

A (Witness Nelson) Correct, it is an available tariff.

Q And you would not expect public customers to charge their electric vehicles at a gas station overnight, would you? You would expect it to happen during the day; right?

A (Witness Akers) Correct. We're just a proxy for the consumer. They come when they come.

MR. HEWITSON: Okay. Thank you. Gentlemen, appreciate your time.

That's all the questions I have.

MADAM CHAIR PRIDEMORE: Redirect?

MR. GALLOWAY: Thank you, Madam Chair.

REDIRECT EXAMINATION

BY MR. GALLOWAY:

Q Let's talk very briefly about the CIEV tariff, CIEV-1.

That is not available yet; is that correct? It will be available January 1 or when the compliance filing is done?

A (Witness Nelson) Correct.

Q Now, I want to ask a couple of questions related to Commissioner Echols' inquiry.

Let us assume the EV charging station is damaged, or the EV charging station does not have the ten-year useful life we have projected in our testimony. Who incurs the economic risk and cost if the charger is damaged and doesn't last as long as it's supposed to, ratepayers or a private company that's deployed the charger?

A (Witness Akers) Private company, from a capital sense and a reputational sense.

Q Right. And would it -- from the experience with EV charging to date, would we have -- would it be fair

to assume that the same issues regarding the condition of the charger, the risk of the charger failing, apply to both a privately owned charger, as well as a charger owned by Georgia Power?

A (Witness Nelson) Yes.

A (Witness Akers) That seems logical.

Q All right. Is there any desire from anyone within AACE to prevent Georgia Power from deploying chargers even if they choose to be an aggressive competitor?

A (Witness Akers) No.

Q Okay. And, Mr. Nelson, could you address how there are similarities between Make Ready, what Make Ready does, and a utility's usual line extension policy?

A (Witness Nelson) Yeah. Generally, line extension policies are for when load is connecting to the grid, and so if the load is significant enough that it's triggering an upgrade on the utility side of the meter, they split up a portion of the system upgrade costs.

So if it costs a hundred dollars, the customer, depending on the line extension policy, would pay $50. And then in many -- under many utility policies, that other $50 goes into rate base. So it's socialized. So some of those -- some line extensions are socialized, some of that load, because they're paying into the system.

And so the Make Ready is similar in the way

that you would socialize a portion of the upgrade. It's distinct because it is on the customer side of the meter.

Q You were asked questions regarding the difference in costs.

Could you turn to page 41 of your testimony, please, and could you describe what this chart shows?

A (Witness Nelson) Yes, I can. So the blue line is the costs that you would -- a charging customer would incur under PLM 14 with the CIEV rider. Essentially, they're still just paying a minimum bill based on their ratcheted demand charge, their billing demand charge, because that's essentially the floor that any customer is going to pay, is that demand charge, because it goes throughout the year.

And then we've got the monthly kWh sold, is the middle purple line. And then the -- Georgia Power's assumed costs is what we are assuming Georgia Power could be charging itself for its rates.

Q And do we have any idea as to what that rate would be, where they're accounting for the cost of electricity they're providing to itself?

A (Witness Nelson) No.

Q All right. Should public access for any charger for which there is ratepayer support, under Make Ready or Community Charging, should they be accessible to

the public?

A (Witness Nelson) We think that's one important factor.

Q And that would mean any member of the public with an EV could come up and use the charger?

A (Witness Nelson) Yes, it's a way to go after the chicken and egg problem because you're benefiting the largest number of ratepayers through the investment.

Q And, Mr. Selvidge, I'll close my redirect to you.

In an environment, in a market where you have a regulated utility that is both the supplier of the electricity or the supplier of a telephone line, and then the competitor has to both acquire service from the utility and then compete with that utility in the marketplace, has cross-subsidy -- the risk of cross-subsidy always been a concern for regulators and people who were developing statutes to allow competitive entry into the markets?

MR. HEWITSON: Madam Chair, are we talking about the telephone industry or the electric industry? I got lost there.

MADAM CHAIR PRIDEMORE: Do you object?

MR. HEWITSON: I do.

MADAM CHAIR PRIDEMORE: Objection. Okay.

MR. GALLOWAY: Let me rephrase it to make it

clearer.

MADAM CHAIR PRIDEMORE: Please do so.

BY MR. GALLOWAY:

Q Let's limit it to electric service, and we're basing it on the assumption Georgia Power desires to be an aggressive competitor, which it has the right to do.

Do you agree that Georgia Power is both the essential supplier of electricity to serve the charger, and also a competitor in the charging market to provide it to the EV?

MR. HEWITSON: I'm going to object as a hypothetical that's not based on facts. The testimony in the record is that Georgia Power does not want to be an aggressive competitor.

MADAM CHAIR PRIDEMORE: And I think we've said it repeatedly. It's been said and asked and answered.

MR. GALLOWAY: Can I take just a little issue with that? The testimony was from Mr. Legg and the Abramovitz panel that, under Community Charging, they were going to be a carrier of last resort for chargers, and that's where we referenced the charging desert.

Georgia Power has the ability to go through and become an aggressive competitor if it chooses, and

I'm not trying to belabor the point.

But bottom line is: Why is cross subsidy an issue in all regulated utilities where they're also competitors?

MR. HEWITSON: I don't think that's part of their testimony, Madam Chair.

MADAM CHAIR PRIDEMORE: Mr. Galloway, you've been given a lot here in this proceeding.

MR. GALLOWAY: Well, it's --

MADAM CHAIR PRIDEMORE: You're pushing it.

MR. GALLOWAY: Well, it's --

MADAM CHAIR PRIDEMORE: You're pushing it. One more shot to ask it a different way.

MR. GALLOWAY: I think he's got the question. Go ahead.

MR. SELVIDGE: I was going give a response. Is that -- is that okay?

MADAM CHAIR PRIDEMORE: Go ahead.

MR. SELVIDGE: All right. So from a cross-subsidy standpoint, obviously, the FCC looked at this and other regulatory agencies have as well. And it opens the door for potential and anticompetitive behavior to occur. It doesn't mean that it's going to, but it certainly gives the incentive, potential incentive to occur, and that's

not in the best interest of consumers.

MR. GALLOWAY: That's all I have. Thank you, Madam Chair.

MADAM CHAIR PRIDEMORE: All right. Very good. Do you need to put anything into evidence?

MR. GALLOWAY: No, ma'am. That's why I did it --

MADAM CHAIR PRIDEMORE: You're good.

Witnesses, you're excused. Have a good evening.

MR. AKERS: Thank you.

MR. SELVIDGE: Thank you.

MR. NELSON: Thank you.

MR. GALLOWAY: Thank you, Commissioner.

MADAM CHAIR PRIDEMORE: Okay. I just want to remind the room, we have completed eight panels, and we have 15 to go. It is quarter to 6:00. We come back in tomorrow at 7:30 in the morning, and people are, like, typing me questions about dinner. We're not taking a dinner break. The HVAC shuts off at 9:00 p.m.

So your comfort and your ability to get some sleep tonight has everything to do with your ability to answer questions succinctly, ask your questions succinctly, and get your witnesses up here and get

them sworn in. Okay?

I would really like to get some type of response to that. Okay?

(All answer yes.)

MADAM CHAIR PRIDEMORE: Thank you. Thank you. Okay. Go ahead. ChargePoint.

MR. DUNBAR: Thank you, Madam Chair. At this time, ChargePoint calls Mr. Justin Wilson to the stand.

Mr. Wilson, could you please stand and raise your right hand.

Whereupon,

JUSTIN WILSON,

having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. DUNBAR:

Q Mr. Wilson, will you please state your full name, your employer, and your responsibilities for the record.

A My name is Justin Wilson. I'm the director of utility partnerships and regulatory affairs at ChargePoint. I oversee ChargePoint's utility partnerships and business development with utilities, as well as our regulatory affairs, which includes Public Service Commission and other regulatory bodies.

Q Thank you.

On October 20th, 2022, did you prefile or cause to be prefiled 12 pages of direct testimony in question-and-answer format?

A I did.

Q Did you also at that time file two exhibits identified as ChargePoint Exhibit 1.1 and ChargePoint Exhibit 1.2?

A Yes.

Q Was your direct testimony and the two exhibits prepared under your supervision or at your direction?

A Yes.

Q Are there any corrections that you need to make to your prefiled testimony or exhibits?

A No.

Q Okay. If I were to ask you the same questions today under oath, would your answers be the same as set forth in your prefiled testimony?

A Yes.

Q Thank you, Mr. Wilson.

MR. DUNBAR: Madam Chair, I now ask that the direct testimony of Mr. Wilson and the two accompanying exhibits be copied into the record as if given here today.

MADAM CHAIR PRIDEMORE: So moved.

**(The documents referred to were marked for identification as ChargePoint Exhibits 1.1 and 1.2.)**

**(Whereupon, the prefiled direct testimony of Justin D. Wilson follows:)**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**STATE OF GEORGIA**

| | | |
|---|---|---|
| **In Re:** | **:** | |
| | **:** | |
| **GEORGIA POWER COMPANY'S** | **:** | **DOCKET NO. 44280** |
| **2022 RATE CASE** | **:** | |
| | **:** | |

# DIRECT TESTIMONY OF

# JUSTIN D. WILSON

# ON BEHALF OF

# CHARGEPOINT, INC.

October 20, 2022

## I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS.

**Q: Please state your name.**

A: My name is Justin D. Wilson.

**Q: By whom are you employed and in what position?**

A: I am Director of Utility Partnerships and Regulatory Affairs at ChargePoint, Inc. (ChargePoint).

**Q: Please describe your background, experience and expertise.**

A: In my current role, I direct ChargePoint's participation in utility programs and our regulatory efforts in North America. I engage on behalf of ChargePoint at utility regulatory commissions and other state agencies to promote public policies that expand electric vehicle infrastructure and advance best practices within the electric vehicle charging industry. I received a bachelor's degree in Public Administration from the University of Arkansas and a master's degree in Public Administration from the University of Colorado Denver.

**Q: Are you sponsoring any exhibits?**

A: Yes, attached to my testimony is ChargePoint Exhibit 1.1, which is my CV, and ChargePoint Exhibit 1.2, which is titled: "States that Allow Charging per kWh."

**Q: Please describe ChargePoint.**

A: ChargePoint is a world leading electric vehicle (EV) charging network, providing scalable solutions for every charging scenario from home and multifamily to workplace, parking, hospitality, retail and transport fleets of all types. ChargePoint's cloud subscription platform and software-defined charging hardware is designed to enable businesses to

support drivers, add the latest software features and expand fleet needs with minimal disruption to overall business.

ChargePoint's hardware offerings include Level 2 (L2) and DC fast charging (DCFC) products, and ChargePoint provides a range of options across those charging levels for specific use cases including light duty, medium duty, and transit fleets, multi-unit dwellings, residential (multi-family and single family), destination, workplace, and more. ChargePoint's software and cloud services enable EV charging station site hosts to manage charging onsite with features like Waitlist, access control, charging analytics, and real-time availability. With modular design to help minimize downtime and make maintenance and repair more seamless, all products are also UL-listed and CE (EU) certified, and Level 2 solutions are ENERGY STAR® certified.

ChargePoint's primary business model consists of selling smart charging solutions directly to businesses and organizations while offering tools that empower station owners to deploy EV charging designed for their individual application and use case. ChargePoint provides charging network services and data-driven, cloud-enabled capabilities that enable site hosts to better manage their charging assets and optimize services. For example, with those network capabilities, site hosts can view data on charging station utilization, frequency and duration of charging sessions, set access controls to the stations, and set pricing for charging services. These features are designed to maximize utilization and align the EV driver experience with the specific use case associated with the specific site host. Additionally, ChargePoint has designed its network to allow other parties, such as electric utilities, the ability to access charging data and conduct load management to enable efficient EV load integration onto the electric grid.

**Q: What is the purpose of your Direct Testimony?**

A: The purpose of my Direct Testimony is to respond to the direct testimony of Georgia Power Company (Georgia Power or the Company) witnesses Christopher C. Womack and Larry T. Legg regarding the Company's proposed EV charging investments and proposed new rider rate schedule for separately metered non-residential EV charging, Schedule Charge It Electric Vehicle (Rider CIEV-1). I also address the ability of EV charging station operators (site hosts) to sell EV charging services by the kilowatt-hour in Georgia Power's service territory.

**Q: Please summarize your recommendations to the Commission.**

A: ChargePoint recommends that the Commission:

- Approve Georgia Power's proposed investments in community charging facilities and EV charging infrastructure upgrades across the state;
- Approve Rider CIEV-1 and direct Georgia Power to allow any qualifying customer to take service on it (not just new customers);
- Clarify that the sale of EV charging services by non-utilities shall not be considered resale of electricity.

## II. Georgia Power's EV programs

**Q: What will you address in this section of your testimony?**

A: In this section of my testimony, I will address the ability for site hosts that participate in Georgia Power's EV make-ready and community charging infrastructure program proposals to choose their preferred charging equipment.

**Q: Do Georgia Power's proposals allow for site hosts to choose the charging equipment installed on their property?**

A: Yes. Based on discussions with Georgia Power, it is my understanding that site hosts will continue to have the ability to choose their charging equipment. I use the term "site host" to refer to the owner or lessor of the property on which an EV charging station is located. Site hosts include residential customers; owners of multi-family housing (MFH); commercial customers that offer charging to the public, their customers, and/or their employees; fleet owners; and government entities.

**Q: Why is site host choice important?**

A: Site host choice is the critical program design element that allows customers to enjoy the benefits of competition, including innovation, cost-competitiveness, and a variety of products and services to satisfy a variety of needs and preferences. In the competitive marketplace for EV charging services, the ability of site hosts to select the technologies they prefer in an open market, invest their own capital, seek any incentives available through public agencies or utilities, and, in the case of commercial stations, offer competitive charging services to attract drivers and recoup necessary expenses, is paramount. Ensuring that site hosts can choose the charging solution that works best for them ensures that the competitive dynamics that exist in the absence of a utility program will function within the confines of the utility program, to the benefit of customers.

**Q: Has Georgia Power proposed to increase investments in community electric vehicle charging facilities?**

A: Yes, Georgia Power witness Womack states that "over the next three years" Georgia Power will "increase… investments in community electric vehicle ('EV') charging facilities and

necessary electric transportation infrastructure upgrades to support customer EV charging."

**Q: Does ChargePoint support these investments?**

A: Yes, ChargePoint supports Georgia Power's proposed investments, so long as site host choice remains a tenet of the programs moving forward.

**Q: What is your recommendation?**

A: ChargePoint recommends that the Commission approve Georgia Power's proposed investments in community charging facilities and EV charging infrastructure upgrades across the state.

## III. Proposed Rider CIEV-1

**Q: Please summarize Georgia Power's proposed Rider CIEV-1.**

A: Georgia Power proposes to establish a new rider rate schedule for separately metered non-residential EV charging, designated as Schedule Charge It Electric Vehicle (Rider CIEV-1).[1] Rider CIEV-1 reduces billed demand charges for up to forty-eight months, or when a customer's rolling twelve-month load factor reaches 15% or greater.[2]

**Q: Does ChargePoint support the design of Rider CIEV?**

A: Yes, ChargePoint supports Rider CIEV-1 as designed by Georgia Power. The proposed Rider is a positive step toward increasing EV charger penetration in the state, which in turn will benefit Georgia Power's customers. Demand charges can pose a significant challenge and expense for EV charging station site hosts, especially when utilization of the charger is low, which is often the case currently as EV adoption is still relatively low. In low

[1] Proposed Original Page No. 12.40.
[2] *Id.*

utilization scenarios, a site host may experience a relatively small number of charging sessions in a month, but if several vehicles charge at the same time, the demand charge will be set for the entire month (and potentially much longer when there is a demand ratchet provision, as there is for schedules PLS, PLM, and PLL). Rider CIEV-1 will effectively mitigate the impact of demand charges on EV charging station site hosts for a four-year period while their load factor is relatively low.

**Q: Do you recommend any modifications to Rider CIEV-1?**

A: ChargePoint has one minor recommendation to the Applicability section of Rider CIEV-1. As proposed, Rider CIEV-1 would only be available to new services dedicated to EV charging that start service on or after January 1, 2023.[3] There is no reason to restrict the availability of this rider to new customers. Existing customers that have already installed EV charging stations behind a dedicated meter should have access to the same rates and rate riders as new customers, especially rate riders like Rider CIEV-1 that will allow them to more cost-effectively manage their EV charging load. The Commission should direct Georgia Power to allow any customer with a dedicated meter for EV charging to take service on Rider CIEV-1.

**Q: What is your recommendation?**

A: ChargePoint recommends that the Commission approve Georgia Power's Rider CIEV-1 and direct Georgia Power to allow any qualifying customer to take service on it (not just new customers).

[3] Proposed Original Page No. 12.40.

## IV. Enable Site Hosts to Price EV Charging Services on a $/kWh basis.

**Q: What will you address in this section of your testimony?**

A: In this section of my testimony, I will address the ability of EV charging station operators (site hosts) to sell EV charging services by the kilowatt-hour in Georgia. As I will discuss, providing regulatory certainty to non-utilities that they can charge a $/kWh price for EV charging is crucial to encouraging EV charging station deployment and EV adoption.

**Q: Can non-utility site hosts currently sell EV charging services on a $/kWh basis in Georgia Power's Service Territory?**

A: No. A non-utility site host would risk violating Georgia Power's prohibition on resale of electricity, which appears in Georgia Power's tariff.[4] Because historically the only commodity or service priced on a $/kWh basis was electricity, any person or entity using a $/kWh pricing arrangement is generally considered to be reselling electricity. The current uncertainty and risk that a site host would violate Georgia Power's tariff by charging drivers to charge their EVs on a $/kWh basis effectively prevents site hosts from doing so in Georgia. For the reasons I will discuss, ChargePoint recommends that the Commission clarify that EV charging station site hosts do not resell electricity.

**Q: Do EV charging stations resell electricity?**

A: No. However, as discussed above, any $/kWh pricing arrangement is generally deemed to be a resale of electricity, which is why EV charging station site hosts risk violating Georgia Power's tariff if they sell EV charging services on a $/kWh basis. In reality, EV charging

[4] Georgia Power Company, Rules and Regulations for Electric Service, General Rules, Page Number 1.11, ¶ 6 ("Electric service will not be supplied in competition with the Company's own service, either wholesale or retail, or for distribution or supply or resale in any territory occupied by the distribution system of the Company, or proposed to be occupied by the distribution system of the Company."), included in MFR F-1 of Georgia Power's initial filing.

stations use electricity to provide a service; specifically, the service of charging the battery of an EV. While the amount of energy stored in a battery is measured in kilowatt-hours, the EV charging station is not reselling electricity but rather using electricity to perform the value-added service of charging a battery (in which energy is stored).

The nature of this service is entirely distinct from the way that a utility sells electricity. A utility sells electricity as a commodity that a customer can use for a wide-variety of purposes, such as powering an air conditioner, cooking, or charging their smart phone. By contrast, an EV charging station uses electricity for a single purpose – charging the battery of an EV – and the EV driver can only use the energy stored in the EV's battery for a single purpose – operating the EV.

Like EV charging station site hosts, many businesses use electricity to provide services to the public. For example, a laundromat uses electricity to run its business, but it would be inaccurate to say that the laundromat resells electricity to its customers that the customers use to wash and dry their clothes. Rather, the more accurate description of the laundromat's business is that it uses electricity to provide the services of washing and drying customers' clothes. By the same token, it is inaccurate to say that an EV charging station site host is reselling electricity to EV drivers. Rather, the accurate way to describe the transaction between a site host and an EV driver is that the site host uses electricity to provide the service of charging the battery of an EV.

**Q: If site hosts cannot charge drivers on a $/kWh basis, how do they price charging services?**

A: The most common alternative pricing arrangement non-utility site hosts use is to charge drivers by the minute ($/minute). Other site hosts provide charging for free as an amenity

to support their primary business, such as a retail store or a restaurant, but free charging is typically limited to Level 2 chargers and is not a sustainable business model for deploying DC fast chargers.

**Q: Why does it make sense to allow EV charging station site hosts to charge EV drivers on a $/kWh basis?**

A: EV charging station site hosts provide a service: namely, the service of charging the batteries of EVs. The amount of energy that is stored in a battery is measured in kilowatt-hours. Allowing EV charging station site hosts to price charging services on a $/kWh basis will allow site hosts to charge drivers accurately and fairly for the battery charging service they provide.

**Q: What are the challenges that arise from charging EV drivers by the minute?**

A: A per-minute pricing arrangement does not account for the amount of energy that is delivered to an EV's battery. Because different EV models have different maximum charging speeds, billing on a per-minute basis leads EV drivers to pay varying costs for the same amount of energy consumed. For example, it may take only 30 minutes for a newer model EV with a high maximum charging speed to add 30 kWh of charge at a DC fast charger. However, at that same fast charger, it could take 90 minutes for an older EV with a lower maximum charging speed to add the same 30 kWh of charge. If the charger used a $/minute pricing scheme, the older EV would pay three times as much to add the exact same amount of charge to its battery. In addition to being disconnected from the amount of energy delivered to the battery the per-minute pricing scheme has the effect of negatively impacting those EV drivers with older vehicle models.

**Q: Have other states addressed this issue?**

A: Yes. EV charging station site hosts may charge EV drivers on a $/kWh basis in each of the 43 states that have addressed this issue, as well as in the District of Columbia and Puerto Rico. Please see ChargePoint Exhibit 1.2.

It is worth noting that the uncertainty and risk faced by site hosts preventing them from charging on a $/kWh basis has arisen in different ways in different states. In some states this issue has been resolved through a statutory change, in other states through a statewide regulatory commission proceeding, and other states through a utility-specific proceeding (such as this docket). Nevertheless, in each of the 43 states and the District of Columbia the result is the same: EV charging station site hosts may charge EV drivers using their preferred pricing arrangement, including on a $/kWh basis.

**Q: Has the federal government addressed this issue?**

A: Yes. The Federal Highway Administration (FHWA) is in the process of implementing the National Electric Vehicle Infrastructure (NEVI) formula program, which was created by the Infrastructure Investment and Jobs Act (IIJA) passed in 2021. Based on current estimates, Georgia is expected to receive $135 million over 5 years to support the expansion of EV charging; Georgia will also have the opportunity to apply for $2.5 billion in grant funding dedicated to EV charging.[5] In its Notice of Proposed Rulemaking, the FHWA proposed the following requirement for chargers that receive NEVI funding:

[5] Federal Highway Administration, National Electric Vehicle Infrastructure (NEVI) Formula Program Guidance (Feb. 2022), available at: https://www.fhwa.dot.gov/environment/alternative_fuel_corridors/nominations/90d_nevi_formula_program_guidance.pdf).

"Chargers must display and base the price for electricity to charge in $/kWh."[6] However, any EV charging station that followed this federal guidance would violate Georgia Power's tariff prohibition on resale of electricity.

**Q: Are any tariff changes needed to resolve this issue?**

A: No, it is not necessary to modify Georgia Power's tariff to resolve this issue. The Commission can resolve this issue simply by clarifying that EV charging stations do not resell electricity and therefore would not violate the tariff by charging for EV charging on a $/kWh basis.

**Q: What do you recommend?**

A: ChargePoint respectfully recommends and requests that, in the final order of this proceeding, the Commission state that the sale of EV charging services by non-utilities shall not be considered resale of electricity.

## V. CONCLUSION

**Q: Please summarize your recommendations to the Commission.**

A: I recommend that the Commission:

- Approve Georgia Power's proposed investments in community charging facilities and EV charging infrastructure upgrades across the state;
- Approve Rider CIEV-1 and direct Georgia Power to allow any qualifying customer to take service on it (not just new customers);

[6] See Proposed Rule for the National Electric Vehicle Infrastructure Formula Program at § 680.116, (pub. June 22, 2022), available at: https://www.federalregister.gov/documents/2022/06/22/2022-12704/national-electric-vehicleinfrastructure-formula-program.

- Clarify that the sale of EV charging services by non-utilities shall not be considered resale of electricity.

**Q: Does this conclude your direct testimony?**

A: Yes.

**BEFORE THE PUBLIC SERVICE COMMISSION**

**STATE OF GEORGIA**

| | | |
|---|---|---|
| **In Re:** | : | |
| | : | |
| **GEORGIA POWER COMPANY'S** | : | **DOCKET NO. 44280** |
| **2022 RATE CASE** | : | |
| | : | |

## CERTIFICATE OF SERVICE

I hereby certify that I have served the following parties with the foregoing Direct Testimony of Justin D. Wilson on behalf of ChargePoint, Inc. via electronic mail as follows:

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Dated: October 20, 2022

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MR. DUNBAR: Thank you, Madam Chair.

With your permission, I will ask Mr. Wilson to summarize his testimony briefly.

MADAM CHAIR PRIDEMORE: Please go ahead.

MR. WILSON: I will be brief. Thank you.

Commissioners, thank you for the opportunity to be here today. I have three recommendations to the Commission which are included in the testimony.

First, to approve Georgia Power's proposed investments in the Community Charging facilities and EV charging infrastructure upgrades across the state.

Second, to approve rider CIEV-1 and direct Georgia Power to allow any qualifying customer to take service on it, not just new customers as Georgia Power has proposed.

And third, to clarify that the sale of EV charging services by nonutilities shall not be considered the resale of electricity. I'll focus just a little bit more on the charging per kilowatt hour. That's been a point of discussion today, and I really appreciate the conversation thus far.

As has been stated, charging on the kilowatt basis sends a clear price signal to customers. It's transparent and it's something that customers understand. While I'm not an attorney, and I

understand that there are some legal questions that will be addressed in briefing, a primary piece that is challenging for EV service providers is a provision in Georgia Power tariffs that prohibits the resale of electricity.

Many states have looked at this. In ChargePoint's testimony we have provided a table of states that have looked at this and addressed this either legislatively or through regulatory means. And in regulatory means that's either been done through a rule making, and it has also been done through individual cases.

And there's an opportunity here in this case to, in my opinion, provide clarity that within Georgia Power service territory EV charging providers can charge per the kilowatt hour. The Commission could state that -- determine that it's not a resale of electricity whether -- rather charging is providing a service to EV drivers.

With that, I know that the testimony has been read, and I will conclude that summary.

MADAM CHAIR PRIDEMORE: Thank you, sir.

Questions from Commissioners?

VICE CHAIRMAN ECHOLS: Just a short one.

MADAM CHAIR PRIDEMORE: Commissioner Echols?

**VICE CHAIRMAN ECHOLS: First of all, thank you for having great charging out there.**

**MR. WILSON: Thank you, sir.**

**VICE CHAIRMAN ECHOLS: Love it.**

**Has there been ChargePoint customers that have received the Make Ready money that would not have done -- not put chargers in were it not for the Make Ready, where it may have been cost prohibitive? Do you know of instances where that happened?**

**MR. WILSON: Specifically in Georgia or throughout the U.S.?**

**VICE CHAIRMAN ECHOLS: No, just the Georgia Power Make Ready. That's the only thing I'm thinking about now.**

**MR. WILSON: I can't speak to any specific customers in Georgia. I would say that, across the United States, we do see incentives, including both Make Ready and rebates, tipping a customer over the edge. Right? Every customer is going to have a different cost calculation, and the ability to reduce those up-front capital costs is extremely helpful. And there's a lot of different ways that we can do that, and Make Ready investments are a key piece of that.**

**VICE CHAIRMAN ECHOLS: All right. And the**

utilization of ChargePoint chargers in Georgia -- and just tell me if you don't know this.

Do you know what the average utilization is for one of your chargers?

MR. WILSON: Yes, I'll clarify here that ChargePoint's primary business model is to sell the chargers and then provide the network services. So the utilization of that charging equipment would be essentially the data of our customers, and so it wouldn't feel comfortable, you know, stating what a customer's utilization is. That's pretty competitively sensitive information.

VICE CHAIRMAN ECHOLS: All right. Thank you so much.

MADAM CHAIR PRIDEMORE: Very good.

Georgia Public Service Commission.

MR. WALSH: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. WALSH:

Q Good afternoon, Mr. Wilson. My name is Dan Walsh. I represent the Public Interest Advocacy Staff.

How many charging stations are in ChargePoint's network in Georgia?

A You know, I don't know if we addressed that in the testimony. I don't think we did. I don't have that

number offhand for you.

Q Do you know if any of the stations in ChargePoint's network have received Make Ready subsidies?

A I can't speak to our -- again, our primary business model is to sell the charger -- charging hardware, and so our customers may have taken advantage of that Make Ready dollars. I can't speak specifically to Georgia Power's Make Ready Program.

Q Is it ChargePoint's recommendation that the Commission approve the power company at Georgia Power's proposed investments in Community Charging facilities and EV charging infrastructure across the state?

A That's correct.

Q Okay. Could you please define term "site host"?

A Yeah. A site host is -- it can really be two different components. So -- and this goes back to a conversation that took place on the previous panel. A site host is, essentially, the owner and the operator of that charging station. So in the instance of the property owner, let's say a Georgia-based fueling supplier, if they own that land, they would be the site host.

A site host also could be a third party who installs charging stations and owns and operates those. So that's a business model that others in the EV charging space

have deployed. Tesla, when they deploy chargers, as well as Electrify America and EVgo oftentimes will lease land and then become the site host for those chargers.

Q Thank you.

Do you state in your testimony that the term "site host" as used in your testimony includes residential customers?

A Could you point me to that?

Q Yes, I believe it's page 4, line 6.

A Yes, it can certainly -- I guess it doesn't have to necessarily be a commercial outside host. Obviously, residential consumers do own and operate charging stations.

Q Are residential customers allowed to participate in the Make Ready subsidy program?

A No.

Q Okay. Is the equipment installed under the Make Ready Program used to provide regulated electric service to residential ratepayers?

A Could you say that one more time?

Q Sure.

Is the equipment that's installed as part of the Make Ready Program used to provide regulated electric service to residential ratepayers?

A No.

Q Are you aware that if Georgia Power Company's Make Ready request is approved, the company will earn the same return on equity it receives for regulated assets that are used and useful in providing regulated electric service?

A Yes.

Q In your testimony -- and I'm looking at page 4 still, lines 10 through 11.

Do I read your testimony correctly to say that the site host's choice is the critical program design element that allows customers to enjoy the benefits of competition?

A Yes, you did read it correctly. I would say it's the critical piece that we've been looking at in this case, based on knowledge of it, I think that there's a lot of critical pieces that we evaluate.

Q And are you referring to the choice of site host for the charging station equipment and operation in that part of your testimony?

A Yes, that's correct.

Q Okay. Would agree that, even without the Make Ready Program, each site host has the ability to choose their charging station?

A Yes.

Q Is it your opinion that the competitive market is able to provide the hardware and software needed to

supply customers with EV chargers?

A I believe there's a competitive market for EV charging, yes.

Q Does ChargePoint install or arrange for the installation of Level 2 and DC Fast Chargers for its customers?

A We do not provide installation services. We can recommend certain installers, but we do not arrange for that.

Q And I'm sorry if your answer to that question already answers this one, but just to clarify, does ChargePoint participate in the installation of any components besides the Level 2 or DC Fast Charger itself? Any other components that would be part of the Make Ready Program?

A Generally, no. I would say, I mean, we -- you know, if we're talking about it in Georgia, that's correct. ChargePoint's, again, primary business model is to sell the hardware and then the ongoing software that allows the chargers to operate.

We do from time to time participate in grant programs and take on that ownership responsibility. Again, I'm not aware of that in Georgia. We've done it from time to time. It's a small number of equipment that we do own and operate.

Q And when you say that, is that for the Level 2 and DC Fast Chargers, or is that for some of the other components that would be installed as part of the Make Ready Program?

A So, again, I want to be clear that I'm not aware of that being the case in Georgia.

Q Okay.

A So -- but, you know, more broadly, it could be either DC FC or Level 2 charging equipment.

Q Thank you very much.

MR. WALSH: Madam Chair, that's all the questions I have.

MADAM CHAIR PRIDEMORE: Thank you very much.

All right. Americans for Affordable Clean Energy.

MS. KYSOR: As Newton's proxy, no questions.

MADAM CHAIR PRIDEMORE: Okay. Commercial Group?

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: EVgo?

MR. VIJAYKAR: No questions.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of

Local Governments?

MS. BROWN: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power and Light?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: Okay. GASEIA?

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch?

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Ms. Medlyn?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: All right. Georgia Power?

MR. HEWITSON: Thank you, Madam Chair.

**CROSS-EXAMINATION**

**BY MR. HEWITSON:**

**Q Good afternoon.**

**A Good evening.**

**Q Good evening.**

**Is it fair to say -- Steve Hewitson on behalf of Georgia Power. Sorry.**

**A Nice to meet you.**

**Q Is it fair to say that ChargePoint does not oppose Georgia Power participating in the EV charging market?**

**A That's correct. You know, I would state that -- I think the conversations are good. I think having these conversations so that everybody is on the same page is really helpful. But we do not oppose Georgia Power participating in this market, so long as there is customer choice in the charging equipment that is on a site host property, which we understand to be the case.**

**Q Okay. And you are familiar with other utilities participating in the EV charging market around the country; right?**

**A I am.**

**Q Okay. And based on your experience, do you agree that utilities participate in the EV charging market, but usually not at the same level as private investment?**

A I would say that that is generally the case, as commissions have looked at proposals by utilities to participate. Generally, the commissions have approved some level of participation. They have not approved participation that is unfettered, so to speak.

And so just like we're talking about some investments in the future here today as part of this case, commissions look at and analyze the impacts on the competitive market and what the utilities are trying to achieve, and there's a variety of approaches to that.

Q Does ChargePoint have any concern with Georgia Power installing DC Fast Chargers at its Community Charging sites, as opposed to limiting them to Level 2 chargers?

A It is not our recommendation to limit it to Level 2 charging. DC Fast Charging is critical to move people along highways, and if that is the solution that is necessary, I would think that's the solution that should be employed.

Q Regarding the Charge It tariff specifically, it seems that ChargePoint supports the rate as designed, meaning that there's a demand component built into the rate that adjusted for time, but your recommendation is the availability; is that a fair statement?

A That's correct. Our recommendation is that -- my understanding of what is proposed is that this rate would

just be for new installations. And we think to make sure that there's a level playing field, it should apply to customers who qualify who have installed previously as well.

Q Okay. But is it your understanding that the company's position as proposed, Charge It would help incentivize new installations?

A Yeah. I think that's a great goal to incentivize new installations. I do think that, you know, we have to weigh that with what's fair. And I think it is completely fair that if a company allocated their own capital just a month ago or two months ago, they should be able to take advantage of that same rate.

MR. HEWITSON: Thank you, Mr. Wilson. That's all I have for you.

MR. WILSON: Thank you.

MR. HEWITSON: Appreciate it.

MADAM CHAIR PRIDEMORE: ChargePoint, redirect?

MR. DUNBAR: We do not have redirect at this time.

MADAM CHAIR PRIDEMORE: You don't have redirect?

MR. DUNBAR: No, ma'am.

MADAM CHAIR PRIDEMORE: All right. Do you have anything to put into evidence?

MR. DUNBAR: We would just want to make sure

that our exhibits get in as ChargePoint Exhibit 1 and ChargePoint Exhibit 2.

MADAM CHAIR PRIDEMORE: So moved. So marked.

(The documents referred to were admitted into evidence as ChargePoint Exhibits 1.1 and 1.2.)

MADAM CHAIR PRIDEMORE: Thank you, Mr. Wilson. You're excused.

MR. WILSON: Thank you.

MADAM CHAIR PRIDEMORE: Next panel.

Commercial Group, Mr. Jenkins?

MR. JENKINS: Thank you.

Commercial Group calls Steve Chriss to the mic.

MADAM CHAIR PRIDEMORE: Hi, Mr. Chriss.

MR. JENKINS: Thank you for raising your hand.

Whereupon,

STEVE W. CHRISS,

having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. JENKINS:

Q Did you cause to be prefiled in this proceeding 17 pages of direct testimony along with Appendix A, Witness Experience?

A Yes.

Q Do you have any corrections?

A No.

**Q If I were to ask you the same questions today, would your answers be the same?**

**A Yes.**

**Q Do you have any corrections to the eight exhibits that were prefiled, labeled CG Exhibits SWC 1 through 8?**

**A No.**

**MR. JENKINS: Madam Chair, I ask that those exhibits be marked as Commercial Group Exhibits 1 through 8?**

**MADAM CHAIR PRIDEMORE: So marked.**

**(The documents referred to were marked for identification as Commercial Group Exhibits SWC 1 through 8.)**

**(Whereupon, the prefiled direct testimony of Steve W. Chriss follows:)**

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

**IN RE:**
**GEORGIA POWER'S 2022 RATE CASE ) DOCKET NO. 44280**

# DIRECT TESTIMONY AND EXHIBITS OF

# STEVE W. CHRISS

# ON BEHALF OF

# THE COMMERCIAL GROUP

**OCTOBER 20, 2022**

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**Ex. CG-___ (SWC-2):** Revenue Requirement Impact of GPC Proposed ROE vs. Currently Approved ROE, 2024

**Ex. CG-___ (SWC-3):** Revenue Requirement Impact of GPC Proposed ROE vs. Currently Approved ROE, 2025

**Ex. CG-___ (SWC-4):** Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2019 to Present

**Ex. CG-___ (SWC-5):** Revenue Requirement Impact of GPC Proposed ROE vs. National Average of Approved ROEs for Vertically Integrated Utilities, 2023

**Ex. CG-___ (SWC-6):** Revenue Requirement Impact of GPC Proposed ROE vs. National Average of Approved ROEs for Vertically Integrated Utilities, 2024

**Ex. CG-___ (SWC-7):** Revenue Requirement Impact of GPC Proposed ROE vs. National Average of Approved ROEs for Vertically Integrated Utilities, 2025

**Ex. CG-___ (SWC-8):** Revenue Requirement Impact of GPC Proposed ROE vs. National Average of Approved ROEs for Vertically Integrated Utilities, 2023

## Introduction

**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.**

A. My name is Steve W. Chriss. My business address is 2608 SE J Street, Bentonville, AR 72716-0550. I am employed by Walmart Inc. as Director, Energy Services.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?**

A. I am testifying on behalf of the Commercial Group. The Commercial Group is an ad hoc association of large customers of Georgia Power Company ("GPC" or "the Company").

**Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.**

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings. I was promoted to Senior Manager, Energy Regulatory Analysis, in June 2011. I was promoted to my current position in October, 2016, and the position was re-titled in October, 2018. My Witness Qualifications Statement is included herein as Appendix A hereto.

**Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION ("COMMISSION")?**

A. Yes. I testified in Docket Nos. 31958, 36989, 40161, 42310, 42516, 44160, and 44161.

**Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?**

A. Yes. As provided in Appendix A, I have submitted testimony in over 240 proceedings before 41 other utility regulatory commissions. I have also submitted testimony before legislative committees in Kansas, Missouri, North Carolina, and South Carolina. My testimony has addressed topics including, but not limited to, cost of service and rate design, return on equity, revenue requirements, ratemaking policy, large customer renewable programs, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

**Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?**

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

## Purpose of Testimony and Summary of Recommendations

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to respond to GPC's rate case filing and to provide recommendations to assist the Commission in its thorough and careful consideration of the customer impact of the Company's proposed rate increase.

**Q. IN SETTING THE REVENUE REQUIREMENT, RETURN ON EQUITY ("ROE"), ALLOCATION, AND RATE DESIGN CHANGES FOR THE COMPANY, SHOULD THE COMMISSION CONSIDER THE IMPACT OF THE PROPOSED RATE INCREASE ON BUSINESS CUSTOMERS?**

A. Yes. Electricity is a significant operating cost for retailers such as those in the Commercial Group. When electric rates increase, the increased cost to retailers can put pressure on consumer prices and on the other expenses required by a business to operate. The Commission should thoroughly and carefully consider the impact on customers when examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in the Company's rates is the minimum necessary to provide safe, adequate, and reliable service, while also providing GPC the opportunity to recover its reasonable and prudent costs, earn a reasonable return on its investment, and meet large commercial customer expectations for customer service.

**Q. WHAT IMPACTS DO YOUR COMPANIES HAVE ON THE GEORGIA ECONOMY?**

A. The companies in the Commercial Group have a significant positive impact on the Georgia economy. For example, as of August, 2022, Walmart alone had 227 facilities and approximately 66,000 associates in Georgia, spent $25.8 billion with Georgia-based suppliers, and supported over 277,000 supplier jobs in the state.[1]

[1] https://corporate.walmart.com/our-story/locations/united-states/georgia

**Q. PLEASE SUMMARIZE THE COMMERCIAL GROUP'S RECOMMENDATIONS TO THE COMMISSION.**

A. The Commercial Group's recommendations to the Commission are as follows:

1) While optimally the Company's shareholders should bear the risk of regulatory lag contained in the traditional regulatory process, the Commercial Group recognizes that Alternate Rate Plans ("ARPs") are typically used by the Commission for ratemaking purposes. As such, for the purposes of this docket, the Commercial Group does not generally oppose the Commission's use of an ARP for ratemaking purposes, subject to the following recommendation and comments to the Commission regarding the proposal:

   a. At the Company's proposed ROE and revenue requirement, the Commercial Group does not oppose the Company's proposed ROE band of 9.5 percent to 12 percent, which is a range of 150 basis points below the proposed ROE of 11 percent to 100 basis points above the proposed ROE. If the Commission approves a lower ROE in this docket than that proposed by the Company, the Commission should contemporaneously reduce the low and high band boundaries and maintain the basis point spread of the band around the approved ROE.

   b. The Commission should consider the near-term financial impacts to customers of the Company's levelization proposal as it determines whether to levelize, and if so, how much revenue requirement should be levelized.

   c. In its consideration on the appropriate ROE for the Company, the Commission should recognize that the proposed ARP shifts risk from the Company's

shareholders to customers by removing the effects of regulatory lag from 2023 through 2025.

2) The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE, especially when viewed in light of:

   a. The customer impact of the proposed revenue requirement increases;

   b. The reduction in risk from regulatory lag from the Company's proposed ARP; and

   c. Recent rate case ROEs approved by other Commissions nationwide.

3) The Commission should approve a revenue allocation in this docket that moves classes toward parity.

**Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE THE COMMERCIAL GROUP'S SUPPORT?**

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

**Revenue Requirement and Cost of Capital**

**Q. WHAT ARE GEORGIA POWER'S PROPOSED REVENUE DEFICIENCIES FOR 2023 THROUGH 2025?**

A. As shown in Table 1, Georgia Power's proposed total company revenue deficiencies start at approximately $599 million in 2023 and increase to approximately $1.3 billion in 2025.

**Table 1. Georgia Power's Proposed Non-Levelized Revenue Deficiencies, 2023-2025 ($000,000)**

| | Base Rate Tariff Revenues | CCR ARO | ECCR | MFF | DSM | Total |
|---|---|---|---|---|---|---|
| 2023 | $461 | $64 | $29 | $14 | $30 | $599 |
| 2024 | $718 | $143 | ($12) | $22 | $56 | $927 |
| 2025 | $1,080 | $189 | ($25) | $31 | $54 | $1,330 |

Source: Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, page 21.

**Q. DOES THE COMPANY PROPOSE TO ADDRESS THE EXPECTED REVENUE DEFICIENCIES FOR 2023 THROUGH 2025 BY FILING ANNUAL RATE CASES?**

A. No. Instead, the Company proposes an ARP. My understanding is that, generally, the proposed ARP consists of the following:

1) Continuation of base rate tariffs through December 31, 2025, with adjustments proposed based on currently projected revenues, expenses, rate base, and cost of capital for a test year ending July 31, 2023, modified for a levelization adjustment.
2) Continuation of the Environmental Compliance Cost Recovery tariff with revisions effective January 1, 2023, and further adjustments to be made on January 1, 2024, and January 1, 2025.
3) Adjustment of the Demand Side Management tariff, with additional annual adjustments in 2024 and 2025.
4) Adjustment of the Municipal Franchise Fee tariff, with additional annual adjustments in 2024 and 2025.
5) Continuation of the previous ARP's ROE range of 9.5 percent to 12 percent.

6) Continuation of the Annual Surveillance report from the previous ARP, with 80 percent of earnings above the ROE band returned to customers and 20 percent retained by the Company.

7) Continuation of the option from the previous ARP to file for Interim Cost Recovery in the event that earnings fall below the ROE band. *See* Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, page 22, line 4 to page 23, line 10.

**Q. HOW HAS GEORGIA POWER PROPOSED TO STRUCTURE ITS PROPOSED REVENUE REQUIREMENTS FOR 2023 THROUGH 2025 THROUGH THE ARP?**

A. As shown in Table 2, Georgia Power has proposed to levelize their proposed revenue requirement changes for 2023 through 2025.

**Table 2. Georgia Power's Proposed Levelized Revenue Deficiencies, 2023-2025 ($000,000)**

| | Base Rate Tariff Revenues | CCR ARO | ECCR | MFF | DSM | Total |
|---|---|---|---|---|---|---|
| 2023 | $739 | $64 | ($1) | $20 | $30 | $852 |
| 2024 | $739 | $142 | ($1) | $22 | $57 | $959 |
| 2025 | $739 | $189 | ($1) | $23 | $55 | $1,005 |

Source: Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, page 9 and APA-SPA-ADH-MBR-1, Schedule 2, Traditional Base.

The Company's proposed levelization will result in an over-collection of revenues of approximately $253 million for 2023 and $32 million for 2024 and an under-collection of revenues of approximately $325 million in 2025 when compared to the proposed deficiencies shown in Table 1. On a net present value basis both options are essentially

equal, using the Company's proposed weighted average cost of capital as the discount rate.

**Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED ROE?**

A. My understanding is that the Company proposes an ROE of 11 percent. *See* Direct Testimony of James M. Coyne, page 3, line 19.

**Q. DOES THE COMMERCIAL GROUP HAVE ANY COMMENTS ON THE COMPANY'S PROPOSED ARP?**

A. Yes. While optimally the Company's shareholders should bear the risk of regulatory lag contained in the traditional regulatory process, the Commercial Group recognizes that ARPs are typically used by the Commission for ratemaking purposes. As such, for the purposes of this docket, the Commercial Group does not generally oppose the Commission's use of an ARP for ratemaking purposes, subject to the following recommendation and comments to the Commission regarding the proposal.

**Q. WHAT IS THE COMMERCIAL GROUP'S RECOMMENDATION?**

A. At the Company's proposed ROE and revenue requirement, the Commercial Group does not oppose the Company's proposed ROE band of 9.5 percent to 12 percent, which is a range of 150 basis points below the proposed ROE of 11 percent to 100 basis points above the proposed ROE. If the Commission approves a lower ROE in this docket than that proposed by the Company, the Commission should contemporaneously reduce the low and high band boundaries and maintain the basis point spread of the band around the approved ROE. As an example, if the Commission approves an ROE of 10 percent,

the band would then be from 8.5 percent to 11 percent.

**Q. DOES THE COMMERCIAL GROUP HAVE ANY ADDITIONAL COMMENTS REGARDING THE PROPOSED ARP?**

A. Yes. The Commercial Group is concerned about the near-term impacts of the Company's levelization proposal on Georgia Power's customers, particularly in light of customer bill impacts from recent increases in fuel rates, and for RTP customers, marginal prices. While the overall impact through 2025, on a net present value basis, is the same as the non-levelized structure, as noted above, the Commission should consider these impacts as it determines whether to levelize, and if so, how much revenue requirement should be levelized.

Additionally, in its consideration on the appropriate ROE for the Company, the Commission should recognize that the proposed ARP shifts risk from the Company's shareholders to customers by removing the effects of regulatory lag from 2023 through 2025.

**Q. WHAT IS THE COMPANY'S PROPOSED ROE IN THIS DOCKET?**

A. GPC is proposing an ROE of 11 percent, based on an estimated range of 8.99 percent to 13.55 percent, with an additional 50 basis point financial risk adjustment. *See* Direct Testimony of James M. Coyne, page 9, line 15 to line 19. The requested ROE at the Company's proposed capital structure results in a proposed overall rate of return of 7.71 percent for 2023, 7.74 percent for 2024, and 7.77 percent for 2025. *See* APA/SPA/ADH/MBR-1, Schedule 1.

**Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S REPORTED ROE FOR THE THIRTEEN MONTHS ENDING DECEMBER 31, 2021?**

A. My understanding is that the Company's reported ROE for the thirteen months ending December 31, 2021, is 12.09 percent. *See* M.F.R. Item – General 1(a), page 1. As I will discuss below, this is well above the ROEs *awarded* by commissions nationwide during the same period.

**Q. IS THE COMMERCIAL GROUP CONCERNED ABOUT THE REASONABLENESS OF THE COMPANY'S PROPOSED ROE?**

A. Yes, especially when viewed in light of:

1) The customer impact of the proposed revenue requirement increases;
2) The reduction in risk from regulatory lag from the Company's proposed ARP; and
3) Recent rate case ROEs approved by other commissions nationwide.

***Customer Impact***

**Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S CURRENTLY APPROVED ROE?**

A. My understanding is that the Company's currently approved ROE is 10.5 percent. *See* Order Adopting Settlement Agreement as Modified, Docket No. 42516 (2019), page 5.

**Q. HAVE YOU CALCULATED AN ESTIMATE OF THE IMPACT OF THE RETURN ON RATE BASE FROM THE COMPANY'S PROPOSED INCREASE IN ROE FROM 10.5 PERCENT TO 11 PERCENT FOR THE COMPANY'S PROPOSED NON-LEVELIZED DEFICIENCIES?**

A. Yes. Using the Company's proposed rate base, cost of debt, and capital structure for each test year, the impact of the proposed changes for 2023 from the increase in ROE is approximately $93.7 million, or 16.1 percent of the proposed non-levelized revenue deficiency. *See* Ex. CG-___ (SWC-1). For 2024, the impact is approximately $100.8 million, or 11.1 percent of the cumulative proposed revenue increases for 2023 and 2024. *See* Ex. CG-___ (SWC-2). Finally, for 2025, the impact is approximately $106.7 million, or 8.2 percent of the cumulative proposed revenue increase for 2023, 2024, and 2025. *See* Ex. CG-___ (SWC-3).

***National Utility Industry ROE and Weighted Equity Cost Trends***

**Q. IS THE COMPANY'S TOTAL PROPOSED ROE SIGNIFICANTLY HIGHER THAN THE ROES APPROVED BY OTHER UTILITY REGULATORY COMMISSIONS IN 2019, 2020, 2021, AND SO FAR IN 2022?**

A. Yes. According to data from S&P Global Market Intelligence ("S&P Global"), a

financial news and reporting company, the average of the 121 reported electric utility rate case ROEs authorized by commissions to investor-owned utilities in 2019, 2020, 2021 and so far in 2022, is 9.45 percent. The range of reported authorized electric ROEs for the period is 7.36 percent to 10.60 percent, and the median authorized electric ROE is 9.50 percent. *See* Ex. CG-___ (SWC-4). As such, the Company's total proposed ROE of 11 percent is counter to broader electric industry trends.

**Q. SEVERAL OF THE REPORTED AUTHORIZED ROES ARE FOR DISTRIBUTION-ONLY UTILITIES OR FOR ONLY A UTILITY'S DISTRIBUTION SERVICE RATES. WHAT IS THE AVERAGE AUTHORIZED ROE IN THE REPORTED GROUP FOR VERTICALLY INTEGRATED UTILITIES?**

A. In the group reported by S&P Global, the average ROE for vertically integrated utilities authorized over the same time period is 9.58 percent, with the overall average generally falling from year to year. The average ROE authorized for vertically integrated utilities in 2019 was 9.73 percent, in 2020 it was 9.55 percent, in 2021 it was 9.55 percent, and so far in 2022 it is 9.35 percent. *Id.* As such, the Company's proposed total ROE of 11 percent is counter to broader electric industry trends and, in fact, as shown in Figure 1, if approved, would be the highest ROEs approved since 2019.

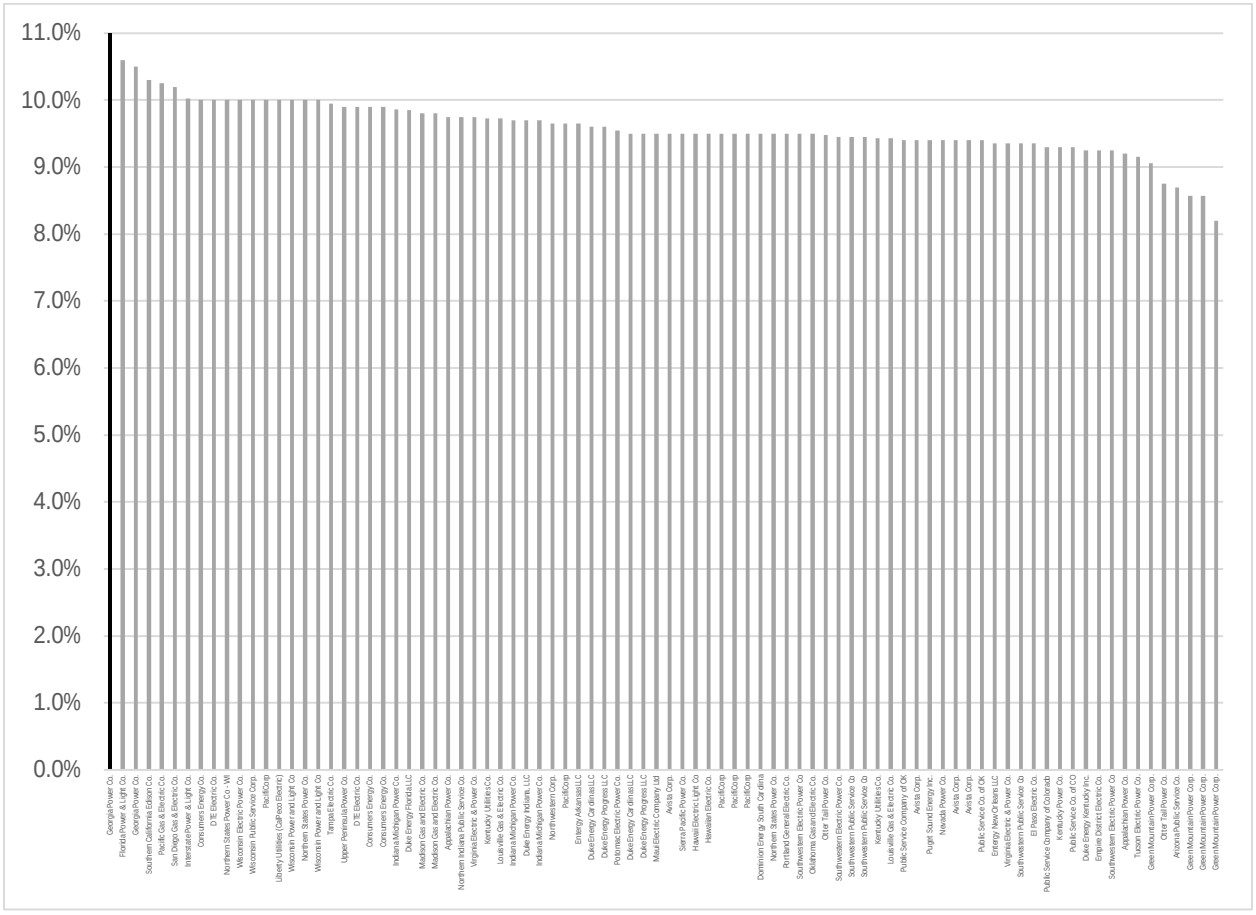


**Figure 1. GPC Proposed Total ROE of 11 Percent Versus Approved ROEs, Vertically Integrated Utilities, 2019 to Present.**

**Q. WHAT IS THE DIFFERENCE IN REVENUE REQUIREMENT BETWEEN THE COMPANY'S PROPOSED 11 PERCENT ROE AND 9.58 PERCENT, WHICH IS THE AVERAGE AUTHORIZED ROE FOR VERTICALLY INTEGRATED UTILITIES FROM 2016 TO PRESENT?**

A. For 2023, the difference in revenue requirement for this difference in ROE is approximately $265.8 million, or 45.5 percent of the Company's proposed non-levelized revenue deficiency. *See* Ex. CG-___ (SWC-5). For 2024, the impact is approximately $285.8 million, or 31.6 percent of the cumulative proposed revenue increases for 2023 and 2024. *See* Ex. CG-___ (SWC-6). Finally, for 2025, the impact

is approximately $302.9 million, or 23.3 percent of the cumulative proposed revenue increase for 2023, 2024, and 2025. *See* Ex. CG-___ (SWC-7).

**Q. IS THE COMMERCIAL GROUP RECOMMENDING THAT THE COMMISSION BE BOUND BY ROES AUTHORIZED BY OTHER STATE REGULATORY AGENCIES?**

A. No. Decisions of other state regulatory commissions are not binding on this Commission. Each commission considers the specific circumstances in each case in its determination of the proper ROE and capital structure. The Commercial Group is providing this information on industry trends on ROE from its perspective as customers with operations that are nationwide as it believes that recently authorized ROEs in other jurisdictions provide a general gauge of reasonableness for the various cost of equity analyses presented in this case. Moreover, the Commercial Group believes that it is appropriate for the Commission to consider how any ROE authorized in this case impacts existing and prospective customers relative to other jurisdictions.

***Conclusion***

**Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE COMPANY'S PROPOSED ROE?**

A. The Commission should closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE, especially when viewed in light of:

1) The customer impact of the proposed revenue requirement increases;
2) The reduction in risk from regulatory lag from the Company's proposed ARP;

and

3) Recent rate case ROEs approved by other commissions nationwide.

**Cost of Service and Revenue Allocation**

**Q. GENERALLY, WHAT IS THE COMMERCIAL GROUP'S POSITION ON SETTING RATES BASED ON THE UTILITY'S COST OF SERVICE?**

A. The Commercial Group advocates that rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, send proper price signals, and minimize price distortions.

**Q. DOES THE COMMERCIAL GROUP TAKE A POSITION ON THE COMPANY'S PROPOSED COST OF SERVICE MODEL AT THIS TIME?**

A. No. However, to the extent that alternative cost of service models or modifications to the Company's model are proposed by other parties, the Commercial Group reserves the right to address any such proposals.

**Q. HOW DOES THE COMPANY REPRESENT WHETHER RATES FOR A CUSTOMER CLASS ACCURATELY REFLECT THE UNDERLYING COST CAUSATION?**

A. The Company reflects this relationship in their cost of service results through the use of class-specific and rate schedule-specific rates of return. These rates of return can be converted into a relative rate of return ("RROR"), which is an indexed measure of the relationship of the rate of return for an individual customer class to the total system rate of return. An RROR greater than 1.0 means that the customer class is paying rates in excess of costs incurred to serve that class, and an RROR less than 1.0 means that the

customer class is paying rates less than the costs incurred to serve that class. As such, those rate classes with an RROR greater than 1.0 are subsidizing the classes with an RROR less than 1.0. A class with an RROR equal to 1.0 is said to be at parity.

**Q. HAVE YOU CALCULATED RATE GROUP RRORs BASED ON THE COMPANY'S COST OF SERVICE RESULTS?**

A. Yes, as shown in Table 3 below:

**Table 3. Rate Group Rates of Return and RRORs, Test Year Ending July 31, 2023, GPC Proposed Cost of Service Study Results.**

| Rate Group | Rate of Return (%) | RROR |
|---|---|---|
| Domestic | 5.21 | 0.83 |
| Small Business | 7.28 | 1.15 |
| Medium Business | 9.35 | 1.48 |
| Large Business | 8.66 | 1.37 |
| Agricultural | 6.31 | 1.00 |
| Government | 3.71 | 0.59 |
| Lighting | 7.96 | 1.26 |
| Marginal | 6.33 | 1.00 |
| *RTP-DA* | *8.25* | *1.31* |
| *RTP-HA* | *6.56* | *1.04* |
| **Total Retail Service** | **6.31** | **1.00** |

Source: LPE-1, page 3 to page 4, LPE-2, page 7, and Exhibit SWC-8.

While the Marginal rate group as a whole provides a rate of return, and RROR, essentially equal to total retail service, it should be noted that the two largest classes within that rate group, RTP-DA and RTP-HA, provide rates of return and RORR significantly above that of total retail service.

**Q. WHY IS THIS IMPORTANT?**

A. This is important because examining the cost of service study results at the rate group level may mask the movements in the allocation of revenues that are needed to bring the underlying schedules closer to their respective costs of service.

**Q. DOES THE COMPANY PROPOSE A REVENUE ALLOCATION THAT MOVES RATE GROUPS AND THEIR UNDERLYING SCHEDULES CLOSER TO COST OF SERVICE?**

A. No. The Company proposes to allocate the proposed base rate increase on an equal percentage basis and generally adjust each rate schedule such that the same percent adjustment is applied to each charge within the schedules. *See* Direct Testimony of Larry T. Legg, page 5, line 6 to line 9. The proposed revenue allocation will largely leave the existing cross-subsidies in place.

**Q. SHOULD THE COMMISSION ADOPT A REVENUE ALLOCATION IN THIS DOCKET THAT MOVES CLASSES CLOSER TO PARITY?**

A. Yes. My understanding is that the Commission has adopted movement towards parity in the several recent Georgia Power rate case. In Docket No. 42516, the 2019 rate case, the Commission found the stipulated allocation, in which Medium Business and Large Business received an increase of 85 percent of the overall base rate increase, with the resulting deficiency spread to other rate groups excluding Small Business, Lighting, and Marginal rate groups, to be just and reasonable. Order Adopting Settlement Agreement as Modified, Docket 42516 (2020), Findings of Fact ⁋16. Additionally, the Commission has previously found in the 2010 and 2013 rate cases that further movement towards parity would also be appropriate in those dockets. Order Adopting Settlement Agreement, Docket 36989 (2013), Findings of Fact ¶7; Final Order adopting settlement agreement, Docket 31958 (2010), *see* Settlement Agreement ¶15.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

# Appendix A

**Steve W. Chriss**
**Walmart Inc.**
**Business Address: 2001 SE 10th Street, Bentonville, AR, 72716-0550**

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**EXPERIENCE**

July 2007 – Present
**Walmart Inc.**, Bentonville, AR
**Director, Energy Services** (October 2018 – Present)
**Director, Energy and Strategy Analysis** (October 2016 – October 2018)
**Senior Manager, Energy Regulatory Analysis** (June 2011 – October 2016)
**Manager, State Rate Proceedings** (July 2007 – June 2011)

June 2003 – July 2007
**Public Utility Commission of Oregon**, Salem, OR
**Senior Utility Analyst** (February 2006 – July 2007)
**Economist** (June 2003 – February 2006)

January 2003 - May 2003
**North Harris College**, Houston, TX
**Adjunct Instructor, Microeconomics**

June 2001 - March 2003
**Econ One Research, Inc.**, Houston, TX
**Senior Analyst** (October 2002 – March 2003)
**Analyst** (June 2001 – October 2002)

**EDUCATION**

| | | |
|---|---|---|
| 2001 | **Louisiana State University** | M.S., Agricultural Economics |
| 1997-1998 | **University of Florida** | Graduate Coursework, Agricultural Education and Communication |
| 1997 | **Texas A&M University** | B.S., Agricultural Development<br>B.S., Horticulture |

**PRESENT MEMBERSHIPS**

Arkansas Advanced Energy Foundation, Board
Clean Energy Buyers Alliance, Advisory Board
Edison Electric Institute National Key Accounts Program, Customer Advisory Group
Florida Advisory Council for Climate and Energy
South Carolina Electricity Market Reforms Measures Study Committee

**PAST MEMBERSHIPS**

Arizona Independent Scheduling Administrators Association, Board, 2020-2022
Southwest Power Pool, Corporate Governance Committee, 2019

**TESTIMONY BEFORE REGULATORY COMMISSIONS**

*2022*

Minnesota Docket No. E-002/GR-21-630: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

Colorado Proceeding No. 22AL-0130E: In the Matter of Advice No. 1881-Electric of Public Service Company of a Resiliency Service Program Tariff in its Colorado PUC No. 8-Electric Tariff Effective April 24, 2022.

Texas Docket No. 53601: Application of Oncor Electric Delivery Company for Authority to Change Rates.

Washington Docket No. UE-220066: Puget Sound Energy 2022 General Rate Case.

Washington Docket No. UG-220067: Puget Sound Energy 2022 Natural Gas General Rate Case.

Idaho Case No. IPC-E-21-40: In the Matter of Idaho Power Company's Application to Expand Optional Customer Clean Energy Offerings Through the Clean Energy Your Way Program.

Georgia Docket No. 44160: Georgia Power's 2022 Integrated Resource Plan.

Georgia Docket No. 44161: Application for the Certification, Decertification, and Amended Demand Side Management Plan.

*2021*

Missouri Case No. ER-2021-0312: In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area.

Indiana Cause No. 45576: Petition of Indiana Michigan Power Company, an Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service through a Phase In Rate Adjustment; and for Approval of Related Relief Including: (1) Revised Depreciation Rates; (2) Accounting Relief; (3) Inclusion of Capital Investment; (4) Rate Adjustment Mechanism Proposals; (5) Customer Programs; (6) Waiver to Declination of Jurisdiction with Respect to Certain Rules; and (7) New Schedules of Rates, Rules, and Regulations.

Oregon Docket No. UE 394: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

Missouri File No. ER-2021-0240: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service.

Florida Docket No. 20210015-EI: In re: Petition for Rate Increase by Florida Power & Light Company.

California Docket No. R-20-08-020: Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering.

New Mexico Case No. 20-00238-UT: In the Matter of Southwestern Public Service Company's Application For: (1) Revision of its Retail Rates Under Advice Notice No. 292; (2) Authorization and Approval to Abandon its Plant X Unit 3 Generating Station; and (3) Other Associated Relief.

North Dakota Case No. PU-20-441: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota.

New Mexico Case No. 20-00222-UT: In the Matter of the Joint Application of Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., Public Service Company of New Mexico and PNM Resources, Inc. For Approval of the Merger of NM Green Holdings, Inc. with PNM Resources, Inc.; Approval of a General Diversification Plan; and All Other Authorizations and Approvals Requires to Consummate and Implement this Transaction.

*2020*

Arizona Docket No. E-01345A-19-0236: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and to Approve Rate Schedules Designed to Develop Such Return.

Florida Docket No. 20200176-EI: In re: Petition by Duke Energy Florida, LLC for a Limited Proceeding to Approve Clean Energy Connection Program and Tariff and Stipulation.

Florida Docket No. 20200092-EI: In re: Storm Protection Plan Cost Recovery Clause.

Nevada Docket No. 20-05003: Application of Nevada Power Company d/b/a NV Energy Filed Under Advice Letter No. 504 to Establish Customer Price Stability Tariff Schedule No. CPST (the "Program") to Assist Certain Qualifying

Customers During the COVID-19 Pandemic and Economic Downturn, and to Address Certain Customer Requests for Price Stability and Potential Cost Savings in Meeting Customer Specific Business Needs and Sustainability Objectives.

Nevada Docket No. 20-05004: Application of Sierra Pacific Power Company d/b/a NV Energy Filed Under Advice Letter No. 629-E to Establish Customer Price Stability Tariff Schedule No. CPST (the "Program") to Assist Certain Qualifying Customers During the COVID-19 Pandemic and Economic Downturn, and to Address Certain Customer Requests for Price Stability and Potential Cost Savings in Meeting Customer Specific Business Needs and Sustainability Objectives.

Utah Docket No. 20-035-04: Application of Rocky Mountain Power for the Authority to Increase its Retail Electric Utility Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Wyoming Docket No. 20000-578-ER-20: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4.

Virginia Case No. PUR-2020-00015: Application of Appalachian Power Company for a 2020 Triennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services Pursuant to §56-585.1 A of the Code of Virginia.

Oregon Docket No. UE 374: In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision.

Florida Docket No. 20200067-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.

Florida Docket No. 20200069-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.

Florida Docket No. 20200070-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Gulf Power Company.

Florida Docket No. 20200071-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.

North Carolina Docket No. E-2, Sub 1219: Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.
Missouri Case No. ER-2019-0374: In the Matter of the Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area.

North Carolina Docket No. E-7, Sub 1214: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Texas Docket No. 49831: Application of Southwestern Public Service Company for Authority to Change Rates.

*2019*
Missouri Case No. ER-2019-0335: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease its Revenues for Electric Service.

Michigan Case No. U-20561: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Indiana Cause No. 45253: Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code §§ 8-1-2-42.7 and 8-1-2-61, For (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Step-In of New Rates and Charges Using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code § 8-1-8.4-1; (4) Approval of

Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customer Classes.

Arizona Docket No. E-01933A-19-0228: In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to its Operations Throughout the State of Arizona and for Related Approvals.

Georgia Docket No. 42516: In Re: Georgia Power's 2019 Rate Case.

Colorado Proceeding No. 19AL-0268E: Re: In the Matter of Advice No. 1797-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8-Electric Tariff to Implement Rate Changes Effective on Thirty Days' Notice.

New York Case No. 19-E-0378: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Case No. 19-E-0380: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

Maryland Case No. 9610: In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates.

Nevada Docket No. 19-06002: In the Matter of the Application by Sierra Pacific Power Company, D/B/A NV Energy, Filed Pursuant to NRS 704.110(3) and NRS 704.110(4), Addressing its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers.

Florida Docket No. 20190061-EI: In Re: Petition of Florida Power & Light Company for Approval of FPL SolarTogether Program and Tariff.

Wisconsin Docket No. 6690-UR-126: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates – Test Year 2020.

Wisconsin Docket No. 5-UR-109: Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates – Test Year 2020.

New Mexico Case No. 19-00158-UT: In the Matter of the Application of Public Service Company of New Mexico for Approval of PNM Solar Direct Voluntary Renewable Energy Program, Power Purchase Agreement, and Advice Notice Nos. 560 and 561.

Indiana Cause No. 45235: Petition of Indiana Michigan Power Company, and Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service through a Phase In Rate Adjustment; and for Approval of Related Relief Including: (1) Revised Depreciation Rates; (2) Accounting Relief; (3) Inclusion in Rate Base of Qualified Pollution Control Property and Clean Energy Project; (4) Enhancements to the Dry Sorbent Injection System; (5) Advanced Metering Infrastructure; (6) Rate Adjustment Mechanism Proposals; and (7) New Schedules of Rates, Rules and Regulations.

Iowa Docket No. RPU-2019-0001: In Re: Interstate Power and Light Company.

Texas Docket No. 49494: Application of AEP Texas Inc. for Authority to Change Rates.

Arkansas Docket No. 19-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Virginia Case No. PUR-2019-00050: Application of Virginia Electric and Power Company for Determination of the Fair Rate of Return on Common Equity Pursuant to § 56-585.1:1 of the Code of Virginia.

Indiana Docket No. 45159: Petition of Northern Indiana Public Service Company LLC Pursuant to Indiana Code §§ 8-1-2-42.7, 8-1-2-61 and Indiana Code §§ 1-2.5-6 for (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase In of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief; and (5) Approval of a New Service Structure for Industrial Rates.

Texas Docket No. 49421: Application of Centerpoint Energy Houston Electric, LLC for Authority to Change Rates.

Nevada Docket No. 18-11015: Re: Application of Nevada Power Company d/b/a NV Energy, Filed Under Advice No. 491, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Nevada Docket No. 18-11016: Re: Application of Sierra Pacific Power Company d/b/a NV Energy, Filed Under Advice No. 614-E, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Georgia Docket No. 42310: In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity From Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant Mcintosh Unit 1, Plant Langdale Units 5-6, Plant Riverview Units 1-2, and Plant Estatoah Unit 1.

Wyoming Docket Nos. 20003-177-ET-18: In the Matter of the Application of Cheyenne Light, Fuel and Power Company D/B/A Black Hills Energy For Approval to Implement a Renewable Ready Service Tariff.

South Carolina Docket No. 2018-318-E: In the Matter of the Application of Duke Energy Progress, LLC For Adjustments in Electric Rate Schedules and Tariffs.

Montana Docket No. D2018.2.12: Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.

Louisiana Docket No. U-35019: In Re: Application of Entergy Louisiana, LLC for Authorization to Make Available Experimental Renewable Option and Rate Schedule ERO.

Arkansas Docket No. 18-037-TF: In the Matter of the Petition of Entergy Arkansas, Inc. For Its Solar Energy Purchase Option.

*2018*

South Carolina Docket No. 2017-370-E: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for Review and Approval of a Proposed Business Combination Between SCANA Corporation and Dominion Energy, Inc., as may be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plans.

Kansas Docket No. 18-KCPE-480-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Virginia Case No. PUR-2017-00173: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Virginia Case No. PUR-2017-00174: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Oregon Docket No. UM 1953: In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100% Renewable Energy Rider Pursuant to § 56-577.A.5 of the Code of Virginia.

Missouri Docket No. ER-2018-0145: In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Missouri Docket No. ER-2018-0146: In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Kansas Docket No. 18-WSEE-328-RTS: In the Matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Oregon Docket No. UE 335: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

North Dakota Case No. PU-17-398: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100 Percent Renewable Energy Rider Pursuant to § 56-577 A 5 of the Code of Virginia.

Missouri Case No. ET-2018-0063: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff.

New Mexico Case No. 17-00255-UT: In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Rates Under Advice Notice No. 272.

Virginia Case No. PUR-2017-00157: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs for Residential and Non-Residential Customers.

Kansas Docket No. 18-KCPE-095-MER: In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.

North Carolina Docket No. E-7, Sub 1146: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Louisiana Docket No. U-34619: In Re: Application for Expedited Certification and Approval of the Acquisition of Certain Renewable Resources and the Construction of a Generation Tie Pursuant to the 1983 and/or/1994 General Orders.

Missouri Case No. EM-2018-0012: In the Matter of the Application of Great Plains Energy Incorporated for Approval of its Merger with Westar Energy, Inc.

*2017*

Arkansas Docket No. 17-038-U: In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line.

Texas Docket No. 47461: Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Wind Catcher Energy Connection Project.

Oklahoma Cause No. PUD 201700267: Application of Public Service Company of Oklahoma for Approval of the Cost Recovery of the Wind Catcher Energy Connection Project; A Determination There is Need for the Project; Approval for Future Inclusion in Base Rates Cost Recovery of Prudent Costs Incurred by PSO for the Project;

Approval of a Temporary Cost Recovery Rider; Approval of Certain Accounting Procedures Regarding Federal Production Tax Credits; Waiver of OAC 165:35-38-5(E); And Such Other Relief the Commission Deems PSO is Entitled.

Nevada Docket No. 17-06003: In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, Filed Pursuant to NRS 704.110(3) and (4), Addressing Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers.

North Carolina Docket No. E-2, Sub 1142: In the Matter of the Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Oklahoma Cause No. PUD 201700151: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Kentucky Case No. 2017-00179: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2017 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; (4) an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting All Other Requested Relief.

New York Case No. 17-E-0238: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation for Electric and Gas Service.

Virginia Case No. PUR-2017-00060: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs Pursuant to §§ 56-577 A 5 and 56-234 of the Code of Virginia.

New Jersey Docket No. ER17030308: In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, for Approval of a Grid Resiliency Initiative and Cost Recovery Related Thereto, and for Other Appropriate Relief.

Texas Docket No. 46831: Application of El Paso Electric Company to Change Rates.

Oregon Docket No. UE 319: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

New Mexico Case No. 16-00276-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice No. 533.

Minnesota Docket No. E015/GR-16-664: In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota.

Ohio Case No. 16-1852-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, In the Form of an Electric Security Plan.

Texas Docket No. 46449: Application of Southwestern Electric Power Company for Authority to Change Rates.

Arkansas Docket No. 16-052-U: In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges, and Tariffs.

Missouri Case No. EA-2016-0358: In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood-Montgomery 345 kV Transmission Line.

Florida Docket No. 160186-Ei: In Re: Petition for Increase in Rates by Gulf Power Company.

*2016*

Missouri Case No. ER-2016-0179: In the Matter of Union Electric Company d/b/a Ameren Missouri Tariffs to Increase its Revenues for Electric Service.

Kansas Docket No. 16-KCPE-593-ACQ: In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar Energy, Inc. by Great Plains Energy Incorporated.

Missouri Case No. EA-2016-0208: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Distributed Solar Program and File Associated Tariff.

Utah Docket No. 16-035-T09: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 34, Renewable Energy Tariff.

Pennsylvania Public Utility Commission Docket No. R-2016-2537359: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537352: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537355: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537349: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Michigan Case No. U-17990: In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Florida Docket No. 160021-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

Minnesota Docket No. E-002/GR-15-816: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota.

Colorado Public Utilities Commission Docket No. 16AL-0048E: Re: In the Matter of Advice Letter No. 1712-Electric Filed by Public Service Company of Colorado to Replace Colorado PUC No.7-Electric Tariff with Colorado PUC No. 8-Electric Tariff.

Colorado Public Utilities Commission Docket No. 16A-0055E: Re: In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program.

Missouri Public Service Commission Case No. ER-2016-0023: In the Matter of the Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company.

Georgia Public Service Commission Docket No. 40161: In Re: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT.

Oklahoma Corporation Commission Cause No. PUD 201500273: In the Matter of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

New Mexico Case No. 15-00261-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 513.

*2015*

Indiana Utility Regulatory Commission Cause No. 44688: Petition of Northern Indiana Public Service Company for Authority to Modify its Rates and Charges for Electric Utility Service and for Approval of: (1) Changes to its Electric Service Tariff Including a New Schedule of Rates and Charges and Changes to the General Rules and Regulations and Certain Riders; (2) Revised Depreciation Accrual Rates; (3) Inclusion in its Basic Rates and Charges of the Costs Associated with Certain Previously Approved Qualified Pollution Control Property, Clean Coal Technology, Clean Energy Projects and Federally Mandated Compliance Projects; and (4) Accounting Relief to Allow NIPSCO to Defer, as a Regulatory Asset or Liability, Certain Costs for Recovery in a Future Proceeding.

Public Utility Commission of Texas Docket No. 44941: Application of El Paso Electric Company to Change Rates.

Arizona Corporation Commission Docket No. E-04204A-15-0142: In the matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realized a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to its Operations Throughout the State of Arizona, and for Related Approvals.

Rhode Island Public Utilities Commission Docket No. 4568: In Re: National Grid's Rate Design Plan.

Oklahoma Corporation Commission Cause No. PUD 201500208: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Public Service Commission of Wisconsin Docket No. 4220-UR-121: Application of Northern States Power Company, A Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-015-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

New York Public Service Commission Case No. 15-E-0283: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0284: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Gas Service.

New York Public Service Commission Case No. 15-E-0285: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0286: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Gas Service.

Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

Public Service Commission of Wisconsin Docket No. 6690-UR-124: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-034-U: In the Matter of an Interim Rate Schedule of Oklahoma Gas and Electric Company Imposing a Surcharge to Recover All Investments and Expenses Incurred Through Compliance with Legislative or Administrative Rules, Regulations, or Requirements Relating to the Public Health, Safety or the Environment Under the Federal Clean Air Act for Certain of its Existing Generation Facilities.

Kansas Corporation Commission Docket No. 15-WSEE-115-RTS: In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in their Charges for Electric Service.

Michigan Public Service Commission Case No. U-17767: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of

Electric Energy, and for Miscellaneous Accounting Authority.

Public Utility Commission of Texas Docket No. 43695: Application of Southwestern Public Service Company for Authority to Change Rates.

Kansas Corporation Commission Docket No. 15-KCPE-116-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Michigan Case No. U-17735: In the Matter of the Application of the Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Kentucky Public Service Commission Case No. 2014-00396: Application of Kentucky Power Company for a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2014 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief.

Kentucky Public Service Commission Case No. 2014-00371: In the Matter of the Application of Kentucky Utilities Company for an Adjustment of its Electric Rates.

Kentucky Public Service Commission Case No. 2014-00372: In the Matter of the Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates.

*2014*

Ohio Public Utilities Commission Case No. 14-1297-EL-SSO: In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

West Virginia Case No. 14-1152-E-42T: Appalachian Power Company and Wheeling Power Company, Both d/b/a American Electric Power, Joint Application for Rate Increases and Changes in Tariff Provisions.

Oklahoma Corporation Commission Cause No. PUD 201400229: In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization Plan.

Missouri Public Service Commission Case No. ER-2014-0258: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Revenues for Electric Service.

Pennsylvania Public Utility Commission Docket No. R-2014-2428742: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428743: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428744: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428745: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Washington Utilities and Transportation Commission Docket No. UE-141368: In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and For Electric Rate Design Purposes.

Washington Utilities and Transportation Commission Docket No. UE-140762: 2014 Pacific Power & Light Company General Rate Case.

West Virginia Public Service Commission Case No. 14-0702-E-42T: Monongahela Power Company and the Potomac Edison Company Rule 42T Tariff Filing to Increase Rates and Charges.

Ohio Public Utilities Commission Case No. 14-841-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of Case No. 14-841-EL-SSO an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 14AL-0660E: Re: In the Matter of the Advice Letter No. 1672-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective July 18, 2014.

Maryland Case No. 9355: In the Matter of the Application of Baltimore Gas and Electric Company for Authority to Increase Existing Rates and Charges for Electric and Gas Service.

Mississippi Public Service Commission Docket No. 2014-UN-132: In Re: Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment.

Nevada Public Utilities Commission Docket No. 14-05004: Application of Nevada Power Company d/b/a NV Energy for Authority to Increase its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto.

Utah Public Service Commission Docket No. 14-035-T02: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 32, Service From Renewable Energy Facilities.

Florida Public Service Commission Docket No. 140002-EG: In Re: Energy Conservation Cost Recovery Clause.

Public Service Commission of Wisconsin Docket No. 6690-UR-123: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Connecticut Docket No. 14-05-06: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Virginia Corporation Commission Case No. PUE-2014-00026: Application of Appalachian Power Company for a 2014 Biennial Review for the Provision of Generation, Distribution and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Virginia Corporation Commission Case No. PUE-2014-00033: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to Va. Code § 56-249.6.

Arizona Corporation Commission Docket No. E-01345A-11-0224 (Four Corners Phase): In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Minnesota Public Utilities Commission Docket No. E-002/GR-13-868: In the Matter of the Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in Minnesota.

Utah Public Service Commission Docket No. 13-035-184: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Missouri Public Service Commission Case No. EC-2014-0224: In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.

Oklahoma Corporation Commission Cause No. PUD 201300217: Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106 Which Requires a Base Rate Case to be Filed by PSO and the Resulting Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Public Utilities Commission of Ohio Case No. 13-2386-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.

*2013*
Oklahoma Corporation Commission Cause No. PUD 201300201: Application of Public Service Company of Oklahoma for Commission Authorization of a Standby and Supplemental Service Rate Schedule.

Georgia Public Service Commission Docket No. 36989: Georgia Power's 2013 Rate Case.

Florida Public Service Commission Docket No. 130140-EI: Petition for Rate Increase by Gulf Power Company.

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

*2012*

Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Virginia State Corporation Commission Case No. PUE-2012-00051: Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

New Jersey Board of Public Utilities Docket No. ER11080469: In the Matter of the Petition of Atlantic City Electric for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and For Other Appropriate Relief.

Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.

Missouri Public Service Commission Case No. EO-2012-0009:In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed

by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

Illinois Commerce Commission Docket No. 11-0721: Commonwealth Edison Company Tariffs and Charges Submitted Pursuant to Section 16-108.5 of the Public Utilities Act.

Public Utility Commission of Texas Docket No. 38951: Application of Entergy Texas, Inc. for Approval of Competitive Generation Service tariff (Issues Severed from Docket No. 37744).

California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

*2011*

Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

Virginia State Corporation Commission Case No. PUE-2011-00037: In the Matter of Appalachian Power Company for a 2011 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Illinois Commerce Commission Docket No. 11-0279 and 11-0282 (cons.): Ameren Illinois Company Proposed General Increase in Electric Delivery Service and Ameren Illinois Company Proposed General Increase in Gas Delivery Service.

Virginia State Corporation Commission Case No. PUE-2011-00045: Application of Virginia Electric and Power

Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

*2010*
Public Utilities Commission of Ohio Docket No. 10-2586-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

Oklahoma Corporation Commission Cause No. PUD 201000050: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

Washington Utilities and Transportation Commission Docket No. UE-100749: 2010 Pacific Power & Light Company General Rate Case.

Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Public Service Commission of Utah Docket No. 09-035-15 *Phase II*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ.*, for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ.* and 8-1-2-42 (a); Authority to Defer Program Costs

Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

Arkansas Public Service Commission Docket No. 10-010-U: In the Matter of a Notice of Inquiry Into Energy Efficiency.

Connecticut Department of Public Utility Control Docket No. 09-12-05: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Arkansas Public Service Commission Docket No. 09-084-U: In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Changes in Rates for Retail Electric Service.

Missouri Public Service Commission Docket No. ER-2010-0036: In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.

Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

*2009*
Virginia State Corporation Commission Case No. PUE-2009-00030: In the Matter of Appalachian Power Company for a Statutory Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

Colorado Public Utilities Commission Docket No. 09AL-299E: Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric.

Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring

the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

*2008*

Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

Indiana Utility Regulatory Commission Cause No. 43374: Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission Approve an Alternative Regulatory Plan for the Offering of Energy Efficiency, Conservation, Demand Response, and Demand-Side Management.

Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

Louisiana Public Service Commission Docket No. U-30192 *Phase II*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Colorado Public Utilities Commission Docket No. 07A-420E: In the Matter of the Application of Public Service Company of Colorado For Authority to Implement and Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Cost Recovery and Incentives.

*2007*

Louisiana Public Service Commission Docket No. U-30192: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Public Utility Commission of Oregon Docket No. UG 173: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas.

*2006*

Public Utility Commission of Oregon Docket No. UE 180/UE 181/UE 184: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.

Public Utility Commission of Oregon Docket No. UE 179: In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

Public Utility Commission of Oregon Docket No. UM 1129 *Phase II*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

*2005*
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I Compliance*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

Public Utility Commission of Oregon Docket No. UX 29: In the Matter of QWEST CORPORATION Petition to Exempt from Regulation Qwest's Switched Business Services.

*2004*
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

**TESTIMONY BEFORE LEGISLATIVE BODIES**
*2020*
Regarding Missouri Senate Joint Resolution 34: Written testimony submitted to the Missouri Senate Transportation, Infrastructure and Public Safety Committee, January 30, 2020.

*2019*
Regarding North Carolina Senate Bill 559: Written testimony submitted to the North Carolina Committee on Agriculture/Environment/Natural Resources, April 17, 2019.

Regarding Missouri Senate Joint Resolution 25: Written testimony submitted to the Missouri Senate Committee on Judiciary, March 28, 2019.

Regarding South Carolina House Bill 3659: Written testimony submitted to the South Carolina Senate Committee on Judiciary, March 14, 2019.

Regarding Kansas Senate Bill 69: Written testimony submitted to the Kansas Committee on Utilities, February 19, 2019.

*2018*
Regarding Missouri Senate Bill 564: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 10, 2018.

*2017*
Regarding Missouri Senate Bill 190: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 25, 2017.

*2016*
Regarding Missouri House Bill 1726: Testimony before the Missouri House Energy and Environment Committee, April 26, 2016.

*2014*
Regarding Kansas House Bill 2460: Testimony Before the Kansas House Standing Committee on Utilities and Telecommunications, February 12, 2014.

*2012*
Regarding Missouri House Bill 1488: Testimony Before the Missouri House Committee on Utilities, February 7, 2012.

*2011*
Regarding Missouri Senate Bills 50, 321, 359, and 406: Testimony Before the Missouri Senate Veterans' Affairs,

Emerging Issues, Pensions, and Urban Affairs Committee, March 9, 2011.

**AFFIDAVITS**

*2015*

Supreme Court of Illinois, Docket No. 118129, Commonwealth Edison Company et al., respondents, v. Illinois Commerce Commission et al. (Illinois Competitive Energy Association et al., petitioners). Leave to appeal, Appellate Court, First District.

*2011*

Colorado Public Utilities Commission Docket No. 11M-951E: In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012.

**ENERGY INDUSTRY PUBLICATIONS AND PRESENTATIONS**

Speaker, Supporting Walmart's Regenerative Journey, Edison Electric Institute National Key Accounts Workshop, New Orleans, Louisiana, March 21, 2022.

Speaker, Walmart and the Co-ops: The Value of Partnership, Texas Electric Cooperatives 22nd Annual Directors Conference, January 11, 2022.

Speaker, Walmart and the Co-ops: The Value of Partnership, Texas Electric Cooperatives Managers Conference, December 2, 2021.

Panelist, Industry Priorities for Building Renewable Infrastructure, ACORE Grid Forum, November 3, 2021.

Panelist, Achieving a 100% Carbon Free Energy Economy, Edison Electric Institute National Key Accounts Workshop, Long Beach, California, October 25, 2021.

Panelist, Public Private Partnerships: How Utilities and Customers are Working Together for a More Sustainable Future, Arkansas Advanced Energy Association Empower Arkansas, Little Rock, Arkansas, October 14, 2021.

Panelist, Understanding Nontraditional Stakeholders, University of Idaho Energy Executive Summit, Austin, Texas, October 12, 2021.

Panelist, US City & Corporate Clean Energy Procurement and its Role in Achieving the Paris Agreement's Goals, United States Environmental Protection Agency, September 1, 2021.

Panelist, WalStreet Fireside Chat – Future of Energy, Bentonville Chamber of Commerce, July 27, 2021.

Panelist, Corporate Customer Partnerships, EEI 2021: The Road to Net Zero, June 9, 2021.

Panelist, Counting to Clean: Corporate Sustainability and Renewable Energy, Energy Bar Association, May 12, 2021.

Speaker, Designing a Customer-Centric Clean Energy Standard, REBA Connect 2021 Virtual Member Summit, May 11, 2021.

Panelist, Delivering 100% Carbon Free Energy: Options & Issues, Northwestern Center on Law, Business, and Economics, March 16, 2021.

Electric Company Updates and Discussion on Best Practices for Serving National Corporate Customers Webinar, Edison Electric Institute, March 9, 2021.

Panelist, ComEd Fleet Electrification Webinar, December 10, 2020.

Panelist, Corporate Offtaker Perspectives Panel, Southeast Renewable Energy Summit, November 18, 2020.

Panelist, EEI National Key Accounts – Connections that Mean Business for Corporate Customers, EEI Fall National Key Accounts Workshop, October 28, 2020.

Panelist, COVID-19, a Catalyzer or a Barrier to Decarbonization?, Power & Renewables Summit 2020, September 28, 2020.

Panelist, What Organized Markets Can Do for You, REBA Connect: Virtual Member Summit 2020, June 2, 2020.

Panelist, Expanding Future Procurement Options, REBA Connect: Virtual Member Summit 2020, May 13, 2020.

Panelist, Renewable Energy Options for Large Utility Customers, NARUC Center for Partnership & Innovation Webinar Series, January 16, 2020.

Panelist, Pathways to Integrating Customer Clean Energy Demand in Utility Planning, REBA: Market Innovation webinar, January 13, 2020.

Panelist, Should Full Electrification of Energy Systems be Our Goal? If it's No Longer Business as Usual, What Does That Mean for Consumers?, National Association of State Utility Consumer Advocates 2019 Annual Meeting, San Antonio, Texas, November 18, 2019.

Panelist, Fleet Electrification, Federal Utility Partnership Working Group Seminar, Washington, DC, November 8, 2019.

Panelist, Tackling the Challenges of Extreme Weather, Edison Electric Institute Fall National Key Accounts Workshop, Las Vegas, Nevada, October 8, 2019.

Panelist, Fleet Electrification: Tackling the Challenges and Seizing the Opportunities for Electric Trucks, Powering the People 2019, Washington, D.C., September 24, 2019.

Panelist, From the Consumer Perspective, Mid-American Regulatory Conference 2019 Annual Meeting, Des Moines, Iowa, August 13, 2019.

Panelist, Redefining Resiliency: Emerging Technologies Benefiting Customers and the Grid, EPRI 2019 Summer Seminar, Chicago, Illinois, August 12, 2019.

Panelist, Energy Policies for Economic Growth, 2019 Energy Policy Summit, NCSL Legislative Summit, Nashville, Tennessee, August 5, 2019.

Panelist, Gateway to Energy Empowerment for Customers, Illumination Energy Summit, Columbus, Ohio, May 15, 2019.

Panelist, Advancing Clean Energy Solutions Through Stakeholder Collaborations, 2019 State Energy Conference of North Carolina, Raleigh, North Carolina, May 1, 2019.

Panelist, Fleet Electrification: Getting Ready for the Transition, Edison Electric Institute Spring National Key Accounts Workshop, Seattle, Washington, April 8, 2019.

Panelist, Where the Fleet Meets the Pavement, Which Way to Electrification of the U.S. Transportation System?, Washington, D.C., April 4, 2019.

Panelist, Improving Renewable Energy Offerings: What Have We Learned?, Advanced Energy Economy Webinar, March 26, 2019.

Speaker, National Governors Association Southeast Regional Transportation Electrification Workshop, Nashville, Tennessee, March 11, 2019.

Speaker, Walmart Spotlight: A Day in the Life of a National Energy Manager, Touchstone Energy Cooperatives Net Conference 2019, San Diego, California, February 12, 2019.

Panelist, National Accounts: The Struggle is Real, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Getting in Front of Customers Getting Behind the Meter Solutions, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Sustainable Fleets: The Road Ahead for Electrifying Fleet Operations, EEI National Key Accounts 2018 Fall Workshop, San Antonio, Texas, October 23, 2018.

Panelist, Meeting Corporate Clean Energy Requirements in Virginia, Renewable Energy Buyers Alliance Summit, Oakland, California, October 15, 2018.

Panelist, What Are the Anticipated Impacts on Pricing and Reliability in the Changing Markets?, Southwest Energy Conference, Phoenix, Arizona, September 21, 2018.

Speaker, Walmart's Project Gigaton – Driving Renewable Energy Sourcing in the Supply Chain, Smart Energy Decisions Webcast Series, July 11, 2018.

Panelist, Customizing Energy Solutions, Edison Electric Institute Annual Convention, San Diego, California, June 7, 2018.

Powering Ohio Report Release, Columbus, Ohio, May 29, 2018.

Panelist, The Past, Present, and Future of Renewable Energy: What Role Will PURPA, Mandates, and Collaboration Play as Renewables Become a Larger Part of Our Energy Mix?, 36th National Regulatory Conference, Williamsburg, Virginia, May 17, 2018.

Panelist, Sustainability Milestone Deep Dive Session, Walmart Global Sustainability Leaders Summit, Bentonville, Arkansas, April 18, 2018.

Panelist, The Customer's Voice, Tennessee Valley Authority Distribution Marketplace Forum, Murfreesboro, Tennessee, April 3, 2018.

Panelist, Getting to Yes with Large Customers to Meet Sustainability Goals, The Edison Foundation Institute for Electric Innovation Powering the People, March 7, 2018.

Panelist, The Corporate Quest for Renewables, 2018 NARUC Winter Policy Summit, Washington, D.C., February 13, 2018.

Panelist, Solar and Renewables, Touchstone Energy Cooperatives NET Conference 2018, St. Petersburg, Florida, February 6, 2018.

Panelist, Missouri Public Service Commission November 20, 2017 Workshop in File No. EW-2017-0245.

Panelist, Energy and Climate Change, 2017-18 Arkansas Law Review Symposium: Environmental Sustainability and Private Governance, Fayetteville, Arkansas, October 27, 2017.

Panelist, Customer – Electric Company – Regulator Panel, Edison Electric Institute Fall National Key Accounts Workshop, National Harbor, Maryland, October 12, 2017.

Panelist, What Do C&I Buyers Want, Solar Power International, Las Vegas, Nevada, September 12, 2017.

Panelist, Partnerships for a Sustainable Future, American Public Power Association National Conference, Orlando, Florida, June 20, 2017.

Panelist, Corporate Renewable Energy Buyers in the Southeast, SEARUC 2017, Greensboro, Georgia, June 12, 2017.

Panelist, Transitioning Away from Traditional Utilities, Utah Association of Energy Users Annual Conference, Salt Lake City, Utah, May 18, 2017.

Panelist, Regulatory Approaches for Integrating and Facilitating DERs, New Mexico State University Center for Public Utilities Advisory Council Current Issues 2017, Santa Fe, New Mexico, April 25, 2017.

Presenter, Advancing Renewables in the Midwest, Columbia, Missouri, April 24, 2017.

Panelist, Leveraging New Energy Technologies to Improve Service and Reliability, Edison Electric Institute Spring National Key Accounts Workshop, Phoenix, Arizona, April 11, 2017.

Panelist, Private Sector Demand for Renewable Power, Vanderbilt Law School, Nashville, Tennessee, April 4, 2017.

Panelist, Expanding Solar Market Opportunities, 2017 Solar Power Colorado, Denver, Colorado, March 15, 2017.

Panelist, Renewables: Are Business Models Keeping Up?, Touchstone Energy Cooperatives NET Conference 2017, San Diego, California, January 30, 2017.

Panelist, The Business Case for Clean Energy, Minnesota Conservative Energy Forum, St. Paul, Minnesota, October 26, 2016.

Panelist, M-RETS Stakeholder Summit, Minneapolis, Minnesota, October 5, 2016.

Panelist, 40th Governor's Conference on Energy & the Environment, Kentucky Energy and Environment Cabinet, Lexington, Kentucky, September 21, 2016.

Panelist, Trends in Customer Expectations, Wisconsin Public Utility Institute, Madison, Wisconsin, September 6, 2016.

Panelist, The Governor's Utah Energy Development Summit 2015, May 21, 2015.

Mock Trial Expert Witness, The Energy Bar Association State Commission Practice and Regulation Committee and Young Lawyers Committee and Environment, Energy and Natural Resources Section of the D.C. Bar, Mastering Your First (or Next) State Public Utility Commission Hearing, February 13, 2014.

Panelist, Customer Panel, Virginia State Bar 29th National Regulatory Conference, Williamsburg, Virginia, May 19, 2011.

Chriss, S. (2006). "Regulatory Incentives and Natural Gas Purchasing – Lessons from the Oregon Natural Gas Procurement Study." Presented at the 19th Annual Western Conference, Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition, Monterey, California, June 29, 2006.

Chriss, S. (2005). "Public Utility Commission of Oregon Natural Gas Procurement Study." Public Utility Commission of Oregon, Salem, OR. Report published in June, 2005. Presented to the Public Utility Commission of Oregon at a special public meeting on August 1, 2005.

Chriss, S. and M. Radler (2003). "Report from Houston: Conference on Energy Deregulation and Restructuring." USAEE Dialogue, Vol. 11, No. 1, March, 2003.

Chriss, S., M. Dwyer, and B. Pulliam (2002). "Impacts of Lifting the Ban on ANS Exports on West Coast Crude Oil Prices: A Reconsideration of the Evidence." Presented at the 22nd USAEE/IAEE North American Conference, Vancouver, BC, Canada, October 6-8, 2002.

Contributed to chapter on power marketing: "Power System Operations and Electricity Markets," Fred I. Denny and David E. Dismukes, authors. Published by CRC Press, June 2002.

Contributed to "Moving to the Front Lines: The Economic Impact of the Independent Power Plant Development in

Louisiana," David E. Dismukes, author. Published by the Louisiana State University Center for Energy Studies, October 2001.

Dismukes, D.E., D.V. Mesyanzhinov, E.A. Downer, S. Chriss, and J.M. Burke (2001). "Alaska Natural Gas In-State Demand Study." Anchorage: Alaska Department of Natural Resources.

BY MR. JENKINS:

Q Would you please give a summary.

A Sure thing.

Now, I'll give you the shortest summary I can to get us through here.

So today I'm testifying on behalf of the Commercial Group, which is an ad hoc group of commercial customers that are in retail, so Wal-Mart, BJ's, Publix, and JCPenney. And I'm looking down to make sure I have the list correct.

And so these are companies that have a significant impact on the Georgia economy and are large customers of Georgia Power, pardon me with the glasses. For Wal-Mart in particular, we have 227 facilities and approximately 66,000 associates in Georgia. And last year spent 25.8 billion with Georgia-based suppliers and supported over 277,000 jobs in the state.

So in terms of our recommendations for this case, so we recognize that optimally the company shareholders should bear the risk of regulatory lag contained in the traditional regulatory process, but we do recognize that the company has and the Commission have used alternate rate plans over time.

As such, for the purposes of this docket, we're

not going to oppose the use of an ARP generally, subject to the following recommendations: That the company's proposed ROE revenue requirement, we don't oppose the proposed ROE band, but we do recommend that if the Commission approves a lower ROE, the Commission should contemporaneously reduce the low and high band boundaries and maintain the basis point spread around the approved ROE.

Additionally, the Commission should consider the near-term financial impacts to customers of the company's levelization proposal, as it determines whether to levelize, and if so, how much revenue should be levelized.

This is a big one. Cost pressures are a big thing right now within our business, and so anything that can be done to save money, particularly in the near term, is a big thing for us.

In consideration of the appropriate ROE for the company, the Commission should recognize the proposed ARP does shift risk from the company's shareholders to customers by removing the effects of regulatory lag.

And the Commission should also closely examine the Company's proposed revenue requirement increase and the associated proposed increase in ROE when

viewed in light of the customer impact of the proposed revenue requirement increases and what the ROE would be do. The reduction in risk regulatory lag, as I just mentioned, and then recent rate case ROEs approved by other commissions nationwide.

And finally, the Commercial Group recommends that the Commission should approve a revenue allocation in this docket that moves classes towards parity, and that concludes my summary.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Chriss.

MR. JENKINS: Mr. Chriss is available for Commissioner questions or cross.

MADAM CHAIR PRIDEMORE: Questions from Commissioners?

Commissioner Echols.

VICE CHAIRMAN ECHOLS: Hey, good to see you again, sir.

MR. CHRISS: Good to see you. Thank you.

VICE CHAIRMAN ECHOLS: Are you seeing ROEs for -- I know you testify a lot, and you also worked at a commission before; right?

MR. CHRISS: Correct.

VICE CHAIRMAN ECHOLS: Are you seeing ROEs for utilities go up or down in the last year or so?

MR. CHRISS: So they've been trending downward.

We actually have some testimony in there that has the trend for vertically integrated ROEs over the last three or four years, and, yeah, there's definitely been a downward trend. It had stabilized for a little bit, but so far in 2022, it's significantly lower than what '21 was.

VICE CHAIRMAN ECHOLS: And I know this isn't in your testimony, but in 2016 -- you were here -- no, we didn't have a rate case in '16. Maybe it was '13.

Were you here in '13?

MR. CHRISS: I believe so.

VICE CHAIRMAN ECHOLS: Yeah. You testified that Wal-Mart was planning on putting solar on most of their stores. Is that still a goal the company has? Have y'all done that, or what's the status of that?

MR. CHRISS: So the status on that right now is we're sitting at about 400 sites across the country that have solar. There were several years where we hadn't really been deploying, but we are going to be looking again at distributing resources and are working on staffing and business plans right now for that.

VICE CHAIRMAN ECHOLS: And are you now doing any batteries associated with that on any of the

sites?

MR. CHRISS: That's a good question. I think that's going to be something they determine on a case-by-case basis. A lot of that will be driven by what the local incentives are for batteries, and then also what the rate structures are and how much value you can derive from having the battery there for load shifting and other purposes.

VICE CHAIRMAN ECHOLS: And my last question: Any plans for Wal-Mart to do EV charging? Any goals that you-all have set at your -- at either your stores or your Sam's Club stores?

MR. CHRISS: So we are currently working through that. We recently added a vice president of mobility and distributed generation, and part of her role is putting together the goals and the plan. So to be decided, but probably not too long from now.

VICE CHAIRMAN ECHOLS: I do love the Scan & Go app at Sam's, by the way. It's one my favorite technology things.

MR. CHRISS: Yeah, mine as well, and I highly recommend it to everybody who is here.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Chriss.

Any other questions from Commissioners?

Okay. Staff?

MR. WALSH: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: ChargePoint?

MR. DUNBAR: No questions.

MADAM CHAIR PRIDEMORE: EVgo?

MR. VIJAYKAR: No questions.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power and Light?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA?

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch?

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Ms. Medlyn?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Power?

CROSS-EXAMINATION

BY MR. MARZO:

Q I have to take advantage of having Mr. Chriss here.

Good evening, Mr. Chriss.

A Good evening.

Q It's been a little while since I've seen you last -- well, actually, I've seen you this year.

A I was going to say at the IRP docket was six months ago.

Q That's right. It's all running together.

Mr. Chriss, is it fair to say that you've not performed a cost of capital analysis or utilized a cost of capital models to determine the company's cost of capital like Mr. Coyne has done in this case?

A That's correct.

Q And you're not holding yourself as a cost of capital expert like Mr. Coyne; is that correct?

A That's correct.

Q Okay. And so to that effect, you've not estimated the company's cost of capital in this case; right?

A That's correct.

Q Okay. Now, as a clarification before I ask you some questions about the averages, on page 9 of your testimony -- I don't know if you have it with you -- line 16 to 18 of your testimony, you state that GPC is proposing an ROE of 11 percent based upon an estimated range of 8.99 percent to 13.55 percent with an additional 50 basis point financial risk adjustment.

Do you see that?

A I do.

Q And I guess my question was, I was kind of baffled when I saw the 50-basis point risk adjustment.

Is that correct, or is that an error?

A I believe that's an error.

Q Okay. I just wanted to make sure we're all on the same page as to what the request was.

A Yeah.

Q Now, in your testimony in this case, you provided information on ROEs granted in other jurisdictions

as did you in 2019; correct?

A That's correct.

Q And would you agree with me that the Commission is not bound to follow the average ROEs granted by other commissions?

A That's correct. We put those in there just as, you know, sort of a benchmarking exercise to see what other commissions are doing and where the industry trends are going.

Q And can we agree that the Commission considered yours and other testimony regarding averages in the last rate case and found that a 10.5 percent ROE was just and reasonable?

A I mean, that's generally my recollection. I would have to reread the order in order to confirm the statement.

Q And is it fair to say or do you recall that the averages reported in 2019 were well below what the Commission awarded?

A Generally, yes.

Q Now, isn't it also true that the averages in the ROE data that you provided with your testimony, that data doesn't distinguish between constructive regulatory environments and ones that are less constructive?

A That's across all regulatory environments. We

haven't broken it out and ranked it that way, but yeah.

Q Okay. It's just --

A That's a long way of saying yes.

Q Yeah. And it's a spreadsheet, and my point is a spreadsheet just doesn't have, like, the ROE rankings for each state and jurisdiction that you've listed?

A Correct.

Q Okay. And the data you provided does not make any distinction between the level of customer service provided by various utilities making up the average; is that correct?

A That's correct.

Q Okay. And it doesn't provide any information on the rates charged or whether the utility's rates are below or above the national average; is that right?

A That's correct.

Q And can you agree with me that each commission considers specific circumstances in each case, and it determines which is the proper ROE and capital structure to award?

A Yeah. I mean, ultimately, the Commission has the duty and the obligation to figure that out.

Q And can we agree that, in this case, the Commission might consider Georgia Power's recognition for service quality and performance in considering this ROE?

A I think to the extent that that evidence is present in the docket.

Q Okay. And they might also consider it -- the Commission might consider the reliability of Georgia Power's generation fleet?

A Again, to the extent that that evidence is in the docket.

Q And the level of customer service and the awards won by Georgia Power for customer service?

A Again, to the extent that that information is provided in the docket.

Q And it could also consider, considering where we've been for the last three years, how the company has responded to the COVID-19 pandemic and has worked through various issues involving customers and keeping the lights on during this difficult time?

A Again, to the extent that that evidence has been presented in the docket.

Q Okay. And the Commission may consider the company's response to extreme weather events as well; correct?

A Correct. Same caveat.

Q Okay. And are you familiar with the term "risk-free rate of return" as it relates to estimated return on equity?

A Generally.

Q Okay. And can we agree that the Treasury yields are representative of the risk-free rate?

A That's my general understanding.

Q Okay. And would you agree with me that, in evaluating recommendations for ROE in this case, the Commission might consider that the 30-year Treasury bond yield was 2.31 percent in December of 2019 when the Commission awarded a 10.5 percent ROE, and that the current 30-year Treasury yield is now 4.27 percent, nearly 2 percent higher than it was in 2019?

A They could certainly consider that.

Q And could the Commission consider that, since 2019, the rate case decision the Moody's Baa utility bond yields have increased from 3.74 percent to 6.35 percent, nearly a 2.61 percent increase?

A They could.

Q Okay. And so the rate for a utility debt investor is up over 2 percent since the Commission approved the settlement in 2019; is that fair?

A From the representation that you have just provided, yes.

Q And can we finally agree, would you agree, that the Commission may find in this case that the current market environment supports a higher ROE as compared to the

financial circumstances in 2019?

A I mean, the Commission can certainly find that, but part of why we provide this information is, you know, does that exist in a vacuum, how do they look at it against other jurisdictions, you know. Other jurisdictions with the same information have found that lower ROEs are appropriate.

So there's a number of factors that are going to go into it. And, obviously, the Commission has its own discretion, but I certainly wouldn't, then, you know, discount what other commissions have done, you know, sort of in that context.

Q But I think, as you agreed earlier, there are very different aspects that make every jurisdiction different and make every case different where these issues are considered in rate cases; is that fair?

A That's fair.

Q Okay. And I know, as one last question, that you had -- you were generally supportive of the band that's in place if the company's recommendation for 11 percent is adopted.

Is it fair to say that the band and the alternative rate plan has been a constructive outcome in these cases that you've been here in Georgia?

A I mean, typically -- our position typically is a little bit mixed on multi-year rate plans. I think one of

the things that I appreciate coming out of these cases is that you have a general sense of what rates are going to be as time goes forward, but we've never -- speaking for Wal-Mart, the Commercial Group is ad hoc for this case in Georgia, so we've never advocated for formula rates or having automatic adjustments based on, you know, ROE-based outcomes.

It seems a little -- I mean, ultimately, we want to pay the cost of service for the service that we're taking. There is some amount of risk that your shareholders take on for providing service, and so mechanisms that provide that sort of installation at a customer cost are certainly going to be a concern because, as you talked about, the market environment, that's -- it's high-cost environment for customers right now.

So, you know, we're trying to watch every penny to make sure that, you know, every penny that's going into rates is closely examined and controlled and, you know, results in fair, just, and reasonable rates, but, you know, not rates that are too high.

Q And I guess, Mr. Chriss, my more fundamental question is that, in the past, Georgia Power Company has been able to come to constructive outcomes in which the Commercial Group felt like they could also agree to; correct? You've signed on the settlements in the past;

correct?

A That's correct.

MR. MARZO: Okay. I appreciate your testimony, Mr. Chriss.

And I thank you, Commissioners, for your time.

MR. CHRISS: Yes.

VICE CHAIRMAN ECHOLS: All right.

MR. JENKINS: Thank you.

REDIRECT EXAMINATION

BY MR. JENKINS:

Q Mr. Marzo asked you to consider the performance of Georgia Power and its awards and presumably the quality of its legal team.

If the Commission were to do so and award Georgia Power an ROE in the top quartile of ROEs awarded to vertically integrated utilities since 2019, what ROE would that be?

A So from the data that we've provided in the exhibit, the top quartile 9.9 percent.

Q And what if the Commission awarded Georgia Power Company in the top five ROEs over that long period?

A So the top five, not including Georgia Power's 2019 result, would be about 10.0. If you include Georgia Power's 2019 result, that would be -- it would be 10.2, so the low tens.

MR. JENKINS: Okay. Thank you. Nothing further. We move Commercial Group Exhibits 1 through 8 into the record.

(Commercial Group Exhibits 1 through 8 were was admitted into evidence.)

VICE CHAIRMAN ECHOLS: All right. It will be, and the witness is excused. Thank you.

EVgo Services, LLC, I think, is next.

MR. VIJAYKAR: Thank you, Commissioner.

VICE CHAIRMAN ECHOLS: Please swear in your witness.

MR. VIJAYKAR: Commissioners, EVgo would call Mr. Colin Murchie to the stand. He's already there.

Mr. Murchie, I'm going to go ahead and swear you in. Could you please raise your right hand.

Whereupon,

COLIN MURCHIE,

having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. VIJAYKAR:

Q Mr. Murchie, could you please state your name for the record.

A Colin Murchie.

Q And could you please state your employer and job title for the record.

A Senior director of business development for utilities and public agencies for EVgo, LLC.

Q Thank you.

And, Mr. Murchie, you are testifying on behalf of the EVgo in this proceeding; is that correct?

A That's correct.

Q On October 20th, did you file or cause to be filed direct testimony in this proceeding, including a cover page, table of contents, and 23 pages of questions and answers?

A I did.

Q Did you prepare or supervise the preparation of that testimony?

A Yes, I did.

Q If I were to ask you the same questions as asked in your direct testimony, would your answers today be the same?

A They would.

Q Do you have any corrections to offer to your testimony today?

A I do not.

Q Mr. Murchie, on October 20, did you also file or cause to be filed an exhibit labeled EVgo Exhibit 1?

A Yes, I did.

Q Do you have any corrections to your exhibit

that you'd like to offer today?

A No.

Q Thank you, Mr. Murchie.

MR. VIJAYKAR: Commissioners, Madam Chair, at this time I would ask for -- to move for the admission of Mr. Murchie's direct testimony and EVgo Exhibit 1 into the record, pending cross.

MADAM CHAIR PRIDEMORE: So moved, so marked.

(The document referred to was marked for identification as EVgo Services, LLC's Exhibit 1.)

(Whereupon, the prefiled direct testimony of Colin Murchie follows:)

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| In re: Georgia Power Company's 2022 Rate Case | ) ) | Docket No. 44280 |

# DIRECT TESTIMONY OF COLIN MURCHIE

**ON BEHALF OF**
**EVGO SERVICES, LLC**

**October 20, 2022**

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## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name and business address.**

**A.** My name is Colin Murchie. My business address is 11835 W. Olympic Blvd. Suite 900E Los Angeles, CA 90064.

**Q. By whom are you employed and in what position?**

**A.** I am employed by EVgo Services, LLC (EVgo) as Senior Director of Business Development, Utilities & Public Agencies.

**Q. On whose behalf are you testifying in this proceeding?**

**A.** I am testifying on behalf of EVgo.

**Q. Please describe your experience and qualifications.**

**A.** As Senior Director of Business Development, Utilities & Public Agencies at EVgo, I work with utility and public sector stakeholders to advise on program design solutions to accelerate transportation electrification. Prior to EVgo, I spent more than 15 years in the solar energy industry at the intersection of regulation, finance, and infrastructure deployment. My previous roles span state and federal government affairs, business development and commercial sales/account management, and wholesale energy markets including roles with Sol Systems, SolarCity (now Tesla), SunEdison, and the Solar Energy Industries Association. I hold a Master of Business Administration degree from the University of Maryland Robert H. Smith School of Business and a Bachelor of Science degree in Natural Resources from Cornell University.

**Q. Have you testified previously before the Georgia Public Service Commission?**

**A.** No, I have not. I have previously provided testimony in front of utility commissions in Colorado, Maryland, and Washington, D.C.

**Q. Please describe EVgo.**

**A.** EVgo owns and operates the nation's largest network of public electric vehicle (EV) fast charging stations, with more than 850 fast charging locations spanning more than 30 states and approximately 444,000 customer accounts. EVgo is working with automakers such as General Motors (GM)[1] and Nissan[2] to build out its network of public fast chargers. Currently, EVgo's public charging network in Georgia includes 48 Direct Current Fast Chargers (DCFC) at 27 locations, including multiple stations in Georgia Power Company's service territory. In addition to its public network, EVgo also partners with fleets and rideshare operators to deploy advanced charging solutions.[3]

**Q. What is the purpose of your testimony?**

**A.** EVgo's primary interest in this proceeding is to ensure that Georgia Power Company's expansion of its investments, programs, and rates in support of electric transportation infrastructure in Georgia fosters a robust competitive market by complementing, and not hindering, the efforts and activities of private market participants. The purpose of my testimony is to provide the Commission, the utility, and stakeholders with the unique perspective of a successful, private sector owner-operator of electric vehicle charging with a decade's experience from across the U.S.

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[1] *See* "General Motors and EVgo aim to accelerate widespread EV adoption by adding fast chargers nationwide." (July 30, 2020). Available at: https://www.evgo.com/about/news/general-motors-and-evgoaim-to-accelerate-widespread-ev-adoption-by-adding-fast-chargers-nationwide/; *see also* "General Motors and EVgo boost build plan for higher power fast chargers across the US." (Nov. 9, 2021). Available at: https://www.evgo.com/press-release/general-motors-evgo-boost-build-plan-high-power-fast-chargers-across-us/.

[2] *See* "Nissan and EVgo expand charging network with 200 new EV fast chargers." (Aug. 6, 2019). Available at: https://www.evgo.com/about/news/nissan-and-evgo-expand-charging-network-with-200-new-ev-fastchargers/.

[3] *See* "EVgo and Lyft announce plans to expand U.S. electric charging partnership." (Nov. 25, 2019). Available at: https://archive.autofutures.tv/2019/11/26/evgo-and-lyft-announce-plans-to-expand-u-s-electric-charging-partnership/; *see also* "Uber and EVgo expand partnership to support high-volume rideshare drivers with fast, reliable public charging." (Nov. 9, 2021). Available at: https://www.businesswire.com/news/home/20211109005710/en/%C2%A0Uber-and-EVgo-Expand-Partnership-to-Support-High-Volume-Rideshare-Drivers-with-Fast-Reliable-Public-Charging.

**Q. Please summarize your recommendations in this proceeding.**

**A.** I recommend that the Commission:

- Approve Georgia Power's proposal to continue funding its make-ready program;
- Direct Georgia Power to develop and publish—as a compliance filing within 30 days following a final order in this case—updated make-ready program rules and requirements that expressly allow participation by third-party charging station owner-operators;
- Direct Georgia Power to develop and implement a transparent, points-based scoring rubric to prioritize make-ready program applications in collaboration with EV charging service providers and other industry stakeholders;
- Direct Georgia Power to allocate funds to make-ready program applications already received by the Company that meet the updated make-ready program rules and requirements;
- Direct the Company to develop, provide, and apply transparent siting criteria that include specific geographic minimum distances from an existing or proposed third-party EV charging station for its Community Charging program as described in my testimony such that new Company-owned charging stations appropriately complement the EV charging market rather than compete with private market participants;
- Direct the Company to provide a list of its proposed utility-owned stations, updated on at least a quarterly basis, to inform the public of locations it has identified as potential gaps in private charging deployment;
- Direct the Company to allow private sector providers the opportunity to develop a proposed station where the private sector charging provider informs the Company that it is building or intends to build a public charging station within the proposed limits of one of Georgia Power's proposed locations, and to remove the site from its Community Charging program;
- Direct the Company to develop a pricing proposal for its Community Charging program subject to stakeholder input—as a compliance filing within 30 days following a final order in this case—to align its Community Charging pricing with the competitive market, and;
- Approve Georgia Power's proposed Charge-It Electric Vehicle (CIEV) rider, but direct the Company to remove discriminatory restrictions on the availability of that rate and make the rate available to separately-metered charging stations installed before January 1, 2023.

## II. BACKGROUND ON ELECTRIC VEHICLE CHARGING

**Q. What is the purpose of this section of your testimony?**

**A.** In this section of my testimony, I provide a brief overview of the EV charging landscape across the nation and in Georgia. More specifically, I summarize the different types of EV charging infrastructure, explain why it is important to broadly deploy public DCFC infrastructure, and describe the state of the nascent charging market in Georgia.

**Q. Please describe the different types of EV charging infrastructure.**

**A.** There are three main types of EV charging infrastructure, each with distinct capabilities:

- "Level 1" charging delivers electricity though a 120 volt plug and is most often used in homes through an existing conventional outlet;
- "Level 2" charging typically provides a full charge in 4 to 8 hours and is used in locations with longer dwell times, such as workplaces, homes, parks, or other destinations where drivers may spend several hours;
- Public or commercial Direct Current Fast Charging or "DCFC" is suited for quick charge needs in and around cities, towns, and suburbs and along high-traffic travel corridors. DCFC stations are located at or near places where drivers live, drive, and shop, including retail locations, restaurants, grocery stores, and other locations where an EV driver will spend usually under an hour of time. EVgo's primary interest in this case is the discussion of DCFC in Georgia Power's service territory.

**Q. What types of needs does DCFC serve, and how does that impact station siting?**

**A.** DCFC serves a variety of needs for EV drivers. In addition to providing a quick charge to EV drivers on longer road trips, public DCFC also plays an important role in serving EV drivers' primary charging needs in dense urban and suburban areas, where not every home

has dedicated parking. In fact, according to the International Council on Clean Transportation, apartment-dwelling EV drivers living in multi-unit dwellings (MUDs) rely on public charging stations to serve 50-80% of their charging needs.[4] Further, a study of EV charging data from the University of California – Los Angeles concluded that "[i]nfrastructure planners should also note MUD users' stronger preferences for DCFC locations near home" and "MUD residents who drive EVs are, on average, heavier users of DCFC than non-MUD residents."[5]

To effectively serve the different needs of EV drivers, therefore, it is important that DCFC be sited not only along high-traffic transit corridors, at service plazas, and at rest areas along interstates and along major highways (traditional DCFC deployments), but also in and close to areas with high concentrations of MUD residents, among other locations. Importantly, whether a DCFC is located along a transit corridor or in a dense urban area, siting DCFC in and around existing amenities (e.g., retail, grocery, restaurants) allows for charging to be integrated into everyday activities, which enhances the customer experience and facilitates EV adoption and use.

**Q. Please provide an overview of the state of private sector investment in DCFC in Georgia.**

**A.** The competitive market to build, own, and operate DCFC stations is robust and growing in Georgia. That infrastructure is essential in order to serve Georgia's EV market. As of June 2022, Georgia ranked number ten out of all states for most registered EVs.[6] The

[4] International Council on Clean Transportation, "Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets" at 9. (Jan. 2019). Available at: https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf.
[5] "Evaluating Multi-Unit Resident Charging Behavior at Direct Current Fast Chargers." (Feb. 2021). Available at: https://innovation.luskin.ucla.edu/wp-content/uploads/2021/03/Evaluating-Multi-Unit-Resident-Charging-Behavior-at-Direct-Charging-Behavior-at-Direct-Current-Fast-ChargersCurrent-Fast-Chargers.pdf.
[6] Alternative Fuels Data Center, Electric Vehicle Registrations by State. Available at: https://afdc.energy.gov/data/.

Georgia Electric Vehicle Infrastructure Deployment Plan developed by the Georgia Department of Transportation (GDOT) notes Georgia is the leader in the Southeast with 4.4 EV registrations per 1,000 registered vehicles, and the market continues to grow.[7]

**Q. Please describe the relationship between private EV charging service providers and site hosts.**

**A.** The needs and preferences of site hosts (the entity on whose property the EV charging station is located, such as a grocery store or a retail shopping center) vary greatly. Reflecting the different needs of site hosts, the EV charging sector is similarly diverse and comprised of service providers whose purposes, business models, and relationships with site hosts vary significantly.

Under its owner-operator model, EVgo works with site host partners[8] across the country—such as gas stations, grocery stores, and shopping centers—that are interested in hosting EV charging stations on their premise but may not want to own the charging infrastructure themselves.[9] Those partners rely on experienced EV charging service

[7] Georgia Electric Vehicle Infrastructure Deployment Plan at 18. Available at: https://nevi-gdot.hub.arcgis.com/.
[8] EVgo's site host partners include chain retailers such as the Save Mart Companies and Wawa, and real estate developers such as CBL properties. *See* "EVgo Energizes New Station at Wawa in Philadelphia Bringing EVgo Chargers to 6 Stores Across the Convenience Retailer's Chain." (Mar. 10, 2022). Available at https://www.evgo.com/press-release/evgo-energizes-new-station-at-wawa-in-philadelphia-bringing-evgo-chargers-to-6-stores-across-the-convenience-retailer-s-chain/; "EVgo and The Save Mart Companies Expand EVgo Advantage™ Program Partnership, Introduce Promotions at Seven Additional Stores." (Mar. 16, 2022). Available at: https://www.evgo.com/press-release/evgo-and-the-save-mart-companies-expand-evgo-advantagetm-program-partnership-introduce-promotions-at-seven-additional-stores/; "EVgo and CBL Properties Partner to Expand Public Fast Charging at Retail Locations, Bringing Convenient Charging Amenities to Shoppers." (Jan. 27, 2022). Available at: https://www.evgo.com/press-release/evgo-cbl-properties-partner-expand-public-fast-charging-retail-locations-bringing-convenient-charging-amenities-shoppers/.
[9] EVgo also has a product called EVgo eXtend™ for site hosts who may prefer to own chargers. EVgo's first eXtend project will deploy 2,000 charging stalls at Pilot and Flying J locations across the country in collaboration with GM and Pilot Company. For more information, see: "EVgo Announces EVgo eXtend Project to Deploy High Power Fast Charging Access to Drivers Across the US." Available at https://www.evgo.com/press-release/evgo-announces-evgo-extend-project-to-deploy-high-power-fast-charging-access-to-drivers-across-the-us/.

providers, like EVgo, for the development, financing, ownership, and operations and maintenance of EV charging stations.

**Q. Please summarize Georgia Power's proposals in support of EV charging in this case.**

**A.** Georgia Power proposes to invest in utility infrastructure upgrades necessary to support EV charging ("make-ready" program),[10] proposes to invest in Company-owned charging stations ("Community Charging" program),[11] and proposes a new rate rider ("Charge It – Electric Vehicle" or "CIEV") that will support public commercial EV charging.[12] I will address each of these proposals in my testimony.

## III. MAKE-READY PROGRAM

**Q. What is "make-ready" infrastructure?**

**A.** "Make-ready" infrastructure refers to the electrical equipment necessary to operate a charging station. This can include sub-panels, main-panels, conductors, wiring, transformers, and other equipment on both the customer- and utility-side of the meter.[13] Utility investments, or incentives for private investment, in make-ready infrastructure bolster market deployment of charging stations. Through make-ready programs, utilities might, for instance, invest in rate-based distribution upgrades and branch line extensions, while leaving investments in chargers, charger ownership, operation and maintenance, marketing, customer service, and network operation to experienced private sector providers. By approving make-ready programs, utility commissions can attract and

[10] Direct Testimony of Christopher C. Womack at 10.
[11] *Id*.
[12] Direct Testimony of Larry T. Legg at 16.
[13] *See* Georgia Power Company response to STF-LA-6-19a.

leverage private capital investment in charging infrastructure to provide ratepayer benefits.[14]

**Q. Have make-ready programs been approved in other states?**

A. Yes. Utility commissions have approved, and utilities have implemented, make-ready programs in numerous states across the country. The following are a handful of examples of those programs:

- In 2021, the Colorado Public Utilities Commission approved a $110 million Transportation Electrification Plan for Public Service Company of Colorado (dba Xcel Energy) with nearly $37 million allocated to commercial make-ready and more than $4 million allocated to commercial rebates.[15]

- Also in 2021, the New Mexico Public Regulation Commission approved the Public Service Company of New Mexico Transportation Electrification Program, which included $1.75 million in rebates for the installation cost of DCFC make-ready infrastructure for non-residential customers.[16]

- The State Corporation Commission of the State of Kansas approved Evergy Kansas' proposal for a $15.4 million program offering Commercial EV Charger Rebates that cover customer-side infrastructure and EV charger equipment costs for Level 2 and DCFC.[17]

**Q. Please describe the Company's proposed make-ready program.**

A. Georgia Power Company has an existing make-ready program, but according to the Company's website, funding for that program has been depleted, and new applicants are being placed on a waiting list "pending the approval of additional funds, if and when such funds are made available."[18] In this rate case, the Company proposes to significantly

[14] During the hearing, Company witnesses expressed that they expect the Company's EV proposals, including its make-ready proposal, to put downward pressure on rates.
[15] Colorado Public Utilities Commission, Proceeding No. 20A-0204E, Commission Decision Granting Application with Modifications (Jan. 11, 2021).
[16] New Mexico Public Regulation Commission, Case No. 20-00237-UT, Final Order Adopting Recommended Decision, at 3-4 (Nov. 12, 2021).
[17] State Corporation Commission of the State of Kansas, Docket No. 21-EMKA-320-TAR, Order (Dec. 6, 2021).
[18] *See* Georgia Power Make-Ready Program (accessed Oct. 13, 2022). Available at: https://www.georgiapower.com/business/products-programs/business-solutions/electric-transportation-business-programs/make-ready.html.

expand that popular program by investing an additional $81 million in make-ready infrastructure over three years (2023-2025).[19] Those investments will enable the growth of the competitive EV charging market in Georgia Power's service territory by reducing the upfront cost of installing charging stations. I strongly support the Company's proposed expansion of its make-ready program.

**Q. How is Georgia Power's make-ready program structured?**

**A.** Through its make-ready program, Georgia Power installs, energizes, owns, and operates make-ready infrastructure, up to but not including the charging equipment.[20]

**Q. Please summarize the eligibility requirements associated with Georgia Power's make-ready program.**

**A.** Georgia Power states that its make-ready program is available to all existing Georgia Power commercial and industrial customers.[21] However, Georgia Power does not and will not offer make-ready funding to third-party EV charging service providers locating a charging station on a site host's[22] property, even if that third-party EV charging service provider is a Georgia Power "customer of record," meaning the entity paying the utility bill.[23] Instead, the Company will *only* make make-ready funding available to the site host.

**Q. Does the Company explain why it will only allow site hosts to receive funding through its make-ready program, and not third-party owner-operators?**

**A.** No, the Company does not, whether in its testimony nor in its existing program terms and conditions. According to the Company's September 2022 internal make-ready standards

[19] *See* Georgia Power Company response to STF-LA-6-19(a).
[20] *See* Georgia Power Company response to STF-LA-6-20.
[21] *See id*., *see also* STF-LA-6-20 Attachment A (ET Make Ready Infrastructure Program Terms and Conditions).
[22] A "site host" is the owner of the premise on which a charging station is located.
[23] It is important to note that a customer of record may be the site host or an EV charging service provider. EVgo is the customer of record at its charging locations in Georgia Power's service territory.

document, however, the Company appears to take the view that allowing third-party EV charging service providers to participate in the make-ready program would "subsidize charging companies' business models."[24] The Company's standards document also appears to amend its existing practice of allowing third-party EV charging service providers to establish a customer account. It states: "Georgia Power will not establish a new account in a charging company's name that is located on a Georgia Power customer's premise. The billing account must be in the name of the premise customer."[25] The legal basis by which Georgia Power proposes to deny electric service to EVgo is not elucidated in this internal document nor is it justified.

**Q. Do you have any concerns with the Company's make-ready program eligibility requirements?**

**A.** Yes. The Company's approach excludes an important segment of the EV charging market—specifically the owner-operator model—which is responsible for 77% of the DCFC deployed nationally today.[26] Excluding EV charging service providers with deep technical experience regarding the installation, operation, and maintenance of EV charging stations from the Company's make-ready program not only risks undermining the program by shutting out the primary mechanism by which DCFC is deployed nationally, but it also undermines customer choice. That is because Georgia Power's eligibility requirements make it harder for Georgia Power's customers to choose to work with EV charging service providers who are owner-operators—without access to make-ready funding through the Company's program, the economics of those deployments are challenged.

[24] *See* Georgia Power Company response to STF-LA-6-20, Attachment B at 2.
[25] *Id*.
[26] *See* Alternative Fuels Data Center, Alternative Fueling Station Locator (Accessed Oct. 19, 2022). Available at: https://afdc.energy.gov/stations/#/analyze.

Further, the Company's practice of investing in make-ready infrastructure *only* where the applicant is the site host and excluding applicants that are third-party owner-operators of charging stations on the premises of other Georgia Power commercial or industrial customers, is arbitrary. Whether the customer of record is a site host, a third-party charging provider, or an owner-operator of EV charging should have no bearing on whether the station is eligible for funding for make-ready infrastructure through the Company's program, and indeed, under the owner-operator model, the EV charging service provider, not the site host, is more likely to be the customer of record on the electricity bill. Nor should it determine whether these competitive offerings will or will not be served by the utility.

In my experience reviewing utility programs across the country, I have not come across any other make-ready program that limits participation to site hosts, and excludes third-party owners and operators, the most predominant model for DCFC deployment, as Georgia Power proposes to do. Georgia Power has not offered any rational reason to support the limitation. Georgia Power's make-ready program should agnostically foster a competitive charging market, not pick winners and losers. I would refer the Commission to Xcel Energy's EV Charging programs in both Colorado[27] and New Mexico[28] as examples of programs with more typical eligibility requirements. These programs allow any applicant (the site host or an EV charging owner-operator) to own, lease, or operate

[27] *See* EVgo Exhibit 1, Xcel Energy Colorado Electric Vehicle Community Charging Hub and Public Charging Customer Service Agreement, available at https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/community-charging-hubs-and-public-evsi-agreement.pdf.
[28] *See* EVgo Exhibit 1, Xcel Energy New Mexico Electric Vehicle Public Charging Customer Service Agreement, available at https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/nm-public-charging-customer-agreement.pdf.

EV charging equipment at the site host premise, and separately meter all load associated with charging equipment.[29]

**Q. How should the Company modify its make-ready program eligibility requirements in order to enable a competitive EV charging market?**

**A.** The Company should expressly allow third-party owner-operators to participate in its make-ready program. This would ensure that the program is business model-agnostic and enables a level playing field. The Company should clearly state in the make-ready program's rules and requirements that the applicant must be the "customer of record" for the EV charging station, and that the customer of record can be the site host or the EV charging service provider that owns and operates the EV charging station. Further, the Company should clarify that it will install a separate meter for the EV charging station, and to the extent that the EV Charging station is owned and operated by an EV service provider, establish a new account for that EV charging station. Finally, the Commission should direct the Company to provide, as a compliance filing within 30 days of a final Order in this proceeding, its updated make-ready program rules and requirements. This would help ensure that both the Commission and prospective applicants have a clear understanding of those requirements.

When Georgia Power's make-ready program was initially approved in its 2019 rate case, the Company failed to transparently disclose its program rules and requirements to the Commission and prospective applicants, leading program applicants to (erroneously) believe that the program's eligibility requirements resembled those that are typical of other

[29] *See* Exhibit CM-1 (Xcel Energy Colorado Electric Vehicle Community Charging Hub and Public Charging Customer Service Agreement).

make-ready programs across the country. The Commission should seek to avoid any confusion over program rules and requirements this time around.

**Q. Do you have any further recommendations regarding Georgia Power's make-ready program?**

**A.** Yes, to the extent the Company is looking to prioritize make-ready applications and optimally leverage any approved make-ready funding, I would recommend that Georgia Power develop (and implement) a transparent, points-based scoring rubric to prioritize applications in collaboration with EV charging companies and other industry stakeholders. This would help ensure that applicants are aware of the characteristics by which their applications will be evaluated ahead of time and will help applicants tailor site applications accordingly.

**Q. Please summarize your recommendations with respect to the proposed make-ready program.**

**A.** I recommend that the Commission:

- Approve Georgia Power's proposal to continue funding its make-ready program;
- Direct Georgia Power to develop and publish—as a compliance filing within 30 days following a final order in this case—updated make-ready program rules and requirements that expressly allow participation by third-party charging station owner-operators;
- Direct Georgia Power to develop and implement a transparent, points-based scoring rubric to prioritize make-ready program applications in collaboration with EV charging service providers and other industry stakeholders, and;
- Direct Georgia Power to allocate funds to make-ready program applications already received by the Company that meet the updated make-ready program rules and requirements.

## III. COMMUNITY CHARGING PROGRAM

**Q. Please describe the Company's Community Charging program.**

A. Through the Community Charging program, Georgia Power installs and maintains public charging infrastructure at select sites in its service territory.[30]

**Q. What does the Company propose with respect to its Community Charging program in this proceeding?**

**A.** Georgia Power proposes to invest $3 million per year between 2023-2025 on community charging stations, totaling an additional 33 stations—more than doubling the Company's current deployments through its Community Charging program.[31]

**Q. Please describe how utility-owned infrastructure programs like the Community Charging program can complement rather than hinder the efforts of private market participants.**

**A.** Both utility programs and private investment are important and complementary for creating a robust, balanced and competitive market for EV charging that will lead to increased EV adoption over the long term.

**Q. Will the Company's Community Charging stations compete with charging stations installed by the private market?**

**A.** Ultimately, this depends on their location, pricing, and quality of service. The Company does state that it "primarily operates [the Community Charging] program as a provider of last resort to provide public DC fast charging options for EV drivers in areas that lack public DC fast charging investments."[32] During the hearing, Company witnesses

[30] *See* STF-HR-1-3 Reference, p. 2.
[31] Georgia Power Company Response to STF-LA-6-17.
[32] Georgia Power Company response to STF-LA-6-16e.

emphasized that Georgia Power intends to focus its Community Charging deployments in areas that the private market is unlikely to serve ("charging deserts").

**Q. How does the Company identify sites for its Community Charging program?**

**A**. The Company states that it "takes several inputs into consideration when determining a new site location: customer interest; other EV charging service providers' plans; and alignment with the Community Charging program design."[33] In order to determine whether the competitive market is likely to serve that new site location, the Company asserts that it consults publicly available information such as the PlugShare EV Charging Station Map (www.plugshare.com), which provides some information regarding future plans of EV charging service providers.[34]

Once the general location of a prospective new site is identified, the Company states that it considers site-specific information to identify and select a specific location. The Company explains:

> To help in final site identification, the Company developed three major categories with weighting measures and ratings (1-3) with 3 as the highest. An overall weighted score of 2 or higher qualifies as a prospective new EV charging site through this process. The criteria require new EV charging sites installed through the Community Charging program must be safe, accessible, and equitable.
>
> - **Safe**: EV drivers need to feel safe when they are charging. Criteria in this category include visibility from the roadway, presence of secure & sufficient lighting, and the operating hours of the business location.
> - **Accessible**: EV drivers need sites to be accessible for EV charging. Criteria in this category include proximity to travel

[33] Georgia Power Company response to STF-LA-6-16a.
[34] *Id*.

corridors and amenities as well as whether the charger itself would be publicly accessible at all times.

- **Equitable**: Within reasonable expectation, new EV charging sites should not interfere with other public charger networks and should meet a public need for EV charging without creating excessive costs for installation. Criteria in this category include proximity to other existing or anticipated public direct current (DC) fast charging sites, the income-level of the community where the new site would be located, and the cost to serve the site.[35]

**Q. How do you respond to the Company's process for identifying specific Community Charging locations?**

**A.** The Company's criteria include "proximity to other existing or anticipated public direct current (DC) fast charging sites." This criterion is important and will help mitigate the competitive risks of the Community Charging program. However, as stated it is a purely subjective, qualitative determination – effectively not subject to Commission oversight and not possible for third parties to incorporate into their own planning. In addition, the National Electric Vehicle Infrastructure (NEVI) program apportions approximately $135 million in formula funding to the Georgia Department of Transportation (GDOT) over five years, with the first two years focused on designated alternative fuel corridors.[36] The Company has stated that it will ensure its Community Charging sites do not "overlap" with any future NEVI-funded sites,[37] but has not explained how it will do so.

[35] *Id*.
[36] *See* Georgia EV Infrastructure Deployment Plan at 1-2 (Aug. 2022).
[37] Georgia Power Company response to STF-PIA-12-1d.

I recommend that Georgia Power establish transparent, publicly-available siting criteria that empirically assess whether a prospective Community Charging site is underserved by the private market.

**Q. How have utilities in other jurisdictions identified charging locations that are not likely to be served by the private market and that are therefore appropriate for utility-owned charging deployments?**

**A.** Utility commissions and utilities have broadly recognized the importance of balancing utility ownership of charging stations with private investment. For example, in Arizona, Arizona Public Service (APS) proposed to limit competition with privately-owned charging stations by applying a geographic buffer around existing stations. APS proposed only three to five locations, all of which were an average of 63 miles from a privately owned DCFC station.[38] Similarly, in Colorado, Xcel Energy sets a 10 mile minimum geographic buffer around its utility-stations located outside of urban areas, and seeks to maximize the distance from other stations.[39] In New Jersey, the Board of Public Utilities (BPU) found that there are narrow instances where it is appropriate for utilities to own and operate charging stations as a provider of "last resort," and gives utilities an opportunity to affirmatively petition the BPU to own stations in locations where the private market has not developed a charging station within 12 to 18 months following program initiation.[40]

[38] *See* Arizona Corporation Commission, Docket No. E-01345A-19-0236, EVgo's Direct Testimony of Sara Rafalson (Oct. 2, 2020).
[39] *See* Colorado Public Utilities Commission, Proceeding No. 20A-0204E, Report on Process and Siting for Xcel Energy DCFC Stations at 6 (Dec. 2021).
[40] *See* N.J. Board of Pub. Utils. Docket No. QO20050357, Order Adopting the Minimum Filing Requirements for Light-Duty, Publicly-Accessible Electric Vehicle Charging at 21 (Sep. 23, 2020).

**Q. What siting criteria do you recommend Georgia Power apply in order to determine whether a prospective Community Charging site is underserved by the private market?**

**A.** I recommend that Georgia Power place Community Charging stations only either where it can show there is no competing >50 kilowatt fast charging within a 15 minute drive in a metropolitan area, or within 25 miles on a highway corridor. Additionally, Georgia Power should provide a list of its proposed utility-owned stations, updated on at least a quarterly basis, to inform the public of locations it has identified as potential gaps in private charging deployment. If a private sector charging provider informs the Company that it is building or intends to build a public charging station within the proposed limits of one of Georgia Power's proposed locations, the Company should allow the private sector provider the opportunity to develop its proposed station, subject to certain progress requirements and should remove the site from its Community Charging program.

**Q. Do you have any concerns with the Company's pricing for its Community Charging stations?**

**A.** Yes. The Company has provided no information regarding the pricing it expects to set for charging stations developed under the Community Charging program, nor has it provided any information on how the pricing for current Company-owned stations is set. Based on publicly available information, Georgia Power charges EV drivers $0.25 per minute to charge at its existing DCFC stations.[41] It is unclear if that price will change in the future and if that pricing will remain for this next set of deployments, if approved.

[41] *See* PlugShare. Available at: https://www.plugshare.com/; *see also* Georgia Power Community Charging Program. Available at: https://www.georgiapower.com/business/products-programs/business-solutions/electric-transportation-business-programs/community-charging.html.

**Q. How do you recommend Georgia Power determine pricing for its Community Charging stations?**

**A.** Should the Company's Community Charging program be approved, I recommend that the Company develop a market analysis to inform its pricing and ensure it is in line with what third-party charging providers offer in the state of Georgia. The Colorado Public Utilities Commission instituted a similar process for Xcel-owned DCFC stations to ensure that the utility set pricing that did not undercut pricing by the private market,[42] which includes a number of other ongoing costs in addition to electricity.[43] The Company should file a pricing proposal with the Commission based on that market analysis, and give stakeholders and the Commission an opportunity to review and provide input on that proposal.

**Q. Please summarize your recommendations with respect to the Community Charging program.**

**A.** I recommend that the Commission:

- Direct the Company to develop, provide, and apply transparent siting criteria that include specific geographic minimum distances from an existing or proposed third party EV charging station for its Community Charging program as described above such that new Company-owned charging stations appropriately complement the EV charging market rather than compete with private market participants;

- Direct the Company to provide a list of its proposed utility-owned stations, updated on at least a quarterly basis, to inform the public of locations it has identified as potential gaps in private charging deployment;

- Direct the Company to allow private sector providers the opportunity to develop a proposed station where the private sector charging provider informs the Company that it is building or intends to build a public charging station within the proposed limits of

[42] *See* Colorado Public Utilities Commission, Proceeding No. 21AL-0494E, Commission Decision Granting, in Part, Exceptions to Recommended Decision No. R22-0378 and Requiring Compliance Filing, at 5 and 11 (Aug. 3, 2022).
[43] *See* EVgo, The Costs of EV Fast Charging Infrastructure and Economic Benefits to Rapid Scale-Up (explaining that "[w]hile electricity remains the largest cost driver, the full stack of costs also includes equipment at the early stage of a technology adoption curve, construction and installation costs, ongoing networking and maintenance costs, among other factors."). Available at https://www.evgo.com/white-papers/costs-ev-fast-charging-infrastructureeconomic-benefits-rapid-scale-up/.

one of Georgia Power's proposed locations, and to remove the site from its Community Charging program, and;

- Direct the Company to develop a pricing proposal for its Community Charging program subject to stakeholder input—as a compliance filing within 30 days following a final order in this case—to align its Community Charging pricing with the competitive market.

## IV. CHARGE IT – ELECTRIC VEHICLE RIDER

**Q. Please describe Georgia Power's proposed Charge It – Electric Vehicle rate rider.**

**A.** As Company witness Legg explains, the Charge It – Electric Vehicle (CIEV) rider will:

> "modify how the Power & Light tariffs price commercial EV charging loads. Specifically, the new Charge It rider will modify the monthly billing demands by using Billing Demand Adjustment Factors as specified in the tariff. Charge It is a temporary rider that will expire either at the end of 48 months or when the rolling 12-month load factor for the account reaches 15% or greater – whichever comes first. Participation in Charge It is available to new, separately metered charging loads that are served on Georgia Power's system after January 1, 2023."[44]

**Q. How can the CIEV rider complement the make-ready program to enable a competitive charging market?**

**A.** The CIEV rider is a well-structured rate that offers an excellent opportunity to encourage additional investment in EV charging infrastructure if implemented appropriately, and EVgo commends Georgia Power for this aspect of its proposal. The procurement of power represents a significant portion of operating costs borne by EV charging operators, so the availability of Commercial EV rates – rates that account for the uniqueness of DCFC loads – factors into the decision making for developing new charging stations. In particular, the demand charge component of traditional commercial rates can present a barrier to increased deployment of public DCFC infrastructure. The CIEV rider lowers that barrier

[44] Direct Testimony of Larry T. Legg at 17.

by reducing the demand charge borne by public DCFC operators for a limited period of time. The CIEV rider can therefore be a valuable catalyst for greater investments in EV charging infrastructure.

Typically, in well designed and comprehensive utility EV charging programs, both EV rates and make-ready are complementary programs. They work hand in hand because each program addresses different aspects of the economics of public charging. In the examples of successful make-ready programs discussed previously, many of these utilities have both a make-ready program and EV rates.[45] Therefore, it is essential that both the Make-Ready program and CIEV rider work in parallel and complement each other. This is easily achieved when they have consistent eligibility requirements. Both programs are essential and complementary pieces of a comprehensive transportation electrification program and are not interchangeable. Unfortunately, as proposed, the CIEV rider will be broadly available to new, separately-metered charging stations, whereas the make-ready program will be limited to a subset of charging station deployments (as discussed above). This misalignment risks compromising the value of both program offerings; the CIEV rate is unlikely to realize its full potential unless Georgia Power makes its make-ready program more broadly available, and vice-versa.

**Q. Do you recommend any modifications to the CIEV rider?**

**A.** Yes. I recommend that Georgia Power make the rate available not only to new, separately metered charging loads as it proposes, but also to charging stations placed in service before January 1, 2023.

[45] *See* Colorado Public Utilities Commission, Proceeding No. 20A-0204E, Commission Decision Granting Application with Modifications (Jan. 11, 2021); New Mexico Public Regulation Commission, Case No. 20-00237-UT, Final Order Adopting Recommended Decision (Nov. 12, 2021); State Corporation Commission of the State of Kansas, Docket No. 21-EMKA-320-TAR, Order (Dec. 6, 2021).

**Q. Why is it important that the Company make the CIEV rider available to both existing and new charging stations?**

**A.** Doing so will help ensure that all similarly-placed charging stations in Georgia Power's service territory (charging stations with low load factors) have equal and non-discriminatory access to the beneficial rate. Importantly, in limiting the availability of the rider to stations with a rolling 12-month load factor of 15% or less as proposed, the Company can ensure that stations with higher utilization rates will not receive a demand charge discount.

**Q. Please summarize your recommendations with respect to the CIEV rider.**

**A.** I recommend that the Commission extend the availability of the CIEV rider to separately-metered charging stations installed before January 1, 2023. Further, I recommend that the Commission view both the CIEV rider and Georgia Power's make-ready program as complementary tools to catalyze the development of public charging infrastructure in the Company's service territory, each of which should be made broadly available in order to spur market uptake.

## V. CONCLUSION

**Q. Please summarize your recommendations to the Commission.**

**A.** I recommend that the Commission:

- Approve Georgia Power's proposal to continue funding the make-ready program;
- Direct Georgia Power to develop and publish—as a compliance filing within 30 days following a final order in this case—updated make-ready program rules and requirements that expressly allow participation by third-party charging station owner-operators;
- Direct Georgia Power to develop and implement a transparent, points-based scoring rubric to prioritize make-ready program applications in collaboration with EV charging service providers and other industry stakeholders;

- Direct Georgia Power to allocate funds to make-ready program applications already received by the Company that meet the updated make-ready program rules and requirements;

- Direct the Company to develop, provide, and apply transparent siting criteria that include specific geographic minimum distances from an existing or proposed third-party EV charging station for its Community Charging program as described in my testimony such that new Company-owned charging stations appropriately complement the EV charging market rather than competing with private market participants;

- Direct the Company to provide a list of its proposed utility-owned stations, updated on at least a quarterly basis, to inform the public of locations it has identified as potential gaps in private charging deployment;

- Direct the Company to allow private sector providers the opportunity to develop a proposed station where the private sector charging provider informs the Company that it is building or intends to build a public charging station within the proposed limits of one of Georgia Power's proposed locations, and to remove the site from its Community Charging program;

- Direct the Company to develop a pricing proposal for its Community Charging program subject to stakeholder input—as a compliance filing within 30 days following a final order in this case—to align its Community Charging pricing with the competitive market, and;

- Approve Georgia Power's proposed CIEV rider, but direct the Company to remove discriminatory restrictions on the availability of the CIEV rider and make that rate available to separately-metered charging stations installed before January 1, 2023.

**Q. Does this conclude your direct testimony?**

**A.** Yes.

**BEFORE THE PUBLIC SERVICE COMMISSION**

**STATE OF GEORGIA**

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| **In Re:** | : | |
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| **GEORGIA POWER COMPANY'S** | : | **DOCKET NO. 44280** |
| **2022 RATE CASE** | : | |
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## CERTIFICATE OF SERVICE

I hereby certify that I have served the following parties with the foregoing Direct Testimony of Colin Murchie on behalf of EVgo Services, LLC via electronic mail as follows:

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Counsel for EVgo

BY MR. VIJAYKAR:

Q Mr. Murchie, have you prepared a summary of your testimony?

A I have.

MR. VIJAYKAR: Madam Chair?

MADAM CHAIR PRIDEMORE: Please go ahead with your summary.

MR. MURCHIE: Thank you, Madam Chair and members of the Commission, staff. I'll give the summary of my summary.

In essence EVgo is a private developer, owner, and operator of DC Fast Chargers in the state of Georgia and throughout the nation, the largest such operator with over 850 locations and more than 1,000 chargers. Essentially, we want to do business in Georgia, and we want to expand that business.

In order to do so, we would look forward to the constructive participation of the utility in the form of its Make Ready Programs; however, we would like to simply know the rules of those programs, cold and going in. And our experience has been that we are sometimes unable to predict the outcome of a Make Ready application, and most recently, we've been informed by Georgia Power that our business model will be deemed ineligible to participate in the Make

**Ready Program or, in fact, to receive electric service in our own account at all.**

**This is not an outcome that we find predictable or conducive to expansion of the business. Similarly, on the Community Charging program, we feel that there is, in fact, likely a role for the investor-owned utility in expanding, you know, provider/resort-type service to parts of Georgia that might otherwise go unserved.**

**However, again, we simply would like to see more empirical, predictable, objective criteria for those, probably in the form of geographic-specific criteria and possibly a right of first refusal-type construct, as referenced by Georgia Power previously in cross.**

**Finally, on the CIEV rate, we fundamentally think it's a good rate. No rate is perfect, but simplicity is virtue in some ways in ratemaking, as well. And we simply think that a good rate is a good rate and doesn't start or stop being a good rate on January 1, 2023. We think that the rate should be made available to existing operations, as well as new build, if it is, in fact, a well-constructed rate. And we believe that some of the internal limitations and constructs within the rate do so limit its**

impact.

MR. VIJAYKAR: Thank you, Mr. Murchie.

Commissioners, tender the witness for cross.

MADAM CHAIR PRIDEMORE: Commissioners?

Commissioner Echols.

VICE CHAIRMAN ECHOLS: Thank you, Madam Chair. Just a couple of quick questions.

MR. MURCHIE: Sure.

VICE CHAIRMAN ECHOLS: Won't the NEVI plan and the, quote, "IRA money" resolve some of these issues that you're talking about? Aren't you going to be getting some subsidies from that?

MR. MURCHIE: Conceivably. Especially in the first years of the NEVI plan are specifically targeted at interstate highway corridor service, which has been the most challenging for owner/operators like ourselves. This can present a little bit of an iterative solution problem in that it's hard to say what is unserved or what will be unserved until we start to see some of the outcome of that significant amount of funding.

In general, I would say our economics are not binding. We are clearly able to build some number of fast charging stations in Georgia Power currently. This is despite headwinds, including what can be

difficult Make Ready costs, what can be difficult rate design and relatively low EV adoption.

If we see more money coming in, whether it's in the form of federal funds, whether it's in the form of Make Ready, whether it's in the form of a better load load factor rate design, there can be more stations, more people can be served.

VICE CHAIRMAN ECHOLS: I was visiting with James Tillman, one of your employees in California, and looking at chargers along the south bay of LA, and he took me to a Chevron station that had a charger.

MR. MURCHIE: I've have been there, yeah.

VICE CHAIRMAN ECHOLS: And he told me that without the California incentives that it was -- that before that unit ever turned a profit, y'all would have to replace it in ten years. That it was -- it was that difficult.

I mean, is that accurate? Are there a lot of places where an incentive is required to make it work?

MR. MURCHIE: There absolutely are. In 2022, 2023, in this state of EV adoption, the chicken and egg problem, as mentioned, there are places where incentives are needed to see charger deployment.

**VICE CHAIRMAN ECHOLS:** Last question: So is there a utilization number that you have to hit in order for that thing to break even? Some of Georgia Power units are getting, you know, less than 5 percent utilization.

So are you -- do you have to -- do you have to have it utilized 50 percent? 30 percent? Do you have a number?

**MR. MURCHIE:** So, obviously, as somebody who works for a publicly held company, I have to be a little bit careful handing out this number, but what I will say is that sub-5 percent utilization would not be enough for the charger to be cash flowing positively in many places.

**VICE CHAIRMAN ECHOLS:** Wait a second. Did you say 75?

**MR. MURCHIE:** No, no, sub. Less than 5 percent.

I will say that above 20 to 25 percent, it actually begins to impact user experience. You may to start see queuing. So you're trying to sort of, you know, thread that needle.

**VICE CHAIRMAN ECHOLS:** Okay. Thank you so much.

**MADAM CHAIR PRIDEMORE:** All right. Very good.

Georgia Public Service Commission.

MR. WALSH: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. WALSH:

Q Good evening. My name is a Dan Walsh with the Service Commission staff.

Is it correct that DC Fast Chargers serve a variety of needs for the EV drivers?

A Yes.

Q For DC Fast Chargers installed outside of the Make Ready Program, who pays for the cost of the EV charging station equipment?

A EVgo in our case.

Q Okay. And EVgo has 48 DC Fast Chargers in Georgia; is that correct?

A I believe we have 48 Fast Chargers currently operational, yes, in the boundaries of the state of Georgia. I wouldn't want to rep to how many of those were with Georgia Power versus EMC.

Q And it's your testimony, then, that those chargers were not subsidized by Georgia Power's electric utility customers; is that correct?

A That's correct.

Q If I can get you to refer to page 5, lines 8 through 10 of your testimony.

A Sure.

Q You asked the Commission to direct Georgia Power to develop and implement a transparent points-based scoring rubric to prioritize Make Ready Program applications in collaboration with EV charging service providers and other industry stakeholders.

A Correct.

Q Is it -- is there any prioritization system currently?

A So Georgia Power, in its terms and conditions and other guidance documents provided to users in the Make Ready Program, none of which I have in front me, does indicate that there are certain criteria considered in prioritizing its Make Ready awards; however, it's a brief qualitative list in one sentence in the Ts and Cs.

We'd prefer to have more than that to go off of, especially since our recent experience has been that Georgia Power, basically, through an internal staff document, has deemed that EVgo itself is ineligible for all Make Ready incentives and, in fact, that they will not be approving new service applications from us.

Q Which locations do you believe should be prioritized to receive the Make Ready subsidy from electric utility customers?

A I'm not prepared to make that policy decision;

however, I'd like to be able to interpret it and predict the outcomes of that policy decision in an empirical way.

Q On page 13, lines 11 through 14 of your testimony, you state that you're not aware of any other Make Ready Program that limits participation to sites hosts and excludes third-party owners and operators besides Georgia Power's program.

And EVgo is a third-party owner or operator; correct?

A In most cases, yes, and we do also serve as a vendor in some cases along the lines of ChargePoint. But generally speaking, that's correct.

Q Is it your testimony that third -- allowing third-party owners and operators to participate would enable a level playing field?

A Yes.

Q So is it, then, your view that the Make Ready Program itself will create an unlevel playing field the way it's currently proposed?

A No, and I don't see how the one follows from the other.

Q Well, let me back up. I thought you were saying -- it's your testimony, I thought, that you're not aware of any other programs that would limit the participation to site hosts and exclude third-party owners

and operators besides the Georgia Power program.

A I see. I thought you were making a distinction between the eligibility criteria and the existence of the program. Given a Make Ready Program, yes, I think that restricting eligibility and not permitting third-party owner/operators creates an unlevel playing field.

Q Okay. Thank you.

MR. WALSH: Madam Chair, that's all the questions that I have.

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: ChargePoint?

MR. DUNBAR: No questions.

MADAM CHAIR PRIDEMORE: Commercial Group?

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power and Light?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA?

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch?

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resources Supply Management?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Ms. Medlyn?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Power?

MR. HEWITSON: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Good evening, Mr. Murchie.

A Good evening, sir.

Q Steve Hewitson on behalf of Georgia Power. Just a few questions for you.

**Does EVgo have any concern with Georgia Power installing DC Fast Chargers at its Community Charging sites, as opposed to Level 2 chargers?**

**A No.**

**Q And based on your understanding of how the program works, would you say Georgia Power's participation in the EV market through the Community Charging Program is complimentary to private investment rather than a hindrance?**

**A It could be designed to be so. I don't believe that there's enough detail or enough guardrails on the program to ensure that that's the case right now.**

**Q Okay. One of your recommendations is to require the company to file with the Commission a proposal for how it will price charging services that is based on market analysis; right?**

**A Yes, sir.**

**Q Okay. You suggest this requirement because you want to give third-party charging providers and other stakeholders an opportunity to provide input regarding Georgia Power's pricing; is that right?**

**A More so regarding their own pricing, the determinates, and pricing that can be somewhat complex. For instance, in some cases we have OEM discounts, we have new membership discounts, we have fleet offerings, et cetera. So just to be able to participate and inform what I believe**

Georgia Power wants to be essentially a market competitive rate and not undercut the market.

Q I assume you've reviewed Georgia Power's pricing for charging services?

A I have.

Q Did you find that Georgia Power charges prices in line with the market currently?

A I think that would be too simple of a statement; however, I think they're within a range where a workshop in public process could produce a reasonable outcome.

Q And let me go back. When we talked about the Community Charging Program being complimentary -- Georgia Power's investment being complimentary with private investment, you said it's a little bit too early to tell, and there'd be some guardrails.

Were you here when I asked the Double AACE panel if there was a right of first refusal provided? Would that be one of the guardrails that you think that EVgo would support?

A Yes, it is one of the guardrails. To be frank, this is a somewhat emerging area of regulatory practice, figuring out how to ensure that IOU participation is complimentary and doesn't depress investment. That is one of the ideas that seems to be gaining traction that's based

along with some form of geographic or supply and demand criteria.

Q Great. Thank you, Mr. Murchie. That's all I have for you.

A Thank you, sir.

MADAM CHAIR PRIDEMORE: Redirect?

MR. VIJAYKAR: No redirect.

MADAM CHAIR PRIDEMORE: There's no redirect. Are we moving anything into evidence?

MR. VIJAYKAR: I did make the request to --

MADAM CHAIR PRIDEMORE: Nothing new?

MR. VIJAYKAR: Nothing new.

MADAM CHAIR PRIDEMORE: All right. Thank you for coming. You're excused.

MR. MURCHIE: Thank you, ma'am.

MADAM CHAIR PRIDEMORE: Okay. Georgia Association of Manufacturers, I believe you have two panels?

MR. JONES: Well, we do. We're going to call Dr. Roger Tutterow to the stand first.

MADAM CHAIR PRIDEMORE: Dr. Tutterow first.

MR. JONES: Here he comes. And then we have agreed to put our other two witnesses up together after this.

MADAM CHAIR PRIDEMORE: Pollock and LaConte?

MR. JONES: That's correct. I think it's LaConte.

MADAM CHAIR PRIDEMORE: LaConte. Thank you.

MR. JONES: Oh, and to be clear, I would waive any objection to Georgia Power splitting up cross on the combined panel, because I think they plan to have one attorney cross one, and one cross the other.

MADAM CHAIR PRIDEMORE: Agreed. That's fine.

MR. JONES: Dr. Tutterow, will you raise your right hand.

Whereupon,

ROGER C. TUTTEROW, Ph.D.,

having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. JONES:

Q Dr. Tutterow, please state your name for the record.

A Roger Tutterow.

Q Thank you.

And how are you employed, sir?

A I'm professor of economics at Kennesaw State University.

Q Okay. Thank you.

And did you file or cause to be prefiled in this testimony 17 pages of written Q-and-A testimony?

**A Yes, I did.**

**Q Okay. Do you have any corrections you need to make to that testimony?**

**A Not of which I'm aware.**

**Q Okay. Thank you.**

**And if I were to ask you the same questions that are contained in your prefiled direct testimony, would your answers be the same?**

**A Yes.**

**MR. JONES: Okay. Madam Chair, I would ask that the witness's Q-and-A testimony be copied into the record as if read from the stand.**

**MADAM CHAIR PRIDEMORE: So moved.**

**(Whereupon, the prefiled direct testimony of Roger C. Tutterow, Ph.D. follows:)**

**DIRECT TESTIMONY OF**
**ROGER TUTTEROW, PH.D.**
**ON BEHALF OF**
**GEORGIA ASSOCIATION OF MANUFACTURERS**
**DOCKET NO. 44280**

**Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.**

A. My name is Roger Tutterow. I am Professor of Economics at Kennesaw State University, 560 Parliament Garden Way, Kennesaw, GA 30144.

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.**

A. I received a Bachelor of Science in Decision Sciences from Berry College, a Master of Arts in Economics and a Doctor of Philosophy in Economics, both from Georgia State University. Subsequent to my graduation, I taught at West Virginia University in Morgantown, West Virginia before accepting a position at Kennesaw State University. At Kennesaw State University, I served as a tenured professor in the Department of Economics & Finance. From 1995 to 2005, I served as Chair of that department. In 2005, I moved to Mercer University where I served as Dean of the Stetson School of Business during 2005 and 2006 and as a tenured Professor of Economics from through 2014. In 2014, I returned to Kennesaw State University as a tenured Professor of Economics. I also serve as Director of the Econometric Center and hold the Henssler Financial Endowed Chair. I have taught a variety of courses in economic theory, finance theory and quantitative analysis at the undergraduate and graduate level. In addition, I conduct research, speak to professional groups and serve as a consultant to businesses. I also have provided

expert testimony on economics, financial and statistical matters in state and federal court, before the Georgia General Assembly and before this Commission in the 2004, 2007, 2010, 2013 and 2019 Georgia Power Company Rate Cases.

**Q. IN ADDITION TO THESE QUALIFICATIONS, HAVE YOU SERVED IN ANY OTHER CAPACITIES THAT WOULD GIVE YOU SPECIAL EXPERTISE AND INSIGHT WITH REGARD TO THE GEORGIA ECONOMY?**

A. Yes. From 2003 until 2011, I served on the Council of Economic Advisors to Governor Perdue. From 2011 through 2019, I served in that capacity for Governor Deal. I currently serve on the Council for Governor Kemp. In 2010, I was named to serve on the Special Council on Tax Reform and Fairness for Georgians, which was charged with conducting a comprehensive review of Georgia's tax code and recommending changes to the General Assembly.

**Q. WHAT ARE THE PURPOSES OF YOUR TESTIMONY?**

A. The purposes of my testimony are:

(1) To describe the importance of manufacturing to the Georgia economy;

(2) To address the impact of energy costs on manufacturing and outline the regional and global competitive pressures that impact manufacturing and distinguish manufacturing from other classes of customers served by Georgia Power Company ("Georgia Power");

(3) To discuss the economic changes that have occurred since my last testimony before the Commission;

(4) Relative to this rate case, to emphasize the importance of a Commission decision that recognizes the importance of manufacturing to the Georgia

economy and policies that encourage continued growth and investment by manufacturers in the state; and

(5) To support the retention of any existing rate design or other mechanisms that promote the goal of a healthy manufacturing base in Georgia, as well as the adoption of positions and proposals that will further that goal in light of the harshly competitive environment posed by surrounding states and other countries as locations for potential manufacturing investment.

## I. THE IMPORTANCE OF MANUFACTURING TO GEORGIA

**Q. WHY DOES MANUFACTURING MATTER TO GEORGIA?**

A. As I have argued in the past, it remains critical to recognize the importance of manufacturing when considering matters of public policy. Manufacturing matters to Georgia for several reasons: (1) it creates wealth for local communities; (2) it remains a significant contributor to Georgia employment; (3) it pays premium compensation to its employees; (4) it plays a disproportionate and important role in the economies of Georgia's smaller communities and local areas; and (5) it produces the largest positive multiplier or "spillover" effects that support related industries and other sectors of the economy.

**Q. PLEASE DESCRIBE WHAT YOU MEAN BY CREATING WEALTH FOR LOCAL COMMUNITIES.**

A. When assessing the impact of a business or sector on a community, it is crucial to recognize the role of that business in "wealth creation"; that is, the degree to which that business or sector creates wealth in the community rather than redistributing wealth that is already present. For this reason, economic developers have long recognized the export-based model of economic growth. Under the export-based

growth model, the ability of a region to grow is linked to the presence of industries that export their products outside that region. In its crudest form, one could argue that, in the absence of the ability to export products outside a region, the inhabitants are selling goods and services to each other and thus only redistributing the collective wealth of the community.

**Q. AREN'T THERE SOME SERVICES THAT ARE EXPORTED OUT OF STATE?**

A. Yes. Major urban areas that are hubs for professional services do, in fact, export those services to some customers outside the region. One example would be a law firm that serves clients from other states. Likewise, an information technology firm that sells software to businesses in other communities, states or countries also "creates wealth." However, manufactured products are distinctive because of the degree to which they are sold outside their region, or even country, of production. For example, at the national level, goods comprised 69% of U.S. exports in 2021. Over 52% of these exported goods were manufactured capital and consumer goods. The remainder, which include agricultural products and industrial supplies, are products that also include a manufacturing component.

**Q. HOW MUCH DOES MANUFACTURING CONTRIBUTE TO GEORGIA EMPLOYMENT?**

A. Manufacturing employment remains significant in Georgia. As of August 2022, the manufacturing sector provided roughly 412,900 jobs in Georgia – or about 8.6% of all non-agricultural employment. In terms of output, the role of manufacturing in the Georgia economy is even more pronounced. For 2021, the manufacturing sector accounted for $64.9 billion, or 9.4%, of Georgia's Gross Domestic Product. Further, if one factors out the public sector, then manufacturing accounted for

10.6% of the private industry component of Georgia's GDP – or roughly $1 in every $9.47 of Georgia's private economic output.

**Q. HOW DOES GEORGIA'S MANUFACTURING OUTPUT COMPARE WITH OTHER STATES?**

A. Georgia is the 11th largest state in the nation in terms of the value of its manufacturing output. By way of comparison, the value of manufacturing's output in Georgia is larger than the manufacturing output of the smallest 33 states combined.

**Q. WHAT HAS BEEN THE EXPERIENCE OF GEORGIA'S MANUFACTURING BASE OVER THE LAST 15 YEARS?**

A. Manufacturing's share of nonagricultural employment in Georgia stands at 8.6%. Georgia lost a significant number of manufacturing jobs during the "Great Recession" of 2008-09, but this subsequently stabilized at roughly the same level from 2010 to 2019. Manufacturing's share of employment fell again, modestly, during the COVID-19 pandemic, but again has been restored to its prior levels. This recent shift to manufacturing expanding more in line with broad employment is likely, to some degree, the effect of shifts in state policy including the tax treatment of energy and the recognition of manufacturing's importance in decisions by this Commission. It is important that the Commission continue this recognition and not make decisions that would impair this stabilization or to discourage future investment in manufacturing.

**Q. TO WHAT EXTENT DOES MANUFACTURING PAY PREMIUM COMPENSATION TO ITS EMPLOYEES?**

A. Manufacturing is distinguished from many other economic sectors because of the higher-than-average compensation it provides. For example, during 2021, average weekly wages in manufacturing were approximately 1.9% higher than the *statewide* average for non-manufacturing employment, but importantly, outside of the Atlanta Metropolitan Statistical Area ("MSA"), manufacturing wages exceed non-manufacturing wages by 16.6%. Thus, the premium of compensation that is paid by manufacturers is even greater – and significantly so – in the less urban regions of the state. In many rural communities, a local manufacturer is both the largest and best compensating employer.

However, even comparing average weekly wage data understates the premium in total compensation paid by manufacturing firms because it does not capture the value of employer–provided fringe benefit packages. At the national level, employers' actual contributions to discretionary fringe benefit programs were 27.4% higher in goods-producing firms than for service-producing firms.

**Q. CAN YOU DISCUSS THE DISPROPORTIONATE IMPACT THAT MANUFACTURING HAS ON GEORGIA'S MORE RURAL COMMUNITIES?**

A. Manufacturing plays a disproportionately large role in the rural economies of Georgia. In August 2022, manufacturing represented 5.9% of non-agricultural employment in the Atlanta MSA and 12.9% of employment outside of the Atlanta MSA. In other words, manufacturing employment comprises twice as large a percentage of employment outside the 28-county Atlanta MSA as it does inside the Atlanta MSA.

**Q. WHAT DO YOU MEAN BY THE "MULTIPLIER EFFECT" AND WHY IS IT CRITICAL FOR UNDERSTANDING THE IMPORTANCE OF MANUFACTURING?**

A. When evaluating the importance of various sectors of the economy, it is important to recognize the broad impacts of spending in one sector upon activity in other sectors. The indirect and induced spending associated with manufacturing creates a "multiplier effect" of the employment directly associated with manufacturing.

**Q. CAN YOU DESCRIBE THE INDIRECT AND INDUCED EFFECTS?**

A. Sure. When a manufacturing firm purchases products, services or raw materials from local suppliers, employment by the supplier enterprises is enhanced. This is known as the indirect effect. Further, when the employees of a manufacturer or its suppliers spend their wages in their community, that spending also supports employment at a variety of businesses. This is known as the induced effect.

The size of the "multiplier effect" in manufacturing is confirmed by data from the U.S. Department of Commerce. Based on its 2021 Input-Output Accounts Data and 2020 Regional Data, the manufacturing sector has a total requirements multiplier of 2.31. In other words, every dollar of final demand for manufactured products generates an additional $1.31 in demand for products that are required to produce the original manufactured product.

Of the fifteen sectors in the Department of Commerce classification, the manufacturing sector had the highest multiplier effect.

Of course, the multiplier effects of manufacturing spill over broadly into most industries in the economy. Of the $1.31 in additional product demand associated

with the multiplier for manufactured products, over $0.74 of that demand is for products outside the manufacturing sectors. The professional and business services, mining, agriculture and wholesale trade sectors benefit the most from manufacturing's multiplier effect. For example, for each dollar of final demand for manufacturing products, there is an associated demand of over $0.14 in demand for professional and business services and over $0.13 of activity in wholesale trade. Finally, these multipliers reflect linkages between the final demand for manufactured products and the associated demand for products from other industries. However, they do not capture the effect of the induced spending of employees at the manufacturing and associated businesses in their communities. Given the competitive compensation paid by the manufacturing sector, that induced spending is likely quite significant.

## II. THE IMPACT OF ENERGY COSTS ON MANUFACTURERS

**Q. DO INCREASES IN ENERGY COSTS IMPACT THE ABILITY OF MANUFACTURERS TO CONTINUE PRODUCTION AND COMPETE EFFECTIVELY?**

A. Yes. Higher electricity rates raise the cost to businesses of producing goods and services. Funds available to finance capital investment are lowered as well. For industrial customers, electricity is not consumed as a final product itself, but rather, is an input into the process through which they produce goods. To use the syntax of microeconomics, energy is a "factor of production" rather than consumption good. As with other factors of production, higher energy rates will increase the cost to industrial customers of producing goods. This increase in cost likely will lead to a reduction in competitiveness, lower production and employment or both, depending on the ability of the business to pass on the higher production cost. In a

competitive global marketplace, manufacturers find it difficult to pass along increased costs of production such as the cost of electricity.

**Q. WHY CAN'T MANUFACTURERS SIMPLY PASS ALONG THESE COSTS IN THE PRICE OF THE PRODUCTS THEY SELL?**

A. In the current competitive environment for manufacturers, it is not easy or even possible to do in many cases. Global competition, especially from low production cost areas of the world, serves as a strong constraint on the ability of manufacturers to pass along cost increases to customers. Customers are more likely to press manufacturers for lower prices than to pay more for the products they produce. Manufacturers, then, are constantly challenged to lower their costs of products to compensate for higher raw material, labor, and energy costs. There are practical limits, including regulatory restrictions, on their ability to do so. When manufacturers cannot meet these pressures, they generally lose customers to a lower cost producer, in many cases from another region or country.

**Q. CAN HIGHER ENERGY COSTS IMPACT A MANUFACTURER'S DECISION AS TO WHERE TO LOCATE PRODUCTION?**

A. Yes. Facing the pressures of surviving in the current environment, manufacturers need to maintain a competitive cost structure in order to succeed. If the costs of production in a particular region, or state, become less competitive than readily available alternatives, a manufacturer might need to relocate production to lower cost states or countries. Energy costs certainly can be a driving factor in this regard.

Further, if a manufacturer with multiple production facilities decides to expand production, there will be a clear preference for expanding activity in the facilities

with the lower production cost. Those locations within the United States with lower production cost are the more likely beneficiaries of any shift in location.

**Q. HOW WOULD YOU DESCRIBE THE REGIONAL ENVIRONMENT IN TERMS OF COMPETITION FOR MANUFACTURING?**

A. There is significant competition for manufacturing investment and jobs from surrounding states. Many industrial customers have production facilities in other states in the region. Since labor flows easily between states, labor differentials will be smaller and energy costs are even more likely to be a factor in domestic location decisions.

With regard to local competition, what matters are the rates charged by electric utilities in similarly situated locations. In the case of Georgia, the most natural comparables would be the rates charged in other Southeastern states including Alabama, North Carolina, South Carolina and Tennessee. To the extent the cost of electricity in Georgia is greater than in neighboring states, it acts as a disincentive to invest and create jobs in the state.

The importance of energy costs for regional locations decisions has long been recognized by economic developers. While incentives are sometimes employed to attract new enterprises, they are less likely to be used to retain existing enterprises. Thus, recognizing the role of base energy prices in the competitive position of existing enterprises is important for retaining, and encouraging the expansion of, existing industry. In a very real sense, Georgia competes with its closest neighboring states to retain and expand industry and manufacturing and the myriad of benefits they bring to the economy and well-being of all Georgia citizens.

That energy costs affect location decisions for goods producing industries was recognized by the Special Council on Tax Reform and Fairness for Georgians on which I served in 2010. The council acknowledged its importance, and the uniqueness of the challenge faced by manufacturing and agricultural businesses, in recommending that energy used in manufacturing be exempted from sales taxes. While that recommendation was translated into policy, the removal of the sales tax from energy only reduced an existing competitive disadvantage faced by Georgia producers.

**Q. ARE INDUSTRIAL AND OTHER CUSTOMER CLASSES EQUALLY IMPACTED BY HIGHER ELECTRICITY RATES?**

A. No. In general, while higher electricity rates will increase the cost of production for industrial customers or other customer classes, the magnitude of that effect will vary across sectors of the economy and across businesses within each sector. For reasons upon which I will further elaborate, the impact of higher electric rates on manufacturers is more adverse than other customer classes.

**Q. WHAT FACTORS DETERMINE THE MAGNITUDE OF THE EFFECT OF HIGHER ELECTRICITY RATES ON BUSINESSES?**

A. Higher electricity rates will impact all businesses primarily through changing their cost structure. The magnitude of the effect of an increase in electricity rates on the cost structure is determined by the proportion of the business's operating cost that is represented by the cost of electricity as well as their ability to substitute among energy sources. For most industrial customers, energy and labor are generally recognized as the two largest costs for conversion of raw materials into final products. For some industrial customers, energy is the largest cost of conversion.

Equally important is the effect of a rate increase on the competitive environment in which the customers operate. Specifically, if an increase in electricity rates leads to a comparable increase in production cost for all competitors in a market area, then the effect on the competitive position of a single business is mitigated. If a customer's competitors are in areas not subject to the rate increase, then an increase in costs associated with a rate increase will diminish the customer's competitive position. These competitors can be global or regional.

**Q. PLEASE ELABORATE ON THE ISSUE OF REGIONAL COMPETITION.**

A. Manufacturers generally will invest capital in locations where they can achieve the lowest costs of production. This is particularly the case for manufacturers that operate in several states within a region. As noted above, a manufacturer's decision as to where to place, consolidate, or curtail production can be significantly influenced by the cost of energy.

**Q. HOW DO INDUSTRIAL AND OTHER CUSTOMERS COMPARE IN THIS REGARD?**

A. One of the challenges facing industrial customers, and one which differentiates their class from other classes of customers, is that they face competition regionally, nationally and globally rather than just locally. Thus, many of the industrial customers' competitors will not be subject to the same increase in electricity rates and resultant increase in production costs. As such, when an industrial customer receives a rate increase, it will hurt their competitive position versus its competitors who are operating outside the regulated area.

It is understood that no business would welcome a rate increase. However, a rate increase generally has less effect on electricity customer who compete only locally because their competitors are likely to be subject to the same increase.

Many industrial businesses have broad geographic markets and multiple production facilities. These production facilities within a company compete among themselves in the sense of having production levels varied in response to cost considerations, including the cost of electricity. They also compete for new investment on the basis of production costs.

Thus, an increase in electricity rates would likely have a greater impact on production, facility location and investment for expansion decisions of industrial class customers than for business that compete only locally. Thus, the outcome of these decisions impact job retention and job creation.

Further, the importance of initially selecting or remaining in a specific geographic location, and hence being subject to a specific utility rate structure, is not the same for all customer classes. Specifically, for businesses who compete only locally, close proximity to their customers and the cost of real estate drive location decisions more than the cost of electricity.

For example, for these businesses, being located in close geographic proximity to their customers is the crucial consideration. Since customers tend to patronize commercial businesses that are close to their residence or employment, the business location is a determinant of the relevant customer market. For manufacturers, however, the decision as to where to locate or expand a production facility is most likely based on the cost of production, of which energy cost is a substantial component.

Businesses that depend on geographic proximity to customers will be less likely to reduce or cease operations in response to an increase in their electricity rates. As has been evident by the regional and international migration of manufacturing firms in past decades, the manufacturing sector has demonstrated the ability to relocate in response to changes in the cost of production.

## III. THE ECONOMIC ENVIRONMENT SINCE 2019

**Q. DR. TUTTEROW, YOU LAST TESTIFIED BEFORE THIS COMMISSION IN 2019, CORRECT?**

A. That is correct. I testified in the last Georgia Power rate case in November 2019.

**Q. AND YOUR TESTIMONY AT THAT TIME, LIKE NOW, SUPPORTED THE IMPORTANCE OF MANUFACTURING AND DEMONSTRATED THE UNIQUE CHARACTERISTICS OF THE MANUFACTURING CLASS OF CUSTOMERS?**

A. Yes.

**Q. HAVE THERE BEEN ANY ECONOMIC DEVELOPMENTS SINCE 2019 THAT YOU BELIEVE TO BE RELEVANT TO THE COMMISSION'S CONSIDERATION IN THIS CASE?**

A. Yes. When I testified in 2019, the national economy had been expanding for over ten years, the longest economic expansion since the end of the second World War. However, there were some indications that the pace of economic growth was slowing. Indeed, increases in the value of the U.S. dollar against the currencies of major trading partners was adversely affecting the trade sector. The strong dollar

was making U.S. exports more expensive on foreign markets. That effect is most pronounced in the manufacturing sector.

In early 2020, climate was disrupted by the Covid-19 pandemic. Both mandatory and voluntary changes in corporate and household behaviors sent the economy into a brief, but steep, recession. As measured by Gross Domestic Product, economic output fell at an 18.2% annual rate in the first half of 2020. For the two months of March and April 2020, industrial production fell by 16.5% while non-farm employment dropped by 14.4%.

The economy began recovering in May 2020. Output, as measured by gross domestic product, surpassed its pre-pandemic peak during 2nd Quarter of 2021. Industrial production surpassed its pre-pandemic high in November 2021. Non-farm payroll finally surpassed its pre-recession high in August 2022.

While surpassing pre-pandemic peaks is certainly commendable, it is also worth noting that economic activity has been slowing in recent quarters. Industrial production has decreased modestly in three of the past five quarters. Further, the Institute of Supply Management's monthly PMI (Purchasing Manager's Index) index has fallen to 50.9 as of September 2022. This index was above 60 for most of 2021. As 50 is the threshold between expansion and contraction in the manufacturing sector, the PMI is signaling that the manufacturing sector is coming under pressure of late.

Finally, inflation pressures are pervasive through the economy. While it is common to think of inflation in terms of the prices that consumers pay, it is also manifest as an increase in the prices of inputs used in producing goods. When these higher input prices are combined with upward pressure on wages, it is clear that many businesses will face challenges maintaining profit margins. Of course, in the case of

manufacturing, the cost of energy is also an important cost of producing final products.

**Q. ARE THERE REASONS TO BE OPTIMISTIC ABOUT THE STATE'S FUTURE?**

A. Yes, looking forward, I am optimistic about the Georgia economy and believe manufacturing can play a key role in its future performance. Competitive energy rates will play an important role in where that production locates. Georgia also remains committed to recruiting new corporate residents and retaining those already here. Energy cost will be important for those decisions as well. Further, infrastructure investments, including enhancements to the transportation system, such as the deepening of the port in Savannah, should also support further growth.

## IV. THE ROLE OF THE COMMISSION

**Q. WHAT ROLE DOES THE COMMISSION PLAY IN TERMS OF ENHANCING GEORGIA AS A COMPETITIVE STATE FOR MANUFACTURING INVESTMENT?**

A. The Commission plays a very important role. The rates and terms under which manufacturers receive electric service are regulated by this Commission. The financial impacts of this Commission's decision are clear. As described in other parts of my testimony, the rates and terms of service for energy service have a direct impact on the competitiveness of manufacturers and the economic decisions they make.

**Q. HOW IMPORTANT IS THE COMMISSION'S DECISION IN THIS CASE FROM THE PERSPECTIVE OF INDUSTRIAL CUSTOMERS?**

A. It is very important. I know that GAM appreciates the pro-business decisions this Commission has made in the past. To the degree that they support employment growth, the decisions benefit all Georgians, not only business entities. I encourage the Commission to adopt an order that is consistent with the policies of growth and enhancing manufacturing in the state of Georgia. We remain in challenging economic times and many manufacturers are facing uncertain futures. In my judgment, this is an important window in which to make decisions that will aggressively improve the competitive position of manufacturers from an energy cost perspective. That is a role that this Commission can play in making Georgia a competitive state for manufacturing investment.

**Q DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

MR. JONES: Thank you.

BY MR. JONES:

Q And, Dr. Tutterow, you didn't file any exhibits with your testimony, did you?

A No.

Q Okay. Have you prepared a summary of your testimony?

A Yes.

MR. JONES: Madam Chair, with your permission, I would like the witness to give his summary.

MADAM CHAIR PRIDEMORE: Please do.

MR. TUTTEROW: Chairman Pridemore, Vice-Chairman Echols, Commissioners Johnson, McDonald, and Shaw, I'm Roger Tutterow, Professor of Economics Kennesaw State University where I currently hold the Henssler Financial Endowed Chair. I previously served as Dean of the Stetson-Hatcher School of Business at Mercer University and as Chair of the Department of Economics and Finance at Kennesaw State. My academic and professional background is further summarized in my attached correct testimony.

In the past, I have testified on the importance of manufacturing to the Georgia economy and outlined the regional and global competitive pressures that

impact manufacturing.

You've already received a copy of my direct testimony, but I would like to reiterate a few concerns but also to emphasize three summary points from that testimony: First, I wish to reiterate the importance of manufacturing to the Georgia economy. Several years ago, I coauthored a discussion paper entitled "Why Manufacturing Matters to Georgia". In that paper, we outlined five factors that make manufacturing important to the Georgia economy. Specifically, we noted that manufacturing was important because it creates wealth for local communities; (2) it remains a significant contributor to Georgia employment; (3) it pays premium compensation to its employees; and (4) it plays a disproportionate role in the Georgia's smaller communities and local areas; and (5) it produces a largest positive multiplier or "spillover" effects that support related industries and sectors in the economy. These arguments are at least as valid today as they were when I first advanced them in 2007.

The most recent Department of Labor estimates suggest that the manufacturing sector accounts for 415,100 jobs. This amounts to 8.6 percent of non-agricultural employment or 10.0 percent of

private non-agricultural employment in the state of Georgia.

Further, manufacturing output accounts for 10.6 percent of private-sector gross state product. However, in assessing the impact of our sector or business on a community, it's also important to recognize the role of that business plays in "wealth creation", that is, the degree to which a business or sector creates wealth in the community, rather than redistributing wealth that is already present.

Economic developers have long recognized the export-based model for economic growth in which the ability of a region to grow is linked to the presence of industries that export products outside that region. In its crudest form, one could argue that, in the absence of an ability to export products outside a region, the inhabitants are selling goods and services to each other and thus redistributing the collective wealth of the community. Because the majority of the products that are exported from a state or country are manufactured goods, their role in wealth creation in the communities for our sector is particularly clear.

Further, when designing policies to support job creation, it is important to acknowledge that not all

jobs are created equally. As is discussed in my direct testimony, the premium compensation paid by manufacturers is distributed broadly throughout the state, that premium is highest in less urbanized parts of Georgia.

Moreover, it is generally acknowledged that the manufacturing sector has the largest "multiplier effect" of any sector of the economy; reflecting both the high compensation of its employees and the levels of indirect spending associated with the manufacturing process itself.

According to the most recent estimates from the U.S. Department of Commerce, the manufacturing sector has the largest multipliers, again, of any sector in the economy.

Further, the importance of manufacturing in the Georgia economy is magnified in the less urban parts of the state where manufacturing plays a greater role. Thus, policies that are adverse to manufacturers will have a greater negative impact in the rural parts of the state, regions that, in many cases, are already lagging urban and suburban areas in terms of growth and economic prosperity.

The second issue I wish to reiterate is the impact of energy costs on manufacturing and how it

distinguishes it from other classes of customers. The effect of changes in electric rates will vary across different sectors of the economy, and by consumer class.

For manufacturers, energy is a significant cost and in some cases, exceeds labor as the largest cost of conversion of raw materials into final product. Higher energy rates will increase the cost to manufacturers of producing goods. Depending upon the ability of businesses to pass on the higher production costs, an increase in cost lead to deterioration in competitive position.

Rate changes also have implications for location decisions. For manufacturers, the decision of where to locate and where to expand the production facility, is most likely based on the cost of production, of which energy cost is substantial component.

As evidenced by the regional and global migration of manufacturing firms, the sector has the ability to relocate in response to changes in the cost of production. Quite simply, for industrial clients, geographic proximity to customers and the costs of real estate are relatively less importance to the location decision than the cost of

**electricity.**

**Further, production facilities within a given company compete against themselves in the sense of having production levels and capital expenditures that vary in response to cost considerations. To the extent that the cost of electricity in Georgia is less competitive than in neighboring states, it would act as a disincentive to invest and create jobs in the state.**

**Simply stated, if a company has several production facilities in a region, the cost of energy would be a factor in deciding which facilities to maintain or expand. Likewise, a foreign entity considering where to investment in production facilities would likely consider energy as a primary determinant.**

**That energy costs affect locational decisions for goods-producing industries was recognized by the Special Council on Tax Reform and Fairness for Americans in which I served in 2010. The council acknowledged its importance, and the uniqueness of the challenge faced by manufacturing and agricultural businesses, and recommended that energy use in manufacturing be exempted from sales taxes.**

**I am pleased that the recommendation was**

translated into policy as it helped remove one disadvantage faced by Georgia manufacturers. In previous rate cases, the Commission has also acknowledged the importance of energy cost for industrial clients.

Third, I wish to comment on the recent turn in economic events for the past three years on the Georgia economy and manufacturing. When I last testified, in 2019, the national economy had been expanding for over ten years, the longest economic expansion since the end of the second World War.

However, there were some indications that the pace of economic growth was slowing. Indeed, increases in the value of the U.S. dollar against the currencies of major trading partners was adversely affecting the trade sector. The strong dollar was making U.S. exports more expensive on foreign markets, and that has a profound effect upon the manufacturing sector.

In early 2020, the economic climate was disrupted by the Covid-19 pandemic. Both mandatory and voluntary changes in corporate and household behaviors sent the economy into a brief, but steep, recession. As measured by Gross Domestic Product, economic output fell at an 18.2 percent annualized

rate in the first half of 2020.

For the two months of March and April 2020, industrial production fell by 16.5 percent while non-farm employment fell by 14.4. The economy began recovering in May 2020. Output, as measured by GDP, surpassed pre-pandemic levels during the second quarter of 2021.

While surpassing pre-pandemic levels is certainly commendable, it is also worth noting that economic activity has been slowing in recent quarters. Industrial production decreased modestly in three of the past five quarters.

Further, the Institute of Supply Management's monthly Purchasing Manager's Index has fallen four of the past five months reaching a level of 50.2 in October of 2022. As 50 is the threshold between expansion and contraction in the manufacturing sector, the PMI is signaling that manufacturing is coming under pressure in recent months.

Finally, inflation pressures are pervasive throughout the economy. While it is common to think about inflation in terms of the prices that consumers pay, it is also manifests as an increase in the prices used in producing goods. When these higher input prices are combined with upward pressure on

wages, it is clear that many businesses will face challenges maintaining profit margins.

Of course, in the case of manufacturing, the cost of energy is also an important cost of producing final products. Finally, I remain optimistic on the longer-term outlook for Georgia and for the role of manufacturing in our nation. But given the important role of energy as a cost of converting raw materials to final product, one would expect energy costs to play a role in deciding if, when, and by how much, specific locations will realize any production gains.

Manufacturing's share of the Georgia's non-farm payrolls reversed a multi-decade trend when it stabilized in late 2013. I am confident that that stabilization, and some recent gains in activity, reflect, in part, thoughtful decisions by the Public Service Commission and the Georgia General Assembly in the last decade.

It was my privilege to testify before this Commission on several previous cases. As before, I appear before the Commission to lend support for policies that promote economic growth, maintain and enhance Georgia's competitive position and enhance the state of manufacturing in the state of Georgia.

This concludes my summary testimony.

**MR. JONES: Thank you, Dr. Tutterow.**

**Madam Chair, the witness is available for questions from the Commission and cross-examination.**

**MADAM CHAIR PRIDEMORE: Questions from Commissioners?**

**Commissioner Echols.**

**VICE CHAIRMAN ECHOLS: Just one question, sir. Professor, good to see you.**

**MR. TUTTEROW: Nice to see you.**

**VICE CHAIRMAN ECHOLS: Again, thank you for being here.**

**I recently had a chance to tour a number of manufacturing plants just over the last couple of months. Do you think that the new solar incentives that are in the IRA could substantially help offset some of this rising energy cost on manufacturing sites that might put that solar on their building or their property, even behind the meter to kind of offset that power? Do you think that's a possibility?**

**MR. TUTTEROW: I guess it certainly is possible that solar could provide us another source of energy, and any offset against purchased energy would be welcomed in the manufacturing sector.**

**VICE CHAIRMAN ECHOLS: Thank you.**

**MADAM CHAIR PRIDEMORE: Commissioner McDonald?**

**COMMISSIONER MCDONALD: Mr. Tutterow, you talked about the broad picture of manufacturing in the state of Georgia.**

**What -- what -- if you looked at a particular company in Georgia, and whichever it was, what are they looking at for a return on their investment on an annual basis if they -- to survive?**

**MR. TUTTEROW: It would depend on a variety of factors, including what their cost of capital would be. I mean, typically, when we think about businesses making capital investment decisions, they benchmark the return on the investment project against the cost of capital. It would depend upon factors including the credit worthiness of the entity.**

**COMMISSIONER MCDONALD: Do you foresee in today's world, especially here in America and what we might be facing over the next 12 months, that the cost of money is going to even become more expensive?**

**MR. TUTTEROW: Well, I think it's likely that the cost of debt would go up. Certainly, the Federal Reserve has already raised interest rates, I think, six times this year. They are likely to do so, based on Fed Funds Futures market, at least three more. So**

debt capital will be getting more expensive.

As for what it means for equity capital depends upon a variety of conditions including, again, the riskiness of the economy and investment projects.

COMMISSIONER MCDONALD: Thank you.

MADAM CHAIR PRIDEMORE: Any other questions? Commissioner Shaw?

COMMISSIONER SHAW: Dr. Tutterow, good to see you. Always good to hear your perspective, and I appreciate everything you've done for the greater good of the state from an advisory role over the years.

MR. TUTTEROW: Thank you, Commissioner.

COMMISSIONER SHAW: Are you aware of -- I know you are, but I just want to ask: Are you aware that many of Georgia's top manufacturers, particularly ones involved in the forest industry, use biomass to produce electric -- their own energy needs?

MR. TUTTEROW: I am aware that biomass is a source of energy that, again, would be of use to manufacturers and other businesses.

COMMISSIONER SHAW: Sure. And there's -- would you also agree there's additional opportunities out there with regards to biomass and what potentials are for another renewable fuel source for the energy

needs of the state?

MR. TUTTEROW: I certainly don't want to hold myself out as an expert in alternative energy sources, but the manufacturers that I talk to clearly would welcome any opportunity to get electricity as cheaply as they can because it is such an important part of their decisions.

COMMISSIONER SHAW: And that being said, with regards to trying to buy energy on the least expensive basis as possible, I know that you -- correct me if I'm wrong, but I know on an advisory role, you were instrumental in advocating for the sales tax exemption on energy costs for manufacturers?

MR. TUTTEROW: Yes, yes, I was. I was part of the 2010 tax reform effort in the state. That was one of the recommendations that was adopted. And what I alluded to in my summary is something that I went back and looked at the data on. If you had looked in 1990 at the percentage of employment in our state that was made up by manufacturing, it came down drastically in the '90s and early 2000s in part because of global competition.

But we stabilized that in 2013, and now the manufacturing sector is doing a much better job at

maintaining its position vis-a-vis other businesses. And I think in large part, it's because of this Commission, and it's because of the sales tax exception for energy that the General Assembly passed.

COMMISSIONER SHAW: So that being said, that savings has paid major dividends with regards to creating jobs for Georgians?

MR. TUTTEROW: I think so. And certainly, if I'm a manufacturer, and I look at whether I expand my production in a surrounding state or Georgia or I do it on the West Coast, I'm going to factor in the cost of electricity.

COMMISSIONER SHAW: Okay. Thank you very much.

MR. TUTTEROW: Thank you, sir.

MADAM CHAIR PRIDEMORE: Anything else from the Commissioners?

(No Response.)

Georgia Public Service Commission, your witness.

MR. THOMAS: No questions.

MADAM CHAIR PRIDEMORE: Okay. Americans for Affordable Clean Energy?

MS. LYNDALL: No questions.

MADAM CHAIR PRIDEMORE: ChargePoint?

(No response.)

MADAM CHAIR PRIDEMORE: ChargePoint?

MR. CLARKSON: ChargePoint asked me to tell you they have no questions.

MADAM CHAIR PRIDEMORE: Okay. Thank you.

Commercial Group?

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: EVgo Services?

MR. CLARKSON: He too asked me to tell you that they have no questions. They left.

MADAM CHAIR PRIDEMORE: Mr. Clarkson, you're very busy this evening.

Georgia Coalition of Local Governments?

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: All right. GIPL?

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA?

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch?

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: All right. MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Mr. Clarkson?

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. JONES: No questions.

MADAM CHAIR PRIDEMORE: Ms. Medlyn?

MS. MEDLYN: No questions.

MADAM CHAIR PRIDEMORE: All right. Here's how we're going to do it next round. If you have questions, say so, and let me know. Okay? All right. Cool.

All right. Georgia Power?

MR. HEWITSON: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Mr. Jones, anything else you would like to do with this witness?

MR. JONES: No, ma'am, other than thank him for his time and ask that he be executed.

MADAM CHAIR PRIDEMORE: Very good. You're excused, Dr. Tutterow.

MR. TUTTEROW: Thank you, Madam Chair. Thank you to all the Commission members for your service to Georgia.

MADAM CHAIR PRIDEMORE: Thank you.

Next panel.

MR. JONES: All right. I'll call Mr. Jeff

Pollock and Ms. Billie LaConte to the stand. And because their testimonies were filed separately, if it's okay with Madam Chair, I'll go through the preliminary questions with each of them all the way through and then let them do their summaries back to back, if that's acceptable.

All right. If y'all will remain standing before you get too comfortable over there and raise your right hand for me.

Whereupon,

JEFFRY POLLOCK,

BILLIE S. LACONTE,

having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. CLAY JONES:

Q All right. I'm going to ask you some preliminary questions here. I'll start with you, Mr. Pollock.

Will you please state your name for the record.

A (Witness Pollock) Jeffry Pollock.

Q Okay. And how are you employed, sir?

A (Witness Pollock) I am president of J Pollock, Incorporated, in St. Louis.

Q And did you file or cause to be filed in this docket 75 pages of Q-and-A testimony, which included 41

pages of public disclosure direct testimony, and appendixes A, B, and C?

A (Witness Pollock) Yes.

Q Do you have any corrections you need to make to that part of your testimony?

A (Witness Pollock) Not to the testimony, no.

Q And if I were to ask you the same questions that appear in your testimony, would your answers be the same?

A (Witness Pollock) Yes.

MR. JONES: Madam Chair, I would like to ask that Mr. Pollock's testimony be copied into the record as if given orally from the stand.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimony of Jeffry Pollock follows:)

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re:** | ) | |
| **Georgia Power Company's** | ) | **Docket No. 44280** |
| **2022 Rate Case** | ) | |

# REDACTED – PUBLIC VERSION

Direct Testimony and Exhibits

of

**Jeffry Pollock**

On Behalf of

**Georgia Association of Manufacturers**

October 20, 2022

J. POLLOCK
INCORPORATED

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re:** | ) | |
| **Georgia Power Company's** | ) | **Docket No. 44280** |
| **2022 Rate Case** | ) | |

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## GLOSSARY OF ACRONYMS

| Term | Definition |
|---|---|
| **1CP** | One Coincident Peak (or Annual System Peak) |
| **4CP** | Four Coincident Peak |
| **12CP** | Twelve Coincident Peak |
| **ARP** | Alternate Rate Plan |
| **CBL** | Customer Baseline Load |
| **CCGT** | Combined Cycle Gas Turbine |
| **CCR** | Coal Combustion Residual |
| **CCOSS** | Class Cost-of-Service Study |
| **DA** | Day Ahead Pricing |
| **DSM** | Demand Side Management |
| **ECCR** | Environmental Compliance Cost Recovery |
| **FCR** | Fuel Cost Recovery |
| **GAM** | Georgia Association of Manufacturers |
| **GPC or Company** | Georgia Power Company |
| **HA** | Hour Ahead Pricing |
| **IRP** | Integrated Resource Plan |
| **kW/kWh** | Kilowatt, Kilowatt-Hour |
| **MW/MWh** | Megawatt, Megawatt-Hour |
| **NPV** | Net Present Value |
| **O&M** | Operation and Maintenance |
| **PPA** | Power Purchase Agreement |
| **ROE** | Return on Equity |
| **RTP** | Real Time Pricing |

# DIRECT TESTIMONY OF JEFFRY POLLOCK

## 1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

**Q WHAT IS YOUR OCCUPATION AND BY WHO ARE YOU EMPLOYED?**

A I am an energy advisor and President of J. Pollock, Incorporated.

**Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University in St. Louis, Missouri. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

**Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of the Georgia Association of Manufacturers (GAM). The members of GAM are customers of Georgia Power Company (GPC). They consume large quantities of electricity, primarily for manufacturing under a variety of tariffs. GAM members purchase nearly 11% of GPC's retail energy sales.

**Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?**

A This is the first of many rate increases that the Commission will decide over the next three years, which I will discuss initially. I am also addressing:

- The proposed Alternate Rate Plan (ARP);
- Cost recovery for regulatory assets;
- Class revenue allocation; and
- Other tariff terms and conditions.

**Q ARE ANY OTHER WITNESSES APPEARING ON BEHALF OF GEORGIA ASSOCIATION OF MANUFACTURERS?**

A Yes. My colleague, Ms. Billie S. LaConte, will address the issues raised by GPC witness, James M. Coyne, in determining the return on equity (ROE) and capital structure. Dr. Roger Tutterow will address the state of manufacturing in Georgia.

**Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?**

A Yes. I'm sponsoring **Exhibits JP-1** through **JP-9**. These exhibits were prepared by me or under my supervision and direction.

**Q DOES THE FACT THAT YOU ARE NOT ADDRESSING ALL ISSUES IN THIS PROCEEDING CONSTITUTE AN ENDORSEMENT OF THE POSITIONS OF GEORGIA POWER COMPANY, OR OTHER PARTIES, ON THESE ISSUES?**

A No. The fact that I am not addressing every issue should not be interpreted as an endorsement of GPC's or other parties' proposals in this proceeding.

## Summary

**Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A My findings and conclusions are as follows:

*This Case in Perspective*

- GPC is on the precipice of a "perfect storm" of at least seven rate increases that could result in cumulative rate increases of up to $2.9 billion over the next three years.
- Even before the first of three step increases is implemented under GPC's proposed ARP, customers taking service under the Real Time Pricing (RTP) rates have already experienced double-digit rate increases.
- Higher RTP prices have generated $565 million of contributions to fixed costs during the current ARP through July 2022. Thus far in 2022, the fixed cost contributions through July 2022 alone ($191 million) exceed the $95 million of fixed cost contributions included in GPC's test-year revenue requirement.
- To offset future rate increases, the Commission should identify alternatives to traditional ratemaking — securitization in particular — that would allow the Company to recover its capital costs while minimizing rate impacts on customers.
- Securitization is an accepted practice for recovering large capital investments (retired plant) and other major unexpected costs (storm damage) to alleviate the upward rate pressures facing GPC's customers. The cost of securitizing utility assets is only a fraction of GPC's pre-tax cost of capital under traditional ratemaking. Further, securitization bonds can extend cost recovery for periods ranging from four to over 20 years, thereby further alleviating upward rate pressure.

*Alternate Rate Plan*

- The proposed ARP would implement three step increases effective on January 1, 2023, 2024, and 2025. However, the vast majority of the increase would occur on January 1, 2023.
- The three step increases are based entirely on three projected test years. Use of three projected test years requires accurate projections of future sales, revenues, investments, expenses and interest rates. Such projections are inherently inaccurate, particularly, in this case, for the 2nd and 3rd years of the proposed ARP.

- GPC's past projections have allowed it to earn above the authorized midpoint ROE in each of the last ten years. In six of those years, the earned ROE exceeded the upper end of the authorized ROE band.
- In light of past experience, the base rate and Environmental Compliance Cost Recovery (ECCR) increases should be implemented in three steps, and GPC should be required to update its base rate and traditional ECCR projections prior to implementing the 2nd and 3rd years of the ARP.

*Cost Recovery of Major Assets*

- Higher depreciation and amortization expenses are a major driver of the proposed base revenue increase. These higher expenses are a direct result of GPC's Integrated Resource Plan (IRP) to retire/early retire major power plants (i.e., Wansley, Scherer, Bowen Units 1-2) with over $3.1 billion of remaining (unrecovered) investment.
- GPC is also seeking recovery of the costs of the six capacity power purchase agreements (PPAs). Excluding Bowen Units 1-2 (for which a retirement decision was deferred), the capacity of these PPAs roughly offsets the capacity of the retired/early retired plants.
- GPC is proposing to earn a return on both the retired/early retired plants and as a result of the additional sums on the six capacity PPAs.
- The simultaneous recovery of both retired/early retired plants and the six capacity PPAs effectively charges retail customers for redundant capacity.
- Retired plants no longer provide electricity to the public. Thus, the costs of retired plants are not used and useful. A utility should not earn a return on equity on investments in facilities that are not used and useful.
- To avoid placing unnecessary upward pressure on rates, GPC should amortize its investment in Scherer Unit Nos. 1, 2 and 3 over their current remaining lives, which range from 20-25 years.
- GPC is proposing to continue deferred recovery of coal combustion residual (CCR) costs, thereby earning a return on any amounts that have not been recovered in rates.
- GPC is projecting to incur $986 million in CCR costs during the ARP. This is in addition to the CCR costs that have been incurred but not yet recovered in rates.

- Securitizing the remaining investments in Plant Wansley and the as-incurred/projected CCR costs would place less upward pressure on rates than under traditional ratemaking.
- Until securitization is authorized, GPC should not earn a return on equity on the regulatory assets (i.e., Plant Wansley, CCR costs).

*Class Revenue Allocation*

- GPC's proposed equal percentage base rate increase would not result in moving rate groups closer to parity.
- Any base rate increase authorized by the Commission should continue the policy established in the 2010 rate case and continued in the 2013 and 2019 rate cases to continue moving each rate group closer to parity.

*Other Tariff Terms and Conditions*

- GPC's proposed Rule 9 would absolve it of any liability for damages sustained by customers, even if outages or equipment failures were the result of gross negligence. Further, GPC is proposing to limit its liability for damages to the net book value of the customer's equipment.
- A customer's damages from electricity outages can be much more extensive than the net book value of the equipment or personal property. For example, outages can result in lost product, lost sales, additional maintenance expense and potentially higher replacement costs for new equipment.
- Consistent with best practices, Rule 9 should be revised so that GPC is liable for damages caused by willful misconduct and gross negligence. The amount of damages should, at a minimum, be sufficient to replace the customer's damaged equipment and/or personal property.

## 2. THE RATE CASE IN PERSPECTIVE

**Q WHAT IS THE COMPANY REQUESTING IN THIS CASE?**

A GPC is asking the Commission to continue the process of a three-year ARP with a one-time "levelized" base rate increase taking effect on January 1, 2023 and two additional step increases for specific cost components that would become effective on January 1, 2024 and January 1, 2025. Originally, GPC requested a one-time $738 million levelized base revenue increase. However, in its Supplemental filing it increased the request to $762 million. The $37.6 million additional base revenue increase reflects various items included in the final Order approved in the 2022 IRP and Demand Side Management (DSM) proceedings.

**Q ARE THESE THE ONLY RATE INCREASES THAT GEORGIA POWER COMPANY WILL BE SEEKING FROM THE COMMISSION?**

A No. As I have testified in past cases, we are on the precipice of a "perfect storm" of rate increases that will occur over the next three years. Table 1 provides an estimate of the potential impact of the seven future rate increases. As Table 1 reveals, GPC will be seeking cumulative rate increases of up to $2.9 billion over the next three years.

**Table 1**
**Upcoming Rate increases**

| Date | Increase | Amount ($ Millions) |
|---|---|---|
| **Jan. 2023** | ARP Step 1 | $889 |
| **Spring 2023** | Vogtle 3 Net of FCR Decrease | $190 |
| **Spring 2023** | Fuel Cost Recovery | $1,100 |
| **Fall 2023** | Vogtle 3-4 Up to Certified Amount Net of FCR Decrease | $600 |
| **Jan. 2024** | ARP Step 2 | $107 |

| Table 1<br>Upcoming Rate increases | | |
|---|---|---|
| **Date** | **Increase** | **Amount ($ Millions)** |
| **2024** | Vogtle Prudence Review & Increase | Unknown |
| **Jan. 2025** | ARP Step 3 | $45 |
| **Total Net Rate Increases** | | $2,931 |

As can be seen, the proposed ARP is but one component of the upcoming rate increases. GPC will be adjusting rates to recognize the commercial operation of Vogtle Unit 3 when it is placed in commercial operation in the spring of 2023 and further in the fall of 2024, and when fuel is loaded into Vogtle Unit 4 in the fall of 2023. In addition, GPC reported a $948 million fuel cost recovery (FCR) under-collection in June.[1] The balance has continued to grow significantly despite the Interim Fuel Rider that was implemented on January 1, 2022. Assuming gas prices remain at current high levels, the FCR rate increase could exceed $1.1 billion.

In summary, retail customers are potentially facing $2.9 billion in rate increases over the next three years.

**Q HAVE ANY RETAIL CUSTOMERS ALREADY EXPERIENCED SUBSTANTIAL RATE INCREASES?**

A Yes. Even before Step 1 of the proposed ARP takes effect, customers taking service under the RTP rate schedules have already experienced and will continue paying record high prices.

[1] Georgia Power Company, Docket No. 3382-U, *Report of Retail Fuel Cost Recovery for August 2022* (Sept. 19, 2022).

**Chart 1**

The much higher prices can be attributed to much higher replacement fuel costs (particularly natural gas) and hotter than normal weather.

**Q WHAT HAS BEEN THE IMPACT OF THE HIGH RTP PRICES?**

A Higher RTP prices have resulted in much higher contributions to fixed costs by RTP customers. The fixed cost contributions consist of:

- A Reliability adder that reflects the marginal cost of generation capacity;
- A Transmission adder that reflects the marginal cost of transmission capacity; and
- Risk adders ranging from $1 to $3 per megawatt-hour (MWh) for Day Ahead (DA) and Hour Ahead (HA) pricing.

The Reliability and Transmission adders apply when demand approaches and exceeds the projected Southern Company system peak, and the Risk adders apply to all hours.

As a result of the higher prices, RTP customers have paid $565 million in fixed cost contributions during the current ARP through July 2022. In 2022 alone, they contributed $191 million to fixed costs through July, which is twice GPC's projected ($95 million) test-year fixed cost contributions. Thus, it is clear that a large segment of GPC's retail customers has already experienced substantial rate increases, even before base rates are adjusted. Further, GPC's non-RTP customers have benefitted and continue to benefit from the fixed costs that RTP customers pay.

**Q RECOGNIZING THE PERFECT STORM OF UPCOMING RATE INCREASES AND THE MUCH HIGHER RTP PRICES, WHAT STEPS SHOULD THE COMMISSION TAKE TO PROTECT THE INTERESTS OF RETAIL CUSTOMERS?**

A The objective should be to minimize future rate impacts while affording GPC a *reasonable* opportunity to earn a *reasonable* return on the facilities that are used and useful in providing electricity service to the public.

**Q HOW CAN THE COMMISSION ACHIEVE THIS OBJECTIVE?**

A First, the Commission should thoroughly scrub each of the three projected test years used to support GPC's proposed ARP.

Second, recognizing that GPC's proposed 11% ROE is approximately 150 basis points above the national average, the Commission should, at a minimum, establish an ROE and capital structure based on the specific corrections to Mr. Coyne's testimony as recommended by Ms. LaConte.

Third, the Commission should identify alternatives to traditional ratemaking that would allow the Company to recover its capital costs while minimizing rate impacts on customers. For example, $297 million of the proposed revenue requirement reflects changes in depreciation rates.[2] As discussed later, GPC is proposing to accelerate the recovery of certain assets due to recent retirement decisions and extend the depreciable lives of other assets. Accelerated/extended depreciation can alleviate rate pressure. However, this option is not cost-free because GPC would continue to earn a return on the unamortized balance. The only alternative that would both alleviate rate pressure and reduce the overall revenue requirement is securitization.

**Q WHAT IS SECURITIZATION?**

A Securitization is a financing mechanism that provides timely recovery of certain regulatory assets by issuing a type of debt that would significantly lower the carrying costs of the assets relative to the costs that would be incurred using traditional ratemaking practices. Specifically, a special purpose entity would be created whose sole purpose is to issue transition bonds that are used solely for purposes of reducing the amount of recoverable regulatory assets and any other amounts as determined by the Commission through the refinancing or retirement of utility debt or equity. This special purpose entity would be entitled to the revenues collected by the utility through a separate cost recovery mechanism in an amount sufficient to timely recovery of the debt services associated with securitization bonds.

[2] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Exhibit___(APA/SPA/ADH/MBR-5, Schedule 1).

Under this structure, securitization bonds would be "AAA" rated and carry the lowest possible interest rate. For example, recently issued securitization bonds have had an average interest rate of 3.6%. This is substantially below GPC's proposed 9.8% pre-tax cost of capital. The much lower cost reflects the fact that there is no equity and no federal and/or state income taxes associated with securitized financing. Further, securitization bonds issued to date have maturities ranging from four to over 20 years. Therefore, securitization financing would be the most economical means of recovering the costs of long-term regulatory assets, such as retired coal plants and CCR obligations.

**Q IS SECURITIZATION WIDELY USED?**

A Yes. **Exhibit JP-1** shows that 27 states, the District of Columbia and Puerto Rico have enacted utility securitization laws. Thus, securitization is authorized in the majority of states.

**Q HOW IS SECURITIZATION FINANCING TYPICALLY USED?**

A Initially, securitization was used to recover utility assets that became stranded when generation was no longer subject to price regulation. More recently, securitization has become more widely used to recover retired coal plant assets, to finance major storm damage, and to recover extraordinary costs incurred during Winter Strom Uri.

**Q CAN SECURITIZATION BE BENEFICIAL FOR CUSTOMERS?**

A Yes. If the legislation is properly drafted, securitization can be a more cost-effective means of recovering retired assets and other obligations than under traditional ratemaking. To demonstrate, **Exhibit JP-2** provides an illustration of the impact of securitizing $1.5 billion of assets. The illustration shows the annual revenue

requirement in both nominal and net present value (NPV) dollar costs to customers under traditional ratemaking (the solid green and dashed black lines) and securitization (the orange bars). For purposes of the illustration, I have used GPC's proposed cost of capital, current state/federal income tax rates and both accelerated (9-year) and nominal (20-year) amortization. Finally, I assumed an average interest rate of 3.61% with upfront costs of 2% of the securitizable amount. The interest rate assumption was based on a securitization issued by Entergy Texas, Inc., on March 25, 2022.

**Q HOW DOES SECURITIZATION COMPARE WITH TRADITIONAL RATEMAKING?**

A The vertical axis shows the annual revenue requirement. The higher the annual revenue requirement, the higher the rate impact.

As can be seen, the annual revenue requirement for securitizing $1.5 billion of regulatory assets is less than $150 million per year over the 14-year average life of the securitization bonds. By contrast, the annual revenue requirements under traditional ratemaking (for either a nine or 20-year amortization period) would be higher than for securitization. Table 2 below compares the net cost to retail customers under those options.

**Table 2**
**Net Cost to Retail Customers**
**$3 Billion Securitization Vs. Traditional Ratemaking**
**($ Billions)**

| Scenario | Nominal Cost | NPV Cost |
|---|---|---|
| **Traditional Ratemaking:** | | |
| **9 Year Recovery** | $2.3 | $1.7 |
| **20 Year Recovery** | $3.0 | $1.9 |
| **Securitization** | $2.0 | $1.5 |

Thus, not only would securitization place less upward pressure on rates, it would be less costly for customers on both a nominal and NPV basis.

**Q HAVE CREDIT RATING AGENCIES EXPRESSED ANY OPINIONS ON THE USE OF SECURITIZED FINANCING?**

A Yes. For example, Moody's Investors Service opined that utility cost recovery through securitization is credit positive provided that it is not over-used. A copy of Moody's assessment is provided in **Exhibit JP-3**. The key takeaways are:

- Securitization typically benefits utilities and their current customers because utilities receive an immediate source of cash and are ensured recovery of large costs in a timely manner, and because the cost of securitized debt is lower than the utility's all-in pre-tax cost of capital, it reduces the impact on customers' monthly bills.
- Utility cost recovery charge securitization has become more versatile and prevalent. It is now used to recover costs associated with storm restoration and environmental costs, utility restructuring, deferred fuel costs and renewable energy projects.
- State law and financing orders strongly protect securitization assets which ultimately protect the assets backing the bonds.
- Too much securitization can have negative consequences such as impacting customer bills substantially while hurting the utility's financial flexibility and ability to raise rates for other reasons.

Regulatory Research Associates, a subsidiary of S&P, recently observed that there has been a rekindled interest in securitization, stating:

> This financing method allows utilities to include the revenue stream to repay the bonds within customer bills as a separate, non-bypassable surcharge that is subject to true-up. Amounts collected by the company through the surcharge are remitted to a special purpose entity, which then disburses the payments to investors.
>
> While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded to the securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a

state commission. In RRA's experience, no state utility regulatory commission has authorized securitization in the absence of enabling legislation.

***Securitization is viewed as an attractive option because it allows regulators to reduce the customer rate impacts related to the recovery of a particular utility asset. The carrying charge on the asset would be the lower interest rate applied to a highly rated, usually AAA, corporate bond as compared to the utility's WACC, which includes both equity and debt components, or even the interest rate applied to typical utility corporate bonds, which are generally rated BBB and carry higher interest rates.***

At the same time, ***securitization reduces the investment risk for the utility by providing the utility up-front recovery of its investment*** in what are usually non-revenue-producing assets — assets that are not dedicated to providing service to current ratepayers. The company can then redeploy those investment dollars elsewhere.[3]

**Q IS SECURITIZATION POSSIBLE UNDER THE CURRENT REGULATORY AND LEGAL ENVIRONMENT IN GEORGIA?**

A No. It is my understanding that securitization would require both a change in law and regulations. I also understand that a securitization bill has been drafted and reviewed by several parties, including GPC. Thus, there is no reason why a securitization bill could not be introduced and enacted in the next legislative session.

**Q WHAT CAN THE COMMISSION DO TO FACILITATE SECURITIZATION?**

A This rate case provides an opportunity to identify the capital assets that would most likely be candidates for securitized financing. For example, as discussed later, GPC is seeking full recovery of the now-retired Plants Wansley and Boulevard. GPC continues to defer CCR costs and is seeking to recover $986 million of additional CCR

[3] S&P Capital IQ, RRA Regulatory Focus*, Kan. commission OK's storm cost bond issuance for Atmos Energy* (Oct. 14, 2022). Emphasis added.

costs over the duration of the ARP.[4] Both the retired plants and unrecovered/expected CCR costs would be ideal candidates for securitization.

Therefore, I recommend that the Commission quantify and set-aside the portion of costs associated with Plant Wansley and the unrecovered/expected CCR costs in this proceeding. Setting aside these specific costs will facilitate a timely rate adjustment once GPC issues securitization bonds to finance these costs, while avoiding double-recovery.

**Q HOW SHOULD THESE COSTS BE RECOVERED PRIOR TO SECURITIZATION?**

A As previously stated, Plant Wansley was retired and the investment is not used and useful. Further, the CCR costs that are associated with Plant Wansley and other retired power plants are also not used and useful. Under these circumstances, the Commission should not allow a return on the unamortized balance. However, recognizing GPC's need to finance regulatory assets, the Commission should authorize a return capped at GPC's cost of long-term debt.

[4] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) at 6.

## 3. ALTERNATE RATE PLAN

**Q HOW IS GEORGIA POWER COMPANY PROPOSING TO IMPLEMENT ITS ALTERNATE RATE PLAN?**

A The proposed ARP is shown in Table 3. Also shown for comparison is the annual revenue increase for the test period, as well as the three step increases under the ARP.

**Table 3**
**Alternate Rate Plan**
**($ Millions)**

| Rate Component | Test Period | Levelized | 1/1/23 | 1/1/24 | 1/1/25 |
|---|---|---|---|---|---|
| **Base Rates** | $318 | $762 | $478 | $269 | $359 |
| **CCR** | $60 | N/M | $64 | $78 | $47 |
| **ECCR** | $44 | $5 | $33 | ($38) | ($12) |
| **DSM** | $37 | N/M | $37 | $27 | ($2) |
| **Total Excl MFF** | $460 | | $612 | $336 | $392 |

**Sources**: APA-SPA-ADH-MBR-1, Schedules 1, 2 and 3 Supplemental.

As previously stated, GPC is proposing to implement a one-time levelized increase in base rates and the traditional ECCR rate. Alternatively, GPC could have proposed three smaller base rate increases.

**Q DO YOU HAVE ANY CONCERNS REGARDING GEORGIA POWER COMPANY'S ALTERNATE RATE PLAN?**

A Yes. The proposed ARP is based entirely on three projected test years: calendar year 2023, calendar year 2024, and calendar year 2025. None of these projections reflect GPC's official corporate budgets, which were prepared last fall. Use of three projected test years requires accurate projections of future sales, revenues, investments,

expenses and interest rates. Such projections, particularly in the 2nd and 3rd years of the proposed ARP, are inherently inaccurate.

**Q IS GEORGIA POWER COMPANY PROPOSING TO UPDATE ITS PROJECTIONS PRIOR TO IMPLEMENTING THE 2ND AND 3RD YEAR INCREASES UNDER THE PROPOSED ALTERNATE RATE PLAN?**

A No. With the exception of the CCR and DSM rate components, which would be updated in November prior to the following rate year, the base rate and ECCR components would be fixed based on the three projected test years.

**Q WHY DO YOU ASSERT THAT GEORGIA POWER COMPANY'S FORECASTS ARE INHERENTLY INACCURATE?**

A **Exhibit JP-4** shows GPC's earned ROE for the past 10 years under the then-applicable Accounting Orders. Under these Accounting Orders, GPC was authorized to earn a mid-point ROE ranging from 10.5% to 11.15%. The ceiling ROE ranged from 12% to 12.25%, and the ROE floor ranged from 9.5% to 10.25%.

As can be seen in **Exhibit JP-4**, reliance on GPC's projections has resulted in GPC consistently earning a ROE above the mid-point in each of the last 10 years. Further, GPC earned above the upper end of the ROE range in six of the last 10 years. At no time did GPC's earnings ever fall below the ROE mid-point or, obviously, the ROE floor.

Thus, based on this past experience, GPC's projections have either overstated future costs, or understated future sales and/or revenues.

**Q WHAT DO YOU RECOMMEND?**

A Recognizing the other substantial rate increases likely to occur in 2023 (as listed in Table 1), prior experience as discussed earlier, and to provide a more gradual rate path, GAM members strongly prefer a three-stepped increase over GPC's proposed levelized increase. GPC should be required to update its base rate and traditional ECCR projections prior to implementing the 2nd and 3rd years of the ARP. Thus, for the years 2024 and 2025, new base rates should be set using updated test-year projections based on GPC's then-official corporate budgets. The updated budget projections should be filed within 60 days prior to the effective date of new rates. This would provide the Commission and parties ample time to review the projections prior to the rates becoming effective.

**Q HAS THE COMMISSION PREVIOUSLY APPROVED STEPPED BASE RATE INCREASES IN AN ALTERNATE RATE PLAN?**

A Yes. In the last rate case, GPC also requested a levelized base rate increase. However, the Commission approved a settlement between GPC, the Commission Staff, GAM and other parties authorizing three stepped base rate increases.

## 4. COST RECOVERY OF MAJOR ASSETS

**Q ARE CHANGES IN THE TIMING OF COST RECOVERY FOR CERTAIN MAJOR ASSETS A DRIVER OF THE PROPOSED BASE REVENUE INCREASE?**

A Yes. As a result of the decisions in the IRP case, GPC is proposing to transfer the remaining investments of Plants Wansley and Boulevard to a regulatory asset account.[5] Both plants were removed from service this year. GPC is also proposing to accelerate the recovery of plants that will be retired early, prior to the lifespans established in the last rate case. This includes Plants Scherer Unit Nos. 1, 2, and 3 and Bowen Units 1 and 2. In these cases, GPC would continue to earn a full return on the amortized balances of the affected assets.

**Q ARE ANY OTHER DECISIONS MADE IN THE INTEGRATED RESOURCE PLANNING CASE ALSO AFFECTING THE PROPOSED BASE REVENUE INCREASE?**

A Yes. During the ARP, GPC will begin incurring purchased capacity costs under the six capacity PPAs approved in the IRP. This includes purchases from Wansley Unit No. 7, Harris Unit No. 2, Monroe Unit Nos. 1 and 2, and Dahlberg Unit Nos. 2, 6, 8, 9 and 10. GPC will also recover an additional sum on these expenses. The additional sum is the financial equivalent of a return on equity.

[5] The remaining net book value of Plant Boulevard is negligible. *Georgia Power Company's 2022 Integrated Resource Plan;* Docket No. 44160, GPC Response to STF-LA-2-51 (Feb. 8, 2022).

**Q WILL THE AMOUNT OF CAPACITY PROVIDED BY THE POWER PURCHASE AGREEMENTS APPROXIMATELY OFFSET THE CAPACITY PREVIOUSLY SUPPLIED BY THE RETIRED/EARLY RETIRED PLANTS?**

A Yes. Table 4 summarizes the approved plant retirements and capacity additions.

**Table 4**
**Approved Capacity Decertifications and Additions**

| Resource | Effective Date | Capacity Retired (MW) | Capacity Added (MW) |
|---|---|---|---|
| **Wansley Units 1-2/CT** | 8/31/22 | 933 | |
| **Boulevard (Oil)** | 8/31/22 | 19 | |
| **Wansley 7/Harris 2/Monroe 1 & 2** | 12/1/24 | | 1,567 |
| **Dahlberg 2, 6, 8, 9, 10** | 6/1/25 | | 380 |
| **Dahlberg 1, 3, & 5** | 1/1/28 | | 228 |
| **Gaston Units 1-4/CT (Gas)** | 12/31/28 | 460 | |
| **Scherer Units 1, 2, and 3** | 12/31/28 | 648 | |
| **Total** | | 2,060 | 2,175 |

**Source:** IRP Main Document at 11-77 and A-137.

Bowen Unit Nos. 1 and 2 were excluded because the Commission deferred a decision to retire these units. As Table 4 demonstrates, the capacity added by the six PPAs will slightly exceed the capacity retired.

**Q WILL THE PROPOSED BASE RATES INCLUDE THE RECOVERY OF BOTH THE CAPITAL COSTS OF THE RETIRED/EARLY RETIRED PLANTS AND THE SIX CAPACITY POWER PURCHASE AGREEMENTS?**

A Yes. The proposed base rates include recovery of the retired/early retired plants as well as the replacement purchased power capacity. As previously stated, GPC will earn a return on both the retired/early retired plants and the six capacity PPAs.

**Retired/Early Retired Plant**

**Q DO THE RETIRED/EARLY RETIRED PLANTS REPRESENT A SIGNIFICANT INVESTMENT?**

A Yes. Table 5 shows that GPC has approximately $3.3 billion of investment in Plants Wansley, Bowen Unit Nos. 1 and 2, and Scherer Unit Nos. 1, 2 and 3.

**Table 5**
**Net Book Value of Retired/Early-Retired Plants**
**($Millions)**

| Resource | Amount At 12/31/21 | Recovery Period | Remaining Life as of 1/1/23 |
|---|---|---|---|
| **Wansley Units 1-2/CT** | $472.2 | 8 | 8 |
| **Scherer Units 1, 2, and 3** | $934.5 | 9 | 20-25 |
| **Bowen Units 1-2** | $1,858.8 | 9 | 8 |
| **Total** | $3,265.5 | | |

Source: IRP Case, GPC Response to STF-LA-1-29.
Amounts for Scherer Units 1 & 2 are estimated.

GPC is proposing to recover Plant Wansley over eight years. This coincides with the remaining life as determined in the last rate case. However, GPC is proposing to recover the investments in Scherer Unit Nos. 1, 2 and 3 and Bowen Unit Nos. 1 and 2 over nine years. The Scherer units have remaining lives ranging from 20 to 25 years. Thus, GPC's proposal to accelerate the recovery of Scherer Unit Nos. 1, 2 and 3 will place upward pressure on rates.

**Q DO YOU HAVE CONCERNS WITH THE COMPANY'S COST RECOVERY PROPOSALS?**

A Yes. First, retail customers would be charged for redundant capacity. Second, Plant Wansley (and after 2028, Scherer Unit Nos. 1, 2 and 3) is no longer used and useful. A utility should not expect to earn a return on investment for facilities that are no longer used and useful in providing electricity to the public. Third, abruptly changing the depreciation schedule for Scherer Unit Nos 1, 2, and 3 is unfair to GPC's current ratepayers.

**Q IS THERE ANY PRECEDENT FOR DENYING A RETURN ON A PLANT THAT IS NOT USED AND USEFUL?**

A Yes. In Docket No. 46449, the Public Utility Commission of Texas denied a proposal by a utility to include its investment in the then-retired Welsh Unit 2 in rate base, thereby denying a return on the unamortized balance. In rejecting the utility's proposed ratemaking treatment, the Commission stated:

> 68. Because Welsh unit 2 is no longer used and useful, SWEPCO may not include its investment associated with the plant in its rate base, and may not earn a return on that remaining investment.
>
> 69. Allowing SWEPCO a return of, but not on, its remaining investment in Welsh unit 2 balances the interests of ratepayers and shareholders with respect to a plant that no longer provides service.
>
> 70. It is reasonable for SWEPCO to recover the remaining undepreciated balance of Welsh unit 2 over the 24-year remaining lives of Welsh units 1 and 3.[6]

[6] *Application of Southwestern Electric Power Company for Authority to Change* Rates, Docket No. 46449, Order on Rehearing at 20 (Mar, 19, 2018).

**Q WHAT DO YOU RECOMMEND?**

A First, as previously discussed, the remaining investment in Plant Wansley should be securitized. This would allow GPC to immediately recover its capital without an additional return. This is appropriate because, as previously stated, Plant Wansley is no longer used and useful. In the interim, Plant Wansley regulatory asset should be amortized over eight years with no return on equity.

Second, to avoid placing unnecessary upward pressure on rates, GPC should amortize its investment in Scherer Unit Nos. 1, 2 and 3 over their current remaining lives, which range from 20-25 years, with a return on the unamortized balance. However, once Scherer Unit Nos. 1, 2 and 3 have been retired, the remaining investments should be securitized.

## CCR Costs

**Q IS GEORGIA POWER COMPANY PROPOSING TO CONTINUE ITS RECOVERY OF COAL COMBUSTION RESIDUAL COSTS?**

A Yes. GPC is proposing to continue the recovery of CCR costs while earning a return on the unamortized CCR obligation. In 2021, GPC recovered $166 million of CCR costs in rates.[7] By 2025, GPC projects that the CCR annual revenue requirement would reach $386 million.[8] Thus, it is a significant and growing component of GPC's overall revenue requirement. But for the sheer magnitude of the CCR obligation, which GPC estimates at $6.8 billion, these costs would be expensed, and GPC would not earn a return on the unamortized CCR balance.[9]

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[7] *Georgia Power Company's 2021 Annual Surveillance Report*, Docket No. 42516, Schedule 15, at 2. (Mar. 15, 2022).

[8] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Exhibit___(APA/SPA/ADH/MBR-1, Schedule 3 ECCR) at 6.

[9] Docket No. 42516, Schedule 15, at 3. (Mar. 15, 2022).

**Q IS A RETURN ON UNAMORTIZED BALANCE THE ONLY COST ASSOCIATED WITH COAL COMBUSTION RESIDUAL COST RECOVERY?**

A No. The return applied to the unamortized CCR obligation includes a return on equity. Further, because equity is taxable, retail customers are paying not only an additional return to shareholders, they are also funding the income tax liability associated with the shareholder return. The inclusion of both a return on equity and associated income taxes places unnecessary upward pressure on rates.

**Q HOW CAN THIS UNNECESSARY UPWARD PRESSURE BE ALLEVIATED?**

A GPC should securitize all unrecovered CCR expenses, as well as a substantial portion of the CCR expenses that will be incurred during the ARP. As previously stated, securitization is a less expensive alternative to traditional ratemaking because it is financed solely by much lower debt cost. Further, securitization bonds can be issued with extended maturities at a cost that is less than 50% of GPC's pre-tax cost of capital. Prior to securitization, the CCR regulatory asset should earn a return based on GPC's long-term cost of debt.

## 5. CLASS REVENUE ALLOCATION

**Q WHAT IS CLASS REVENUE ALLOCATION?**

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be spread to each customer class the utility serves.

**Q HOW IS GEORGIA POWER COMPANY PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?**

A GPC is proposing to spread the proposed base revenue increase by applying an approximately equal percentage increase to current base revenues. This is shown in **Exhibit JP-5**.

**Q WOULD AN EQUAL PERCENTAGE INCREASE MOVE RATE GROUPS CLOSER TO PARITY?**

A No. As discussed later, the class cost-of-service study (CCOSS) results show that the rate groups are not currently at parity. Some rate groups are below parity while other rate groups are above parity. Moving rates toward parity means applying above-average base revenue increases to those rate groups that are currently below parity and below-average base revenue increases to those rate groups that are currently above parity.

**Q WHAT IS A CLASS COST-OF-SERVICE STUDY?**

A A CCOSS is an analysis used to determine each class's responsibility for a utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly

serve many customers. For purposes of revenue allocation and rate design, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures typically used in a CCOSS are described in more detail in **Appendix C**.

**Q HAS GEORGIA POWER FILED A CLASS COST-OF-SERVICE STUDY IN THIS CASE?**

A Yes. GPC filed four CCOSSs – two studies were based on calendar year 2021 (the historical test period) and two studies were based on the test year ending July 31, 2023. One set of studies was presented by rate group and by rate schedule while the other set of studies was presented by customer class.

**Q DID GEORGIA POWER ACKNOWLEDGE AN ERROR IN THE FILED CLASS COST-OF-SERVICE STUDIES?**

A Yes. GPC acknowledged that there was an error in the filed CCOSSs. Specifically, the filed studies overstated the revenues from the Medium Business rate group and understated the revenues from the Marginally Priced rate group. A corrected CCOSS was provided.

**Q DOES THE CORRECTED CLASS COST-OF-SERVICE STUDY GENERALLY COMPORT WITH ACCEPTED INDUSTRY PRACTICE?**

A Yes. The corrected CCOSS generally comports with accepted industry practice. Specifically, it recognizes the different types of costs incurred by the utility, as well as the different ways electricity is delivered to, and used by, the various types of customers. In particular:

- All production and transmission plant costs and related expenses were classified to demand.
- A portion of the distribution network was classified as a customer-related cost.
- For the Marginally Priced rate group, production/transmission demand allocation factors were based on the customer baseline load (CBL), which is the load that GPC must plan to serve.

Thus, GPC's CCOSSs are consistent with the principles of cost causation; that is, costs are allocated to rate groups based on the degree that each rate group caused GPC to incur each specific cost.

This is in stark contrast to theoretical studies that allocate production plant costs on energy usage on the mistaken belief that some investment is incurred to save fuel costs or that individual power plants benefit certain customer classes more than others and, therefore, should be allocated differently, rather than as a unified generation fleet. A more in-depth assessment of GPC's CCOSSs and these other competing allocation theories is provided in **Appendix C**.

**Q ARE THERE DIFFERENCES BETWEEN THE TWO SETS OF COST STUDIES?**

A Yes. The CCOSSs used the same methodologies except for the allocation of production and transmission plant and related expenses. GPC's preferred CCOSS allocates production and 20% of transmission plant and related expenses using the twelve coincident peak (12CP) method. The remaining transmission costs were allocated to classes using the four coincident peak (4CP) method.

**Q PLEASE DESCRIBE THE 12CP AND 4CP METHODS.**

A Under 12CP, each class's share of allocated costs is based on the demand that occurs coincident with the system peak in all 12 months. GPC also filed a second CCOSS

using the 4CP method. Like 12CP, the 4CP method allocates costs based on the demand that occurs coincident with the system peak during the summer months, June through September.

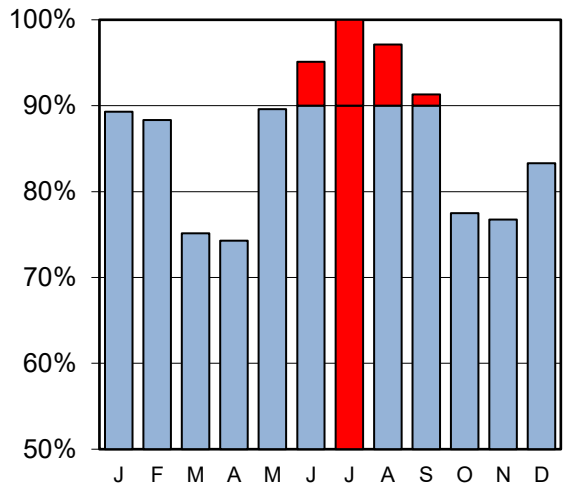
**Q WHAT IS THE RATIONALE FOR USING A SPECIFIC DEMAND ALLOCATION METHOD, SUCH AS 12CP OR 4CP.**

A The choice of an allocation method should reflect the load characteristics of the utility. For example, 4CP is appropriate for a utility that is primarily summer peaking, while 12CP is appropriate for a utility that has no discernable peak periods. The rationale for using 12CP and 4CP is discussed in more detail in **Appendix C**.

**Q IS GEORGIA POWER COMPANY A SUMMER PEAKING UTILITY?**

A Yes. Chart 2 below compares the monthly system peaks as a percent of GPC's annual system peak. The red bars denote when the annual system peak occurs. The red/blue bars show the months when the system demand is close to the annual system peak. The other months are shown in the blue bars.

**Chart 2**
**Monthly Peak Demands as a Percent of**
**GPC's Historical and Test Year Annual System Peak**



As Chart 2 demonstrates, GPC is summer-peaking. However, GPC's winter peaks are growing faster than its summer peaks, and as a consequence, GPC will have both summer and winter peaks in future test years.

**Q ARE THERE DIFFERENCES IN THE SHARE OF PRODUCTION/TRANSMISSION COSTS ALLOCATED TO EACH RATE GROUP UNDER THE 12CP AND 4CP METHODS?**

A Yes. **Exhibit JP-6** provides a comparison of the allocation factors for each rate group under 12CP (column 1) and 4CP (column 3). Recognizing the convergence between the summer and winter peaks, I have also quantified the allocation factors based on an average of the four summer and two winter system peaks (column 2). As can be seen, each method allocates a different share of production/transmission costs to rate groups.

**Q WHICH OF THE ALLOCATION METHODS SHOWN IN EXHIBIT JP-6 BEST FITS GEORGIA POWER COMPANY'S SYSTEM LOAD CHARACTERISTICS?**

A Currently, the 4CP method best reflects GPC's load characteristics. However, in the future the average of the four summer/two winter CP method will become a better fit as the summer and winter peaks converge. As can be seen in **Exhibit JP-6**, the allocation factors under this approach more closely resemble 4CP than the 12CP. demand allocation factors.

In any event, the 12CP method is not reflective of GPC's load characteristics. Thus, the results of GPC's preferred CCOSS are not an accurate reflection of the parity ratios. The additional flaws with the 12CP method are discussed in **Appendix C**.

**Q DESPITE THE DIFFERENCES IN THE VARIOUS ALLOCATION METHODOLOGIES SHOWN IN EXHIBIT JP-5, DO THE RESULTS OF THE CORRECTED CLASS COST-OF-SERVICE STUDIES CONFIRM THAT CERTAIN RATE GROUPS ARE EITHER ABOVE OR BELOW PARITY?**

A Yes. **Exhibits JP-7** and **JP-8** present the corrected CCOSS results at present rates under the 12CP/4CP and 4CP methods described above. The results are summarized in **Table 6** below. If the rates were at parity, each rate group would have a parity ratio (or relative rate of return) of 100%. As Table 6 demonstrates, the Medium and Large Business groups are well above parity, while the Domestic and Government/Institution groups are well below parity.

**Table 6**
**Parity Ratios Derived From**
**Georgia Power Company's**
**Class Cost-of-Service Studies**
**At Present Rates By Rate Group**

| Rate Group/ Methodology | 12CP/4CP | 4CP/4CP |
|---|---|---|
| **Domestic** | 83 | 81 |
| **Small Business** | 116 | 107 |
| **Medium Business** | 144 | 140 |
| **Large Business** | 137 | 146 |
| **Agricultural** | 100 | 146 |
| **Government/Institution** | 59 | 63 |
| **Lighting** | 126 | 139 |
| **Marginally Priced** | 105 | 118 |

**Q REFERRING TO EXHIBITS JP-7 AND JP-8, PLEASE EXPLAIN THE TERMS RATE OF RETURN, RELATIVE RATE OF RETURN, AND SUBSIDY.**

A The rate of return (column 3) is the net operating income (*i.e.,* revenues less allocated expenses – column 2) divided by the allocated rate base (column 1). The relative rate

of return or parity ratio (column 4) measures each rate group's rate of return (column 3) as a percent of the 6.31% Total Retail rate of return (line 9, column 3). The subsidy (column 5), measures the difference between actual revenues and the allocated costs. Thus, a negative amount means that a class is providing revenues less than its allocated costs, while a positive amount means that a class is providing revenues above its allocation costs.

**Q DO YOU HAVE ANY FURTHER OBSERVATIONS ABOUT THE CORRECTED CLASS COST-OF-SERVICE STUDY RESULTS?**

A Yes. The results for the Marginally Priced rate group are significantly affected by the test-year contribution to fixed costs by RTP customers. This is because RTP customers are included in this class, and the contributions to fixed costs is a large portion of the revenue stream from RTP sales. As discussed previously (in Section 2), fixed cost contributions from RTP sales during the test-year were only $95 million, which was only 50% of the ($191 million) of fixed cost contributions in the first seven months of 2022. Thus, the net revenues and rates of return from the Marginally Priced rate group are clearly under-stated. This group is clearly much more profitable to GPC than is indicated in the corrected CCOSSs.

**Q DOES THE COMMISSION HAVE TO APPROVE A SPECIFIC CLASS COST-OF-SERVICE STUDY TO DETERMINE AN APPROPRIATE CLASS REVENUE ALLOCATION?**

A No. Despite the different methodologies, the CCOSS results are relatively consistent. The rate groups that are below parity under GPC's preferred CCOSS are also below parity under each of the alternative CCOSSs, and vice versa.

**Q WOULD RATES MOVE CLOSER TO PARITY UNDER GEORGIA POWER COMPANY'S PROPOSED CLASS REVENUE ALLOCATION?**

A No. The movement to parity is shown in **Exhibit JP-9** using GPC's preferred CCOSS for illustrative purposes. As can be seen, GPC's equal percent base increases applied to each rate group would, for the most part, result in higher subsidies. Thus, rates would not move closer to parity.

**Q HAS THE COMMISSION ENDORSED MOVING RATES CLOSER TO PARITY?**

A Yes. In the 2010, 2013, and 2019 rate cases, the Commission approved class revenue allocations that moved rates closer to parity. In each case the Commission approved parity adjustments ranging from 75% to 125% of the system average base revenue increase.[10] For example, in 2010 the Commission found:

> …the allocation of costs and rate design contemplated and specified in the Stipulation are reasonable and in the best interests of all customer groups, and represent a balanced and fair settlement of the positions advocated by the parties in this docket.[11]

Furthermore, in the 2013 rate case the Commission stated:

> The resulting rate increases will be allocated by rate group using the revenue distribution method recommended by Staff Witness Watkins, with some exceptions and with the spread adjusted for balancing. (Panel Rebuttal Testimony, p.19). The exceptions are based on testimony by the Company and several intervenors with regard to further movements towards parity and the importance of the RTP rate to remain as currently designed and for further RTP tariff availability. (Panel Rebuttal Testimony, p 19-20). In order to further address rate parity issues, in particular with respect to the TOU-MB rate, that

[10] *Georgia Power Company's 2010 Rate Case*, Docket No. 31958, Direct Testimony and Exhibits of Glenn A. Watkins, Exhibit GAW-11, page 1, column 2 (Oct. 22, 2010); *Georgia Power Company's 2013 Rate Case*, Docket No. 36989, Joint Direct Testimony and Exhibits of Glenn A. Watkins and Jamie C. Barber, Staff Exhibit ___ (GAW/JCB-8), column 2 (Oct. 18, 2013).

[11] Docket No. 31958, *Final Order* at 15 (Dec. 29, 2010).

group will receive a rate increase of 80% of what would otherwise be allocated Watkins' proposed revenue distribution method.[12]

In the most recent (2019) rate case, the Commission stated:

> The Proposed Agreement provides that beginning in 2021, with the adjustment to traditional base rate tariff, the rate increase shall be allocated by rate group, except as otherwise provided in Proposed Agreement, with adjustments for balancing. Rates in Medium Business and Large Business rate groups will receive 85% of the overall base rate increase with the resulting revenue deficiency being spread to the other rate groups excluding the Small Business, Lighting and Marginal rate groups which will receive the overall base rate increase (Agreement Provision 17). The Commission finds this provision of the Proposed Agreement to be just and reasonable, and is hereby approved.[13]

**Q SHOULD RATES CONTINUE TO MOVE TOWARD PARITY?**

A Yes. Base revenues should reflect the actual cost of providing service to each rate group as closely as practicable. Cost-based rates are fair (because each class's rates reflect its cost to serve, no more and no less); they are efficient (because, when coupled with a cost-based rate design, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility); they enhance revenue stability (because changes in revenues due to changes in sales will translate into offsetting changes in costs); and they encourage conservation (because cost-based rates will send the proper price signals to customers, thereby allowing customers to make rational consumption decisions).

**Q ARE THERE ANY OTHER COMPELLING REASONS TO SET RATES CLOSER TO COST IN THIS PROCEEDING?**

A Yes. As Dr. Tutterow testifies, manufacturing is essential to creating wealth for local

[12] Docket No. 36989, *Order Adopting Settlement Agreement* at 10 (Dec. 17, 2013).

[13] *Georgia Power Company's 2019 Rate Case*, Docket No. 42516, Order Adopting Settlement Agreement as Modified at 13 (Feb. 6, 2020).

communities. However, economic activity has been slowing, industrial production has decreased modestly in three of the past five quarters, and inflation pressures are persuasive through the economy. Many businesses will face challenges because in a competitive global marketplace, it is difficult to pass along higher production costs, such as the cost of electricity. Further, as previously discussed, much higher RTP prices have already resulted in higher electricity costs. For all of these additional reasons, minimizing base rate increases to the Medium and Large Business and Marginally Priced classes is critical to retaining and potentially increasing manufacturing jobs (and the attendant economic benefits) in Georgia.

**Q WHAT DO YOU RECOMMEND?**

A Based on the CCOSS results shown in **Table 6** and **Exhibit JP-9**, I recommend that the Commission continue to move rate groups closer to parity. **Table 7** summarizes my recommended target parity adjustments.

**Table 7**
**GAM Recommended**
**Target Relative Increases Excluding FCR**

| Rate Group | Relative Increase | With 7% Increase |
|---|---|---|
| **Domestic** | 128% | 9.0% |
| **Small Business** | 77% | 5.4% |
| **Medium Business** | 77% | 5.4% |
| **Large Business** | 77% | 5.4% |
| **Agricultural** | 99% | 6.9% |
| **Government** | 128% | 9.0% |
| **Outdoor Lighting** | 77% | 5.4% |
| **Marginally Priced (Excluding RTP)** | 82% | 5.7% |

For example, if GPC receives a 7% base rate increase, the target base rate increases to each class before FCR charges would range from 5.4% to 9%. The specific parity adjustments will need to be refined to yield the Commission-approved revenue requirement.

Acknowledging gradualism, the target parity adjustments constrained to between 0.77 times and 1.28 times the system average revenue increase excluding FCR. These adjustments were applied to each rate group based on the current rate of return. Rate groups with current parity ratios above 100% would receive below system-average increases, while rate groups with current parity ratios below 100 would receive above system-average increases.

**Q SHOULD THE SAME PARITY ADJUSTMENTS BE APPLIED IN DETERMINING THE 2024 AND 2025 BASE RATE INCREASES UNDER GEORGIA ASSOCIATION OF MANUFACTURERS' RECOMMENDED ALTERNATE RATE PLAN?**

A Yes.

**Q IF THE COMMISSION APPROVES LOWER BASE REVENUE INCREASES THAN GEORGIA POWER COMPANY IS PROPOSING, HOW SHOULD THESE LOWER INCREASES BE ALLOCATED BY RATE GROUP?**

A The same parity adjustments should be applied.

## 6. OTHER TARIFF TERMS AND CONDITIONS

**Q IS GEORGIA POWER COMPANY PROPOSING ANY CHANGES IN ITS TARIFF RULES?**

A Yes. GPC is proposing Rule 9 be added to its Rules and Regulations for Electric Service, Contract and Enforcement Regulations, on January 1, 2023. Proposed Rule 9 states:

> Without restricting the limitations of liability provided elsewhere within these rules, to the extent a cognizable claim arises, the customer waives any right to consequential, special, indirect, treble, exemplary, incidental, punitive, loss of business reputation, interruption of electric service or loss of use (including loss of revenue, profits, or capital costs) damages in connection with any outage, surge, voltage fluctuation, disturbance or other variation or failure of electric service, or the Company's equipment, even where such variation, interruption, or failure of electric service was reasonably foreseeable, contemplated, or avoidable. To the extent the Company is liable under an agreement, and to the extent allowed by applicable law, the Company's liability is expressly limited to proven direct damages. The Company's liability for damage to personal property will be limited to the depreciated value of such personal property.[14]

**Q WHAT IS THE REASON FOR HAVING A LIMITATION OF LIABILITY PROVISION?**

A Limitation of liability provisions are designed to protect the utility from the risks of incurring costs caused by equipment failures and/or outages. Through Rule 9, GPC aims to limit its liability to compensate the customer based on net book value of the property damaged by an equipment failure or outage, even when damages are due to gross negligence.

**Q WHAT IS NET BOOK VALUE?**

A Net book value is an asset's original cost minus its accumulated depreciation.

[14] Application, MFRs, Traditional, F1 at 1.60.

**Q WHAT ARE YOUR CONCERNS WITH THE PROPOSED RULE 9 LANGUAGE?**

A Rule 9 absolves GPC of responsibility for any damages, even if equipment failures or outages were the result of gross negligence. Further, limiting damages to the net book value of the customer's damaged equipment is not a sufficient remedy.

**Q WHAT IS GROSS NEGLIGENCE?**

A Black's Law Dictionary defines gross negligence as: A conscious, voluntary act or omission in reckless disregard of a legal duty and of the consequences to another party, who may typically recover exemplary damages.[15]

**Q HOW WOULD THE PROPOSED RULE 9 ABSOLVE GEORGIA POWER COMPANY OF LIABILITY DUE TO GROSS NEGLIGENCE?**

A Rule 9 would waive GPC's liability, "even where such variation, interruption, or failure of electric service was reasonably foreseeable, contemplated, or avoidable."[16] This language demonstrates GPC's intent to leave customers defenseless against gross negligence through Rule 9.

**Q SHOULD GEORGIA POWER COMPANY BE ABSOLVED OF ANY RESPONSIBILITY DUE TO GROSS NEGLIGENCE?**

A No. GPC should be held accountable for its decisions and actions so that it does not prioritize its self-interest over the safety and well-being of customers. Further, it is well within the Company's direct control to avoid actions that could be deemed to be willful

[15] West Group, Bryan A. Garner, editor-in-chief, *Black's Law Dictionary*, 1st pocket ed. (1996).

[16] Application, MFRs, Traditional, F1 at 1.60.

misconduct or grossly negligent. Otherwise, customers would be placed in an unfairly vulnerable position.

**Q WHY IS LIMITING COMPENSATION FOR DAMAGES BASED ON THE NET BOOK VALUE OF THE CUSTOMER'S DAMAGED EQUIPMENT CONCERNING?**

A Net book value decreases an asset's worth through accumulated depreciation, which is the depreciation or amortization expense per year multiplied by the number of years. If GPC were to damage a fully depreciated asset, the asset's owner could not claim any compensation under Rule 9.

**Q IS THE VALUE OF DAMAGED PROPERTY OR EQUIPMENT THE ONLY DAMAGES A CUSTOMER MAY INCUR AS A RESULT OF EQUIPMENT FAILURES OR SERVICE OUTAGES?**

A No. Any service disruption (for whatever reason) can be costly to a customer. For example, product can be lost, order fulfillment delayed, and equipment may require additional maintenance and/or replacement. Some processes may require many hours or days to restore production to pre-outage levels.

**Q WHY ARE YOU ASSERTING THAT THE PROPOSED RULE 9 IS NOT CONSISTENT WITH INDUSTRY BEST PRACTICES?**

A I conducted a survey of electric utility tariffs to determine whether other utilities have a similar rule to Rule 9. Through this survey, I came to the conclusion that GPC's Rule 9 proposal is overly protective.

First, several utilities have specific language addressing gross negligence. For example:

- El Paso Electric Company states: "the **Company will be liable** to the Customer for any damages occasioned by such suspension only when the damages are the result of **gross negligence or willful misconduct** on the part of the Company."[17]

- Public Service Company of Oklahoma (PSO) states: "PSO will not be liable for any damages, whether direct or consequential, including without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by fluctuations or interruptions **unless it be shown PSO has not made reasonable provisions to supply steady and continuous electric service,** consistent with the customer's class of service or in compliance with Oklahoma Corporation Commission Electric Utility Rules."[18]

- PECO Energy Company states: "the liability of the Company to customers or other persons for damages, direct or consequential, including damage to computers and other electronic equipment and appliances, loss of business, or loss of production caused by any interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity shall in no event, **unless caused by the willful and/or wanton misconduct of the Company,** exceed an amount in liquidated damages equivalent to the greater of $1000 or two times the charge to the customer for the service affected during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs."[19]

- Duke Energy Florida states: "The Customer shall indemnify, hold harmless and defend the Company from and against any and all liability, proceedings, suits, costs or expense for loss, damage, death or injury to persons or property, in any manner directly or indirectly connected with, or growing out of the use or disposition of electricity by the Customer at or on the Customer's side of the Point of Delivery, **unless such loss, damage, death or injury shall result from the sole negligence of the Company**.[20]

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[17] El Paso Electric Company, *Rules and Regulations Regarding Electric Service*, Section 2, Sheet No. 2, 13th Revision at 10-11 (Nov. 3, 2021). Emphasis added.

[18] Public Service Company of Oklahoma, *Electric Service Rules, Regulations and Conditions of Service*, Sheet No. 2-1, 8th Revision at (Jan. 31, 2022). Emphasis added.

[19] PECO Energy Company, Electric Service Tariff, Electric PA. P.U.C. No. 5, *Rules and Regulations*, Section 12.1 (Eff. Jan. 1, 2016). Emphasis added.

[20] Duke Energy, *Terms and Conditions of Service*, Part IV, Section 4.05 (Apr. 29, 2013).

Further, to the extent the utility is found to have been grossly negligent, the damages paid are not limited to the net book value of the customer's equipment. For example:

- CenterPoint Energy Houston Electric states: "Company will not be liable for any damages, whether direct or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity, occasioned by fluctuations or interruptions unless it be shown that Company has not made reasonable provision to supply steady and continuous Delivery Service, consistent with the Retail Customer's class of service, and in the event of a failure to make such reasonable provisions, whether as a result of negligence or otherwise, Company's liability shall be limited to the ***cost of necessary repairs of physical damage proximately caused by the service failure to those electrical delivery facilities of Retail Customer*** which were then equipped with the protective safeguards recommended or required by the then current edition of the National Electrical Code."[21]
- El Paso Electric Company states, "in the event of the Company's gross negligence or willful misconduct, the Company's liability under this paragraph will be limited to the **cost of necessary repair or replacement of tangible property damaged or destroyed** by the interruption or fluctuation."[22]

While the above examples specify a broad range of damage, the vast majority of tariffs are not specific about the amount of any damages. Therefore, the damages can be determined by litigation on a situational basis.

**Q WHAT DO YOU RECOMMEND?**

A I recommend that Rule 9 be revised to require that GPC be liable for damages from equipment failures or outages that are demonstrated to be the result of GPC's gross negligence. Further, the compensation to customers for such outages should be sufficient to at least replace any damaged equipment. Alternatively, the Rule should not limit the amount of the damages, consistent with industry practice.

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[21] CenterPoint Energy Houston Electric, LLC, *Tariff for Retail Delivery Service*, Section 5.2.1, Sheet No. 5.1 (Jan. 15, 2015).

[22] El Paso Electric Company, *Rules and Regulations Regarding Electric Service*, Section 2, Sheet No. 2, 13th Revision at 10-11 (Nov. 3, 2021).

## 7. CONCLUSION

**Q WHAT FINDINGS SHOULD THE COMMISSION MAKE ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?**

A The Commission should make the following findings:

- Securitization is a lower cost option than traditional recovery of retired assets and CCR costs.
- The remaining costs of Plant Wansley and the CCR costs incurred through 2022 but not yet recovered in rates, and up to 50% of the CCR costs GPC expects to occur in the ARP, should be identified and separated from the costs recovered in base rates and the ECCR.
- The base rate increases should be implemented in three steps.
- To alleviate rate pressure and to mitigate the amount of redundant capacity recovered in rates, GPC should amortize its remaining investment in Scherer Units 1, 2, and 3 over their current remaining lives.
- The authorized base rate increases should be spread to customer groups in a manner that continues the movement toward parity.
- The proposed Rule 9 should be modified so that GPC will be liable for damages that are determined to be the result of willful misconduct and gross negligence, and the amount of damages either should not be specified, or should be sufficient to at least replace the customer's damaged equipment and/or personal property.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes.

# APPENDIX A

## Qualifications of Jeffry Pollock

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

**Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am an energy advisor and President of J. Pollock, Incorporated.

**Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

**Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.**

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320 | Rebuttal | NY | | 10/18/2022 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 22-00155-UT | Direct | NM | Capacity Reservation Charge; Backup Power Charge; Maintenance Power; Distribution Capacity Costs | 10/17/2022 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | E002/GR-21-630 | Direct | MN | Class Cost-of-Service Study; Class Revenue Allocation; Multi-Year Rate Plan; Interim Rates; TOU Rate Design | 10/3/2022 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 22-E-0317 / 22-G-0318 22-E-0319 / 22-G-0320 | Direct | NY | Electric and Gas Embedded Cost of Service Studies; Class Revenue Allocation; Rate Design | 9/26/2022 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 22-00177-UT | Direct | NM | Renewable Portfolio Standard Incentive | 9/26/2022 |
| CENTERPOINT HOUSTON ELECTRIC LLC | Texas Industrial Energy Consumers | 53442 | Direct | TX | Mobile Generators | 9/16/2022 |
| ONCOR ELECTRIC DELIVERY COMPANY LLC | Texas Industrial Energy Consumers | 53601 | Cross-Rebuttal | TX | Class Cost-of-Service Study, Class Revenue Allocation; Distribution Energy Storage Resource | 9/16/2022 |
| ONCOR ELECTRIC DELIVERY COMPANY LLC | Texas Industrial Energy Consumers | 53601 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Tariff Terms and Conditions | 8/26/2022 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 53034 | Cross-Rebuttal | TX | Energy Loss Factors; Allocation of Eligible Fuel Expense; Allocation of Off-System Sales Margins | 8/5/2022 |
| MIDAMERICAN ENERGY COMPANY | Tech Customers | RPU-2022-0001 | Direct | IA | Application of Advanced Ratemaking Principles to Wind Prime | 7/29/2022 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 53034 | Direct | TX | Allocation of Eligible Fuel Expense; Allocation of Winter Storm Uri | 7/6/2022 |
| AUSTIN ENERGY | Texas Industrial Energy Consumers | None | Cross-Rebuttal | TX | Allocation of Production Plant Costs; Energy Efficiency Fee Allocation | 7/1/2022 |
| AUSTIN ENERGY | Texas Industrial Energy Consumers | None | Direct | TX | Revenue Requirement; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 6/22/2022 |
| DTE ELECTRIC COMPANY | Gerdau MacSteel, Inc. | U-20836 | Direct | MI | Interruptible Supply Rider No. 10 | 5/19/2022 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers | 44160 | Direct | GA | CARES Program; Capacity Expansion Plan; Cost Recovery of Retired Plant; Additional Sum | 5/6/2022 |
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan, Inc. | 52195 | Cross-Rebuttal | TX | Rate 38; Class Cost-of-Service Study; Revenue Allocation | 11/19/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Supplemental | NM | Responding to Seventh Bench Request Order (Amended testimony filed on 11/15) | 11/12/2021 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan, Inc. | 52195 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate 15 Design | 10/22/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51802 | Cross-Rebuttal | TX | Cost Allocation; Production Tax Credits; Radial Lines; Load Dispatching Expenses; Uncollectible Expense; Class Revenue Allocation; LGS-T Rate Design | 9/14/2021 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers | 43838 | Direct | GA | Vogtle Unit 3 Rate Increase | 9/9/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 21-00172-UT | Direct | NM | RPS Financial Incentive | 9/3/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51802 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; LGS-T Rate Design | 8/13/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51802 | Direct | TX | Schedule 11 Expenses; Jurisdictional Cost Allocation; Abandoned Generation Assets | 8/13/2021 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51997 | Direct | TX | Storm Restoration Cost Allocation and Rate Design | 8/6/2021 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | R-2021-3024601 | Surrebuttal | PA | Class Cost-of-Service Study; Revenue Allocation | 8/5/2021 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | R-2021-3024601 | Rebuttal | PA | Class Cost-of-Service Study; Revenue Allocation; Universal Service Costs | 7/22/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Supplemental | NM | Settlement Support of Class Cost-of-Service Study; Rate Desgin; Revenue Requirement. | 7/1/2021 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | R-2021-3024601 | Direct | PA | Class Cost-of-Service Study; Revenue Allocation | 6/28/2021 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20940 | Rebuttal | MI | Allocation of Uncollectible Expense | 6/23/2021 |
| FLORIDA POWER & LIGHT COMPANY | Florida Industrial Power Users Group | 20210015-EI | Direct | FL | Four-Year Rate Plan; Reserve Surplus; Solar Base Rate Adjustments; Class Cost-of-Service Study; Class Revenue Allocation; CILC/CDR Credits | 6/21/2021 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 20-067-U | Surrebuttal | AR | Certificate of Environmental Compatibility and Public Need | 6/17/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Rebuttal | NM | Rate Design | 6/9/2021 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20940 | Direct | MI | Class Cost-of-Service Study; Rate Design | 6/3/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 51415 | Supplemental Direct | TX | Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate | 5/17/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Direct | NM | Class Cost-of-Service Study; Class Revenue Allocation, LGS-T Rate Design, TOU Fuel Charge | 5/17/2021 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 20-067-U | Direct | AR | Certificate of Environmental Compatibility and Public Need | 5/6/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51625 | Direct | TX | Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor | 4/5/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 51415 | Direct | TX | ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge | 3/31/2021 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51215 | Direct | TX | Certificate of Convenience and Necessity for the Liberty County Solar Facility | 3/5/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 50997 | Cross Rebuttal | TX | Rate Case Expenses | 1/28/2021 |
| PPL ELECTRIC UTILITIES CORPORATION | PPL Industrial Customer Alliance | M-2020-3020824 | Supplemental | PA | Energy Efficiency and Conservation Plan | 1/27/2021 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 20-E-0428 / 20-G-0429 | Rebuttal | NY | Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study | 1/22/2020 |
| MIDAMERICAN ENERGY COMPANY | Tech Customers | EPB-2020-0156 | Reply | IA | Emissions Plan | 1/21/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 50997 | Direct | TX | Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity | 1/7/2021 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 20-E-0428 / 20-G-0429 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism | 12/22/2020 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 20-E-0380 / 20-G-0381 | Rebuttal | NY | AMI Cost Allocation Framework | 12/16/2020 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51381 | Direct | TX | Generation Cost Recovery Rider | 12/8/2020 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 20-E-0380 / 20-G-0381 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation | 11/25/2020 |
| LUBBOCK POWER & LIGHT | Texas Industrial Energy Consumers | 51100 | Direct | TX | Test Year; Wholesale Transmission Cost of Service and Rate Design | 11/6/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20889 | Direct | MI | Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds | 10/30/2020 |
| CHEYENNE LIGHT, FUEL AND POWER COMPANY | HollyFrontier Cheyenne Refining LLC | 20003-194-EM-20 | Cross-Answer | WY | PCA Tariff | 10/16/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00143 | Direct | NM | RPS Incentives; Reassignment of non-jurisdictional PPAs | 9/11/2020 |

# APPENDIX B
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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-578-ER-20 | Cross | WY | Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs | 9/11/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-578-ER-20 | Direct | WY | Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs | 8/7/2020 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 50790 | Direct | TX | Hardin Facility Acquisition | 7/27/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Surrebuttal | PA | Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism | 7/24/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20697 | Rebuttal | MI | Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs | 7/14/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Rebuttal | PA | Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions | 7/13/2020 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2020-3019290 | Rebuttal | PA | Network Integration Transmission Service Costs | 7/9/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20697 | Direct | MI | Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit | 6/24/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Direct | PA | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 6/15/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20650 | Rebuttal | MI | Distribution Mains Classification and Allocation | 5/5/2020 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers and Georgia Industrial Group | 43011 | Direct | GA | Fuel Cost Recovery Natural Gas Price Assumptions | 5/1/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20650 | Direct | MI | Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues | 4/14/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 90000-144-XI-19 | Direct | WY | Coal Retirement Studies and IRP Scenarios | 4/1/2020 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20642 | Direct | MI | Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues | 3/24/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Cross | TX | Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense | 3/10/2020 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00315-UT | Direct | NM | Time-Differentiated Fuel Factor | 3/6/2020 |
| SOUTHERN PIONEER ELECTRIC COMPANY | Western Kansas Industrial Electric Consumers | 20-SPEE-169-RTS | Direct | KS | Class Revenue Allocation | 3/2/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Direct | TX | Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony) | 2/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Direct | TX | Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony) | 2/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00134-UT | Direct | NM | Renewable Portfolio Standard Rider | 2/5/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Settlement | NM | Settlement Support of Rate Design, Cost Allocation and Revenue Requirement | 1/20/2020 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 49737 | Direct | TX | Certificate of Convenience and Necessity | 1/14/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Rebuttal | NM | Class Cost-of-Service Study; Class Revenue Allocation | 12/20/2019 |
| ALABAMA POWER COMPANY | Alabama Industrial Energy Consumers | 32953 | Direct | AL | Certificate of Convenience and Necessity | 12/4/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Direct | NM | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 11/22/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49616 | Cross | TX | Contest proposed changes in the Fuel Factor Formula | 10/17/2019 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers and Georgia Industrial Group | 42516 | Direct | GA | Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design | 10/17/2019 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 19-E-0378 / 19-G-0379<br>19-E-0380 / 19-G-0381 | Rebuttal | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design | 10/15/2019 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 19-E-0378 / 19-G-0379<br>19-E-0380 / 19-G-0381 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation | 9/20/2019 |
| AEP TEXAS INC. | Texas Industrial Energy Consumers | 49494 | Cross-Rebuttal | TX | ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs | 8/13/2019 |
| AEP TEXAS INC. | Texas Industrial Energy Consumers | 49494 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions | 7/25/2019 |
| CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC | Texas Industrial Energy Consumers | 49421 | Cross-Rebuttal | TX | Class Cost-of-Service Study | 6/19/2019 |
| CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC | Texas Industrial Energy Consumers | 49421 | Direct | TX | Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions | 6/6/2019 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 48973 | Direct | TX | Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales | 5/21/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20322 | Rebuttal | MI | Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage | 4/29/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20322 | Direct | MI | Class Cost-of-Service Study; Transportation Rate Design | 4/5/2019 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 49042 | Cross-Rebuttal | TX | Transmsision Cost Recovery Factor | 3/21/2019 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 49057 | Direct | TX | Transmsision Cost Recovery Factor | 3/18/2019 |
| DUKE ENERGY PROGRESS, LLC | Nucor Steel - South Carolina | 2018-318-E | Direct | SC | Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense | 3/4/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Settlement | AR | Testimony in Support of Settlement | 3/1/2019 |
| ENERGY+ INC. | Toyota Motor Manufacturing Canada | EB-2018-0028 | Updated Evidence | ON | Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design | 2/15/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Surrebuttal | AR | Solar Energy Purchase Option Tariff | 2/14/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 48847 | Direct | TX | Fuel Factor Formulas | 1/11/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Direct | AR | Solar Energy Purchase Option Tariff | 1/10/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20165 | Direct | MI | Integrated Resources Plan; Projected Rate Impact, Risk Assessment; Early Retirement of Coal Units; Financial Compensation Mechanism | 10/15/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20134 | Rebuttal | MI | Class Cost-of-Service Study; Average Historical Profile; Distribution Cost Classification and Allocation; Rate Design | 10/1/2018 |
| ENERGY+ INC. | Toyota Motor Manufacturing Canada | EB-2018-0028 | Initial Evidence | ON | Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design | 9/27/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20134 | Direct | MI | Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design | 9/10/2018 |
| KANSAS GAS AND ELECTRIC COMPANY | Occidental Chemical Corporation | 18-KG&E-303-CON | Rebuttal | KS | Benefits of the Interruptible Load Provided in the Special Contract | 8/29/2018 |
| TEXAS-NEW MEXICO POWER COMPANY | Texas Industrial Energy Consumers | 48401 | Cross-Rebuttal | TX | 4CP Moderation Adjustment | 8/28/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 48371 | Cross-Rebuttal | TX | Class Cost-of-Service Study; Schedule FERC | 8/16/2018 |
| TEXAS-NEW MEXICO POWER COMPANY | Texas Industrial Energy Consumers | 48401 | Direct | TX | Tax Cuts and Jobs Act; Rider TCRF; 4CP Moderation Adjustment | 8/13/2018 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2018-3000164 | Surrebuttal | PA | Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Distribution System Improvement Charge | 8/8/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 48371 | Direct | TX | Revenue Requirements; Tax Cuts and Jobs Act; Riders | 8/1/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 48371 | Direct | TX | Class Cost-of-Service Study; Firm, Interruptible and Standby Rate Design | 8/1/2018 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2018-3000164 | Rebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation | 7/24/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 48233 | Cross-Rebuttal | TX | Allocation of TCJA reduction | 7/19/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 48233 | Direct | TX | Allocation of TCJA reduction | 7/5/2018 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2018-3000164 | Direct | PA | Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Class Revenue Allocation | 6/26/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 47527 | Cross-Rebuttal | TX | Class Cost-of-Service Study; Revenue Allocation | 5/22/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00255-UT | Rebuttal | NM | Class Cost-of-Service Study; Revenue Allocation | 5/2/2018 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 17-041 | Stipulation | AR | Support of Stipulation | 4/27/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 47527 | Direct | TX | Present Base Revenues<br>Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 4/25/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 47527 | Direct | TX | Tax Cuts and Jobs Act; SPP Transmission and Wheeling Costs; Depreciation Rate; LLPPAs; Imputed Capacity; Off-System Sales Margins | 4/25/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00255-UT | Direct | NM | Class Cost-of-Service Study; Revenue Requirements; Revenue Allocation | 4/13/2018 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 17-041 | Surrebuttal | AR | Certificate of Convenience and Necessity | 4/6/2018 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY | MEIUG, PICA and WPPII | 2017-2637855<br>2017-2637857<br>2017-2637858<br>2017-2637866 | Rebuttal | PA | Recovery of NITS Charges | 3/22/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | 2nd Supplemental Direct | TX | Support of Stipulation | 3/2/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-18424 | Direct | MI | Class Cost of Service | 2/28/2018 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 17-041 | Direct | AR | Certificate of Convenience and Necessity | 2/23/2018 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47553 | Direct | TX | Off-System Sales Margins; Renewable Energy Credits | 2/20/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47461 | 2nd Supplemental Direct | TX | Certificate of Convenience and Necessity | 2/7/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47461 | Supplemental Direct | TX | Certificate of Convenience and Necessity | 1/4/2018 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 17-E-0459/G-0460 | Rebuttal | NY | Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Gas Rate Design; Revenue Decoupling Mechanism | 12/18/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00044-UT | Supplemental Direct | NM | Support of Unanimous Comprehensive Stipulation | 12/11/2017 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47461 | Direct | TX | Certificate of Convenience and Necessity | 12/4/2017 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 17-E-0459/G-0460 | Direct | NY | Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Customer Charges; Revenue Decoupling Mechanism; Carbon Program and EAM | 11/21/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00044-UT | Direct | NM | Certificate of Convenience and Necessity | 10/24/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | Cross-Rebuttal | TX | Certificate of Convenience and Necessity | 10/23/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | Supplemental Direct | TX | Certificate of Convenience and Necessity | 10/6/2017 |
| KENTUCKY POWER COMPANY | Kentucky League of Cities | 2017-00179 | Direct | KY | Class Cost-of-Service Study; Class Revenue Allocation | 10/3/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | Direct | TX | Certificate of Convenience and Necessity | 10/2/2017 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 17-E-0238 / 17-G-0239 | Rebuttal | NY | Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design | 9/15/2017 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-18322 | Rebuttal | MI | Class Cost-of-Service Study, Rate Design | 9/7/2017 |
| PENNSYLVANIA-AMERICAN WATER COMPANY | Pennsylvania-American Water Large Users Group | R-2017-2595853 | Rebuttal | PA | Rate Design | 8/31/2017 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 17-E-0238 / 17-G-0239 | Direct | NY | Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation | 8/25/2017 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-18322 | Direct | MI | Revenue Requirement, Class Cost-of-Service Study, Rate Design | 8/10/2017 |
| FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY | Florida Industrial Power Users Group | 170057 | Direct | FL | Fuel Hedging Practices | 8/10/2017 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 46449 | Cross-Rebuttal | TX | Class Revenue Allocation and Rate Design | 5/19/2017 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 46449 | Direct | TX | Revenue Requirement, Class Cost-of-Service Study, Class Revenue Allocation and Rate Design | 4/25/2017 |
| KENTUCKY UTILITIES COMPANY | Kentucky League of Cities | 2016-00370 | Supplemental Direct | KY | Class Cost-of-Service Study; Class Revenue Allocation | 4/14/2017 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 46416 | Direct | TX | Certificate of Convenience and Necessity - Montgomery County Power Station | 3/31/2017 |
| SHARYLAND UTILITIES, L.P. | Texas Industrial Energy Consumers | 45414 | Cross-Rebuttal | TX | Cost Allocation Issues; Class Revenue Allocation | 3/16/2017 |
| ENTERGY LOUISIANA, LLC | Occidental Chemical Corporation | U-34283 | Direct* | LA | Approval to Construct Lake Charles Power Station | 3/13/2017 |
| LOUISVILLE GAS AND ELECTRIC COMPANY | Louisville/Jefferson Metro Government | 2016-00371 | Direct | KY | Revenue Requirement Issues; Class Cost-of-Service Study Electric/Gas; Class Revenue Allocation Electric/Gas | 3/3/2017 |
| KENTUCKY UTILITIES COMPANY | Kentucky League of Cities | 2016-00370 | Direct | KY | Revenue Requirement Issues; Class Cost-of-Service Study; Class Revenue Allocation | 3/3/2017 |
| SHARYLAND UTILITIES, L.P. | Texas Industrial Energy Consumers | 45414 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals | 2/28/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46025 | Direct | TX | Long-Term Purchased Power Agreements | 12/12/2016 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 15-826 | Surrebuttal | MN | Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source | 10/18/2016 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 15-826 | Rebuttal | MN | Class Cost-of-Service Study, Class Revenue Allocation | 9/23/2016 |
| VICTORY ELECTRIC COOPERATION ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-VICE-494-TAR | Surrebuttal | KS | Formula-Based Rate Plan | 9/22/2016 |
| NATIONAL FUEL GAS DISTRIBUTION CORPORATION | Multiple Intervenors | 16-G-0257 | Rebuttal | NY | Embedded Class Cost of Service; Class Revenue Allocation; Rate Design | 9/16/2016 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 45524 | Cross-Rebuttal | TX | Class Cost-of-Service Study; | 9/7/2016 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER | MEIUG, PICA and WPPII | 2016-2537349<br>2016-2537352<br>2016-2537359 | Surrebuttal | PA | Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 8/31/2016 |
| VICTORY ELECTRIC COOPERATION ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-VICE-494-TAR | Direct | KS | Formula-Based Rate Plan | 8/30/2016 |
| WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-WSTE-496-TAR | Direct | KS | Formula-Based Rate Plan and Debt Service Payments | 8/30/2016 |
| NATIONAL FUEL GAS DISTRIBUTION CORPORATION | Multiple Intervenors | 16-G-0257 | Direct | NY | Embedded Class Cost of Service; Class Revenue Allocation; Rate Design | 8/26/2016 |

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## Testimony Filed in Regulatory Proceedings
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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER | MEIUG, PICA and WPPII | 2016-2537349<br>2016-2537352<br>2016-2537359 | Rebuttal | PA | Class Cost-of-Service; Class Revenue Allocation | 8/17/2016 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 45524 | Direct | TX | Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design | 8/16/2016 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER | MEIUG, PICA and WPPII | 2016-2537349<br>2016-2537352<br>2016-2537359 | Direct | PA | Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 7/22/2016 |
| FLORIDA POWER & LIGHT COMPANY | Florida Industrial Power Users Group | 160021 | DIrect | FL | Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design | 7/7/2016 |
| CENTERPOINT ENERGY ARKANSAS GAS | Arkansas Gas Consumers, Inc. | 15-098-U | Supplemental | AR | Support for Settlement Stipulation | 7/1/2016 |
| MIDAMERICAN ENERGY COMPANY | Tech Customers | RPU-2016-0001 | Direct | IA | Application of Advanced Ratemaking Principles to Wind XI | 6/21/2016 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 15-826 | Direct | MN | Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design | 6/14/2016 |
| CENTERPOINT ENERGY ARKANSAS GAS | Arkansas Gas Consumers, Inc. | 15-098-U | Surrebuttal | AR | Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design | 6/7/2016 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 15-00296-UT | Direct | NM | Support of Stipulation | 5/13/2016 |
| CHEYENNE LIGHT, FUEL AND POWER COMPANY | Dyno Nobel, Inc. and<br>HollyFrontier Cheyenne Refining LLC | 20003-146-ET-15 | Cross | WY | Large Power Contract Service Tariff | 4/15/2016 |
| CENTERPOINT ENERGY ARKANSAS GAS | Arkansas Gas Consumers, Inc. | 15-098-U | Direct | AR | Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan | 4/14/2016 |
| CHEYENNE LIGHT, FUEL AND POWER COMPANY | Dyno Nobel, Inc. and<br>HollyFrontier Cheyenne Refining LLC | 20003-146-ET-15 | Direct | WY | Large Power Contract Service Tariff | 3/18/2016 |
| ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC | Occidental Chemical Corporation | U-33770 | Cross-Answering | LA | Approval to Construct St. Charles Power Station | 2/26/2016 |
| NORTHERN INDIANA PUBLIC SERVICE COMPANY | NLMK-Indiana | 44688 | Cross-Answering | IN | Cost-of-Service Study, Rider 775 | 2/16/2016 |
| ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC | Occidental Chemical Corporation | U-33770 | Direct | LA | Approval to Construct St. Charles Power Station | 1/21/2016 |
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan Copper & Gold, Inc. | 44941 | Cross-Rebuttal | TX | Class Cost-of-Service Study, Class Revenue Allocation; Rate Design | 1/15/2016 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-015 | Supplemental | AR | Support for Settlement Stipulation | 12/31/2015 |
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan Copper & Gold, Inc. | 44941 | Direct | TX | Class Cost-of-Service Study, Class Revenue Allocation; Rate Design | 12/11/2015 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-015 | Surrebuttal | AR | Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan | 11/24/2015 |
| MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-MKEE-023 | Direct | KS | Formula Rate Plan for Distribution Utility | 11/17/2015 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 45084 | Direct | TX | Transmission Cost Recovery Factor Revenue Increase. | 11/17/2015 |
| GEORGIA POWER COMPANY | Georgia Industrial Group and Georgia Association of Manufacturers | 39638 | Direct | GA | Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity | 11/4/2015 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 15-E-0283<br>15-G-0284<br>15-E-0285<br>15-G-0286 | Rebuttal | NY | Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation | 10/13/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-015 | Direct | AR | Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan | 9/29/2015 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 15-E-0283<br>15-G-0284<br>15-E-0285<br>15-G-0286 | Direct | NY | Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design | 9/15/2015 |
| SHARYLAND UTILITIES | Texas Industrial Energy Consumers | 44620 | Cross-Rebuttal | TX | Transmission Cost Recovery Factor Class Allocation Factors. | 9/8/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 14-118 | Surrebuttal | AR | Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery | 8/21/2015 |
| SHARYLAND UTILITIES | Texas Industrial Energy Consumers | 44620 | Direct | TX | Transmission Cost Recovery Factor Class Allocation Factors | 8/7/2015 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2015-2468981 | Surrebuttal | PA | Class Cost-of-Service, Capacity Reservation Rider | 8/4/2015 |
| WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 15-WSEE-115-RTS | Cross-Answering | KS | Class Cost-of-Service Study, Revenue Allocation | 7/22/2015 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2015-2468981 | Rebuttal | PA | Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling | 7/21/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 15-00083 | Direct | NM | Long-Term Purchased Power Agreements | 7/10/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-014 | Surrebuttal | AR | Solar Power Purchase Agreement | 7/10/2015 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 15-WSEE-115-RTS | Direct | KS | Class Cost-of-Service and Electric Distrbution Grid Resiliency Program | 7/9/2015 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 43958 | Supplemental DIrect | TX | Certificiate of Need for Union Power Station Power Block 1 | 7/7/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 14-118 | Direct | AR | Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery | 7/2/2015 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2015-2468981 | Direct | PA | Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider | 6/23/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-014-U | Direct | AR | Solar Power Purchase Agreement | 6/19/2015 |
| FLORIDA POWER & LIGHT COMPANY | Florida Industrial Power Users Group | 150075 | Direct | FL | Cedar Bay Power Purchase Agreement | 6/8/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 43695 | Cross-Rebuttal | TX | Class Cost of Service Study; Class Revenue Allocation | 6/8/2015 |
| FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY | Florida Industrial Power Users Group | 140226 | Surrebuttal | FL | Opt-Out Provision | 5/20/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 43695 | Direct | TX | Post-Test Year Adjustments; Weather Normalization | 5/15/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 43695 | Direct | TX | Class Cost of Service Study; Class Revenue Allocation | 5/15/2015 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 43958 | Direct | TX | Certificiate of Need for Union Power Station Power Block 1 | 4/29/2015 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 42370 | Cross-Rebuttal | TX | Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff. | 1/27/2015 |
| WEST PENN POWER COMPANY | West Penn Power Industrial Intervenors | 2014-2428742 | Surrebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 1/6/2015 |
| PENNSYLVANIA ELECTRIC COMPANY | Penelec Industrial Customer Alliance | 2014-2428743 | Surrebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 1/6/2015 |
| METROPOLITAN EDISON COMPANY | Med-Ed Industrial Users Group | 2014-2428745 | Surrebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 1/6/2015 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| WEST PENN POWER COMPANY | West Penn Power Industrial Intervenors | 2014-2428742 | Rebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 12/18/2014 |
| PENNSYLVANIA ELECTRIC COMPANY | Penelec Industrial Customer Alliance | 2014-2428743 | Rebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 12/18/2014 |
| METROPOLITAN EDISON COMPANY | Med-Ed Industrial Users Group | 2014-2428745 | Rebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 12/18/2014 |
| PUBLIC SERVICE COMPANY OF COLORADO | Colorado Healthcare Electric Coordinating Council | 14AL-0660E | Cross | CO | Clean Air Clean Jobs Act Rider; Transmission Cost Adjustment | 12/17/2014 |
| WEST PENN POWER COMPANY | West Penn Power Industrial Intervenors | 2014-2428742 | Direct | PA | Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider | 11/24/2014 |
| PENNSYLVANIA ELECTRIC COMPANY | Penelec Industrial Customer Alliance | 2014-2428743 | Direct | PA | Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider | 11/24/2014 |
| METROPOLITAN EDISON COMPANY | Med-Ed Industrial Users Group | 2014-2428745 | Direct | PA | Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider | 11/24/2014 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 14-E-0318 / 14-G-0319 | Direct | NY | Class Cost-of-Service Study; Class Revenue Allocation (Electric) | 11/21/2014 |
| PUBLIC SERVICE COMPANY OF COLORADO | Colorado Healthcare Electric Coordinating Council | 14AL-0660E | Direct | CO | Clean Air Clean Jobs Act Rider; Electric Commodity Adjustment Incentive Mechanism | 11/7/2014 |
| FLORIDA POWER AND LIGHT COMPANY | Florida Industrial Power Users Group | 140001-E | Direct | FL | Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities | 9/22/2014 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-446-ER14 | Surrebuttal | WY | Class Cost-of-Service, Rule 12 (Line Extension Policy) | 9/19/2014 |
| INDIANA MICHIGAN POWER COMPANY | I&M Industrial Group | 44511 | Direct | IN | Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider | 9/17/2014 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-446-ER14 | Cross | WY | Class Cost-of-Service Study; Rule 12 Line Extension | 9/5/2014 |
| VARIOUS UTILITIES | Florida Industrial Power Users Group | 140002-EI | Direct | FL | Energy Efficiency Cost Recovery Opt-Out Provision | 9/5/2014 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | E-002/GR-13-868 | Surrebuttal | MN | Nuclear Depreciation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design | 8/4/2014 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-446-ER14 | Direct | WY | Class Cost-of-Service Study, Rule 12 Line Extension | 7/25/2014 |
| DUKE ENERGY FLORIDA | NRG Florida, LP | 140111 and 140110 | Direct | FL | Cost-Effectiveness of Proposed Self Build Generating Projects | 7/14/2014 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | E-002/GR-13-868 | Rebuttal | MN | Class Cost-of-Service Study, Class Revenue Allocation | 7/7/2014 |
| PPL ELECTRIC UTILITIES CORPORATION | PP&L Industrial Customer Alliance | 2013-2398440 | Rebuttal | PA | Energy Efficiency Cost Recovery | 7/1/2014 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | E-002/GR-13-868 | Direct | MN | Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation | 6/5/2014 |
| PPL ELECTRIC UTILITIES CORPORATION | PP&L Industrial Customer Alliance | 2013-2398440 | Direct | PA | Energy Efficiency Cost Recovery | 5/23/2014 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 42042 | Direct | TX | Transmission Cost Recovery Factor | 4/24/2014 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 41791 | Cross | TX | Class Cost-of-Service Study and Rate Design | 1/31/2014 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 41791 | Direct | TX | Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues | 1/10/2014 |
| DUQUESNE LIGHT COMPANY | Duquesne Industrial Intervenors | R-2013-2372129 | Supplemental Surrebuttal | PA | Class Cost-of-Sevice Study | 12/13/2013 |
| DUQUESNE LIGHT COMPANY | Duquesne Industrial Intervenors | R-2013-2372129 | Surrebuttal | PA | Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation | 12/9/2013 |
| DUQUESNE LIGHT COMPANY | Duquesne Industrial Intervenors | R-2013-2372129 | Rebuttal | PA | Rate L Transmission Service; Class Revenue Allocation | 11/26/2013 |
| ENTERGY TEXAS, INC.<br>ITC HOLDINGS CORP. | Texas Industrial Energy Consumers | 41850 | Direct | TX | Rate Mitigation Plan; Conditions re Transfer of Control of Ownership | 11/6/2013 |
| SHARYLAND UTILITIES | Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC | 41474 | Cross-Rebuttal | TX | Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs | 11/4/2013 |
| MIDAMERICAN ENERGY COMPANY | Deere & Company | RPU-2013-0004 | Surrebuttal | IA | Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus | 11/4/2013 |
| DUQUESNE LIGHT COMPANY | Duquesne Industrial Intervenors | R-2013-2372129 | Direct | PA | Class Cost-of-Service, Class Revenue Allocations | 11/1/2013 |
| PUBLIC SERVICE ENERGY AND GAS | New Jersey Large Energy Users Coalition | EO13020155 and GO13020156 | Direct | NJ | Energy Strong | 10/28/2013 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| GEORGIA POWER COMPANY | Georgia Industrial Group and Georgia Association of Manufacturers | 36989 | Direct | GA | Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design | 10/18/2013 |
| SHARYLAND UTILITIES | Texas Industrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC | 41474 | Direct | TX | Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design | 10/18/2013 |
| MIDAMERICAN ENERGY COMPANY | Deere & Company | RPU-2013-0004 | Rebuttal | IA | Class Cost-of-Service Study | 10/1/2013 |
| FLORIDA POWER AND LIGHT COMPANY | Florida Industrial Power Users Group | 130007 | Direct | FL | Environmental Cost Recovery Clause | 9/13/2013 |
| MIDAMERICAN ENERGY COMPANY | Deere & Company | RPU-2013-0004 | Direct | IA | Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up | 9/10/2013 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 12-00350-UT | Rebuttal | NM | RPS Cost Rider | 9/9/2013 |
| WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 13-WSEE-629-RTS | Cross-Answering | KS | Cost Allocation Methodology | 9/5/2013 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 12-00350-UT | Direct | NM | Class Cost-of-Service Study | 8/22/2013 |
| WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 13-WSEE-629-RTS | Direct | KS | Class Revenue Allocation. | 8/21/2013 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 41437 | Direct | TX | Avoided Cost; Standby Rate Design | 8/14/2013 |
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 13-MKEE-699 | Direct | KS | Class Revenue Allocation | 8/12/2013 |
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 13-MKEE-447 | Supplemental | KS | Testimony in Support of Settlement | 8/9/2013 |
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 13-MKEE-447 | Supplemental | KS | Modification Agreement | 7/24/2013 |
| TAMPA ELECTRIC COMPANY | Florida Industrial Power Users Group | 130040 | Direct | FL | GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense | 7/15/2013 |
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 13-MKEE-452 | Supplemental | KS | Testimony in Support of Nonunanimous Settlement | 6/28/2013 |
| JERSEY CENTRAL POWER & LIGHT COMPANY | Gerdau Ameristeel Sayreville, Inc. | ER12111052 | Direct | NJ | Cost of Service Study for GT-230 KV Customers; AREP Rider | 6/14/2013 |
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 13-MKEE-447 | Direct | KS | Wholesale Requirements Agreement; Process for Exemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down | 5/14/2013 |
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 13-MKEE-452 | Cross | KS | Formula Rate Plan for Distribution Utility | 5/10/2013 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 13-MKEE-452 | Direct | KS | Formula Rate Plan for Distribution Utility | 5/3/2013 |
| ENTERGY TEXAS, INC.<br>ITC HOLDINGS CORP. | Texas Industrial Energy Consumers | 41223 | Direct | TX | Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings Subsidiary | 4/30/2013 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 12-961 | Surrebuttal | MN | Depreciation; Used and Useful; Cost Allocation; Revenue Allocation | 4/12/2013 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 12-961 | Rebuttal | MN | Class Revenue Allocation. | 3/25/2013 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 12-961 | Direct | MN | Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders | 2/28/2013 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 38951 | Second Supplemental | TX | Competitive Generation Service Tariff | 2/1/2013 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 38951 | Second Supplemental | TX | Competitive Generation Service Tariff | 1/11/2013 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 40443 | Cross Rebuttal | TX | Cost Allocation and Rate Design | 1/10/2013 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 40443 | Direct | TX | Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design | 12/10/2012 |
| FLORIDA POWER AND LIGHT COMPANY | Florida Industrial Power Users Group | 120015 | Corrected Supplemental Rebuttal | FL | Support for Non-Unanimous Settlement | 11/13/2012 |
| FLORIDA POWER AND LIGHT COMPANY | Florida Industrial Power Users Group | 120015 | Corrected Supplemental Direct | FL | Support for Non-Unanimous Settlement | 11/13/2012 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 12-E-0201/12-G-0202 | Rebuttal | NY | Electric and Gas Class Cost-of-Service Studies. | 9/25/2012 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 12-E-0201/12-G-0202 | Direct | NY | Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand | 8/31/2012 |
| MID-KANSAS ELECTRIC COMPANY, LLC | Western Kansas Industrial Electric Consumers | 12-MKEE-650-TAR | Direct | KS | Transmission Formula Rate Plan | 7/31/2012 |
| WESTAR ENERGY INC. and<br>KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 12-WSEE-651-TAR | Direct | KS | TDC Tariff | 7/30/2012 |
| FLORIDA POWER AND LIGHT COMPANY | Florida Industrial Power Users Group | 120015 | Direct | FL | Class Cost-of-Service Study, Revenue Allocation, and Rate Design | 7/2/2012 |
| LONE STAR TRANSMISSION, LLC | Texas Industrial Energy Consumers | 40020 | Direct | TX | Revenue Requirement, Rider AVT | 6/21/2012 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 39896 | Cross | TX | Class Cost-of-Service Study, Revenue Allocation, and Rate Design | 4/13/2012 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 39896 | Direct | TX | Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design | 3/27/2012 |

# APPENDIX C

## Assessment of Georgia Power Company's Class Cost-of-Service Study

### Procedures for Conducting a Class Cost-of-Service Study

**Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?**

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kW). This includes production, transmission, and some distribution investment and related fixed Operation and Maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

**Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?**

A A properly conducted CCOSS recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

**Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?**

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that

a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- operate at higher load factors;
- take service at higher delivery voltages; and
- use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

**Q DOES GEORGIA POWER COMPANY'S CLASS COST-OF-SERVICE STUDY GENERALLY FOLLOW THE ABOVE PROCEDURES?**

A Yes. In particular, GPC classifies all production and transmission plant and related operating expenses as demand-related costs, and it also recognizes that a portion of the distribution network is a customer-related cost. The classification of these costs not only comport with generally accepted cost of service principles, they are consistent with cost causation and system planning criteria.

For example, GPC classified a portion of its distribution network investment as customer-related. This is consistent with the purpose of the distribution system, which is to deliver power from the transmission grid to the customer, where it is eventually

consumed. Certain investments (*e.g.,* meters, service drops) must be made just to attach a customer to the system. These investments are customer-related.

## Classification of Distribution Network Costs

**Q WHAT DO YOU MEAN BY THE DISTRIBUTION NETWORK?**

A The distribution "network" consists of GPC's investment in poles, towers, fixtures, overhead lines, and line transformers. These investments are booked to FERC Accounts 364, 365, 366, 367, and 368.

**Q WHY IS IT APPROPRIATE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK INVESTMENTS AS A CUSTOMER-RELATED COST?**

A Classifying a portion of the distribution network as a customer-related cost recognizes the reality that every utility must provide a physical connection and voltage support to allow electricity to be delivered to each and every customer regardless of the customer's peak demand or energy consumed. Further, that path and the required voltage support must be in place if the utility is to meet its obligation to provide service upon demand.

Absent a connection to the system, a customer cannot take power. Further, the connecting facilities must be sized to provide voltage support before any power or energy can be consumed. These prerequisites (*i.e.,* a grid connection with facilities sized to provide voltage support) are clearly related to the existence of the customer.

Further, it is a recognized and accepted practice. For example, the National Association of Regulatory Utility Commission Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles,

conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[23]

For this reason, many utilities and state regulatory commissions have approved CCOSSs in which a significant portion of the distribution network is classified as a customer-related cost.

## Classification and Allocation of Production Plant

**Q YOU PREVIOUSLY STATED THAT GEORGIA POWER COMPANY CLASSIFIED ALL PRODUCTION PLANT AS A DEMAND-RELATED COST. IS THIS PRACTICE CONSISTENT WITH COST CAUSATION?**

A Yes. Classifying all production plant as a demand-related cost is consistent with system planning principles. It recognizes a utility's obligation to provide reliable service at the lowest reasonable cost. It also recognizes that once an investment is made to meet peak demand, that same investment can be used to meet demand throughout the year. The latter is a bi-product of meeting peak demand. Meeting peak demand is the cost-causer.

Further, proposals to classify production plant as energy-related are both overly simplistic and fraught with internal inconsistencies. For example, advocates of energy-based allocations often cite the lower cost of operating base load units as a reason to allocate the higher capital costs on an energy basis. However, such advocates often fail to allocate the lower fuel costs to those customer classes that purportedly benefit more from base load capacity. The reality is that all classes are served from system resources. Any methodology that is premised on an assumption that each customer

[23] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* at 90 (Jan. 1992).

class is served from a different mix of resources that does not also address the allocation of both capital costs and operating costs is, at best, an over-simplification of the planning process and is inherently flawed.

**Q ARE THERE ANY ASPECTS OF GEORGIA POWER COMPANY'S CLASS COST-OF-SERVICE STUDY THAT DO NOT REFLECT COST-CAUSATION PRINCIPLES?**

A Yes. GPC's preferred CCOSS allocates production and a portion of transmission costs using the 12CP method. The 12CP method allocates costs to customer classes based on their contribution to each of the 12 monthly system peaks. The 12CP method gives equal weight to all 12 monthly peaks. That is, March and April (which are always low demand months) are treated the same as July and August (which are always high demand months). This equal weighting fails to recognize that GPC has pronounced peaks in the summer.

**Q DOES THE 12CP METHOD VIOLATE THE PRINCIPLE OF COST CAUSATION?**

A Yes. Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate demand-related costs. If a utility is to fulfill its obligation to provide continuous service, it must install sufficient generation capacity to meet the expected peak demands of its customers and to provide an adequate reserve margin.

Thus, consistent with cost causation, a utility that has a high summer peak demand relative to the demands in other seasons should allocate production plant costs relative to each customer class's contribution to that summer peak (or peaks). Summer peak demands are still the primary driver in determining how much capacity is needed by GPC to provide reliable service.

Thus, either the 4CP or Annual System Peak (1CP) methods would explicitly recognize the seasonal (summer-peaking) nature of GPC's load and would be more appropriate and better reflect cost causation than the 12CP method.

**Q GEORGIA POWER COMPANY IS EXPERIENCING A GROWING CONVERGENCE BETWEEN ITS SUMMER AND WINTER SYSTEM PEAKS. DOES THIS JUSTIFY USING THE 12CP METHOD?**

A No. Despite the recent winter peaks, which are due to extreme cold weather, GPC is still projecting to be a summer-peaking utility on a weather-normalized basis. Thus, GPC continues to plan resources to meet the summer peak because the summer peaks are higher and more prolonged in nature than the recently experienced winter peaks. I would also observe that the entire southeast region remains summer-peaking.

**Q IS THERE AN ALLOCATION METHODOLOGY THAT WOULD GIVE SOME WEIGHT TO THE GROWING WINTER PEAK DEMAND?**

A Yes. As an alternative to 12CP, a methodology similar to what Santee Cooper uses (*i.e.,* the average of the summer and winter peaks) would give explicit weight to both the growing winter peak demand as well as the summer peak demand, which is still the primary planning criteria. Based on GPC's test-year load characteristics, the highest peak demands are projected to occur in the months January, June, July, August, September, and December. Thus, a method that reflects both seasonal peak demands would give weight to GPC's growing winter peak.

## Marginal Cost Rates

**Q HOW DOES GEORGIA POWER COMPANY HANDLE MARGINAL COST RATES, SUCH AS REAL TIME PRICING, IN ITS CLASS COST-OF-SERVICE STUDY?**

A GPC's CCOSS includes both embedded costs and revenues, as well as marginal costs and revenues for RTP customers. Thus, GPC's CCOSS is a hybrid study which incorporates both embedded and marginal costing principles due to the inclusion of marginal cost-based rates (*i.e.,* RTP). GPC's hybrid treatment parallels the design of RTP in which a portion of the service (*i.e.,* the CBL) is priced under a standard tariff, which reflects average or *embedded* costs, while the incremental load is priced to reflect *marginal* costs. In GPC's CCOSS, embedded production and transmission costs are allocated to the CBL portion of the RTP loads using the same allocation methods as apply to all non-RTP classes. For the incremental loads, GPC allocates distribution costs for service provided at distribution voltage, and it directly assigns the marginal or incremental costs to the RTP classes. The latter step is accomplished by assuming that the test period incremental cost of serving RTP customers is equal to the expected incremental revenue, which is based on the revenue GPC expects to receive during the test period from customers on RTP rates.

**Q IS IT REASONABLE TO ALLOCATE EMBEDDED COSTS ONLY TO THE CUSTOMER BASELINE LOAD PORTION OF REAL TIME PRICING?**

A Yes. Embedded production and transmission costs are not allocated to the incremental RTP load because the incremental load is capable of responding to price under appropriate circumstances. Further, real time prices recover *marginal* production, transmission, and system energy costs. Therefore, it would be inappropriate to allocate

*embedded* production, transmission, and system energy costs to the incremental RTP load. To do so would charge RTP customers twice for these services.

**Q SHOULD AN EMBEDDED CLASS COST-OF-SERVICE STUDY BE USED TO DETERMINE THE COST OF PROVIDING REAL TIME PRICING SERVICE?**

A No. An embedded CCOSS should not be used to measure the cost of providing RTP service. This is because hourly (RTP) prices are based on *marginal* costs. An embedded CCOSS allocates average, rather than marginal costs, to customer classes. Thus, using an embedded CCOSS to determine the cost of providing RTP service would create an economic mismatch because the revenues are based on marginal cost, while the allocated costs are based on average costs. Incremental RTP load should be priced using marginal cost principles, and not allocated embedded costs.

**Q DOES GEORGIA POWER COMPANY'S TREATMENT OF THE REAL TIME PRICING RATES IN ITS CLASS COST-OF-SERVICE STUDY RECOGNIZE THAT REAL TIME PRICING IS A MARGINAL COST-BASED RATE?**

A Yes. GPC's adjustments appropriately recognize that a full allocation of embedded costs should only apply to the CBL component of the RTP usage, while incremental costs should be directly assigned to the marginal loads. The Commission should reject any attempt to allocate full embedded costs to loads which are priced through marginal cost methodologies.

## Why Production Plant Costs Are Not Energy-Related

**Q WHY DO SOME ANALYSTS RECOMMEND ALLOCATING A PORTION OF PRODUCTION PLANT COSTS ON AN ENERGY BASIS?**

A Energy-based allocation methods are based on a theory that the "extra" investment

associated with certain types of generation (*i.e.*, units that are operated as base load and/or load following) provides fuel cost savings. Since fuel costs are typically allocated on an energy (or kWh) basis, the assumption is that this investment is also driven by kWh sales. This theory is referred to as Capital Substitution. Capital Substitution overlooks four realities:

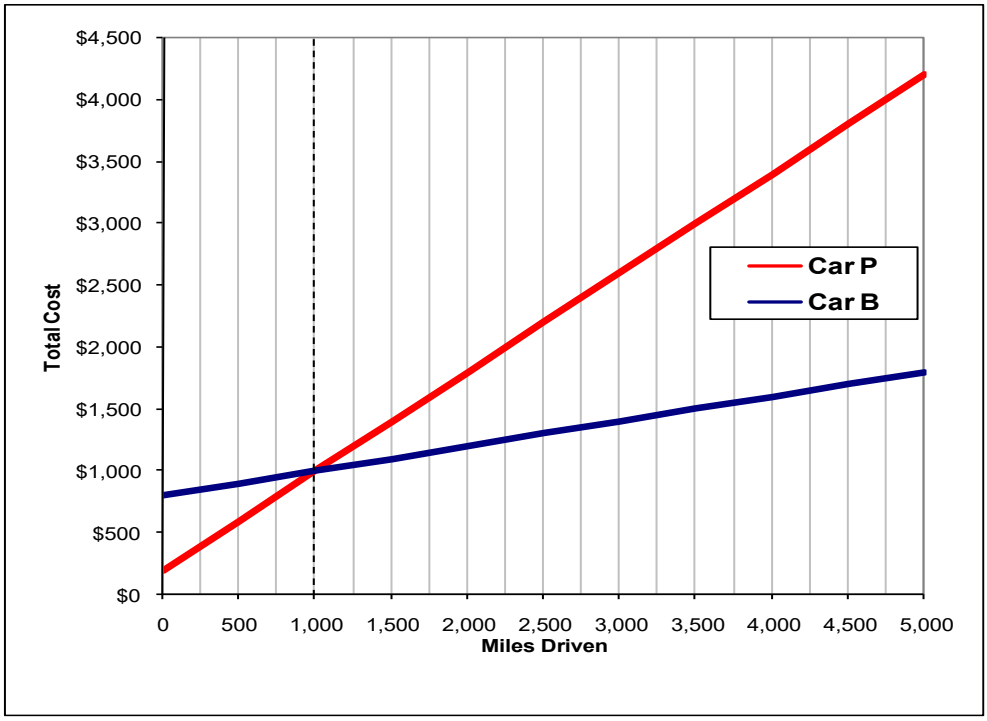
- The need for new capacity is driven by both projected peak demands and reserve requirements to ensure that electricity is reliable. Using 12CP to allocate a portion of production plant that GPC considers demand-related does not recognize the peak demands that drive capacity needs.
- Fuel savings are not a cost driver. All new plants save fuel costs because of improvements in generation technology, not because they are more capital intensive. Although the choice of plant technology is determined by economics, the objective is to provide reliable service at the lower overall cost and not solely to lower fuel costs.
- Combined cycle gas turbines (CCGTs) have become the technology of choice not because they have lower fuel costs but because they can provide flexible load following capabilities needed to balance loads and resources in real time and meet operating reserve requirements.
- An energy allocation assumes all hours are critical to the choice of generation. However, not all production from a specific plant determines the type of capacity to install. **Thus, allocating investment to all hours is contrary to cost causation.**

**Q HOW IS ALLOCATING INVESTMENT TO ALL HOURS CONTRARY TO COST CAUSATION?**

A The following simplified example of how an energy allocation is contrary to cost causation. Let us suppose two drivers are required to rent cars from a fleet that contains only two types of cars, "**Car P**" and "**Car B**":

| | **Car P** | **Car B** |
|---|---|---|
| Fixed Charge | $200 | $800 |
| Mileage Charge | 80¢ | 20¢ |

**Car B** has a high fixed charge and gets high mileage (like a base load plant), while **Car P** has a low fixed charge but gets poor mileage (like a peaker). The graph below shows total cost of both cars over a range of miles driven.




The total cost is also calculated in the following table. As can be seen, the *break-even point* between **Car P** and **Car B** is 1,000 miles.

| Miles Driven | Total Cost | | | Best Choice |
|---|---|---|---|---|
| | Car P | | Car B | |
| 0 | $200 | | $800 | P |
| 500 | $600 | | $900 | P |
| 1,000 | $1,000 | | $1,000 | P or B |
| 1,500 | $1,400 | | $1,100 | B |
| 2,000 | $1,800 | | $1,200 | B |
| 2,500 | $2,200 | | $1,300 | B |
| 3,000 | $2,600 | | $1,400 | B |
| 3,500 | $3,000 | | $1,500 | B |
| 4,000 | $3,400 | | $1,600 | B |
| 4,500 | $3,800 | | $1,700 | B |
| 5,000 | $4,200 | | $1,800 | B |

That is, **Car B** has a lower total cost per mile than **Car P** if it is operated more than 1,000 miles. If one customer needed to drive 1,500 miles and a second customer needed to drive a car 4,500 miles, both customers would choose to drive **Car B**. In other words, the decision to drive **Car B** was based on whether the car would be driven at least 1,000 miles. It doesn't matter how many miles over 1,000 it will be driven.

The same break-even construct applies to electric utilities. For example, assuming the break-even point between Base Load and Peaking capacity is 1,000 hours per year, it doesn't matter whether the Base Load plant will operate 5,000 hours, 6,000 hours, of 8,000 hours per year. Thus, ***load duration*** can affect the decision of whether to install Base Load or Peaking capacity. However, once the decision is made, duration beyond the break-even point is irrelevant.

Energy-based allocation methods ignore this fundamental planning construct because investment would be allocated to all kWh usage. *This is at odds with Capital Substitution because the extra investment in base load generation can be justified by load duration up to the economic break-even point between Base Load and Peaking capacity*. That is, once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, then a load following or base load unit will be more economical.

Therefore, annual energy usage does not cause plant investment. However, load duration up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity.

**Q WHY ELSE ARE ENERGY-BASED ALLOCATION METHODS WRONG?**

A Energy-based allocation methods also suffer from the lack of symmetry in how plant and fuel costs are allocated (*i.e.*, the "Fuel Symmetry" problem) and average demand is double-counted (i.*e.*, the Double-Counting" problem).

The fuel symmetry problem was one of the primary reasons cited by the Public Utility Commission of Texas in rejecting every type of energy-based allocation method proposed in rate cases throughout the 1980s and 1990s (see for example Docket No. 5560; Docket No. 5700; Docket Nos. 7460 and 7172; Docket No. 8032).

For example, in Docket No. 7460, the Commission adopted the Hearing Examiner's Report, which cited the apparent lack of "fuel symmetry" in rejecting capital substitution, and energy-based allocation method.

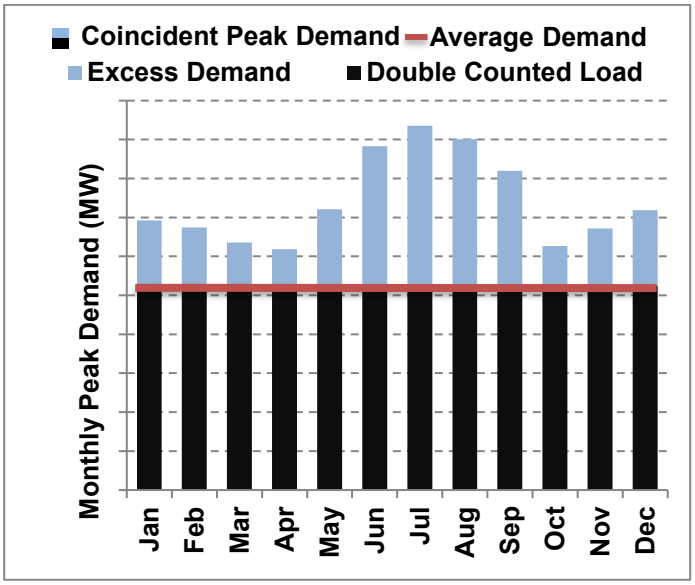
> The Examiner's find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal, the high load factor classes, which will bear the higher cost responsibility for base load units will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units.[24]

**Q WHAT IS THE DOUBLE-COUNTING PROBLEM INHERENT IN AN ENERGY-BASED ALLOCATION METHOD?**

A Double-counting can occur when plant-related costs are properly allocated partially on a coincident peak basis and an average demand (or energy) basis. Average demand is annual energy consumption divided by 8,760 hours. It is also a component of

[24] *Application of El Paso Electric Company for Authority to Change Rates* and *Application of El Paso Electric Company for Review of the Sale and Leaseback of Palo Verde Nuclear Generating Station Unit 2*, Consolidated Docket Nos. 7460 and 7172, Examiner's Report, at 238 (Jun. 16, 1988), adopted in Second Order on Rehearing (May 10, 1989), 14 Tex. P.U.C. Bull. 929.

coincident peak demand. This is illustrated in the following figure for a hypothetical summer peaking utility.




Average demand is equivalent to the black shaded area of the chart. Coincident peak demand is represented by the combined black and blue shaded areas. Double-counting occurs because coincident peak demand incorporates average demand.

By allocating some plant-related costs relative to average demand and some relative to coincident peak demand, energy usage is counted twice in the allocation process: once by itself and a second time as a subset of coincident peak demand. If you presume that base load units are built to meet average year-round demand, then it follows that the only time load-following (*e.g.*, intermediate and peaking) units would be needed is when system demands exceed the average demand. Capital Substitution proponents would allocate the cost of this additional capacity relative to coincident peak demand (*i.e.*, the entire bar including both the black and blue portions of the bars), rather than just the excess demand (*i.e.*, the blue portion of the bar).

**Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLOW IN ENERGY-BASED ALLOCATION METHODOLOGIES?**

A Yes. For example, both the Iowa Utilities Board and the Public Utility Commission of Texas have cited the double-counting problem in numerous cases. Specifically, the Public Utility Commission of Texas states:

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50% of the intermediate demand, includes with it an energy component. Dr. Johnson has elected to use a 4CP demand allocator, but such an allocator, because it looks at peak energy usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and this "double dipping" is taking place.[25]

[25] *Id.* at 199.

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**Utility Securitization as of June 2021**

Since 1997 Ratepayer-Backed Bond Laws: 27 States + DC + Puerto Rico
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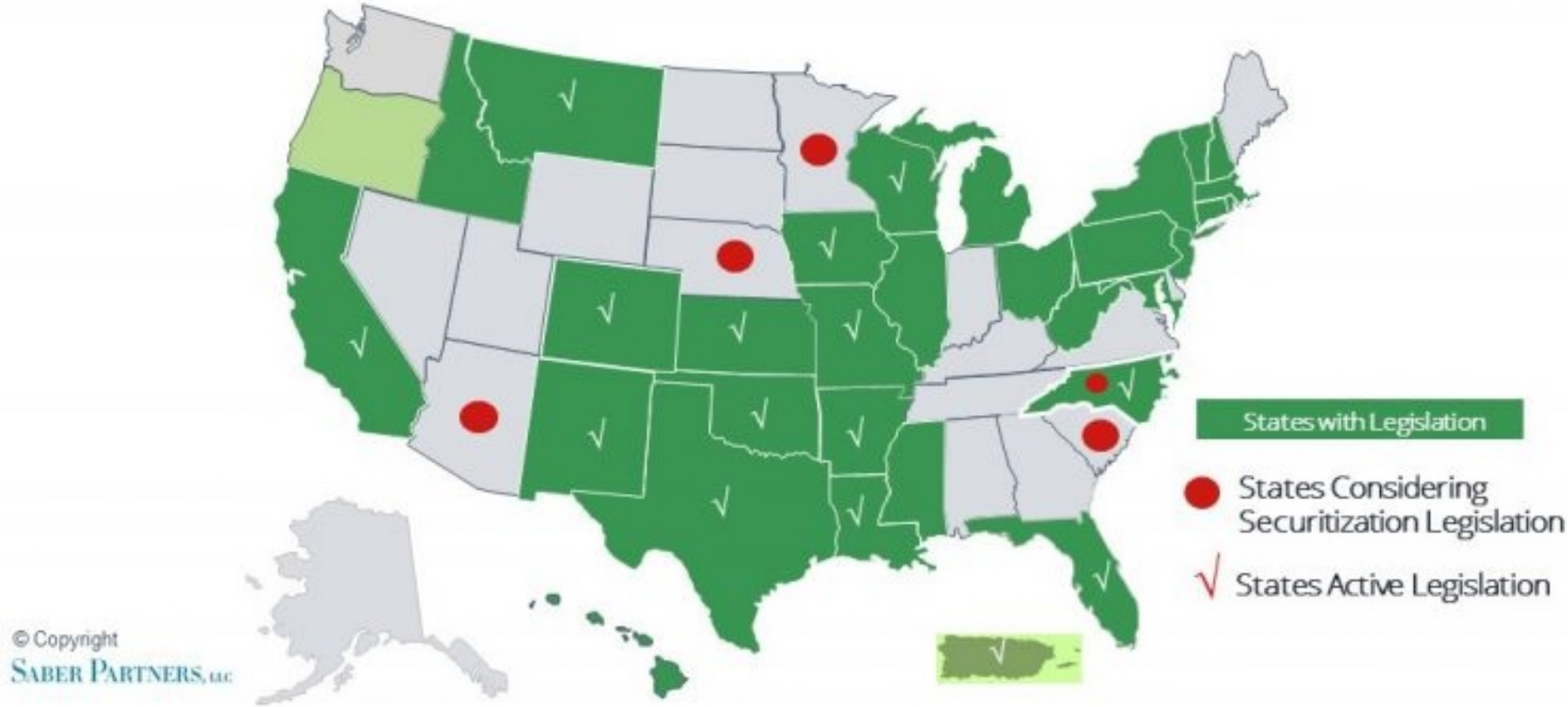


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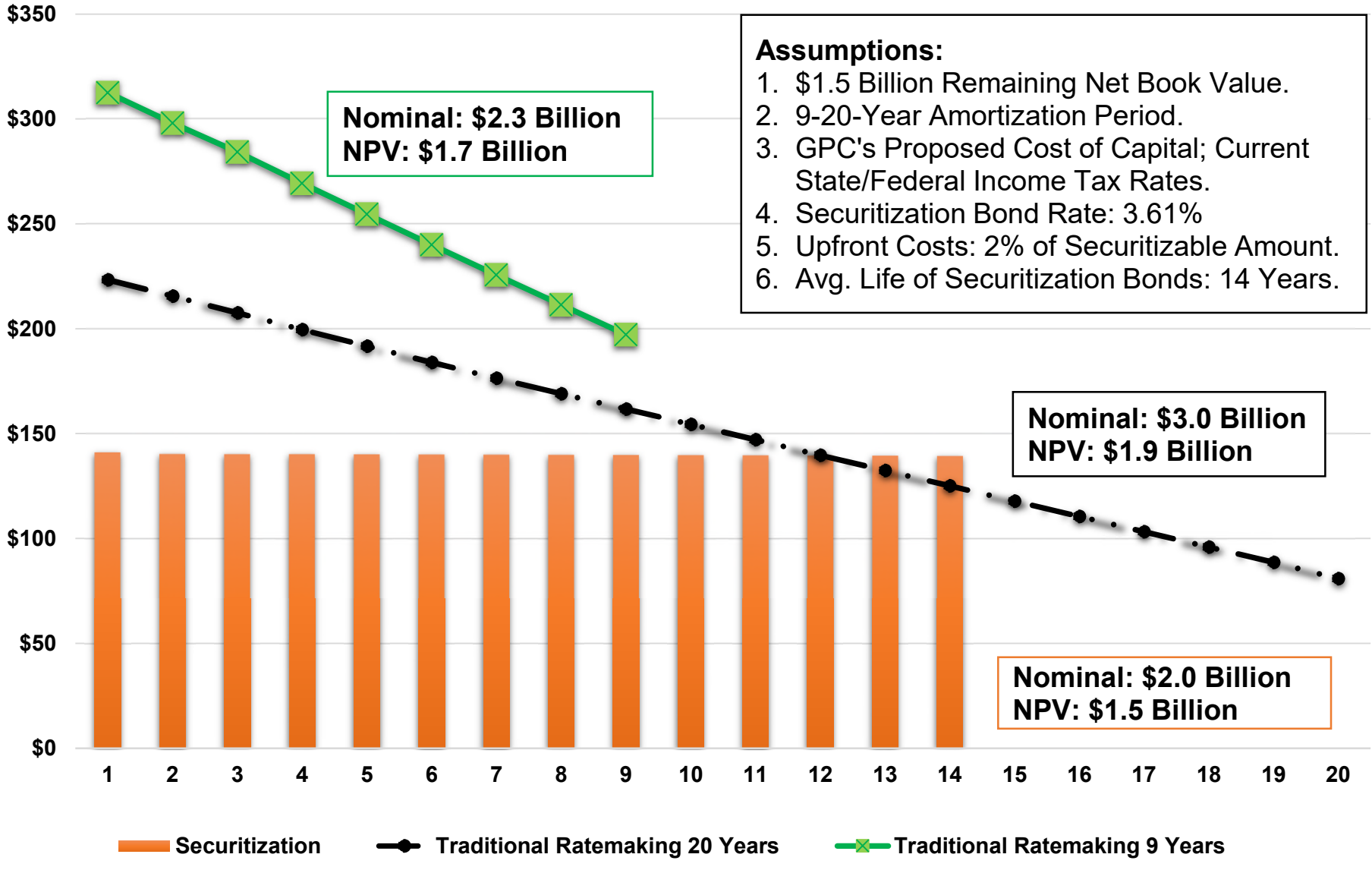
# Traditional Ratemaking Versus Securitization
## (Dollars in Millions)



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Regulated utilities - US

# Utility cost recovery through securitization is credit positive

Utility cost recovery charge (UCRC) securitization, a financing technique used to recover stranded costs, storm costs and other expenses, can be a credit positive tool for regulated utilities. UCRC securitization, whereby utilities issue bonds with lower financing costs that are paid back through a special customer charge, is typically underpinned by state legislation and in recent years has become more versatile and widespread. The ability to use securitization as a tool to recover, often significant, costs related to large or unforeseen developments allows utilities to avoid potentially credit negative events. However, though the mechanism typically benefits utilities and their customers, too much securitization can have negative consequences.

» **Securitization typically benefits utilities and their current customers.** Utilities benefit because they receive an immediate source of cash from the securitization proceeds and are ensured recovery of large costs in a timely manner that may, otherwise, be recovered over a lengthy period of time or denied recovery altogether. Current utility customers benefit because the cost of the securitized debt is lower than the utility's cost of debt, which reduces the impact on their monthly bills.

» **UCRC securitization has become more versatile and prevalent.** Utility securitization became widespread for the recovery of stranded costs following deregulation of the sector in the late 1990s. It is now used to recover costs associated with storm restoration and environmental costs, utility restructuring, deferred fuel costs and renewable energy projects.

» **State law and financing orders strongly protect securitization assets.** There are three major components of a UCRC securitization—state legislation, a financing order and a true-up mechanism—which ultimately protect the assets backing the bonds.

» **Too much securitization can have negative consequences.** The use of securitization removes the utility's opportunity to include the corresponding asset in its rate base and the ability to earn a return on that asset. A significant amount of securitization debt could impact customer bills substantially while hurting the utility's financial flexibility and ability to raise rates for other reasons, such as to recover future costs and investments.

## Securitization typically benefits utilities and their current customers

UCRC securitization was widely used after the deregulation of the utility sector in the late 1990s as a way to finance so-called stranded costs—the shortfall between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation assets. In UCRC securitization, utilities issue bonds with lower financing costs that are paid back through a discrete customer charge. We typically view use of the technique as credit positive for utilities.

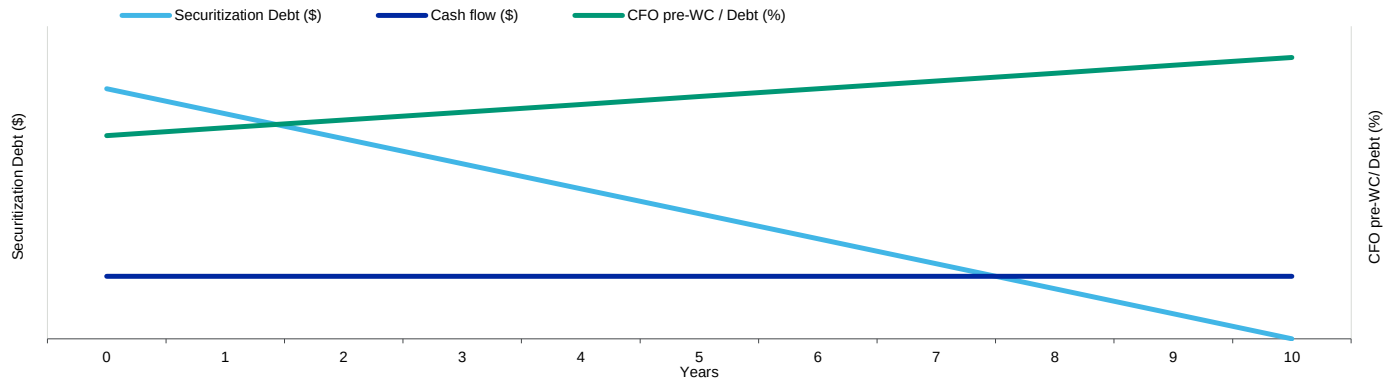
A utility benefits from the securitization because it receives an immediate source of cash. The ability to use securitization generally means the utility is allowed to recover all or most of the costs in question in a timely manner. The ability to use securitization as a tool to recover costs related to large or unforeseen developments allows utilities to avoid potentially credit negative events. The utility's ratepayers benefit because customer rates are lower than if the securitization was not utilized and in many cases avert the need for a substantial rate increase. Under state legislation, the utility must show that the savings to its customers on a net present value basis will be higher than they would have been without securitization.

The savings result from the cost of the securitized debt being lower than the utility's unsecuritized cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery. The special surcharges involved are also spread out over a long period, typically corresponding to the maturity of the securitization bonds. This eases the impact on customer bills when compared with requesting cost recovery from customers through a one-time payment.

Exhibit 1 shows an illustrative example of the potential impact over time on a utility's ratio of cash flow from operations pre-working capital changes (CFO pre-W/C) to debt, all else being equal. Depending on the size of the securitization debt as a proportion of total debt, the impact on a utility's financial metrics can vary. If the securitization is a significant component of total debt then a utility's ratio of CFO pre-W/C to debt could be severely negatively affected.

Exhibit 1

**Illustrative example of the impact UCRC securitization can have on a utility's ratio of CFO pre-W/C to debt**




*Source: Moody's Investors Service*

In the presentation of securitization debt in our published financial ratios, we make our own assessment of the appropriate credit representation, but in most cases we follow the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most cases, utilities have been required to consolidate securitization debt under GAAP, even though it is technically non-recourse.

We typically view securitization debt of utilities as on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's financial ratios by including the securitization debt and related revenues in our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of financial ratios that

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exclude securitization debt and related revenues to ensure that the benefits of securitization are not ignored. Since securitization debt amortizes mortgage-style, including it makes financial ratios look worse in early years, when most of the revenue collected goes to pay interest, and better in later years, when most of the revenue collected goes to pay principal.

### CenterPoint Energy Houston Electric has a long history of issuing securitization bonds

In 1999, the Texas legislature adopted the Texas Electric Choice Plan, under which integrated utilities operating within the Electric Reliability Council of Texas, Inc. (ERCOT, Aa3 stable) were required to unbundle their operations into separate retail sales, power generation, and transmission and distribution companies. The legislation provided for a transition period and a true-up mechanism for the utilities to recover stranded and certain other costs resulting from the transition. Those costs were recoverable, after approval by the Public Utility Commission of Texas (PUCT), either through the issuance of securitization bonds or through the implementation of a competition transition charge as a rider to the utility's tariff.

In the early 2000s, CenterPoint Energy Houston Electric, LLC (CEHE, A3 stable) restructured its business in accordance with the new law and its generating stations were sold to third parties. Over the years that followed, CEHE has worked with regulators to obtain recovery of most its stranded assets and associated costs through the use of securitization bonds and other regulatory mechanisms.

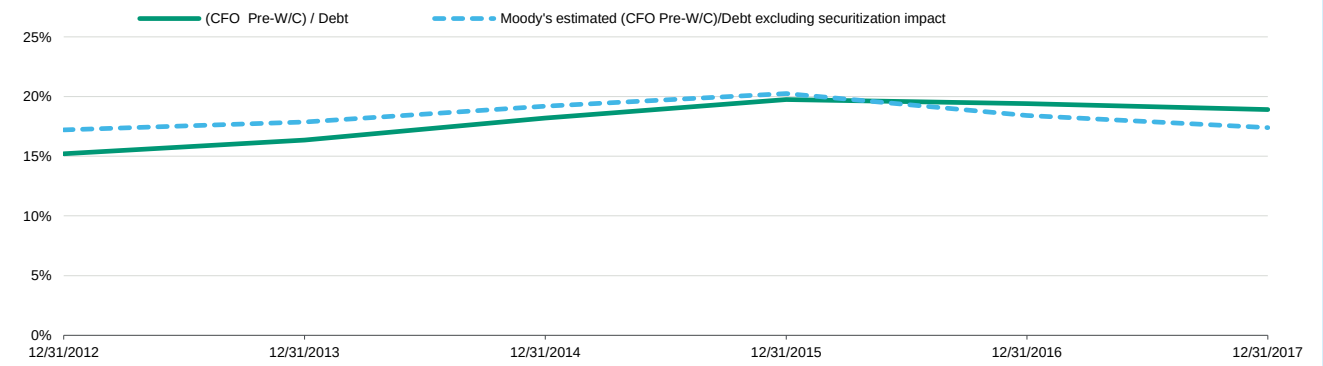
In October 2011, PUCT approved a final order that allowed CEHE to recover an additional $1.695 billion of stranded costs through the use of securitization bonds. In January 2012, CEHE created a new special purpose subsidiary, CenterPoint Energy Transition Bond Company IV, LLC, which issued $1.695 billion of securitization bonds in three tranches with interest rates ranging from 0.9012% to 3.0282% and final maturity dates ranging from April 15, 2018 to October 15, 2025. The securitization bonds will be repaid over time through a charge imposed on customers in CEHE's service territory.

The overall time-weighted interest rate of approximately 2.5% for the securitization bonds was substantially lower than the average rate on CEHE's unsecuritized debt of about 7.66% at that time. The PUCT estimated that the reduced interest charges from the securitization of the stranded costs resulted in savings for CEHE's customers of more than $700 million over the life of the bonds.

Exhibit 2 shows our estimate of the impact on CEHE's ratio of CFO pre-W/C to debt from 2012 through 2017 due to the impact of the $1.695 billion securitization debt. We estimate that the securitization debt had at most a 200-basis-point impact on CEHE's ratio of CFO pre-W/C to debt either positive or negative, depending on the year.

Exhibit 2

**How CEHE's ratio of CFO pre-W/C to debt was impacted by securitization debt from 2012 through 2017**




*Source: company's filings, Moody's Investors Service*

## UCRC securitization has become more versatile and widespread

UCRC bonds were created after the deregulation of utilities in the late 1990s as a way to finance stranded costs. To date, more than 20 states have used this model to recover not only stranded costs but also costs associated with storm recovery and to a lesser degree environmental restoration, utility restructuring, deferred fuel costs and renewable energy projects.

In June 2005, for example, Section 366.8260 of the Florida Statutes was enacted through Senate Bill 1366, allowing the Florida Public Service Commission to authorize the state's utilities to securitize storm recovery costs. Following Hurricanes Katrina, Rita and Wilma in 2005, Arkansas, Louisiana, Mississippi and Texas joined Florida by passing special legislation giving utilities operating in their jurisdictions the option of utilizing securitization for recovery of storm costs. Recently in California, legislators are considering an amended version of Assembly Bill 33 which, as amended, would allow securitization to be used for prudently incurred costs arising from wildfires, a credit positive step for utilities dealing with potentially significant wildfire-related liabilities. Exhibit 3 shows a list of securitizations completed by utilities in recent years.

In each case, with the exception of the Entergy New Orleans LLC's (ENO, Ba1 stable) bond issuance (Aa1 (sf)) in 2015, we rated the securitization bonds Aaa (sf) owing to the strength of the state legislation, including the state's non-impairment pledge, the irrevocable financing order typically from the state public utility commission, credit enhancement consisting of a statutory uncapped true-up adjustment mechanism, the manageable size of the cost recovery charge and the remote likelihood of a successful legal, political or regulatory challenge, among other factors.

The Aa1 (sf) rating on ENO's securitization bond issuance, which is one-notch lower than the typical Aaa (sf) rating, reflects the relative small size and concentration of the ratepayer base from whom the storm recovery charge will be collected. The bonds are exposed to the risk of declines in the rate payer base in the service area of ENO in case of severe events, such as anther severe hurricane.

Exhibit 3

## Moody's rated UCRC securitizations issued since 2012

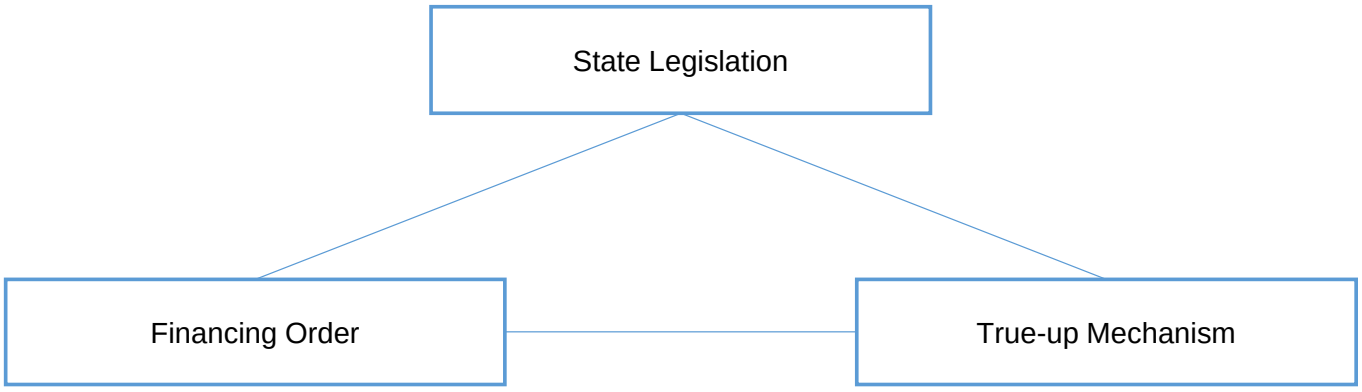
| Deal Name | Servicer | Issuance ($ millions) | Year Completed | Rating (sf) | State |
|---|---|---|---|---|---|
| PSNH Funding LLC 3, Series 2018-1 | Public Service Co. of New Hampshire | $636 | 2018 | Aaa | New Hampshire |
| Utility Debt Securitization Authority Restructuring Bonds, Series 2017 | Long Island Power Authority | 369 | 2017 | Aaa | New York |
| Utility Debt Securitization Authority Restructuring Bonds, Series 2016B | Long Island Power Authority | 469 | 2016 | Aaa | New York |
| Duke Energy Florida Project Finance, LLC | Duke Energy Florida LLC | 1294 | 2016 | Aaa | Florida |
| Utility Debt Securitization Authority Restructuring Bonds, Series 2016A | Long Island Power Authority | 637 | 2016 | Aaa | New York |
| Utility Debt Securitization Authority Restructuring Bonds, Series 2015 | Long Island Power Authority | 1002 | 2015 | Aaa | New York |
| Entergy New Orleans Storm Recovery Funding I, L.L.C. | Entergy New Orleans LLC | 99 | 2015 | Aa1 | Louisiana |
| State of Hawaii Department of Business, Economic Development, and Tourism - Green Energy Market Securitization Bonds, 2014 Ser. A | Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited | 150 | 2014 | Aaa | Hawaii |
| Louisiana Local Government Environmental Facilities and Community Development Authority - System Restoration Bonds (Louisiana Utilities Restoration Corporation Project/EGSL), Ser. 2014 (Federally Taxable) | Entergy Gulf States Louisiana, L.L.C. | 71 | 2014 | Aaa | Louisiana |
| Louisiana Local Government Environmental Facilities and Community Development Authority - System Restoration Bonds (Louisiana Utilities Restoration Corporation Project/ELL), Ser. 2014 (Federal Taxable) | EL Investment Company, LLC | 244 | 2014 | Aaa | Louisiana |
| Consumer 2014 Securitization Funding LLC - Senior Secured Securitization Bonds, Series 2014-A | Consumers Energy Company | 378 | 2014 | Aaa | Michigan |
| Utility Debt Securitization Authority Restructuring Bonds Series 2013T and Series 2013TE | Long Island Power Authority | 2022 | 2013 | Aaa | New York |
| Appalachian Consumer Rate Relief Funding LLC - Senior Secured Consumer Rate Relief Bonds | Appalachian Power Company | 380 | 2013 | Aaa | West Virginia |
| Ohio Phase-In-Recovery Funding LLC | Ohio Power Company | 267 | 2013 | Aaa | Ohio |
| FirstEnergy Ohio PIRB Special Purpose Trust 2013 | Cleveland Electric Illuminating Company (The), Ohio Edison Company, Toledo Edison Company | 445 | 2013 | Aaa | Ohio |
| AEP Texas Central Transition Funding III LLC, Senior Secured Transition Bonds | AEP Texas Central Company | 800 | 2012 | Aaa | Texas |
| CenterPoint Energy Transition Bond Company IV, LLC, Series 2012 Senior Secured Transition Bonds | CenterPoint Energy Houston Electric, LLC | 1695 | 2012 | Aaa | Texas |

*Source: Moody's Investor Service*

## State law and financing order strongly protect the securitization assets

There are three major components of a UCRC securitization: state legislation, a financing order and a true-up mechanism, as shown in Exhibit 4. The securitization law and financing order legally protect the assets backing the bonds.

Exhibit 4
**UCRC securitization has three major components**




*Source: Moody's Investors Service*

The state legislature typically passes a law authorizing the utility to finance the recovery of certain costs through the issuance of securitization bonds. The legislation authorizes the creation of a property right allowing the issuer to collect special charges from customers which are used to repay the bonds. Bondholders receive protection through a non-impairment pledge, under which the state pledges that it will not take any actions that alter the charges or the law until the bonds have been repaid in full.

The legislation also mandates an irrevocable financing order, typically issued by the state public utility commission, which means the state cannot change or revoke the financing order once it is issued. The order authorizes the transaction servicer, typically the utility, on behalf of the issuer of the debt, to charge and collect the special surcharges from the utility's ratepayer base.

The securitization law and the financing order mandate a true-up adjustment mechanism under which the servicer must adjust the charges at least annually to ensure the collection of adequate funds to provide for timely payments on the securitization bonds. The securitization law also establishes the issuer of the debt as a bankruptcy-remote special purpose entity (SPE), and the utility sells the securitized asset (the property right) to the SPE via a true sale transaction. The assets are thus legally isolated from the utility. The SPE issues the bonds and uses the proceeds to acquire the asset. The SPE then uses the charge collected from the utility's customers to pay debt service until the bonds are repaid in full. The utility receives the proceeds from the bond issuance.

## Too much securitization can also have negative consequences

While the use of securitization does provide more timely recovery of costs for the utility, there can be some downside. In cases where utilities use securitization to recover stranded costs, the mechanism requires utilities to give up the opportunity to include the corresponding asset in its rate base as well as the ability to earn a return on that asset. This diminishes the utility's future earnings power and cash flow generation.

A significant amount of securitization debt could represent a substantial portion of the utility's customer bills. This would not only raise customer rates but could also prevent regulators from approving rate increases in the future, out of concern that rates are rising too much. This could in turn affect the utility's capital investments and the ability to add any such investments to rate base and earn on a return on them.

In addition, since the surcharge on customer bills used to pay off the securitization bonds will typically exist for several years, any new customers in the utility's service territory will be subject to this surcharge. As a result, future customers will be paying for costs related to historical occurrences, which may deter new commercial and industrial businesses from moving into the service territory if rates become less competitive.

Further, customer rates or cash flow used to service securitization debt is senior and has a higher legal priority to the utility's remaining cash flow generation. As such, securitization bondholders would have a senior claim in a liability waterfall during times of financial distress. So a significant amount of securitization debt within a capital structure could put secured and unsecured debt holders at risk of less than full recovery in a bankruptcy filing.

**Pacific Gas & Electric's securitization during bankruptcy in the early 2000's demonstrates the enforceability and resiliency of the legal structure**

In 1997, Pacific Gas & Electric Company (PG&E, A3 negative) issued $2.9 billion of securitization bonds after obtaining approval by the California Public Utility Commission to recover stranded asset costs associated with the state's utility deregulation. When PG&E filed for bankruptcy on 6 April 2001, both the company and bankruptcy court respected the bankruptcy-remote structure of the securitization that the parties had established in order to isolate the assets of PG&E's securitization from PG&E's bankruptcy estate. PG&E remained the servicer of the transaction and continued to collect and remit the securitization payment. The securitization cash flows were not affected by the bankruptcy due to a build-up in the reserve fund and the base level of customer consumption used to calculate the 2001 tariff remained relatively stable. For these reasons among others, the Aaa (sf) rating on PG&E's stranded costs recovery securitization bonds was maintained throughout the company's bankruptcy.

The bankruptcy remoteness of securitization transactions is stronger than that of other, purely corporate asset-backed securities for several reasons including the explicit recognition, by state legislation, of the right to collect the special surcharge from customers as well as the first lien on the asset that is often granted by statute upon its transfer. The consumption-based fee is imposed on ratepayers and is not dependent on a particular electrical supplier. The fee is not affected if the servicer becomes bankrupt. The underlying legislation usually requires that any successor to the original utility (due to bankruptcy, reorganization, merger, or acquisition) must satisfy all obligations of the original utility, including the collection of the special surcharge. The right to collect the special surcharge is irrevocable and cannot be altered by either the state utility commission or the state.

In January 2005, PG&E issued $1.9 billion of securitization known as energy recovery bonds (ERBs). The securitization financing accelerated the company's collection of the regulatory asset that was created as part of PG&E's bankruptcy. A second securitization financing was completed in late 2005 which enabled PG&E to largely recover the entire regulatory asset. This was another example where securitization was used as a tool to significantly reduce the uncertainty and length of time in the recovery of significant costs, a credit positive, while also reducing costs for customers by keeping rates lower over the long-term.

## Moody's related publications

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**Rating Methodologies:**

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» Regulated Electric and Gas Networks 16 March 2017

» U.S. Electric Generation & Transmission 15 April 2013

» Natural Gas Pipelines 6 July 2018

» Moody's Global Approach to Rating Securities Backed by Utility Cost Recovery Charges 22 June 2015

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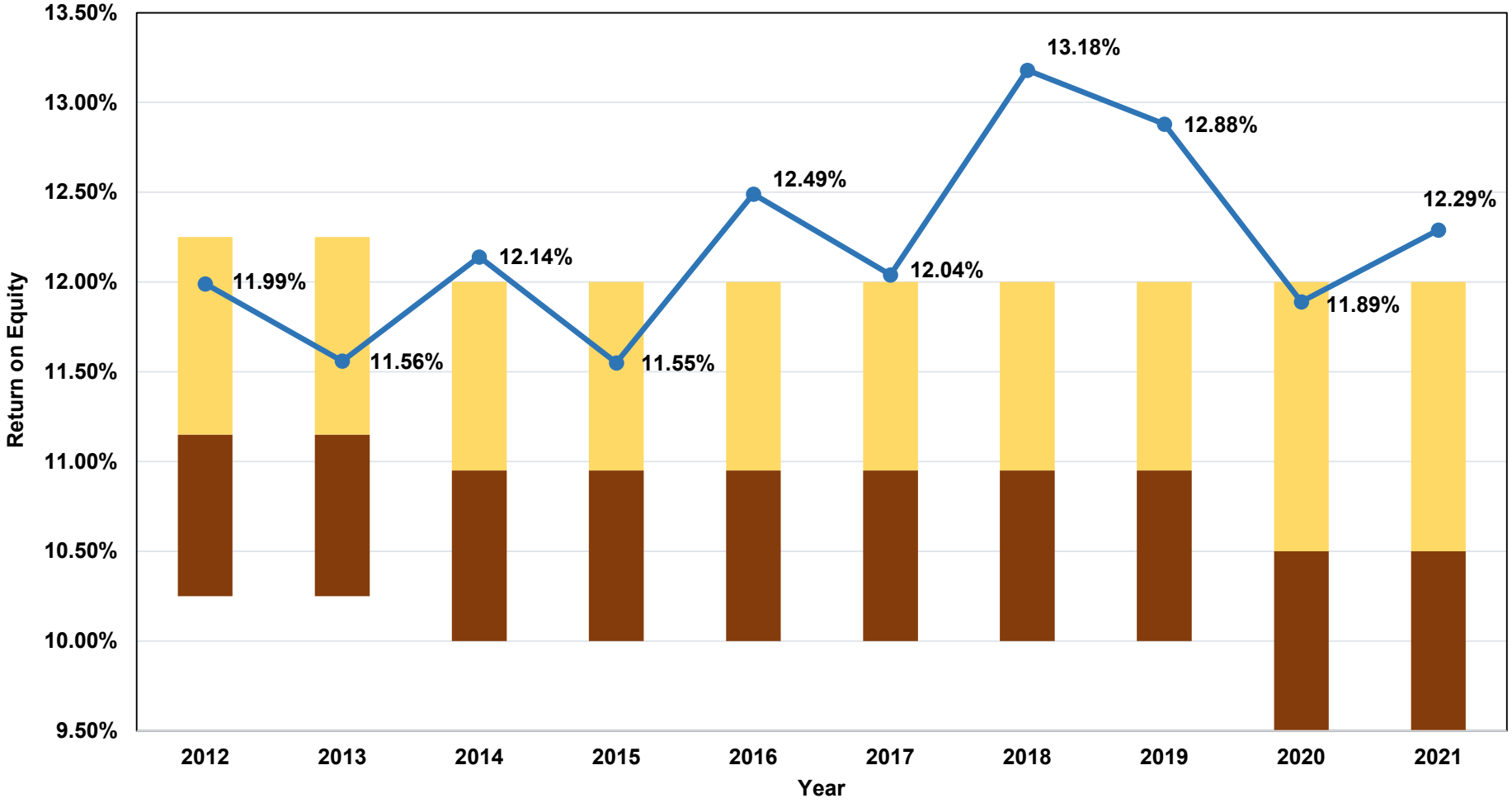
REPORT NUMBER 1128247

# GEORGIA POWER COMPANY
## Authorized Versus Earned Return on Equity




| ROE Range | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 10.25% | 11.15% | 12.25% | 10.00% | 10.95% | 12.00% | 9.50% | 10.50% | 12.00% |

**Source:** Annual Surveillance Reports.

# GEORGIA POWER COMPANY
## GPC's Proposed Class Revenue Allocation
## Test Year Ending July 31, 2023
## (Dollar Amounts in Thousands)

| Line | Rate Group | Revenue at Present Rates Excl. FCR | Proposed Increase Amount ($000) | Proposed Increase Percent |
|---|---|---|---|---|
| | | (1) | (2) | (3) |
| 1 | Domestic | $2,934,736 | $428,026 | 14.6% |
| 2 | Small Business | 646,878 | 95,689 | 14.8% |
| 3 | Medium Business | 989,821 | 145,195 | 14.7% |
| 4 | Large Business | 216,955 | 31,452 | 14.5% |
| 5 | Agricultural | 14,316 | 2,100 | 14.7% |
| 6 | Government/Institution | 117,104 | 17,224 | 14.7% |
| 7 | Outdoor Lighting | 120,753 | 17,602 | 14.6% |
| 8 | Marginally Priced | 1,050,893 | 114,512 | 10.9% |
| 9 | Total Retail | $6,091,456 | $851,800 | 14.0% |

# GEORGIA POWER COMPANY

## Comparison of Demand Allocation Methods

| Line | Rate Group | Average of 12 Monthly Coincident Peaks | Average of 4 Summer/ 2 Winter Monthly Coincident Peaks | Average of 4 Summer Coincident Peaks |
|---|---|---|---|---|
| | | (1) | (2) | (3) |
| 1 | Domestic | 50.36% | 52.24% | 51.12% |
| 2 | Small Business | 7.86% | 7.97% | 8.44% |
| 3 | Medium Business | 16.65% | 16.19% | 16.99% |
| 4 | Large Business | 4.18% | 4.01% | 4.01% |
| 5 | Agricultural | 0.21% | 0.17% | 0.14% |
| 6 | Government/Institution | 2.84% | 2.79% | 2.76% |
| 7 | Outdoor Lighting | 0.14% | 0.11% | 0.00% |
| 8 | Marginally Priced | 17.76% | 16.53% | 16.53% |
| 9 | Total Retail | 100.00% | 100.00% | 100.00% |

**Source:** GPC Response to STF-TAI 1-1, Attachments A and C.

# GEORGIA POWER COMPANY

## Corrected Class Cost-of-Service Study Results
## At Present Rates By Rate Group
## 12CP/4CP Method
## Test Year Ending July 31, 2023
## (Dollar Amounts in Thousands)

| Line | Rate Group | Rate Base | Operating Income at Present Rates | Rate of Return | Relative Rate of Return | Subsidy |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| 1 | Domestic | $12,839,314 | $669,011 | 5.21% | 83 | ($189,392) |
| 2 | Small Business | 2,320,075 | 169,126 | 7.29% | 116 | 30,430 |
| 3 | Medium Business | 3,546,941 | 321,763 | 9.07% | 144 | 131,237 |
| 4 | Large Business | 797,199 | 69,074 | 8.66% | 137 | 25,147 |
| 5 | Agricultural | 56,311 | 3,558 | 6.32% | 100 | 6 |
| 6 | Government/Institution | 582,289 | 21,638 | 3.72% | 59 | (20,255) |
| 7 | Outdoor Lighting | 415,504 | 33,059 | 7.96% | 126 | 9,163 |
| 8 | Marginally Priced | 3,460,494 | 228,591 | 6.61% | 105 | 13,664 |
| 9 | Total Retail | $24,018,127 | $1,515,820 | 6.31% | 100 | $0 |

# GEORGIA POWER COMPANY

## Corrected Class Cost-of-Service Study Results
## At Present Rates By Rate Group
## 4CP Method
## Test Year Ending July 31, 2023
## (Dollar Amounts in Thousands)

| Line | Rate Group | Rate Base | Operating Income at Present Rates | Rate of Return | Relative Rate of Return | Subsidy |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| 1 | Domestic | $12,921,507 | $657,717 | 5.09% | 81 | ($211,484) |
| 2 | Small Business | 2,383,491 | 160,412 | 6.73% | 107 | 13,386 |
| 3 | Medium Business | 3,583,468 | 316,744 | 8.84% | 140 | 121,420 |
| 4 | Large Business | 778,999 | 71,574 | 9.19% | 146 | 30,039 |
| 5 | Agricultural | 49,161 | 4,541 | 9.24% | 146 | 1,927 |
| 6 | Government/Institution | 573,773 | 22,808 | 3.98% | 63 | (17,966) |
| 7 | Outdoor Lighting | 399,991 | 35,191 | 8.80% | 139 | 13,333 |
| 8 | Marginally Priced | 3,327,737 | 246,833 | 7.42% | 118 | 49,345 |
| 9 | Total Retail | $24,018,127 | $1,515,820 | 6.31% | 100 | $0 |

# GEORGIA POWER COMPANY
## Movement to Parity Using GPC's Proposed Class Revenue Allocation
## 12CP/4CP Method
## Test Year Ending July 31, 2023
## (Dollar Amounts in Thousands)

| | | Present Rates | | | Proposed Rates | | | |
|---|---|---|---|---|---|---|---|---|
| Line | Rate Group | Rate of Return | Relative Rate of Return | Subsidy | Rate of Return | Relative Rate of Return | Subsidy | Movement to Parity |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | Domestic | 5.21% | 83 | ($189,392) | 7.70% | 86 | ($216,711) | -14% |
| 2 | Small Business | 7.29% | 116 | 30,430 | 10.37% | 116 | 43,838 | -44% |
| 3 | Medium Business | 9.07% | 144 | 131,237 | 12.13% | 135 | 150,641 | -15% |
| 4 | Large Business | 8.66% | 137 | 25,147 | 11.61% | 130 | 28,326 | -13% |
| 5 | Agricultural | 6.32% | 100 | 6 | 9.10% | 102 | 109 | -1761% |
| 6 | Government/Institution | 3.72% | 59 | (20,255) | 5.92% | 66 | (23,682) | -17% |
| 7 | Outdoor Lighting | 7.96% | 126 | 9,163 | 11.12% | 124 | 12,030 | -31% |
| 8 | Marginally Priced | 6.61% | 105 | 13,664 | 9.07% | 101 | 5,450 | 60% |
| 9 | Total Retail | 6.31% | 100 | $0 | 8.96% | 100 | $0 | -11% |

BY MR. JONES:

Q You also caused to be prefiled a trade secret version of your testimony; is that correct?

A Correct.

Q And do you have any changes to the trade secret version?

A No.

Q Okay. And if I were to ask you the same questions in your trade secret version, would your answers be the same?

A (Witness Pollock) Yes.

MR. JONES: Madam Chair, I would ask that the trade secret version be marked as GAM Exhibit 2.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as GAM Exhibit 2.)

BY MR. JONES:

Q Now, you also caused to be filed nine exhibits with your testimony; is that correct?

A (Witness Pollock) Yes.

Q And you have a change to one of those?

A (Witness Pollock) I do.

MR. JONES: Madam Chair, may I approach the court reporter?

MADAM CHAIR PRIDEMORE: You may approach.

MR. JONES: I have distributed this already to staff and...

BY MR. JONES:

Q Mr. Pollock, I'm showing you an errata for Exhibit JP-4.

Can you please describe the changes that you made to this of your exhibit?

A (Witness Pollock) Yes, I made some changes to the data points that are shown for the years 2013 and 2021. Specifically, in 2013, the earned return of equity was 11.44 percent, not 11.56. Similarly, in 2021, the earned return on equity was 12.09 percent, rather than 12.29 percent.

Q Okay. Do any of the changes to JP-4 change anything regarding the conclusions in your testimony?

A No.

Q Okay. And were the exhibits all, including this errata, prepared under your supervision?

A They were.

MR. JONES: Okay. Madam.

Chair, I would ask that Mr. Pollock's exhibits JP-1 through JP-9, including the amended JP-4, be marked JM-3 through 11.

MADAM CHAIR PRIDEMORE: So marked.

The documents referred to were marked for

identification as GAM Exhibits JM-1 through 9, and amended JP-4.)

BY MR. JONES:

Q Now, Ms. LaConte, let me ask you a couple questions.

Will you please state your name for the record.

A (Witness LaConte) Billie Sue LaConte.

Q LaConte. There we go. See, it's my fault.

All right. So can you tell me where you're employed.

A (Witness LaConte) I'm an associate consultant at J Pollock, Incorporated, in St. Louis.

Q Okay. Great.

And did you file or cause to be prefiled in this docket 36 pages of prefiled Q-and-A testimony, including 24 pages of direct testimony and appendixes A, B, and C?

A (Witness LaConte) Yes, I did.

Q Do you have any changes that you need to make to your testimony?

A (Witness LaConte) No, sir.

Q And if I were to ask you the same questions in your testimony this evening, would your answers be the same?

A (Witness LaConte) Yes, they would.

MR. JONES: Madam Chair, I would ask that

**Ms. LaConte's testimony be copied into the record as if read from the stand.**

**MADAM CHAIR PRIDEMORE: So moved.**

**(Whereupon, the prefiled direct testimony of Billie S. LaConte follows:)**

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re:** | ) | |
| **Georgia Power Company's** | ) | **Docket No. 44280** |
| **2022 Rate Case** | ) | |

Direct Testimony and Exhibits

of

**Billie S. LaConte**

On Behalf of

**Georgia Association of Manufacturers**

October 20, 2022

J. POLLOCK
INCORPORATED

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re:** | ) | |
| **Georgia Power Company's** | ) | **Docket No. 44280** |
| **2022 Rate Case** | ) | |

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## LIST OF EXHIBITS


| Exhibit | Description |
|---|---|
| **BSL-1** | Impact of Corrected ROE |
| **BSL-2** | Excerpt from RRA Regulatory Focus, Major Energy Rate Case Decisions in the US January – June 2022 |
| **BSL-3** | Impact of Reducing ROE to National Average Authorized ROE |
| **BSL-4** | Proxy Group Common Equity Ratio |
| **BSL-5** | Impact of Reducing Common Equity Ratio to Proxy Group Average |
| **BSL-6** | Impact of Corrected ROE and Common Equity Ratio |

## GLOSSARY OF ACRONYMS

| Term | Definition |
|---|---|
| **ARP** | Alternate Rate Plan |
| **CAPM** | Capital Asset Pricing Model |
| **DCF** | Discounted Cash Flow |
| **GAM** | Georgia Association of Manufacturers |
| **GPC or Company** | Georgia Power Company |
| **MRP** | Market Risk Premium |
| **RRA** | Regulatory Research Associates |
| **ROE** | Return on Equity |

# Direct Testimony of Billie S. LaConte

## 1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Billie S. LaConte, 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

**Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am an energy advisor and Associate at J. Pollock, Incorporated.

**Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Arts degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University. Since graduating in 1995, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. More details are provided in **Appendix A**. A list of my appearances is provided in **Appendix B**.

**Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of the Georgia Association of Manufacturers (GAM). The members of GAM are customers of Georgia Power Company (GPC). They consume large quantities of electricity, primarily for manufacturing under a variety of tariffs. GAM members purchase nearly 11% of GPC's retail energy sales.

**Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?**

A I shall discuss GPC's requested return on equity (ROE) and capital structure.

**Q ARE ANY OTHER WITNESSES APPEARING ON BEHALF OF GEORGIA ASSOCIATION OF MANUFACTURERS?**

A Yes. My colleague, Mr. Jeffry Pollock, will address issues regarding the Alternate Rate Plan (ARP), cost recovery, revenue allocation and other tariff terms and conditions. Dr. Roger Tutterow will address the state of manufacturing in Georgia.

**Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?**

A Yes. I'm sponsoring **Exhibits BSL-1** through **BSL-6**. These exhibits were prepared by me or under my supervision and direction. In addition, I have prepared **Appendix C** which provides more detailed information on the various ROE methodologies utilized by analysts to estimate the ROE.

**Q DOES THE FACT THAT YOU ARE NOT ADDRESSING ALL ISSUES IN THIS PROCEEDING CONSTITUTE AN ENDORSEMENT OF THE POSITIONS OF GEORGIA POWER COMPANY, OR OTHER PARTIES, ON THESE ISSUES?**

A No. The fact that I am not addressing every issue should not be interpreted as an endorsement of the proposals in this proceeding.

## Summary

**Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A My findings and recommendations are as follows:

*Return on Equity*

- The 11% ROE recommended by GPC's ROE witness, Mr. James M. Coyne, is based on improper application of widely used and accepted methods, as well the Risk Premium and Expected Earnings methods, which are not widely used.
- Correcting Mr. Coyne's ROE analyses reveals that GPC's cost of equity does not exceed 9.83%.
- Mr. Coyne further inflates his derived ROEs by including a flotation cost adjustment. It is unnecessary to include flotation costs because GPC does not directly incur these costs and Mr. Coyne's flotation cost adjustment is not based on the flotation costs incurred by GPC's parent company, Southern Company.
- GPC's proposed 11% cost of equity is excessive relative to the returns authorized by other state regulatory commissions nationwide in rate case decisions in 2021 (9.53%) and 2022 year to date (9.47%) for vertically integrated electric investor-owned utilities. In fact, authorized ROEs have averaged below 10% since 2013.

*Capital Structure*

- GPC's proposed 56% common equity ratio is clearly excessive. Its proposed cost of common equity of 11% is 747 basis points more expensive than its long-term debt cost (3.53%). The excessive equity ratio results in a higher cost of capital and higher rates than a utility with a more leveraged capital structure.
- On average, the companies in the proxy group with credit ratings similar to Georgia Power's A- credit rating collectively had an average 53% common equity ratio in 2021, which is 300 basis points lower than the equity ratio GPC is proposing in this case.
- GPC's capital structure is inefficient because it fails to employ an appropriate amount of leverage. Accordingly, for ratemaking purposes, the Commission should adjust GPC's common equity ratio so that it is more in line with the average of other vertically integrated electric investor-owned utilities and should not exceed 53%.

## 2. EVALUATION OF MR. COYNE'S RETURN ON EQUITY ANALYSIS

**Q HAVE YOU REVIEWED THE BASIS FOR GEORGIA POWER COMPANY'S PROPOSED 11% RETURN ON EQUITY?**

A Yes. Mr. Coyne's proposed ROE of 11% is excessive because it is based on erroneous assumptions, which I discuss in-depth later. Further, he improperly uses a flotation cost adjustment to increase his requested ROE.

**Q WHAT METHODS DOES MR. COYNE USE TO SUPPORT HIS RECOMMENDED 11% RETURN ON EQUITY?**

A Mr. Coyne based his recommendation on four methodologies: Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Risk Premium and the Expected Earnings method, using a proxy group of companies that are similar to GPC. **Appendix C** provides a detailed description of the DCF, CAPM, and Risk Premium methodologies.

**Q WHAT ARE THE RESULTS OF MR. COYNE'S ANALYSES?**

Q Mr. Coyne's analyses result in an estimate of GPC's ROE within the range of 8.99% to 13.55%.[1]

**Q DID MR. COYNE MAKE ANY ADJUSTMENTS TO HIS RETURN ON EQUITY ANALYSIS?**

A Yes. He made a flotation cost adjustment to the results derived under the various methods, which is discussed more fully later.

[1] Direct Testimony of James M. Coyne at 3.

**Q WHAT IS YOUR ASSESSMENT OF MR. COYNE'S RETURN ON EQUITY ANALYSIS?**

A Mr. Coyne's ROE estimates are too high for numerous reasons. His CAPM, Risk Premium, and Expected Earnings analyses use unrealistic assumptions and his flotation cost adjustment is unnecessary because it does not reflect the actual flotation costs incurred by GPC.

## Proxy Group

**Q WHAT IS A PROXY GROUP?**

A A proxy group is a group of companies involved in operations similar to the utility being analyzed.

**Q WHY IS A PROXY GROUP RELEVANT IN DETERMINING AN APPROPRIATE RETURN ON EQUITY?**

A A proxy group is relevant because it provides a group of companies that are comparable in risk to GPC, hence estimating the cost of equity for the proxy group represents the economic opportunity costs that have an impact on the ROE for GPC.

**Q DO YOU AGREE WITH THE GROUP OF COMPANIES THAT MR. COYNE INCLUDED IN HIS PROXY GROUP?**

A Yes. Mr. Coyne's criteria for inclusion in his proxy group are based on industry standards and the companies in his proxy group are generally comparable to GPC.

## Mr. Coyne's DCF Analysis

**Q DO YOU HAVE ANY CONCERNS REGARDING MR. COYNE'S DISCOUNTED CASH FLOW ANALYSES?**

A No. Mr. Coyne's DCF analyses are based on sound assumptions regarding stock prices, projected dividend yields, and projected growth rates for each company in his proxy group. Therefore, the results of his DCF analyses, which produce a range of ROEs, from 7.99% to 9.99%, are reasonable and representative of the cost of equity for GPC. I have selected the result of Mr. Coyne's 180-day mean average DCF (9.09%) because the time period for the stock price better captures recent conditions in the stock market over a longer term, including the 30-day and 90-day data.

## Flaws With Mr. Coyne's CAPM Analysis

**Q WHAT IS THE CAPITAL ASSET PRICING MODEL?**

A The CAPM is a risk premium method that is used to estimate the ROE. It states that the expected return of a security equals the risk-free rate plus a risk premium. Simply put, investors require a premium over the risk-free rate if they are going to invest in a riskier security.

**Q WHAT CAPITAL ASSET PRICING MODEL METHODS DID MR. COYNE USE?**

A Mr. Coyne's CAPM analysis uses various estimates of the market risk premium (MRP), based on projected data.

His first CAPM analysis use a projected risk-free rate of 3.4%, and the average of his projected long-term market risk premiums based on expected market returns (15.87%, 14.03% and 15.63%).[2] His average expected market return is 15.18%, which

[2] *Id.* at 33.

produces an 11.78% MRP.[3] His second CAPM method uses the current risk-free rate (2.72%) and the same projected MRP which produced an 12.46% MRP.[4] Mr. Coyne used two beta estimates. The first is based on the average beta as assigned by Value Line for each company in his proxy group, or 0.88.[5] The second is the average beta for the proxy group using Bloomberg data, or 0.85.[6] Using this data, he estimates the return on equity for each company in his proxy group.

**Q WHAT IS THE ESTIMATED RETURN ON EQUITY USING MR. COYNE'S CAPITAL ASSET PRICING MODEL METHODOLOGY?**

A Mr. Coyne's estimated ROE is 13.6% using the projected long-term risk-free rate and 13.5% using the current 30-day average risk-free rate.[7]

**Q DO YOU HAVE CONCERNS WITH MR. COYNE'S CAPITAL ASSET PRICING MODEL RETURN ON EQUITY ESTIMATE?**

A Yes. Two of his projected MRPs are based on the projected growth of stocks in the S&P 500. However, he includes companies with negative growth and growth above 20% which results in a distorted MRP. Both of those growth estimates are unsustainable and should be removed. Correcting the projected MRP reduces the average MRP to 8.28% (from 11.78%) and lowers the estimated ROE to 10.57%.

While I agree with Mr. Coyne's use of a projected MRP, he failed to estimate the ROE using a historical MRP. Therefore, his estimated CAPM ROE is significantly overstated.

---

[3] *Id.*
[4] *Id.*
[5] *Id.* at 33-34.
[6] *Id.*
[7] *Id.*

**Q IS IT A COMMON PRACTICE TO ALSO USE THE LONG-TERM HISTORICAL MARKET RISK PREMIUM TO ESTIMATE THE CAPITAL ASSET PRICING MODEL RETURN ON EQUITY?**

A Yes. A long-term estimate of the historical MRP is a commonly used method which is based on actual, historical MRPs over several decades and provides a reliable estimate of the expected MRP. Long-term data provides the MRP throughout many economic cycles, providing a reasonable expectation of future performance.

**Q WHY DOES LONG-TERM HISTORICAL DATA PROVIDE A GOOD APPROXIMATION OF FUTURE RISK PREMIUMS?**

A Dr. Roger A. Morin, whom Mr. Coyne quotes in his testimony, states in *New Regulatory Finance* "it is reasonable to believe that long-run average realized returns provide an unbiased estimate of what were expected returns."[8] Further, Dr. Morin states "a regulatory body should rely on the results of both historical and prospective studies in arriving at an appropriate risk premium..."[9]

**Q HAVE YOU CALCULATED THE RETURN ON EQUITY USING THE CAPITAL ASSET PRICING MODEL AND LONG-TERM HISTORICAL MARKET RISK PREMIUM?**

A Yes. The historical MRP (1926-2021) is 7.40%, based on Kroll's *2022 SBBI Valuation Yearbook* (formerly published by Duff & Phelps).[10] Using the projected 3.4% long-term risk-free rate, Mr. Coyne's 0.87 average beta and the 7.40% historical MRP, the estimated ROE is 9.84%.

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[8] Public Utility Reports, Inc. *New Regulatory Finance,* Roger Morin PhD at 156 (Jun. 2006).

[9] *Id.* at 163.

[10] *Application of Duke Energy Progress, LLC For Authority to Adjust and Increase its Electric Rates Schedules and Charges*, Docket No. 2022-254-E, Direct Testimony of Roger A. Morin at 44 (Sept. 1, 2022).

## Impact of Correcting Mr. Coyne's DCF and CAPM ROE Analysis

**Q IF THE VARIOUS FLAWS IN MR. COYNE'S RETURN ON EQUITY ANALYSES ARE CORRECTED, HOW WOULD THIS AFFECT GEORGIA POWER COMPANY'S ESTIMATED RETURN ON EQUITY?**

A GPC's ROE would be significantly lower after correcting the errors in Mr. Coyne's analysis and removing his flotation cost adjustment. Based on the results of my revisions, it is clear that GPC's cost of equity should not exceed 9.83%. The derivation of the 9.83% is shown below in Table 1.

**BSL Direct Table 1**
**Revised ROE**

| Methodology | ROE |
|---|---|
| DCF 180-day Mean | 9.09% |
| CAPM Projected MRP | 10.57% |
| CAPM Historical MRP | 9.84% |
| Average | 9.83% |

My revised ROE reflects the inclusion of Mr. Coyne's 180-day DCF analysis, my CAPM results (1) using the corrected projected MRP and (2) using the historical MRP. Additionally, the flotation cost adjustment was excluded because GPC does not issue stock.

**Q WHAT IS THE IMPACT ON GEORGIA POWER COMPANY'S REVENUE REQUIREMENT USING YOUR REVISED RETURN ON EQUITY?**

A Replacing GPC's requested 11% ROE with the revised 9.83% ROE reduces GPC's revenue requirement by $299 million in 2023. **Exhibit BSL-1** provides the detailed calculations.

## Flaws With Mr. Coyne's Risk Premium Analyses

**Q DO YOU HAVE ANY COMMENTS REGARDING THE RISK PREMIUM METHOD?**

A Yes. The risk premium is not as widely accepted as the DCF and CAPM methodologies when estimating the ROE for a regulated utility. Mr. Coyne's Risk Premium method analyzes the relationship between historical authorized ROEs and the risk-free rate. The Risk Premium method is sometimes used by Commissions as a "check" on the reasonableness of the DCF and CAPM results. Therefore, while the Risk Premium method may not factor in directly when estimating the ROE, it may contribute by measuring the reasonableness of the DCF and CAPM results.

**Q IS MR. COYNE'S RISK PREMIUM ANALYSIS VALID?**

A No. Mr. Coyne's Risk Premium method estimates the ROE based on the historical relationship between allowed ROEs in electric utility rate cases and the risk-free rate at the time the ROEs were authorized, from 1992 through February 2022. Using this data, Mr. Coyne created a regression analysis to estimate the risk premium.[11] Mr. Coyne's regression analysis purports to demonstrate that there is an inverse relationship between equity risk premium and interest rates. However, his regression analysis does not take into account other factors that can affect the equity risk premium (*e.g.*, different Federal monetary and fiscal policies, and economic risk, such as employment, consumption and growth). These factors can have an impact on authorized ROEs due to their effect on market risk, which may cause regulators to adjust their authorized ROEs. The change in interest rates is one of many factors that may affect a utility's authorized ROE.

[11] Direct Testimony of James M. Coyne at 35.

**Q HAVE YOU REVISED MR. COYNE'S RISK PREMIUM ANALYSIS?**

A Yes, using data provided by Mr. Coyne, I used the long-term average equity risk premium of 6.06% and long-term risk-free rate of 3.4% to derive an estimated ROE of 9.46%. The long-term risk premium estimate is calculated using authorized ROEs and the long-term risk-free rate at the time the ROE was authorized. The long-term risk premium estimate recognizes that the risk premium can fluctuate depending on market conditions and investor expectations. Therefore, using the average risk premium over this time-period is a reasonable method to estimate GPC's cost of equity.

**Q HOW DO THE RESULTS OF YOUR RISK PREMIUM ANALYSIS COMPARE TO YOUR CORRECTED RETURN ON EQUITY?**

A While the 9.46% risk premium ROE is slightly below my revised average 9.83% ROE, it provides support that my revised ROE is not too low and provides a reasonable estimate of GPC's ROE.

## Flaws with Expected Earnings

**Q PLEASE DESCRIBE THE EXPECTED EARNINGS METHODOLOGY.**

A The Expected Earnings methodology estimates the cost of equity using projected returns on book equity.

**Q WHAT IS MR. COYNE'S ESTIMATED RETURN ON EQUITY USING HIS EXPECTED EARNINGS METHODOLOGY?**

A Mr. Coyne's Expected Earnings analysis results in a 11.03% and a 11.08% ROE, based on the mean and median of the results, respectively.

**Q WHY DO YOU DISAGREE WITH THE EXPECTED EARNINGS METHODOLOGY?**

A The Expected Earnings methodology is not a reliable method to estimate the ROE because it represents a forecast return on book equity and not a required return or cost of equity.

**Q WHAT DO YOU MEAN BY THE ESTIMATED EARNINGS METHOD REPRESENTS A FORECAST RETURN ON EQUITY AND NOT A REQUIRED RETURN OR COST OF EQUITY?**

A This methodology uses forecasted returns on *book equity*. This is not a reasonable proxy for investors' expected *market* returns. It is a book accounting return and does not reflect investors' market expectations. FERC rejected this methodology in 2019, explaining "Because an investor cannot purchase a utility's common stock at book value and must instead pay the prevailing market price for common equity, the utility's expected earned return on book value is indicative of neither what an investor can expect to earn on an investment in the utility's common stock nor what return an investor requires to invest in the utility's common stock."[12]

As such, Mr. Coyne's Expected Earnings method is not a reliable proxy for the estimated ROE for GPC and should be rejected.

## Flotation Costs

**Q WHAT ARE FLOTATION COSTS?**

A Flotation costs include two components. The first component is the actual cost paid by

[12] *Association of Businesses Advocating Tariff Equity et al. v. Midcontinent Independent System Operator, Inc. et al,* Docket No. EL 14-12-003 and EL 15-45-000, Opinion No. 569 at 104 (Nov. 21, 2019).

a company to the underwriter for issuing stock. The second is indirect and represents the potential dilutive impact due to the issuance of new stock.

**Q HOW DO FLOTATION COSTS AFFECT THE RETURN ON EQUITY DETERMINATION?**

A Flotation costs increase the ROE. For example, Mr. Coyne made an upward adjustment of eight basis points.[13]

**Q SHOULD GEORGIA POWER COMPANY'S RETURN ON EQUITY INCLUDE A FLOTATION COST ADJUSTMENT?**

A No. First, Mr. Coyne's estimate of flotation costs was based on the companies in his proxy group, not on any actual flotation costs incurred by GPC. This is because GPC is a regulated utility that does not issue stock and, therefore, does not incur flotation costs. The flotation costs are incurred by GPC's parent company, the Southern Company. Therefore, a flotation cost adjustment is not necessary.

**Q IF GEORGIA POWER COMPANY IS RESPONSIBLE FOR THE SOUTHERN COMPANY'S FLOTATION COSTS, SHOULD THE COMMISSION APPROVE MR. COYNE'S ADJUSTMENT?**

A No. As noted above, Mr. Coyne's adjustment is not based on actual flotation costs incurred by GPC and, therefore, is unnecessary and unwarranted. If the Commission allows GPC to recover flotation costs, it should be based on a reasonable projection of flotation costs that GPC's parent company will incur during the ARP period.

[13] Direct Testimony of James M. Coyne at 41-42.

## Summary of the Flaws With Mr. Coyne's ROE Analysis

**Q PLEASE SUMMARIZE YOUR CRITIQUE OF MR. COYNE'S RETURN ON EQUITY ANALYSES.**

A Mr. Coyne's recommended ROE of 11% does not recognize GPC's reduced risk due to the regulatory mechanisms it has in place which reduce regulatory lag and income variability, as discussed more fully in my next section. Further, his reasoning for adjusting GPC's ROE due to flotation costs is inaccurate and should be rejected.

Mr. Coyne relies on four methods to estimate an ROE for GPC. His CAPM analysis includes incorrect estimates of the projected MRP and excludes the historical MRP, which results in overstating the ROE.

The Risk Premium analysis uses a regression analysis that relies solely on the relationship between interest rates and the equity risk premium. It does not include other factors that could impact the risk premium, such as Federal monetary and fiscal policies. Ignoring other factors that affect the equity risk premium produces inaccurate ROE estimates and the results should be rejected.

The Expected Earnings methodology is not a common method used to estimate the cost of equity for a regulated utility. The utility's expected return on book value is indicative of neither what an investor can expect to earn on an investment in the utility's common stock, nor what return an investor requires to invest in the utility's common stock. Therefore, it should be rejected.

Lastly, the flotation cost adjustment is misplaced because GPC does not issue stock.

## 3. FACTORS IMPACTING THE RETURN ON EQUITY

**Q WHAT FACTORS SHOULD THE COMMISSION CONSIDER WHEN DETERMINING AN APPROPRIATE RETURN ON EQUITY FOR GEORGIA POWER COMPANY?**

A First and foremost, a fair and reasonable ROE should be based on results derived from accepted methodologies, such as the DCF and CAPM methods, and using the Risk Premium method as a check on the reasonableness of the DCF and CAPM results. Further, the inputs and assumptions used in applying the accepted methodologies should consider current financial and economic realities, such as:

- GPC's financial and business risk; and
- The ROEs authorized by state regulatory commissions.

I discuss each of these considerations in detail below.

### Financial Risk

**Q WHAT IS FINANCIAL RISK?**

A Financial risk represents variability in income. Quantifying financial risk includes an analysis of a utility's financial statements and cash flow/leverage analyses. To the extent such variability is small, or has been reduced by other means, the risk to GPC's shareholders is lower.

**Q WHAT FACTORS CAN INFLUENCE THE LEVEL OF FINANCIAL RISK FOR A PARTICULAR UTILITY?**

A Financial risk is highly influenced by the regulatory climate. All other things being equal, a utility is less risky if it is regulated by a Commission that:

- authorizes rates for a multi-year period;
- authorizes separate piecemeal cost recovery clauses and revenue decoupling that adjusts rates automatically outside of base rate cases; and
- employs other constructive ratemaking practices.

**Q WHAT DO YOU MEAN BY PIECEMEAL COST RECOVERY CLAUSES?**

A Piecemeal (or single-issue) ratemaking refers to a utility being allowed to implement adjustment clauses that permit it to change rates outside of a base rate case, while ignoring the utility's earnings. Utilities are able to mitigate risk by implementing an adjustment clause that allows rates to change on an expedited basis, outside the context of a traditional rate case in which all costs and revenues would be considered.

**Q DOES GEORGIA POWER COMPANY CURRENTLY HAVE ANY ADJUSTMENT CLAUSES IN PLACE THAT REDUCE ITS VARIABILITY IN INCOME AND LOWER ITS FINANCIAL RISK?**

A Yes. GPC has numerous adjustment clauses in place that reduce its financial risk, such as Fuel Cost Recovery, Environmental Compliance Cost Recovery, Demand Side Management rider, the Nuclear Construction Cost Recovery, and an Interim Fuel Rider. GPC's cash flow is improved due to its adjustment clauses and positively affects its credit quality, which reduces its financial risk.

**Q HOW DOES LOWER RISK IMPACT GEORGIA POWER COMPANY'S EXPECTED COST OF CAPITAL?**

A Lower risk leads to lower financial volatility. GPC has several tools available to reduce its regulatory lag, including the aforementioned adjustment clauses. Therefore, investors' required return for GPC will be lower. Hence, these risk-reducing measures support a reduction to GPC's requested ROE of 11%.

**Q DOES THE PROPOSED ALTERNATE RATE PLAN AFFECT GEORGIA POWER COMPANY'S RISK PROFILE?**

A Yes. The proposed ARP is a three-year plan in which rates are based on test-year ending July 31, 2023, modified for a levelization adjustment. The ARP provides GPC with rate stability and predictability, reduces regulatory lag by allowing the Company more-timely recovery of costs, and is considered favorable by the credit rating agencies.[14]

**Q HOW WILL THE PROPOSED THREE-YEAR ALTERNATE RATE PLAN AFFECT GEORGIA POWER COMPANY'S RISK PROFILE?**

A The proposed three-year ARP will lower GPC's risk because it will reduce its business risk (regulatory lag) and its financial risk (revenue volatility). The ARP has lower risk than a traditional ratemaking plan because rates will be adjusted to recover GPC's levelized revenue deficiency over the three-year period. Under normal ratemaking conditions, GPC would file a rate case every year to increase its rates. Having an ARP lowers the risk faced by GPC because it provides predictable and reliable rates, reduces regulatory lag and also reduces revenue volatility.

## ROEs Authorized By State Regulatory Commissions

**Q WHAT RETURNS ON EQUITY HAVE STATE REGULATORY COMMISSIONS RECENTLY AUTHORIZED FOR REGULATED ELECTRIC INVESTOR-OWNED UTILITIES?**

A From roughly 2010 to 2021, average authorized ROEs ranged from 9.53% to 10.42%.

[14] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson at 24-25.

However, in the most recent years this number has been trending downward. The national average authorized ROE for vertically integrated electric utilities was 9.53% in 2021 and 9.47% in the first six months of 2022 as reported by Regulatory Research Associates (RRA), a subsidiary of S&P Global. An excerpt of the RRA Report is provided in **Exhibit BSL-2**. These averages reflect the actual decisions from rate cases in Georgia as well as decisions by other state regulatory commissions in general rate cases. As discussed later, this is a reasonable basis for assessing the trend in authorized ROEs.

**Q HOW DOES GEORGIA POWER COMPANY'S REQUESTED RETURN ON EQUITY COMPARE TO THE NATIONAL AVERAGE RETURN ON EQUITY FOR ELECTRIC UTILITIES?**

A GPC's requested 11% ROE is 153 basis points higher than the national average authorized ROE for other vertically integrated electric utilities of 9.47% during the first six months of 2022.

**Q HOW WOULD GEORGIA POWER COMPANY'S PROJECTED REVENUE DEFICIENCY BE AFFECTED IF THE COMMISSION SET GEORGIA POWER COMPANY'S RETURN ON EQUITY AT THE RRA NATIONAL AVERAGE FOR 2022?**

A GPC's projected revenue deficiency would decrease by $391 million. The details of this calculation are shown in **Exhibit BSL-3**.

**Q SHOULD THE COMMISSION CONSIDER DETERMINATIONS MADE IN OTHER REGULATORY JURISDICTIONS?**

A Yes. This Commission should be informed by the determinations made by other state regulatory commissions. This is because the trend in authorized ROEs indicates that, in general, utilities' financial and credit risks are lower than in the past due, in part, to the implementation of a plethora of cost recovery mechanisms and other enhancements that have reduced regulatory lag. The national authorized average ROE is an important consideration when determining the ROE for GPC, however, as demonstrated previously, my review of Mr. Coyne's quantitative analysis supports a 9.83% ROE.

## 4. CAPITAL STRUCTURE

**Q WHAT IS GEORGIA POWER COMPANY'S PROPOSED CAPITAL STRUCTURE?**

A GPC's proposed capital structure includes 44% debt and 56% equity, which is an excessive equity ratio.

**Q WHAT IS THE BASIS FOR YOUR STATEMENT THAT GEORGIA POWER COMPANY'S PROPOSED EQUITY RATIO IS EXCESSIVE?**

A GPC's proposed equity ratio is excessive because it results in unnecessarily higher costs to ratepayers. Table 2 summarizes the average equity ratio of each vertically integrated electric investor-owned utility in the most recent rate cases decided during the period 2016 through 2022 to date.

**Table 2**
**Average Authorized**
**Financial Equity Ratios**
**2016 - 2022**

| Year | Average Common Equity Ratio |
|---|---|
| **2016** | 50.43% |
| **2017** | 50.94% |
| **2018** | 49.83% |
| **2019** | 51.99% |
| **2020** | 50.99% |
| **2021** | 51.23% |
| **2022** | 51.58% |

As shown above, the average common equity ratio in 2022 is 442 basis points lower than GPC's proposed 56% common equity ratio. GPC's proposed equity ratio is excessive, as compared to the national average ratio and considering GPC's requested

11% ROE. For example, in February 2022 Southwestern Public Service Company was authorized a 54.72% common equity ratio; however, the authorized return on equity was 9.35%, or 165 basis points lower than GPC's requested ROE.[15]

**Q HOW DOES GEORGIA POWER COMPANY'S PROPOSED COMMON EQUITY RATIO COMPARE TO THE AVERAGE COMMON EQUITY RATIO FOR THE COMPANIES IN THE PROXY GROUP?**

A The average common equity ratio for the companies in Mr. Coyne's proxy group is 52.44%.[16] The average common equity ratio includes companies with credit ratings that are lower than GPC's (A-). If we remove companies with a lower credit, the average common equity ratio is 53%, which is significantly below GPC's proposed 56% equity ratio. **Exhibit BSL-4** provides each proxy group company's credit rating and common equity ratio. A company's common equity ratio contributes to its credit score, therefore a company with a credit rating that is similar to GPC's should have a common equity ratio that is supportive of its rating and a good proxy for GPC's common equity ratio. As demonstrated in **Exhibit BSL-4**, GPC's proposed common equity ratio is significantly above the average common equity ratio of its peers and should be rejected.

[15] *In the Matter of Southwestern Public Service Company's Application for: (1) Revision of Its Retail Rates Under Advice Notice No. 292; (2) Authorization and Approval to Abandon Its Plant X Unit 3 Generating Station; and (3) Other Associated Relief*, Docket No. 20-00238-UT, Order Adopting Certification of Stipulation with Modification at 4. (Feb. 2, 2022).

[16] Direct Testimony of James M. Coyne, Exhibit JMC-10 at 1.

**Q ARE THERE ANY CONSEQUENCES OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?**

A Yes. GPC's higher percentage of equity and lower percentage of debt in its capital structure lowers its financial risk. Furthermore, common equity is more expensive than debt. In this case, GPC is proposing a 56% common equity ratio, but the proposed cost of debt is 3.53%, which is 747 basis points lower than the proposed 11% return on equity. A utility with too much equity in its capital structure has a higher cost of capital than a utility with a more balanced common equity ratio. All else being equal, the higher the overall common equity ratio, the greater the benefits to GPC's shareholders and executives and the higher the rates all GPC retail customers will bear. GPC should not be rewarded for its overly conservative use of debt and high equity ratio.

**Q WHAT IS THE IMPACT ON GEORGIA POWER COMPANY'S REVENUE REQUIREMENT IF ITS COMMON EQUITY RATIO IS REDUCED TO THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN THE PROXY GROUP WITH THE SAME CREDIT RATING?**

A If GPC's financial common equity ratio is reduced to 53%, its revenue requirement would be $108 million lower. The detailed calculations are shown in **Exhibit BSL-5**.

**Q WHAT IS THE IMPACT ON GEORGIA POWER COMPANY'S REVENUE REQUIREMENT IF ITS RETURN ON EQUITY IS CORRECTED AND ITS COMMON EQUITY RATIO IS REDUCED TO YOUR CORRECTED AVERAGE COMMON EQUITY RATIO?**

A If GPC's ROE is reduced to my corrected ROE of 9.83% and its common equity ratio

is reduced to 53% (which, as explained earlier, is GPC's proxy group, excluding companies with credit rating below A-) its revenue requirement would be $392 million lower in 2023. The detailed calculations are shown in **Exhibit BSL-6**.

**Q WHAT DO YOU RECOMMEND REGARDING GEORGIA POWER COMPANY'S COMMON EQUITY RATIO?**

A I recommend that GPC's capital structure should be more in line with the average equity ratio for companies in Mr. Coyne's proxy group that have similar credit ratings as GPC. Accordingly, I recommend that GPC's equity ratio not exceed 53%.

## 5. CONCLUSION

**Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?**

A The Commission should make the following findings:

- GPC's return on equity should be no higher than 9.83%.
- GPC's common equity ratio should be no higher than the average common equity ratio for companies in the proxy group with similar credit ratings as GPC, or 53%.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes.

# APPENDIX A

## Qualifications of Billie S. LaConte

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Billie S. LaConte. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

**Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am an energy advisor and am currently employed by J. Pollock, Incorporated as Associate Consultant.

**Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Arts Degree in Mathematics from Boston University and a Master's degree in Business Administration from Washington University.

Upon graduation in May 1995, I joined Drazen Consulting Group, Inc. (DCGI). DCGI was incorporated in 1995 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. I joined J.Pollock in May 2015.

During my tenure at DCGI and J.Pollock my work has focused on revenue requirement issues, cost of capital (return on equity and capital structure), cost allocation, rate design, sales and price forecasts, power cost forecasting, electric restructuring issues, integrated resource plans, formula rate plans, asset management agreements and contract interpretation.

I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This has included advising clients on economic and strategic issues concerning the natural gas pipeline, oil pipeline, electric, wastewater and water utilities. I have prepared cost allocation and rate design studies to provide timely

support to clients engaged in settlement negotiations in electric and gas utilities, provided power cost forecasting studies to assist clients in project planning and negotiated contracts with electric utilities for standby services and interruptible rates. I have also prepared studies on electric and gas utilities' performance-based rates (PBR) and benchmarking programs to evaluate their success and to provide recommendations on methods to be used. I worked on contract interpretation to resolve contract disputes for several clients. I have provided financial and cost of service analysis for natural gas pipelines certificate approval from the Federal Energy and Regulatory Commission (FERC) and the Canadian National Energy Board (NEB). Additionally, I completed the Corporate Credit Rating Analysis course presented by Moody's Analytics.

I have worked on various projects located in many states and several Canadian provinces including Alberta, British Columbia, Saskatchewan, Nova Scotia and Quebec. I have testified before the state regulatory commissions of Arkansas, Florida, Georgia, Iowa, Louisiana, Michigan, Minnesota, Missouri, New Mexico, Pennsylvania, Texas and South Carolina, and the provincial regulatory boards of Alberta and Nova Scotia. I similarly have appeared before the St. Louis Metropolitan Sewer District Commission.

**Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.**

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered Class I aggregator in the State of Texas.

# APPENDIX B

## Billie S. LaConte's Partial List of Appearances

TO BE INSERTED LATER

# APPENDIX C

## Return on Equity Methodologies

*Single Stage Discounted Cash Flow*

The discounted cash flow model is used by investors to determine the present value of a stock, based on future cash flows (dividends), which are discounted by the stock's known return and its forecast growth.

The formula is:

$$P = \frac{\mathrm{D}}{\mathrm{r}-\mathrm{g}}$$

Where:

P = current stock price

D = dividend yield

r = rate of return

g = growth rate

We can re-arrange the formula thus:

$$r = \frac{\mathrm{D}}{\mathrm{P}} + g$$

In other words, the expected return equals (1) the current dividend rate, plus (2) the expected growth in dividends. The expected growth in dividends is also measured by the expected growth in earnings.

The stock prices are based on the average closing prices for the past 30 days. The 30-day average is used to ensure that the results reflect stock prices over a period of time that is not overly reliant on any particular events affecting stock prices on a given day and that represent capital market conditions over the past month.

The growth rates are the forecast earnings per share growth rates for the next five years from Value Line, Yahoo! Finance, and Zacks. The dividends are forecast figures, also from Value Line. These have been adjusted to reflect any quarterly adjustments during the year.

*Multi-Stage Discounted Cash Flow Methodology*

A multi-stage DCF analysis uses three separate growth estimates or stages. The first stage measures the near-term growth rate based on the analysts' forecast earnings growth used in my constant growth DCF analysis. The second stage (intermediate-term) growth rates are linear interpolations of the first and third stage growth rates. The third stage (long term) is the forecast of the long-term growth rate of gross domestic product (GDP). Using these inputs, the model calculates the required internal rate of return to meet these dividend growth rates, or the ROE. I calculated three multi-stage ROE analyses using a low, mean, and high first year growth rate that is based on the analysts' forecast estimates of growth, similar to the constant growth DCF analysis.

The multi-stage method is used because analysts' growth rates for the first stage may not be sustainable over the long term. The multi-stage model recognizes short-term growth (whether it be higher or lower than the long term), but also accounts for a more realistic, long-term growth rate. Analysts' growth rates should be viewed in conjunction with other growth estimates to achieve a reasonable forecast of expected earnings.

The long-term growth in GDP is used because the underlying assumption is that mature, established companies can grow at a rate that is similar to, or lower than, the GDP growth rate. While some companies in the economy will grow faster than GDP for a while, this cannot happen consistently over a long period.

*Capital Asset Pricing Model*

The CAPM is a Risk Premium method that is used to estimate the ROE. It states that the expected return of a security equals the risk-free rate plus a risk premium. Simply put, investors require a premium over the risk-free rate if they are going to invest in a riskier security. The formula for the CAPM is:

*Expected ROE = Risk-Free Rate + β*Market Risk Premium*

The equity risk premium for a particular stock is the MRP times the stock's beta (β). The MRP is the difference between the return on the market on average (*i.e.*, the S&P 500) and the risk-free rate. Thus, it is the premium that reflects the risk on an average stock. Beta is the price volatility of that stock relative to the market as a whole. Thus, the risk premium for a *specific* stock equals the *average MRP* times the beta. Since utility stocks are lower risk than the average stock, the risk premium for a utility stock is lower than the average MRP. Multiplying the beta times the MRP gives the appropriate risk premium for the company (or group of comparable companies) being studied.

The risk-free rate is the projected yield on 30-year U.S. Treasury bonds. This rate is considered to be risk-free because the return is guaranteed by the U.S. government.

Two MRP estimates may be used, including the historical MRP estimate and a projected MRP. The historical MRP is based on historical data dating back to 1996. The projected MRP is based on the projected median three-to-five year price appreciation of the 1,700 stocks from Value Line and the projected median dividend yield over the next 12 months for all dividend paying stocks. The forecast annual return is based on the forecast annual growth rate of the stocks plus the forecast median dividend produces a projected annual return. The projected risk-free rate is deducted from the projected annual return to determine the projected MRP.

Beta measures the volatility of a security in comparison to the market as a whole. A beta equal to 1.00 means that a stock's price fluctuates exactly as the market as a whole. A beta higher than 1.00 implies that the stock's price is more volatile than the market; a beta less than 1.00 implies the stock's price is less volatile than the market. The standard formula for estimating beta is the covariance between a security's return and the return of the market divided by the variance of the market returns over a specified period. Beta is based on the betas provided in Value Line. Beta measures the amount of compensation an investor needs to take on additional risk, as compared to the risk-free rate. Value Line's method to estimate beta is based on "a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Composite Index over a period of five years. Value Line then adjusts these Betas to account for their long-term tendency to converge toward 1.00."[17]

The risk-free rate is based on the projected return on long-term treasuries. This rate is considered risk-free because the security is backed by the U.S. government.

*Risk Premium Method*

The Risk Premium method estimates the ROE for a utility as the sum of a bond yield plus a risk premium yield. The bond yield is the projected return on the long-term government bond plus the historical risk premium. The risk premium is a measure of the additional return an investor requires due to the additional risk of the security. The risk premium is the measure of the difference between the historical authorized return on equity regulated electric, natural gas or water utilities and the historical yield on 30-year Treasury bonds.

[17] Value Line Publishing, Using Beta, Andrew J. Cueter, (Oct. 2, 2012).

BY MR. JONES:

Q And, Ms. LaConte, you also caused to be prefiled with your testimony six exhibits marked BSL-1 through BSL-6; is that correct?

A (Witness LaConte) That's correct.

Q Do you have any changes you need to make to those exhibits?

A (Witness LaConte) No, I do not.

MR. JONES: Okay. Madam Chair, I would ask that those exhibits be marked GAM 12 through 17, if I've done the math right.

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were marked for identification as GAM Exhibits 12 through 17.)

BY MR. JONES:

Q Okay. Mr. Pollock, did you prepare a summary of your testimony?

A I did.

MR. JONES: Madam Chair, with your permission, I would ask him to give it now.

MADAM CHAIR PRIDEMORE: Please read your summary.

MR. POLLOCK: Thank you. Good evening, Commissioners. It's always a pleasure to appear before you, and at the risk of sounding like a broken

record, Georgia Power is on the precipice of a perfect storm of at least seven rate increases that could result in cumulative increases of up to $2.9 billion over the next three years: We have the three increases under the proposed annual rate plan; at least two increases for the Vogtle units three and four, and the fuel increase that will be even bigger than the other two individually.

Even before the first step of the increase is implemented under proposed Alternate Rate Plan, RTP rates have already experienced double-digit rate increases. And the proposals by Mr. Watkins to shift base rate and ECCR costs by approximately 6 million to large business customers and by approximately 160 million to marginally priced customers would result in permanent additional base rate increases ranging from over 20 percent to up to 51 percent just in year one. This would further exacerbate the severe price increases that these customers have already experienced.

The cost allocation theories underlying Mr. Watkins' proposals are extreme, unprincipled, and not widely accepted. In fact, the probability of dispatch method favored by Mr. Watkins has not been adopted by any state regulatory commission in this

century. With the prospect of up to $2.9 billion of rate increases, this is not the time to change long-standing cost recovery mechanisms, which the Commission has supported to the benefit of manufacturers in this state.

We agree with Staff, however, that the base rate and ECCR increases should be stepped if an Alternate Rate Plan is approved. To offset future rate increases, the Commission should identify alternatives to traditional ratemaking, securitization in particular, that would allow the Company to recover its capital costs while minimizing rate impacts on customers.

Securitization is a widely accepted practice for recovering large capital investments, such as retired plants, and other major unexpected costs like storm damage, and it's used to alleviate upward pressure on rates, and this would be particularly important in this case, given the perfect storm that we're facing.

The cost of securitizing utility assets is only a fraction of Georgia Power's pre-tax cost of capital. For example, Georgia Power is asking for 9.8 percent pre-tax cost of capital on this case. The most recent securitization carried an interest

rate of 3.6 percent. That's more that a 60 percent savings in cost of capital.

Further, securitization bonds can extend cost recovery for periods ranging from four to over 20 years, thereby further alleviating upward rate pressures. But until securitization is possible, we recommend changing the cost recovery for coal plants that the company has already retired or will be retiring early.

Retired plants can no longer provide electricity to the public. Thus, the costs of the retired plants are not used and useful. The utility should not earn a return on equity on investments on facilities that are not used and useful.

Further, it's unfair to customers to raise rates solely because of a decision to retire Plant Scherer 20 to 25 years before the end of the useful lives of Units 1, 2, and 3.

Accordingly, we recommend that Georgia Power should amortize its investment in Scherer Units 1, 2 and 3 over their current operating remaining lives, which range from 20 to 25 years.

Changing subjects, consistent with past practice, any base rate increase should continue moving rates closer to parity. This is one of the

Commission policies that has been very supportive of manufacturers. An equal percentage increase, as proposed by the company, would not accomplish this objective. So we recommend some movement to parity as has been done in prior cases.

GAM members are also very concerned with the proposed Rule 9 language, limitation of liability. Under this proposal, customers would be solely at risk for damages caused by electrical outages that are later determined to be the result of willful misconduct or gross negligence by the company.

Further, the compensation for these outages would be limited to the net book value of the damages sustained, thereby ignoring lost production and revenues and the need to replace any damaged property at the current value or equipment at today's costs.

Consistent with industry practice, we recommend that Georgia Power be held liable for damages caused by willful misconduct and gross negligence. Further, the amount of damages should be, at a minimum, sufficient to replace the customers damaged equipment and/or personal property.

Finally, in light of the concerns raised by Dr. Tutterow, I cannot over-emphasize the need for stability in maintaining the Commissions

long-standing policies with respect to the support of the real-time pricing RTP rates, the continued application of the ECCR rate as was approved in 2007, and, of course, your long-standing practice of moving all rates closer to parity using a reasonable cost-of-service study.

That concludes my summary. Thank you.

MR. JONES: Thank you, Mr. Pollock. If it's okay, I'll ask Ms. LaConte to give her summary and then open them up with questions.

BY MR. JONES:

Q Ms. LaConte, have you prepared a summary of your testimony?

A (Witness LaConte) Yes, I have.

MADAM CHAIR PRIDEMORE: Please go ahead, Ms. LaConte.

MS. LACONTE: Good evening. Thank you for the opportunity to appear before you today on behalf of the Georgia Association of Manufacturers. I appear today to discuss the appropriate return on equity and capital structure for Georgia Power.

The return on equity and common equity ratio for Georgia Power are important components of its revenue requirement and should be authorized at a level that provides Georgia Power with the

opportunity to earn a reasonable return while, at the same time, protecting customers from unnecessarily higher rates.

Five rate increases will be determined by the ROE authorized in this case. The next three ARP rate increases and the rate changes for Vogtle 3 and Vogtle 4 will use the ROE authorized in this case.

My recommendations are based on the review of Georgia Power witness James Coyne's direct testimony and analysis regarding GP's ROE and capital structure. Rather than perform a separate return on equity analysis, I assessed the methodologies and assumptions used by Mr. Coyne and corrected his analysis to determine the appropriate ROE for Georgia Power.

While I agree with some of Mr. Coyne's analysis, there are areas where I disagree; therefore, I corrected some of his methodologies to conform with the approach used by many ROE experts.

My recommended 9.83 percent ROE is based on the results of Mr. Coyne's discounted cash flow methodology, as well as his capital asset pricing model, with a few adjustments. The DCF and CAPM analyses are accepted methodologies that are used in most jurisdictions to estimate a utility's cost of

**equity.**

**I disagree with Mr. Coyne's expected earnings model and his upward flotation cost adjustment. The expected earnings methodology is not widely used by ROE experts because it is based on expected return on book value, rather than expected return on market value.**

**The flotation cost adjustment, which purportedly represents costs associated with issuing equity, does not apply to GP because it does not issue equity. Therefore, my revised ROE does not incorporate the expected earnings methodology or the flotation cost adjustment.**

**Separate from ROE estimates and my recommendations, a more robust view of GP's financial risk should be considered to determine the appropriate ROE. My testimony considers GP's financial risk, such as its variability in income, which may be quantified by the analysis of GP's financial statements and cash flow and leverage. To the extent the variability is small or reduced by other means the risk to GP's shareholders is lower.**

**GP's financial risk is reduced due the multi-year ARP, which is based on projected costs. The alternate rate plan provides GP with rate**

**stability and predictability, reduces regulatory lag by allowing more timely recovery of costs, and is viewed favorably by credit rating agencies. Hence, GP's income variability is reduced.**

**As an example, due to the risk-reducing nature of the forward-looking ARP, Georgia Power has earned above the mid-point of its authorized ROE band over the past 10 years.**

**I ask the Commission to also consider the authorized ROEs in other jurisdictions when setting Georgia Power's ROE. The average authorized ROE in 2021 was 9.53 percent and 9.35 percent for the first nine months of 2022. My recommended 9.83 percent ROE for Georgia Power is above the national average ROE, and will provide GP with the opportunity to earn a reasonable return that is comparable to other similarly situated utilities, while also maintaining its credit rating.**

**My recommended 53 percent common equity ratio for Georgia Power is based on a comparison of the capital structures for the companies used in Mr. Coyne's analysis when estimating the ROE. GP's proposed common equity ratio is excessive, compared to all vertically integrated electric utilities, as well as the companies in Mr. Coyne's proxy group.**

A higher common equity ratio produces unnecessarily higher costs to ratepayers. The average common equity ratio for the utilities in Mr. Coyne's proxy group that have similar credit ratings as Georgia Power is 53 percent, compared to Georgia Power's proposed 56 percent common equity ratio.

I recommend the Commission adjust Georgia Power's common equity ratio so that it is more in line with the average of vertically integrated investor-owned electric utilities with the same credit rating as Georgia Power, or 53 percent.

Thank you for your time, and I am available to answer any questions you may have

MR. JONES: Madam Chair, thank you. That concludes the witnesses' summaries. They're available for questions from the Commission and cross-examination.

MADAM CHAIR PRIDEMORE: Questions from Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: I just have a historical question for Mr. Pollock, and I'm not going to get on the securitization train tonight. It's 7:00, and none of these people want to listen to

me do it.

So were you involved with Georgia Association of Manufacturers with the state at the time when -- as Commissioner Shaw referenced, at the time that Georgia did away with sales tax on energy?

MR. POLLOCK: Yes, I've been advising GAM for quite some time, and that occurred when the sales tax was eliminated.

MADAM CHAIR PRIDEMORE: Did you testify at the Capitol during that time?

MR. POLLOCK: I did not.

MADAM CHAIR PRIDEMORE: Did you talk with legislators during that time?

MR. POLLOCK: I did not.

MADAM CHAIR PRIDEMORE: Okay. Just wondering.

All right. Here we go.

Georgia Public Service Commission.

MR. THOMAS: No questions.

MADAM CHAIR PRIDEMORE: Does anybody have questions? Anybody -- anybody alphabetically in front of Ms. Medlyn?

Oh, Ms. Coyle.

Sorry, Ms. Medlyn.

MS. COYLE: I'll keep it light.

CROSS-EXAMINATION

BY MS. COYLE:

Q Good evening. Been a long day. I don't think we've met.

Mr. Pollock, good to see you again.

A (Witness Pollock) Likewise.

Q You testified -- in your testimony you stated that you believe that authorizing legislation has been drafted that will allow the company to use the option of securitization; is that correct?

A (Witness Pollock) Yes.

Q Are you aware that, in fact, the bill was not only drafted, but that it was introduced in the 2022 legislative session?

A (Witness Pollock) Yes, I believe that was the case.

Q And that it passed regulated industries in the Senate?

A (Witness Pollock) I think it got one level of approval, yes.

Q It just didn't get out of rules.

And did you follow the hearing in the round when Georgia Power's witnesses were on the stand?

A (Witness Pollock) I did not.

Q Okay. Would it surprise you to hear that when I asked company witnesses about securitization,

Mr. Abramovitz and Mr. Womack suggested that the company had plenty of other tools in the toolbox and that securitization wouldn't really be beneficial to them or their customers?

MR. HEWITSON: I'm going to object because that misstated Mr. Womack's and Mr. Abramovitz's testimony. It was that this Commission has the tools necessary, not that the company does.

MS. COYLE: Okay. Thank you for that correction.

BY MS. COYLE:

Q In light of that correction, would you agree that securitization is a necessary tool for this Commission to welcome with open arms?

A (Witness Pollock) Well, I think the Commission should embrace all the available tools given the perfect storm that we're facing in rate increases and particularly the circumstances surrounding these rate increases. So I think it's all-of-the-above strategy that really must be considered, and we really shouldn't take anything off the table at this stage.

Q And do you feel that, including securitization as one of those tools in the toolbox as an optional tool, in any way disadvantages or takes away the Commission's authority?

A (Witness Pollock) Not at all, because the

Commission will be heavily involved in determining the terms of the securitization after legislation has been enacted by the legislature. So the Commission's role will be the same as it is in a rate case.

Q And, finally, can securitization be applied to any costs that have not already been deemed recoverable by this Commission?

A (Witness Pollock) No. Securitization should really only apply to costs that the Commission has previously determined to be prudent, and then only if the company has no alternative means of mitigating the effects of those costs.

Q Thank you.

MS. COYLE: No further questions.

MADAM CHAIR PRIDEMORE: Ms. Medlyn?

CROSS-EXAMINATION

BY MS. MEDLYN:

Q Good evening. Emily Medlyn on behalf of DOD.

A (Witness Pollock) Good evening.

MADAM CHAIR PRIDEMORE: Ms. Medlyn -- sorry. Somebody has messed with your mic. Straighten it up. Speak into it, please.

BY MS. MEDLYN:

Q Just a few questions for you, Mr. Pollock.

On page 9, lines 4 and 5 of your testimony, you

mentioned the significant fixed cost contributions from RTP customers.

A (Witness Pollock) I'm there.

Q Okay. But isn't it true that currently RTP customers are exempt from ECCR on incremental load?

A (Witness Pollock) That's correct.

Q Okay. What is the rationale for exempting RTP customers from paying ECCR?

A (Witness Pollock) So the ECCR costs are average costs. They're embedded costs. And RTP is a marginal cost rate, which means RTP customers pay the incremental costs of generation capacity, transmission capacity, fuel, losses, and then plus a risk adder. So the rate structure itself is based on totally different paradigm than all the other rates. It's a marginal cost rate, not an average or embedded cost rate.

And, hence, because ECCR and other riders recover average costs, those average costs apply to customers that are on average cost rates. RTP is not an average cost rate. It's a marginal cost rate, and that's why the ECCR does not apply to incremental RTP sales.

Q Thank you.

MS. MEDLYN: That's all I have.

MADAM CHAIR PRIDEMORE: Okay. Georgia Power Company?

MR. HEWITSON: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Since everybody has asked Mr. Pollock questions, I'll stick with Mr. Pollock, and I guess, Ms. LaConte --

A (Witness Pollock) See, I drew the short straw tonight.

Q Is that because I get to ask you questions, Mr. Pollock?

A (Witness Pollock) It's okay.

Q All right. Mr. Pollock, you advocate for securitization of certain assets; right?

A (Witness Pollock) I've certainly suggested that's a good tool.

Q And you also recognize that securitization would require a change in the law in Georgia; right?

A (Witness Pollock) It would, yes.

Q And this Commission can't change the law on its own accord; right?

A (Witness Pollock) Correct.

Q Are you aware of any state that has passed a securitization statute over the objection of the utility to which it applied?

A (Witness Pollock) I am not.

Q All right. And Georgia Power has been clear that it feels this Commission already has the tools necessary to appropriately balance cost recovery with the needs of customers?

Is that your understanding?

A (Witness Pollock) Well, that's what I hear, but I want to see the tools. And since we're from Missouri, you've got to show us.

Q I thought it was called misery.

A (Witness Pollock) Misery?

A (Witness LaConte) No, it's the show-me state.

Q Show-me state.

You also recommend that the Commission set aside a portion of costs related to Plant Wansley and CCR ARO; is that right?

A (Witness Pollock) Yes.

Q Okay. You are not recommending that the Commission deny recovery of these assets, but rather delay recovery pending a potential change in the law related to securitization.

Do I have that right?

A (Witness Pollock) Not delay recovery, but simply identify them, and perhaps in a separate cost recovery mechanism. So if the securitization was possible, you would then be able to identify the specific costs in

which would be subject to that securitization. So it's not a delayed recovery. It's simply putting a box around it so that it can be identified if securitization is then enacted, and then bonds are actually issued.

Q But you are not advocating for there to be a change in Georgia Power's recovery January 1, 2023, related to those assets?

A (Witness Pollock) No, other than the fact that the return should be limited to cost of debt. As I said, the assets are not used and useful.

Q Regarding the alternative rate plan, you propose that Georgia Power implement a step increase whereby the company would be required to update its base rate and ECCR projections for years two and three; right?

A (Witness Pollock) Yes.

Q Okay. Now, you propose that new base rates be set using the updated -- or using updated test year projections; is that right?

A (Witness Pollock) Yes.

Q Isn't that more like a series of three mini rate cases?

A (Witness Pollock) It is, but you have to, you know, realize that every test year is forward looking and the further forward looking it is, the less accurate it is. So the goal is to try to get more accurate information upon

which to set the base rate.

Q Well, do you propose that the earnings band that gets decided on by this Commission gets retained over those many rate cases?

A (Witness Pollock) I would think so, yes.

Q And you're aware that the company must agree to any alternative rate plan for it to be implemented; right?

A (Witness Pollock) Yes.

Q And in the absence of the company's agreement to an alternative rate plan, we would end up with a traditional rate case annually; right?

A (Witness Pollock) Yes.

Q All right. One of issues you raised in your testimony is that the company should no longer earn a return on retired assets.

And, specifically, you point to Plant Wansley; right?

A (Witness Pollock) Yes.

Q You also have a concern regarding the company's additional sum on the six capacity PPAs for the gas units; is that right?

A (Witness Pollock) It's not a concern. It's just a recognition that the company is getting a return on the plant, as well as a return on the replacement capacity, so it becomes a redundancy issue.

Q Excuse me. On page 22, lines 9 through 23, you point to a Texas PUC decision regarding a retired SWEPCO unit as support for your position that a utility should not be allowed to earn a return on a retired unit; right?

A (Witness Pollock) Yes.

Q And that decision was issued in 2018; right?

A (Witness Pollock) Yes, that's right.

Q And the unit at issue, Welsh Unit 2, had been retired since 2011; right?

A (Witness Pollock) No. No, it was not retired at that point. It was retired subsequent to that.

Q It was retired, though, prior to the 2018 decision; right?

A (Witness Pollock) Testing my memory.

Q Well, I've got the SWEPCO decision, if you want to look at it.

MR. HEWITSON: May I approach?

MR. POLLOCK: SWEPCO retired Welsh Unit 2 in April of 2016. I have the decision too.

BY MR. HEWITSON:

Q You've got the decision?

A (Witness Pollock) I do.

MR. MARZO: Can I still approach?

MR. HEWITSON: Well, he's got the decision. But they don't.

MADAM CHAIR PRIDEMORE: I don't.

MR. MARZO: Well, that was my question.

BY MR. HEWITSON:

Q All right. And what paragraph are you looking at for that?

A (Witness Pollock) That's in the order on rehearing. That's finding of fact 65.

Q Okay. On paragraph 61, which is page 19 of 59 it says, "Compliance deadlines for environmental programs such as NAAQS and the MATS rule were reasonably viewed by SWEPCO management as requiring a decision to retire Welsh Unit 2 in June 2011"; right?

A (Witness Pollock) I see that, Yes.

Q Okay. So either way, it was retired prior to the 2018 decision; right?

A (Witness Pollock) That's right.

Q Okay. And, to your knowledge, the Welsh Unit 2 retirement decision was not made by the Texas PUC after a public hearing to weigh the benefits and costs of continued operation of the units, was it?

A (Witness Pollock) It was largely dictated because of the fact that SWEPCO had built a bigger coal unit and the fact that Welsh Unit 2 would cause a violation of ambient air standards. SWEPCO had little choice. They either had to build the bigger coal unit or retire one of

their smaller coal units.

Q Right.

But that was SWEPCO's decision; right?

A (Witness Pollock) Yes, it was.

Q And my --

A (Witness Pollock) Actually, it was a result of a negotiation that SWEPCO engaged with the various parties that led to that result.

Q Right.

But it wasn't after a decision by the Texas PUC allowing them to do that; right? It was done -- the decision was made before going to the Texas PUC?

A (Witness Pollock) Yes.

Q And, to your knowledge, there was no Texas PUC decision providing for the desertification and retirement of the Welsh unit on a specific day and for amortization of unrecovered costs; right?

A (Witness Pollock) Could you say that again?

Q Yeah.

To your knowledge, there was no Texas PUC decision providing for the decertification and retirement of the Welsh unit on a specific date and for amortization of the unrecovered costs?

A (Witness Pollock) You're talking about before the Commission decision?

Q Before the -- well, when they made the decision -- when SWEPCO made the decision to retire the units.

A (Witness Pollock) Yes, at that point, SWEPCO had done a depreciation study which identified that the Welsh Unit 2 had a significant amount of remaining useful life and that was the basis for the Commission's determination to say you get to recover the costs over the remaining life without a return.

Q But that happened after SWEPCO --

A (Witness Pollock) It was retired, that's right.

Q And you're generally familiar with the IRP statute here in Georgia; right?

A (Witness Pollock) Yes.

Q Is it your understanding that the IRP statute provides that a utility may recover the remaining net book value of an asset that has been retired after decertification by the Commission?

A (Witness Pollock) Yes.

Q Do you know if there was a Texas statute similar to our IRP statute?

A (Witness Pollock) Texas does not have an IRP statute, per se, but the Commission does review retirement decisions.

Q You were involved in this year's IRP; right?

A (Witness Pollock) Yes.

Q And your client, the Georgia Association of Manufacturers, signed a stipulation in that case; right?

A (Witness Pollock) Yes.

Q And that stipulation was adopted by this Commission as part of its order in the 2022 IRP?

A (Witness Pollock) Yes.

Q The stipulation and the adopting order provide that Plant Wansley shall be retired by August 31st, 2022; right?

A (Witness Pollock) Yes.

Q Okay. And the IRP -- in the IRP, the coal units were found to be economically challenged; right?

A (Witness Pollock) Yes.

Q Keeping them running presented risks and cost consequences that were mitigated by decertification and retirement; is that your understanding?

A (Witness Pollock) Yes, particularly for Plant Wansley.

Q And thank you. I should have given you that reminder. I'm just talking about the Plant Wansley decision right now.

A (Witness Pollock) Yes.

Q In securing long-term gas combined cycle PPAs at favorable competitive prices at the time lessened

environmental impacts and provided greater flexibility and resilience than the older coal units; right?

A (Witness Pollock) Certainly, the gas units do provide some additional degree of flexibility, but, of course, you have the cost of gas associated with those units. So that's a problem because those costs would be passed through to customers.

Q And would it be fair to say that the Commission's express decision to decertify Plant Wansley reflects a judgment call about the benefits and detriments of relying further on an aging coal plant versus locking in beneficial, flexible, and efficient gas energy and capacity?

A (Witness Pollock) I would characterize it as a judgment call, yes.

Q And all that weighed into the decision to approve the capacity PPAs during the transition of the retiring coal units; right?

A (Witness Pollock) Yes.

Q And, as we said, that was done through the public IRP process; right?

A (Witness Pollock) Yes.

Q Okay. And the stipulation provides for the certification of the capacity PPAs for the gas companies; right?

A (Witness Pollock) Yes.

Q And the stipulation also provides for the company to recover an additional sum on the PPAs; right?

A (Witness Pollock) Yes.

Q The stipulation also provides that the remaining net book value of Plant Wansley shall be reclassified as a regulatory asset and amortized at the depreciation rate approved in the 2019 rate case; right?

A (Witness Pollock) Yes.

Q Now the timing of recovery was deferred to this rate case, but not the recovery itself; is that a fair statement?

A (Witness Pollock) Yes. And we're not disputing the recovery of the capital costs.

Q But you are disputing the recovery of the remaining net book value as a depreciation?

A (Witness Pollock) No. We're disputing weather there should be a return on unamortized capital costs.

Q Which you are not -- okay.

Your testimony in this case is not addressing simply the timing? It's addressing the amount as well; right?

A (Witness Pollock) Only insofar as whether the unamortized balance should earn a return.

Q I view that as a yes.

You're not arguing just the timing? You're

arguing an amount of recovery as well; right?

A (Witness Pollock) If you consider the return as part of the amount recovered, yes, that's correct.

Q And in the stipulation paragraph 39, it was only the timing of recovery that was deferred to the rate case; right?

A (Witness Pollock) You expect me to remember paragraph 39?

Q Well, I've got it for you.

A (Witness Pollock) That's okay. I'll take your word for it.

Q Thank you. All right.

Just a couple of last questions on the class revenue allocation.

You recognize that in the last three rate cases, the Commission approved class revenue allocations that moved rates closer to parity; right?

A (Witness Pollock) Correct.

Q Okay. And do you agree that movements towards parity are something that should be done over time, not abruptly from one rate case to another?

A (Witness Pollock) That's absolutely correct, and that's consistent with my recommendation in this case.

Q And you also agree, I would imagine, that parity movements are a policy decision for the Commission to

make?

A (Witness Pollock) They are, yes.

Q Thank you, Mr. Pollock. I will yield the podium to Mr. Marzo.

CROSS-EXAMINATION

BY MR. MARZO:

Q Good evening, Mr. Pollock, Ms. LaConte.

A (Witness LaConte) Good evening.

Q I thought earlier the worst thing you could do is depreciation cross after lunch. I think I've topped myself tonight doing ROE cross.

A (Witness Pollock) You could also refrain from doing ROE cross.

Q You make it so entertaining, though.

MR. JONES: We'll be glad to stipulate his testimony.

MR. MARZO: You can stipulate my cross.

BY MR. MARZO:

Q Let me start off by asking, Ms. LaConte, is it fair to say that you have not conducted your own independent analysis of the ROE and capital structure for Georgia Power in this case; correct?

A (Witness LaConte) I did an independent analysis of Mr. Coyne's ROE analysis, and I made adjustments.

Q Okay. So is it fair to say -- I'm sorry I

didn't mean to interrupt you.

A (Witness LaConte) I was saying I made adjustments to a few of his methodologies.

Q Okay. So is it fair to say that you've examined Mr. Coyne's ROE analysis, and you changed certain of his model assumptions to arrive at your own recommendation in this case?

A (Witness LaConte) That's right. I didn't totally disagree with his method that he used. I just made some adjustments.

Q And can we agree that, in rate cases, ROE experts use judgment regarding which models to use and which assumptions to rely upon?

A (Witness LaConte) Yes, that's correct.

Q And would you agree with me that ROE experts in rate cases can and they do often disagree on models and assumptions that were inputs into those models?

A (Witness LaConte) That's right.

Q Okay. And you take issue with some of the inputs that Mr. Coyne used in his models and you characterize these as corrections in your testimony, but, really, they're just differences of opinion as to what inputs should go into a model; correct?

A (Witness LaConte) They could be differences of opinion, but I would say that the adjustments I made are

recognized by other ROE experts. It's not just my opinion.

Q Okay. But you made those -- in lack of a better term, you made that using your judgment, and Mr. Coyne made his recommendations using his judgment perceivably; correct?

A (Witness LaConte) Yes.

Q And it wouldn't -- it probably doesn't surprise you that Mr. Coyne disagrees with your judgment in changing some of the inputs to his recommendation; right?

A (Witness LaConte) That does not surprise me.

Q Now, if I can first ask you a question about your testimony on often page 3, lines 25 to 27, and as we discussed corrections, in your discussion of the appropriate equity level for the company, you refer on page 3, lines 25 to 27, to Georgia Power as having an A-minus credit rating.

Do you see that?

A (Witness LaConte) Yes.

Q You similarly refer to GPC, Georgia Power, as having an A-minus credit rating on pages 21 and pages 23 of your testimony.

And I wanted to ask you: Are you aware that Georgia Power does not have an A-minus credit rating?

A (Witness LaConte) It was my understanding that it was an A-minus credit rating.

Q Okay. So you're not aware that Georgia Power

has a senior unsecured rating of BB+, Baa1, and a BBB+ from S&P, Moody's, and Fitch, respectfully?

A (Witness LaConte) Now I'm aware of it.

Q Okay. So that's an error in your assumptions in this case; correct?

A (Witness LaConte) Yes.

Q Okay. Now, you agree with Mr. Coyne on certain aspects of his analysis; correct?

A (Witness LaConte) Yes.

Q And you agree that his proxy group is reasonable and generally comparable to Georgia Power Company; correct?

A (Witness LaConte) Yes, that's correct.

Q And you find that his DCF is based on sound assumptions and is generally reasonable; correct?

A (Witness LaConte) Yes.

Q And you disagree with him on concern aspects as well. For example, you discuss your concerns with his risk premium model on page 11 of your testimony.

And is it your view -- from what I could take from your testimony, is your view that the risk premium method may not factor in directly when estimating ROE, but you believe that is serves as a reasonable check of the DCF and cap end results; is that correct?

A (Witness LaConte) Yes. It can be used for

that.

Q Okay. Now, you used Mr. Coyne's risk premium analysis, but instead of using the regression analysis that he developed to determine the relationship between interest rates and allow returns, you calculated the long-term historic average of both the risk premium and the historic interest rates, and you added them together; is that correct?

A (Witness LaConte) I estimated the historical risk premium and added that to the projected long-term risk-free rate.

Q Okay. And your judgment was that the long-term historical average was more representative of the current costs of equity?

A (Witness LaConte) I used that to evaluate whether my recommended 9.83 percent was reasonable.

Q Okay. And when I looked at your analysis of that, it looked as if you were using Mr. Coyne's data; is that correct?

A (Witness LaConte) I did.

Q Okay. Now, let me show you JMC No. 6, which is an exhibit to Mr. Coyne's testimony. It's already been entered into the record.

MR. MARZO: I'll let Mr. Hewitson get that to you.

MADAM CHAIR PRIDEMORE: You may approach.

MR. MARZO: I'm sorry, Madam Chair.

MADAM CHAIR PRIDEMORE: You're okay. It's just got to go in the record.

MR. MARZO: Can he approach?

MADAM CHAIR PRIDEMORE: He can approach.

BY MR. MARZO:

Q Let me turn your attention to the third column on page 2, which is the average long-term risk premium Mr. Coyne calculated.

And that number is represented at 6.06 percent; is that right?

A (Witness LaConte) Yes.

Q And that's the same number that you cite in line 3, page 11 of your testimony; correct?

A (Witness LaConte) That's right.

Q Okay. Now, in the second column, which is the US Treasury yields for 30-year bonds -- current treasuries, the bottom line on page 2, the average long-term interest rate is represented by Mr. Coyne, and it's calculated by him to be 4.57 percent; is that right?

A (Witness LaConte) Yes.

Q And that served as the basis of the risk premium; correct?

A (Witness LaConte) It was used to calculate the

risk premium, yes.

Q Now, if I looked at your testimony, though, on page 11, you cite a long-term risk-free rate of 3.4 percent.

Do you see that?

A (Witness LaConte) Yes, and I pulled that from Mr. Coyne's testimony. That's the forecast long-term risk-free rate from 2023 to 2027.

Q But do you understand the average long-term interest rate that Mr. Coyne calculated is represented here in JMC-6?

A (Witness LaConte) Yes, but it differs.

Q Okay. And do you understand that if you were to use his long-term average interest rate, and you were to make the same calculation adding that to the risk premium long-term average, that would equal out to 10.62 percent?

A (Witness LaConte) I'll accept that, yes.

Q Okay. And that's much closer to the ROE determined by Mr. Coyne using his multiple models of 10.92 percent, isn't it?

A (Witness LaConte) Yes.

Q Now, you recommended that the Commission lower Georgia Power Company's equity ratio from 56 percent to 53 percent; is that correct?

A (Witness LaConte) Yes.

Q And you reached this conclusion based upon the

analysis that Mr. Coyne provided of the actual capital structure for his proxy group of companies; right?

A (Witness LaConte) Yes.

Q And I probably should have asked this as a precursor to my other questions.

Now that there's been a correction that you understand now to the company's actual credit rating, does it impact your equity analysis at all, because that was where that particular representation appeared in your testimony?

A (Witness LaConte) It may. It may adjust the average common equity ratio for the utilities that have similar credit ratings to Georgia Power.

Q Okay. Now, just to close the loop here, in your particular analysis on equity levels, I believe you used some of Mr. Coyne's information included in JMC Exhibit 10. And let me show you a copy of that.

MR. MARZO: Madam Chair, may he approach. I'm sorry.

MADAM CHAIR PRIDEMORE: He may approach.

MR. MARZO: And by the way, Madam Chair, just for the record, these have already been entered into the record, so I'm not asking to mark them again.

MADAM CHAIR PRIDEMORE: Okay.

BY MR. MARZO:

Q Now, here, Mr. Coyne provided the actual capital structures of the proxy group of companies; correct?

A (Witness LaConte) Yes.

Q And he provided book equity ratios of each operating company from 2019 Q4 to 2021 Q4; is that right?

A (Witness LaConte) Yes.

Q And if I look at his average that he provided in his analysis, he averaged these for each company at the whole coal level, which reflected a mean average of 52.93 percent; is that correct?

A (Witness LaConte) Yes, but the proper comparison would be to look at the subsidiaries of the whole coal companies.

Q Okay. And I'm about to ask about that too.

But is the 5.293 percent, is that the basis of your 53 percent recommendation?

A (Witness LaConte) No.

Q That was not. Okay.

And if you looked at the operating companies that you just referenced there, will you confirm for me my calculation, which is that the range there is 45 percent to 62 percent?

A (Witness LaConte) Actually, I think the range is higher, if you look at the --

Q It is. I'm sorry. The 45 to 62 is actually at the whole co level. The operating company range is wider. It's from 42.8 percent to 83.1 percent.

A (Witness LaConte) That's right.

Q Okay. And can you agree with me that that's well within the range that Mr. Coyne has recommended for Georgia Power's equity ratio?

A (Witness LaConte) It's within the range, but it also represents common equity ratios for utilities that have higher credit ratings than Georgia Power and lower credit ratings than Georgia Power. So you can't look at the totality of that and take the average to come up with the appropriate common equity ratio for Georgia Power.

Q But you agree with me, do you not, that the information -- well, let me ask this: Have you done -- have you broken those out into what the differences are in terms of credit ratings?

A (Witness LaConte) I compare the common equity ratios for utilities that had similar credit ratings as Georgia Power.

Q And you understand that for Mr. Coyne's analysis in looking at both the operating companies that fall below his proxy group, that the 56 percent that he recommended is well within the range of both the proxy group, as well as the operating companies; correct?

A (Witness LaConte) It is.

MR. JONES: That's asked and answered.

MS. LACONTE: I would point out, though, that the Evergy Kansas South common equity ratio of 83 percent is an extreme outlier, and if you take that out, you would show that the recommended 56 percent for Georgia Power is at the high end of the range of these utilities.

BY MR. MARZO:

Q And that's only if you selectively take certain numbers out; correct?

A (Witness LaConte) Well, 83 percent is an outlier. That's not a normal common equity ratio for most utilities.

Q And there's others on this chart that are 58 percent; correct?

A (Witness LaConte) There's a few.

Q There's some at 56 percent, so --

A (Witness LaConte) There's a few.

Q -- you say it's an outlier, but if you look at the percentages here, several of these utilities are in the same range as Georgia Power?

A (Witness LaConte) Yes, and there are several that are not within the same range. I see 42.81 for AEP Texas, 43 percent for Entergy Louisiana.

Q And I guess, likewise, if you were to take the lowest numbers out, if you're going to take the highest numbers out, we could then calculate a range?

A (Witness LaConte) Sure. You could take out the lowest number and the highest number.

Q Yeah.

Now, on page 16 of your testimony, you state that Georgia Power has numerous adjustment clauses in place that prevent the company to change rates outside of a base rate case; is that correct?

A (Witness LaConte) Yes. But that was incorrect. It's my understanding that the adjustment clauses are determined and the base rate cases. They are based on projected years -- projected numbers.

Q Okay. Well, you just may have eliminated some questions from me.

A (Witness LaConte) Okay.

Q So now that you understand that, I assume that affects your recommendation because one of your recommendations was, my understanding was, built on what you considered to be the risks -- perceived risks of the company's ability to adjust rates.

A (Witness LaConte) Well, I would say that the adjustment clauses are still based on projected year costs, which lowers the risk and also reduces the regulatory lag.

**And it's my understanding that the fuel clause can have an interim adjustment.**

**Q Okay. But do you understand that fuel cases before this Commission are determined in fully litigated proceedings?**

**A (Witness LaConte) Yes.**

**Q Okay. So that's not an automatic adjustment in the sense of a rise; correct?**

**A (Witness LaConte) No, but you do have interim rates, which adjusts.**

**Q And do you understand with the interim fuel adjustment rider, there's a cap on that 15 percent? You can't adjust higher than 15 percent of what was ordered by the Commission?**

**A (Witness LaConte) Yes, but it also allows the utility to collect the additional funds sooner rather than later.**

**Q And it also allows the utility to refund dollars to customers sooner than later; correct?**

**A (Witness LaConte) If necessary.**

**Q Okay. So that particular interim rider works both ways; correct?**

**A (Witness LaConte) Yes.**

**Q Okay. Now, your analysis -- well, let me jump over to this one.**

Now, in your opinion -- in interest of time, in your opinion, the Commission should consider ROEs of other utilities as relevant because the recent averages suggest that the financial and credit risks are lower than in the past, in part due to the implementation and plethora of cost recovery mechanisms, and you discuss that in your testimony; is that correct?

A (Witness LaConte) Yes.

Q And you also talk about other enhanced and reduced regulatory lags, as you discussed in your summary.

But isn't it true that if we're going to talk about Georgia Power, we're going to talk about how to compare it to other utilities, we should look at what are other comparable utilities? For example, isn't it true that Florida Power and Light has a similar risk profile and cost recovery mechanism as Georgia Power Company?

A (Witness LaConte) Yes.

Q Okay. And as a rate -- it actually has an A credit rating from S&P, which is two notches higher than Georgia Power, so one could argue that it has a lower level of risk from a debt investment standpoint; correct?

A (Witness LaConte) Yes.

Q And it has similar multi-year rate plans and cost recovery mechanisms for fuel; correct?

A (Witness LaConte) Yes.

Q And are you aware that FP&L had a settlement approved in August of 2021 incorporating a 10.6 percent ROE and 59.6 percent equity?

A (Witness LaConte) Yes, and that equity ratio is an outlier.

Q And are you aware that under provision of that particular settlement, that was only decided in 2021, FP&L's equity ROE level was actually increased to 10.8 percent due to Treasury bond yields increasing?

A (Witness LaConte) Yeah, that's based on the settlement.

Q And isn't it true that, like Georgia, Florida's regulatory environment is ranked above average by ROE in terms of constructive nature of its regulatory environment?

A (Witness LaConte) Yes, and that actually affects their risk. It reduces the risk in the eyes of credit rating agencies.

Q And hasn't FP&L, like Georgia Power, historically been awarded ROEs substantially higher than the national averages?

A (Witness LaConte) Yes, it has.

Q Thank you, Ms. LaConte. Thank you, Mr. Pollock.

MR. MARZO: Thank you, Madam Chair.

MADAM CHAIR PRIDEMORE: Redirect?

MR. JONES: Very briefly. Thank you, Madam Chair.

REDIRECT EXAMINATION

BY MR. JONES:

Q Mr. Pollock, you were asked questions about the alternative rate plan's stepped increases versus more upfront increases like Georgia Power has proposed.

Do you recall those questions?

A (Witness Pollock) Yes.

Q And your proposal of -- can you explain the rationale for your proposal of updating assumptions in future test years instead of assuming a rate up front?

A (Witness Pollock) Yeah, so the alternative rate plan we have now, and particularly the levelized increase, is based on three forward-looking test years, none of which are based on official corporate budgets which means, you know, the farther out you get, the less accurate that those forecasts are going to be.

Our recommendation would be let's update -- using the official corporate budget, let's do the update, use the same parameters that were established in the rate case to determine the revenue requirement, but just refresh the numbers. So it's not a separate full rate case. It's simply a refresh of the numbers using the parameters from the rate case decision.

Q Are you familiar with the settlement of the 2019 rate case?

A (Witness Pollock) Yes.

Q What sort of -- how did that stipulation -- approved stipulation address this issue?

A (Witness Pollock) It didn't so much address it on the base rate side, but it really -- it -- like with the other riders, it did -- the company did have to update its projections.

Q Okay.

A (Witness Pollock) I'm suggesting it needs to carry it through to the base rate part of it.

Q Okay. Ms. LaConte, you were asked a question about Florida Power and Light's recent stipulation in that case.

How would you say that that case and that ROE determined in that case compares with the bulk of the ones that you looked at in your testimony?

A (Witness LaConte) Florida Power traditional receives the highest return on equity and common equity ratios that I've seen in the country.

A (Witness Pollock) In fact, I would add that Tampa Electric also had a rate case going and settled for less than 10 percent ROE.

Q Okay. Now, you were also asked some questions

about the capital structure with the average common equity ratio by Mr. Marzo, and we had some discussion about -- is it Evergy Kansas South that is 83.11 percent. Why did you exclude that one from consideration?

A (Witness LaConte) That's just obviously an outlier. Most utilities have credit -- or common equity ratios within the range of, I would say, 45 at the low and maybe up to 60 percent.

Q And if you look on that list, is there anything even in that ballpark?

A (Witness LaConte) Well, aside from Evergy, no. That's the only one.

MR. JONES: Okay. Madam Chair, I think that's all I've got. And I would ask that the witnesses' exhibits be entered into the record and that the witnesses be excused unless there are further questions. So moved. Witnesses you're excused.

(The documents referred to were admitted into evidence as GAM Exhibits 1 through 17.)

MR. POLLOCK: Thank you for your time. Thank you, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments.

MS. ARIZA: Madam Chair, may I swear in the Georgia Coalition of Local Governments?

MADAM CHAIR PRIDEMORE: You absolutely can, Ms. Ariza.

I would like to remind everybody that we have 22 total panels, and we just completed our 13th.

MS. ARIZA: Thank you. Could you each please raise your right hands.

Whereupon,

C. NICHOLAS DEFFLEY,
DAVID A. NIFONG,

having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. ARIZA:

Q Would you each please state your name for the record along with your employer and your title or role with that employer.

A (Witness Nifong) My name is Dave Nifong. I am the energy and sustainability manager for the City of Decatur.

A (Witness Deffley) Good evening. My name is Nick Deffley. I am the sustainability director at the City of Savannah.

Q Thank you.

And on October 20, 2022, did you file or cause to be filed with this Commission public disclosure direct testimony and exhibits in a question-and-answer format on behalf of the Georgia Coalition of Local Governments that

consisted of 20 pages of testimony and two exhibits labeled DAN-1 and CND-1?

A (Witness Nifong) Yes.

A (Witness Deffley) Yes.

Q And on October 20, 2022, did you also file or cause to be filed with this Commission trade secret testimony?

A (Witness Nifong) Yes.

A (Witness Deffley) Yes.

Q But none of those exhibits contained trade secret information; correct?

A (Witness Nifong) Correct.

A (Witness Deffley) Correct.

Q And on November 3rd, 2022, did you file or cause to be filed with this Commission an errata version of your testimony and exhibits that contained corrections to your testimony?

A (Witness Nifong) Yes, we did.

A (Witness Deffley) Yes.

Q And on November 3rd, 2022, did also file or cause to be filed with this Commission trade secret testimony and exhibits in an errata version?

A (Witness Nifong) Yes.

A (Witness Deffley) Yes.

Q If I were to ask you the same questions today

as were asked in your prefiled testimony, would your answers and exhibits be the same?

A (Witness Nifong) Yes, they would.

A (Witness Deffley) Yes.

MS. ARIZA: Madam Chair, I ask that Mr. Deffley's and Mr. Nifong's errata testimony and exhibits be copied into the record as if given here orally today.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimonies of C. Nicholas Deffley and David A. Nifong follows:)

**STATE OF GEORGIA**
**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re:** | **)** | |
| **Georgia Power Company's 2022** | **)** | **Docket No. 44280** |
| **Rate Case** | **)** | |

# DIRECT TESTIMONY OF C. NICHOLAS DEFFLEY AND DAVID A. NIFONG

## IN SUPPORT OF

## THE GEORGIA COALITION OF LOCAL GOVERNMENTS

**October 20, 2022**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAMES, TITLES AND BUSINESS ADDRESSES.**

A. My name is Nick Deffley, and I am the Director of Sustainability for the City of Savannah. My business address is 801 E. Gwinnett Street, Savannah, Georgia 31401.

A. My name is David Nifong, and I am the Energy and Sustainability Manager for the City of Decatur. My business address is 2635 Talley Street, Decatur, Georgia 30030.

**Q. MR. DEFFLEY, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I have served as the Director of Sustainability for the City of Savannah for over 8 years. I am a graduate of the Hubert H. Humphrey School of Public Affairs at the University of Minnesota where I earned a Master's in Public Policy. I also completed a multi-disciplinary Bachelor's degree in political science, environmental studies and communications from the University of Minnesota. Our office works on a variety of sustainability and resilience topics including alternative transportation, energy efficiency and renewables, climate resilience, environmental assessment and cleanup, and green job training. More recently, in alignment with the City of Savannah's clean energy goals and subsequent implementation plan, we have participated in three GA Power Make Ready projects to support community and fleet transition to EVs, assisted in transition of 93 internal combustion city fleet vehicles to hybrid and 23 to electric, entered into a 1.7 MW Solar Energy Procurement Agreement (SEPA) for city facilities, and are in the process of entering into an Energy Savings Performance Contract (ESPC) for city facilities.[1]

[1] Mr. Deffley's resume appears in Exhibit CND-1

**Q. MR. DEFFLEY, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. No I have not.

**Q. MR. NIFONG, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I have worked with the City of Decatur for three years, becoming the City's first Energy and Sustainability Manager in July 2021. During my time with the City, I led the development of the City's Clean Energy Plan, which established clean energy targets for City operations and the Decatur community. The City has participated in the Georgia Environmental Finance Authority's Solar Resiliency Technical Assistance Program, which partially funded a 105 kW solar array and 125 kW/220 kWh battery energy storage system installation at the City's Public Works Building. I hold a degree in Environmental Science from Emory University.[2]

**Q. MR. NIFONG, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. No I have not.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of the panel's testimony is to provide recommendations to the Commission in the interest of the City governments included in the Coalition and the approximately 1 million GPC ratepayers we represent. These measured recommendations can help increase the impact of Georgia Power's programs and support our communities' transitions to a clean energy future.

[2] Mr. Nifong's resume appears in Exhibit DAN-1

Specifically, our testimony provides recommendations on four topics included in the Company's Rate Case filing. The first is to support the company's expansion of its electric transportation programs and propose changes to the "Make Ready" program to make smaller sites eligible for work. The second is to propose changes to the Community Solar program to increase participation and provide a viable option for those who cannot benefit from rooftop solar due to the ownership, condition, or shading of their home. The third is to ensure that all commercial customers have access to hourly interval data free of charge, as approved in the 2019 rate case. The final recommendation is to reject the Smart Usage tariff, which includes a confusing and punitive demand charge, as the default rate structure for new premises.

**Q. PLEASE SUMMARIZE THE COALITION'S RECOMMENDATIONS REGARDING THE EV MAKE READY PROGRAM.**

A. The Coalition supports the Company's request for $81 million over the next three years for the EV Make Ready Program. This program has been a tremendous benefit to our member governments as we seek to transition our fleets, and it has also supported our efforts to provide public charging for our citizens.

**Q. WHICH OF THE COALITION MEMBER GOVERNMENTS HAVE RECEIVED MAKE READY FUNDING?**

A. The City of Savannah and DeKalb County have received Make Ready Funding. The City of Decatur and City of Atlanta have applied for Make Ready funding at one site and three sites, respectively, but have not yet received funds.

**Q. MR. DEFFLEY, GIVEN SAVANNAH'S EXPERIENCE WITH THE MAKE READY PROGRAM, WOULD YOU RECOMMEND ANY CHANGES?**

A. Yes. The program currently prioritizes locations that seek to install 5 or more chargers at the time the Make Ready work is completed. This makes it hard for

smaller sites to compete for and receive funding, which in turn makes it less likely that those locations will be able to provide charging.

This has implications for equitable access to electric vehicles. As an example, the City of Savannah is applying for a grant to establish EV carshares at community centers in USDA defined food deserts. Because there will only be one car per community center, and because many of the community centers have limited parking, this project is not a good candidate for the Make Ready program as it is currently operated. However, this project should be supported because it will provide critical transportation support to communities in need and increase community comfort with EVs. Both academic[3] and market research[4,5] studies have demonstrated that customers who ride in an EV are more likely to purchase one than those who have not.

**Q. IS THE REQUESTED AMOUNT OF FUNDING APPROPRIATE GIVEN CURRENT RATES ADOPTION OF ELECTRIC VEHICLES?**

A. Yes. The requested amount is appropriate given 1) the over-subscription of the program for the 2019 rate case cycle 2) the influx of federal dollars for charging through the NEVI program, Clean School Bus Program, and other programs, which will likely bring additional competitive pressure to the Make Ready program 3) the positive financial impact that this program is having on non-participating customers, which will only grow as charger utilization increases and 4) increasing requirements from vehicle manufacturers for dealerships to install charging infrastructure in order to continue selling electric vehicles.

[3] Roberson, L. A. and Helveston, J. P. (2020, Sept. 7). "Electric Vehicle Adoption: Can Short Experiences Lead To Big Change?" *Environmental Research Letters.* Vol. 15. No. 9. https://iopscience.iop.org/article/10.1088/1748-9326/aba715/meta

[4] https://www.consumerreports.org/hybrids-evs/interest-in-electric-vehicles-and-low-carbon-fuels-survey-a8457332578/

[5] https://www.forbes.com/wheels/news/j-d-power-electric-vehicle-consideration-study/

**Q. HOW DOES THE INFLUX OF FEDERAL FUNDING FOR EV CHARGING AFFECT THE MAKE READY PROGRAM?**

A. Several federal agencies are in the process of implementing provisions from the Bipartisan Infrastructure Law that create funding streams for electric charging in Georgia. Examples include 1) DOT's National Electric Vehicle Infrastructure "NEVI" program, which is providing $135 million in formula funding to Georgia over the next five years for fast charging stations along major highways; 2) DOT's Charging and Fueling Infrastructure program, a $2.5 billion competitive funding opportunity for rural and disadvantaged communities that might be missed by the NEVI program; 3) EPA's Clean School Bus program, which provides funds for electric school bus acquisition; and 4) the Congestion Mitigation Air Quality Program, which provides funds for public transit buses and other medium and heavy duty vehicles. Each of these funding streams is expressly intended to be leveraged with other funding streams, including utility funds.

Together, these programs will require a tremendous amount of Make Ready work. For example, the NEVI program for highway fast charging mandates that each charging station have at least four charging ports that can each deliver up to 150 kW simultaneously, or 600 kW total. That is a tremendous amount of power demand that few sites are prepared to meet in their current state. These Make Ready costs will only grow if infrastructure is "future proofed," or sized in anticipation of the EVs of the future. As an example, while the NEVI program requires chargers to provide 150 kW of power, vehicles and chargers are already being mass marketed for charging at 300 kW, which can provide 62 miles of range in as little as four minutes.[6]

To summarize, the anticipated pace and scale of charging buildout, as well as the need to make prudent, future-proofed investments, necessitates the significant increase in funding for the Make Ready program that the Company requested.

[6] https://www.kbb.com/car-advice/fastest-charging-electric-cars/

**Q. ARE THERE ANY OTHER FACTORS THAT THE COMMISSION AND THE COMPANY SHOULD CONSIDER IN LIGHT OF THE PREVIOUSLY DISCUSSED FEDERAL FUNDING OPPORTUNITIES?**

A. Yes. As discussed previously, federal funding will enable charging deployments at a rate and scale that we have never seen. As this occurs, Georgia Power will likely be required to make investments in its transmission and distribution systems to accommodate the additional load. These "major grid upgrades,"[7] as the Federal Highway Administration calls them, are explicitly not eligible for NEVI funding. The same is true for the Clean School Bus Program, which requires that funds be spent entirely behind the meter. In other words, unless paid for with state matching funds, these investments will need to be made by Georgia Power and approved by the Commission. If a different approach is taken, and the Commission decides that grant recipients like school systems and transit systems should pay for all or part of the needed grid upgrades, some grant recipients may be forced to decline their awards.

As with the Make Ready funding, it is the Coalition's recommendation that these investments not only be made by Georgia Power, but also be "future proofed." That is, the system should be built out to not only serve four 150 kW fast chargers per 50 miles or the maximum 25 school buses that can be received through the Clean School Bus Program, but to serve the expected number and capacity of chargers that will be needed in 2030 or 2035.

In some ways, the NEVI requirements are already somewhat obsolete. According to Bloomberg New Energy Finance ("BNEF"), national EV sales are expected to

[7] These "major grid upgrades include but are not limited to "bulk power transmission," "substations," and "longer line extensions or upgrades."

hit 52% by 2030, due to the incentives in the Inflation Reduction Act.[8] If sales reach or exceed that projection, four chargers per 50 miles won't even begin to meet the demand for fast charging.

The Commission should also consider another form of "future proofing," preparing for and supporting vehicles and chargers with vehicle to grid ("V2G") capability. While not strictly necessary for charging, V2G capability could provide significant benefits to the utility system and non-participating ratepayers. School buses are particularly well suited to serve as distributed energy storage resources because they are largely idle in the hot summer months when the grid is most stressed. A good model is Dominion Energy's V2G program in Virginia, which currently has 50 buses enrolled. This program is designed to scale to 1000 buses to ultimately provide 105 MWh of storage, or enough to power 10,000 homes.[9]

**Q. PLEASE SUMMARIZE THE COALITION'S RECOMMENDATIONS REGARDING THE COMMUNITY SOLAR PROGRAM.**

A. The Coalition recommends that the Commission reject Georgia Power's request to raise the price of a 1 kW subscription block from $24.99 to $27.99. The Coalition further recommends that the Commission direct Georgia Power to file a new subscription price that is based on the cost of the program, rather than avoidance of lost revenues. There are four key reasons to support this change.

1) **Participation has been underwhelming, at best, and will continue to be underwhelming until the program provides some potential upside to customers**. As of February of 2022, only 1954 out of 8000 blocks had been subscribed, a decrease from a high of 2013 subscribers in December of 2021.[10] The

[8] https://www.bloomberg.com/news/articles/2022-09-20/more-than-half-of-us-car-sales-will-be-electric-by-2030#:~:text=Prior%20to%20passage%20of%20the,was%20revised%20upwards%20to%2052%25.

[9] https://news.dominionenergy.com/2020-01-16-Dominion-Energy-Moves-Forward-with-Electric-School-Bus-Program

[10] Docket 44160. Company Response to STF-DEA-2-20.

Company's proposed solutions—opening up the program to General Service Customers and seeking subsidies from corporations and non-profits for income-qualified customers—do little to address the core issue of poor value proposition and as such make it unlikely that the program will be fully subscribed, much less grow the program as proposed in the Company's 2022 IRP filing.

2) **Community solar provides benefits to all ratepayers.** Until the 2022 IRP, all solar resources had to demonstrate that they would produce energy at a rate below the Company's long-term avoided cost to be approved. In other words, those resources had to put downward pressure on rates for all customers, or they would not be built. This means that the solar resources that are used for the community solar program were deemed to provide benefits to all customers. [redacted]

3) **As the primary alternative to rooftop solar, community solar should have at least as much upside as rooftop solar**, if not more, because it can take advantage of economies of scale and because it can be strategically located by the utility to meet specific system needs. However, while rooftop solar customers pay an average cost per kWh that is significantly less than the average cost of grid energy[11], community solar participants have paid an average per kWh premium of [redacted]% over grid energy under the R tariff[12] over the past 12 months. Notably, this premium is higher for subscribers who use less energy than those who use more,

[11] Solar.com (an online marketplace for solar quotes) puts the average cost per kWh at 6-8 cents before O&M and any financing costs. Adjusting for estimated O&M expenses from NREL of $29/kW-yr adds .33 cents/kWh.

[12] Author's calculation using the Company's response to STF-TAI-3-12 (TS) to calculate the average cost per kWh for the community solar program and the Company's response to STF-PIA-6-41 to calculate the average cost per kWh on the R tariff (median bill – customer charge)/(median usage)

because higher users can offset higher cost kilowatt hours under the Company's inclining block rates.[13]

4) **The lost revenues approach to pricing defeats the purpose of participating.** By enrolling in a community solar program, a customer is effectively contracting for a dedicated renewable energy supply for a portion of his or her consumption. In doing so, and assuming all the accompanying risks, the customer is also effectively opting out of the generic mix of energy for the covered consumption. As such, it is unreasonable to charge the participant for fuel, environmental compliance, or nuclear cost recovery, since those relate to generation resources that the solar is meant to replace.

Further, because the community solar subscription fee is based upon an *expected* amount of production, there is a very real risk that customers could pay for fuel, environmental compliance, and the like twice if production is less than projected.

**Q. WHY IS THE COMMUNITY SOLAR PROGRAM IMPORTANT TO THE COALITION?**

A. As local governments who have adopted aggressive clean energy goals, we are very concerned about our citizens' access to robust, financially feasible clean energy programs. While rooftop solar receives a lot of attention, rooftop solar is difficult or impossible for certain groups, including occupants of multi-family housing, renters, and households who live in shaded or structurally deficient homes.

We are also interested in community solar as a potential means of reducing energy burden. In other parts of the country, community solar is one of the primary means of making solar more accessible for low-income families. However, that has not been the case with Georgia Power's program, which GPC openly describes as a premium program. The Company seeks to address this criticism through a program

[13] Company's response to STF-TAI-1-36, Attachment C (TS).

that subsidizes a majority of the cost for low-income customers through corporate sponsorship and external philanthropic donations. However, this does not address the core issue of poor value proposition. Asking companies to pay $127/REC[14] as a form of corporate good citizenship is simply diverting much-needed funding away from causes that provide more assistance to low-income customers or more impact to the climate.

**Q. WHAT SPECIFIC RECOMMENDATIONS DOES THE COALITION HAVE FOR THE PRICING AND STRUCTURE OF THE PROGRAM?**

A. The Coalition is open to several options, so long as customer costs are more proportionate to the program and resource costs. One option is to maintain the existing structure where customers pay a fixed price per kW block and receive credits through virtual net metering, but reduce the fixed price to exclude "lost revenues" related to fuel, environmental compliance cost recovery (ECCR), and nuclear construction cost recovery (NCCR).

To understand what this option would look like in practice, it is helpful to first understand how the Company calculates a customer's bill. First, the customer is billed for his or her energy use on either an inclining block rate (in the summer) or a declining block rate (in the winter). An inclining block scale means that customers pay more per kWh as they use more energy, and a declining block rate means that they pay less as they use more. Across both seasons, Georgia Power uses blocks that go from 0-650 kWh, 651 kWh – 1000 kWh, and 1000+ kWh. The usage within each block is multiplied times the rate for that block, and the results are summed to calculate a customer's "base bill."

Once the base bill is calculated, a percentage adjustment is applied to the base bill for Environmental Cost Recovery (ECCR), Nuclear Construction Cost Recovery (NCCR), and DSM. Then, the customer is charged for fuel at a cents/kWh rate.

[14] 75% * $27.99/kW * 1 kW/165 kWh * 1000 kWh/REC = $127.23/REC

Finally, the sum of the adjusted base bill and the fuel bill is subjected to a percentage adjustment for the municipal franchise fee and sales taxes, if applicable.

To justify its proposed price of $27.99 per 1 kW block of community solar, Georgia Power calculated[15] the delta between the annual bill of a typical customer without a 1 kW community solar subscription and the typical bill of a customer with a 1 kW subscription for every year between 2023 and 2025, inclusive. This delta averaged [redacted]. Excluding the municipal franchise fee, this delta falls to an average of [redacted] per month. The Company then calculates the delta for fuel, which averages to [redacted] per month. Adjusting the remaining [redacted] to exclude ECCR and NCCR, costs that are driven by fuels unrelated to solar, results in a delta of [redacted]. Thus, the Commission should consider adopting a per kW subscription price of [redacted].[16]

Another option would be to maintain the existing structure, but "lock in" a customer's subscription price at the current rate of $24.99/kW for the duration of his or her participation. While this would not provide immediate financial benefits like the first option, it would provide a valuable hedge against future rate increases, particularly those tied to fuel, nuclear, and environmental compliance costs.

**Q. OTHER THAN FINANCIAL BARRIERS, ARE THERE ANY OTHER BARRIERS TO PARTICIPATION IN THE COMMUNITY SOLAR PROGRAM?**

A. Yes. The current Community Solar tariff specifies that the program is only available to customers on the R tariff. If that tariff is being closed to new premises, customers in new premises will be left out. While these homes should be more

[15] Company's response to STF-TAI-1-36, Attachment C (TS).
[16] Author's calculations using Company's response to STF-TAI-1-36, Attachments A-C (TS).

structurally sufficient, they could have the same ownership issues that many existing premises have.

Possible solutions include 1) developing a customer-specific allocator for time of use (TOU) customers to allocate their virtual net metering credits between the peak and off-peak periods or 2) expanding eligibility for the Community Solar tariff to Pre-Pay customers.

**Q. PLEASE SUMMARIZE THE COALITION'S RECOMMENDATIONS REGARDING HOURLY USAGE DATA.**

A. Georgia Power is seeking $786,000 in cost recovery for expenses incurred in providing hourly usage data to all residential and commercial customers, as required in the 2019 rate case. While no Georgia Power witness seemed to be fully prepared to speak on this issue, Witness Legg suggested that this information is currently available to all residential customers and certain commercial customers through the My Power Usage platform.

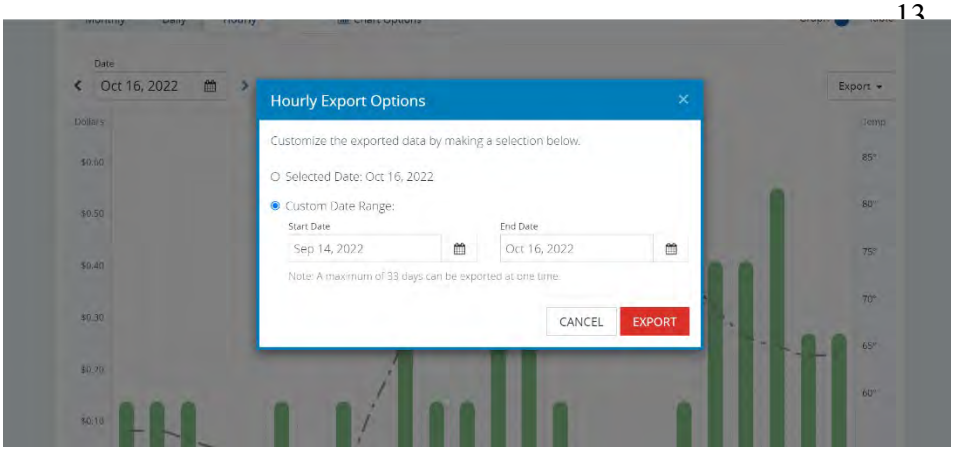
Over the past couple of years, our governments have sought this information for a variety of reasons, including rate selection, energy load forecasting, informing more energy efficient behaviors, solar sizing, and Energy Savings Performance Contracting (ESPC) projects. When we have inquired about getting this information, the answers have been convoluted and inconsistent. Sometimes, we have been told that the data simply isn't collected, either because the meter has not been programmed to do so or is not capable of doing so. Other times, we have been told that the data is collected, but is only stored for a certain period of time, generally a few months. Still other times, we have been told that it is collected and stored indefinitely, but that we have to pay for a premium subscription of Energy Direct to access it.

Our best assessment of the situation is that some meters are not automatically configured to collect interval data, while others are. Savannah, for example, has been told that no interval data exists for certain meters receiving service under PLS-C and PLM-C tariffs. Follow up conversations with Company representatives have suggested that this is due to a decision by the Company to install the cheapest meter that can capture the necessary readings for the rate.

Given this assessment, the Coalition has four recommendations:

1) GPC should ensure that all commercial customers, regardless of their rate schedule, have free access to hourly usage data through My Power Usage or Energy Direct. If this requires the replacement or reprogramming of existing meters, this should be done promptly at the Company's cost, and all future meters should have the capability and programming that is required to collect this data.

2) Customers should have the ability to export a full year of hourly usage data as a .csv file for analysis. This is a shortfall of the My Power Usage platform, which currently limits exports to 33 days of data at a time, as shown in the screen capture below.



3) GPC should provide clear messaging to account managers and other key contacts in the organization to ensure that questions about data access are answered consistently and correctly.

4) GPC should make it simple to share hourly usage information with third parties as needed.

**Q. PLEASE SUMMARIZE THE COALITION'S RECOMMENDATIONS REGARDING THE DEFAULT RESIDENTIAL TARIFF.**

A. The Company is proposing to close the R tariff to new residential customers and to place those customers on a deceptively named "Smart Usage" tariff instead. This tariff is described as a three-part rate, which includes a fixed customer charge, a time-varying energy rate, and a demand charge. The Company spins this as providing customers three ways to save, when the reality is that even the most sophisticated customers struggle to comprehend demand.

A large body of academic research has demonstrated that customers struggle to understand which appliances use the most energy and which use the least.[17] This

[17] Lesic et al. (2018). "Consumers Perceptions of Energy Use and Energy Savings: A Literature Review." *Environmental Research Letters.* Vol. 13. https://iopscience.iop.org/article/10.1088/1748-9326/aaab92/pdf

pattern holds true for both representative samples of customers[18] and more motivated or sophisticated samples of customers.[19]

The Coalition recommends that the Commission reject the Smart Usage tariff as the default tariff and either maintain the R tariff as the default or replace it with a rate that is more understandable to customers and more aligned with system needs, like an energy-only time of use rate.

**Q. DOES THE COALITION BELIEVE THAT RATES LIKE THE SMART USAGE RATE WILL BE A POSITIVE FOR THE CLIMATE AND DECARBONIZATION?**

A. No. Each of the five governments in the Coalition has a community-wide clean energy goal that will depend on electrification of many end-uses, including space heating, water heating, cooking, and transportation. Residential demand charges encourage the opposite—the continued use of natural gas.

**Q. DOES THE COALITION HAVE ANY OTHER CONCERNS WITH THE DECISION TO MAKE THE SMART USAGE RATE THE DEFAULT RESIDENTIAL RATE?**

A. Yes. The Coalition is concerned that the Smart Usage rate will result in customers paying a higher cost per unit of electricity than customers on any other rate.

**Q. WHY DOES THE COALITION HAVE THIS CONCERN?**

A. In its response to the data request STF-PIA-6-41, the Company provided median bills and median usage for each of the six residential tariffs. This information can

[18] Attari et al. (2010). "Public Perceptions of Energy Consumption and Savings." *Proceedings of the National Academy of Sciences.* Vol. 107, No. 37. https://www.pnas.org/doi/pdf/10.1073/pnas.1001509107
[19] Lesic et al. (2019). "Comparing Consumer Perceptions Of Appliances' Electricity Use to Appliances' Actual Direct-Metered Consumption." *Environmental Research Communications.* Vol. 1. https://iopscience.iop.org/article/10.1088/2515-7620/ab4a99/pdf

be used to calculate the average price per kWh for each residential tariff. The results of this analysis are shown below.

| | Median kWh Used | Median Bill | Average Price Per kWh |
|---|---|---|---|
| **TOU-RD** | 629 | $101.59 | $0.161 |
| **Pay-by-Day** | 1,103 | $169.07 | $0.153 |
| **FlatBill** | 987 | $140.00 | $0.142 |
| **Pre-Pay** | 946 | $123.24 | $0.130 |
| **Residential** | 785 | $98.03 | $0.125 |
| **TOU-REO** | 870 | $103.84 | $0.119 |
| **TOU-PEV** | 1,325 | $147.19 | $0.111 |

As you can see in the table above, customers on the TOU-RD, or "Smart Usage" rate, pay the highest average cost per kWh of any residential rate, even though they have the lowest median amount of energy usage.

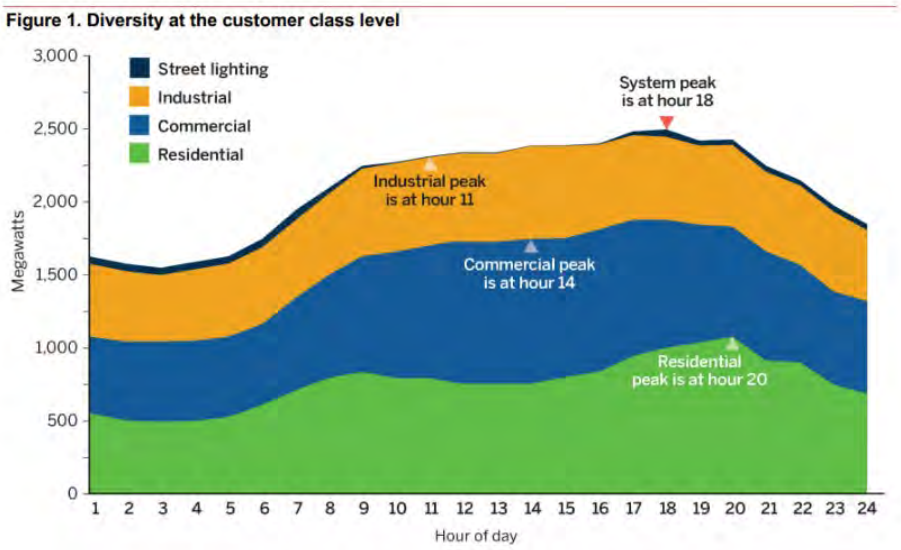
It is also worth noting that the Company intends to close two of the three lowest cost tariffs on a per unit basis—the R tariff and the TOU-REO tariff—and insists on maintaining a confusing name for the other, the TOU-PEV rate, which is available to customers regardless of their ownership of an electric vehicle.

**Q. IS THE SMART USAGE RATE ACTUALLY BETTER AT ASSIGNING COSTS AND SENDING PRICE SIGNALS THAN ENERGY ONLY RATES?**

A. No. Consider the scenario that Witness Legg developed:

"To the extent that you would have two customers who use the exact amount of energy – same amount of energy – but one of them peaks, their peak demand for the month is 5 kW and the other one is 10 kW. The one that's 10 kW is causing more cost because we have to build more infrastructure because they're causing a higher peak demand. But on the R rate, if they use the same energy and have different demands they pay the exact same amount. That's a bad price signal."

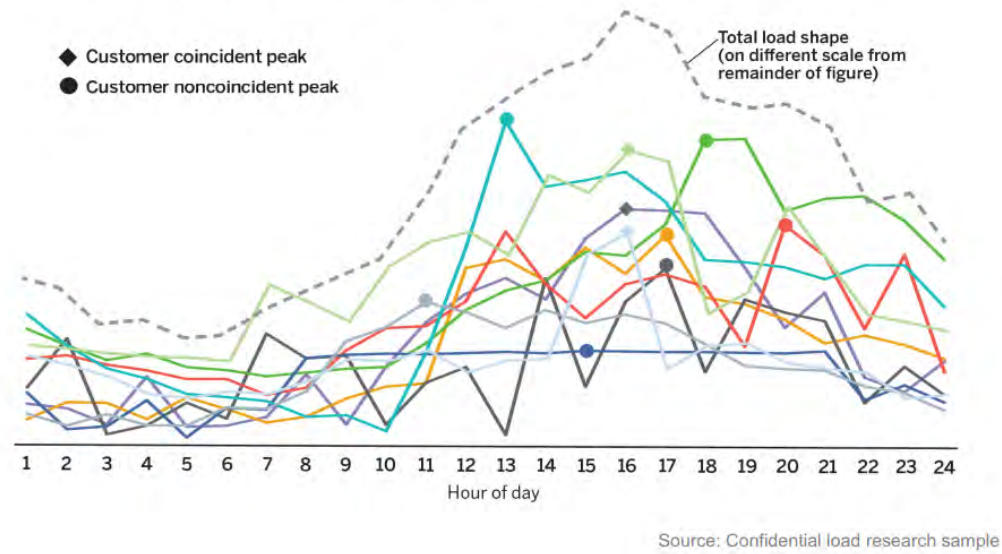
There are a couple problems with this example. First, it assumes that individual customer demands generally coincide with the system peak, which isn't necessarily the case. As shown in the illustrative figure[20] below, entire class demands can vary from the system peak.




[20] Lebel, M. & Weston, F. (2020, Nov.) "Demand Charges: What Are They Good For? An Examination of Cost Causation." *Regulatory Assistance Project.* Pg. 14. https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf

Further, within a given class, individual customer demands can vary from the aggregated demand that drives investment in infrastructure. Consider, for example, the figure[21] below, which uses actual data from 10 residential customers on a single transformer.

**Figure 3. Summer peak day load from 10 residential customers on one line transformer**




Source: Confidential load research sample

As shown above, only three of the ten customers have an individual peak demand that is coincident with the peak demand on the transformer. The surrounding report goes on to reveal that the coincident peak is only 86% of the individual customer peaks. In other words, assessing demand charges on the individual peak demand of each customer would over-recover the aggregated demand-driven cost.

**Q. WILL THE SMART USAGE RATE AFFECT ALL CUSTOMERS EQUALLY?**

A. No. Customers with better access to technologies like smart thermostats, time delay appliances, and water heater controls will be much better prepared to control their costs on the Smart Usage rate than those who don't have those technologies.

[21] *Ibid.* Pg. 18

Further, customers with flexible schedules will be better able to stagger loads than somebody who works multiple jobs, for example.

**Q. DOES THE COALITION HAVE ANY OTHER RECOMMENDATIONS RELATED TO RATE DESIGN?**

A. Yes. The Coalition further recommends that the remaining energy-only time of use rate— the Time of Use Plug-In Electric Vehicle (TOU-PEV) rate—be renamed to avoid confusion that it is only available to EV owners.

**Q. DOES THE COALITION HAVE ANY FINAL THOUGHTS?**

A. Yes. Our Coalition is deeply concerned about energy affordability and the effects that energy prices can have on community health and economic development. The cumulative impact of this base rate case, the upcoming fuel docket, and the hopeful completion of Vogtle Units 3 and 4 could add an additional $55-60[22] to the average residential bill. Because of this, we encourage the Commission to examine this request with a heightened level of scrutiny. Some particular questions that we believe ought to be asked include:

1. Should the 2022 IRP modeling be re-run to account for the tax benefits and other funding opportunities in the Inflation Reduction Act?

2. Are the expected reliability improvements from proposed T&D investments significant enough to warrant the high cost?

3. Does Georgia Power truly need the requested ROE to maintain its credit rating?

[22] Staff Attorney Preston Thomas Cross Examination of C. Womack, Docket 44280.

4. What can the Company to do to promote deeper awareness of and easier access to programs like the Income Qualified Senior Citizen Discount and the HEEAP Program?

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes it does.

**Exhibit DAN-1**

**David A. Nifong**
2635 Talley Street
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David.nifong@decaturga.com (404-377-5571)

## Education

***Emory University* –** Atlanta, Georgia

- Bachelor of Arts in Environmental Science with minor in Community Building and Social Change
- Emory Scholar, Emory 100 Senior Honorary

## Experience

***City of Decatur, Department of Public Works* –** Decatur, GA

- Energy and Sustainability Manager (July 2021 – Present)
- Lead for America Fellow (August 2019 – July 2021)
    - Directs the City of Decatur's clean energy, climate resilience, resource recovery and sustainability efforts, including policy research and design
    - Lead the development of Decatur's Clean Energy Plan
    - Coordinates the City's clean energy projects from scoping to installation
    - Serves as staff liaison to resident Environmental Sustainability Board
    - Secured approximately $1 million in federal funding and technical assistance

***Cross Keys Sustainable Neighborhood Initiative* –** DeKalb Co., GA

- Community Building and Social Change Fellow (March – December 2018)
    - Worked with supervisors and a team of peers to conduct affordable housing research along the Buford Highway corridor
    - Completed affordable housing report and presented key findings to community stakeholders. Findings were then used in organization's affordable housing plans
    - Created a Housing Toolkit based upon report findings and best practices research to guide CKSNI's policy planning and development

***The Nature Conservancy* –** Atlanta, GA

- Conservation Policy Intern (Summer 2017)
    - Conducted conservation policy research for projects at the local, state, and federal level
    - Prepared detailed reports and summaries of information for the use of supervisors, such as an examination of the framework for stewardship contracting between non-governmental organizations and the United States Fish and Wildlife Service

**Leadership and Professional Development**

**Climate Reality Leadership Training –** Atlanta, GA (March 2019)

**City of Atlanta Office of Resilience Sustainability Ambassador –** Atlanta, GA (2018)

**Presentations**

Nifong, David (2019). "Community Engagement in Resilience and Equity Planning". Presentation at the Atlanta Studies Symposium, Atlanta, GA.

**Exhibit CND - 1**

**C. Nicholas Deffley**

Savannah, GA Email: Ndeffley@savannahga.gov

EXPERIENCE: **Director** (July 2014 - present) City of Savannah, Sustainability Department Savannah, GA

- Manage staff, programs, and projects leading sustainability and resilience efforts for internal operations, infrastructures, and the broader community
- Secure over $11M in grants, leveraged funds and project sponsorship for various sustainability and resilience initiatives
- Present on various sustainability topics as panelist, presenter and keynote at state, regional and national conferences
- Direct or manage City of Savannah initiatives including:
    - Clean energy implementation plan
    - Tide to Town bicycle/pedestrian transportation network
    - Smart Sea Level Sensor project
    - Brownfield assessment, cleanup and redevelopment
    - Urban tree nursery
    - Community engagement events
- **Program Manager** (August 2013 – July 2014) Step Up Savannah - Chatham Apprentice Program Savannah, GA

- Designed and implemented a new, intensive workforce training program called "E3" (Educate. Empower. Employ.) with wrap-around services for unemployed and underemployed individuals
- Achieved an 80% retention rate of program participants
- Achieved over 65% job placement rate for program participants with jobs averaging at least 20% over minimum wage
- Actively participated in securing over $50,000 of grant funding to improve program impact
- Increased in-kind program contributions through focused community outreach and partnership with area organizations
- Increased the number of class locations within Chatham County, offering more access and flexibility for potential participants
- Standardized and formalized program processes to improve efficiency and better utilize limited staff resources

- **Project Manager & Consultant** (August 2012 - September 2013) Emergent Structures Savannah, GA
  - Provided project management for the design and construction of a 600 SF community greenhouse
  - Provided community outreach through presentations to various community groups, increasing project awareness and raising financial support
  - Guided board of directors through organizational development process to formalize their mission, vision and organizational goals

- Participated in short and long-term strategic planning efforts for organization and set goals accordingly

- Program Manager: Sustainability, Targeted Business & Contract Administration (January 2004 - April 2012) University of Minnesota, Department of Capital Planning & Project Management Minneapolis, MN

- Supervised staff and managed project teams for the following programs:

  - Sustainability Program

    - Developed and implemented the University's first sustainable building program focused on increasing sustainable design features and construction practices in all building projects system-wide

    - Wrote the University's first Construction Standards dedicated to sustainable building practices, which included the topics of adaptable reuse, site planning, water efficiency, energy efficiency, indoor air quality, materials, waste and education/outreach

    - Assisted in the development of an enterprise level greenhouse gas inventory and reduction initiative, including the development of departmental reduction goals and corresponding action plan to achieve those goals

    - Created a system of sustainability measurement, tracking and reporting in order to target areas of improvement

    - Collaborated with the procurement department to create green purchasing guidelines for internal use and as criteria in vendor selection process

- Evaluated the appropriateness and feasibility of various sustainable building practices by using return-on investment, cost-benefit and life-cycle analysis tools

- Provided regular updates and presentations on sustainability progress to leadership groups and administration • Assisted University in achieving Leadership in Energy and Environmental Design (LEED) certification on multiple building projects totaling over 1.5M SF.

- Conducted an education and outreach campaign that included the development of a sustainability website and regular presentations to students, staff and the public

- Developed sustainability curriculum for various academic programs • Supervised students through semester-long projects on a range of real-world sustainability challenges, using the University as a 'living laboratory'

- Represented the University on multiple sustainability strategy committees system-wide, at the state level and regionally that focused on increasing sustainability across all aspects of operations and daily life

o Targeted Business Program

- Planned, organized and led outreach and education efforts for the women and minority-owned design and construction community state-wide, aimed at providing them with the tools necessary to successfully compete on University building projects

- Achieved a 40% increase in the number of women and minority-owned design firms pre-qualified to work on University building

projects through a series of intensive outreach and awareness efforts

- Contract Administration Program
  - Wrote, processed, administered, and managed over 1200 project-specific agreements annually for design, engineering and construction services
  - Reduced overall contract processing time by 60% through streamlining of existing business processes and increased use of pre-signed service contracts
  - Organized and implemented contract training and outreach for both internal staff and external partners
  - Partnered with legal and procurement departments to develop and implement prequalification process for designers, engineers and contractors

EDUCATION:

- Master's of Public Policy – Environmental Policy and Organizational Effectiveness 2010 University of Minnesota, Humphrey School of Public Affairs
- B.A. – Political Science, Communications & Environmental Studies 2005 University of Minnesota, College of Liberal Arts

CERTIFICATIONS & MEMBERSHIPS:

- LEED Accredited Professional, US Green Building Council 2008

- Lean/Kaizen Continuous Improvement Team Leader, Rucker Associates 2009 Member
- USGBC-GA Savannah Branch

**CERTIFICATE OF SERVICE**

## City of Decatur, Georgia

Personally, appeared before the undersigned authorized officer in the state and county aforesaid, C. Nicholas Deffley and David A. Nifong, who after being duly sworn, deposes and says that they expert witnesses for the Georgia Coalition of Local Governments and that the facts contained in the foregoing Testimony of C. Nicholas Deffley and David A. Nifong, for Docket 44280 are true and correct to the best of their information and knowledge.

This 18th day of October, 2022

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David A. Nifong
Georgia Coalition of Local Governments

**CERTIFICATE OF SERVICE**

## City of Savannah, Georgia

Personally, appeared before the undersigned authorized officer in the state and county aforesaid, C. Nicholas Deffley and David A. Nifong, who after being duly sworn, deposes and says that they expert witnesses for the Georgia Coalition of Local Governments and that the facts contained in the foregoing Testimony of C. Nicholas Deffley and David A. Nifong, for Docket 44280 are true and correct to the best of their information and knowledge.

This 18th day of October, 2022

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C. Nicholas Deffley
Georgia Coalition of Local Governments

## CERTIFICATE OF SERVICE

I hereby certify that I have this 20th day of October, 2022 served the following parties with the foregoing 2022 Rate Case Testimony of David Nifong and Nicholas Deffley for the Georgia Coalition of Local Governments by electronic mail.

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MS. ARIZA: And that their prefiled errata testimony and exhibits be marked as COG2, COG3, COG4, and their trade secret version as COG5.

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were marked for identification as Georgia Coalition of Local Government Exhibits COG-2, COG-3, COG-4 and COG-5.)

MS. ARIZA: Thank you.

BY MS. ARIZA:

Q Could you please briefly summarize your testimony for the Commission?

A Yes.

MR. NIFONG: So good evening, Madam Chair, and Commissioners. The purpose of our testimony is to provide recommendations to the Commission in the interest of the City governments included in the Coalition and the approximately 1 million Georgia Power Company ratepayers we represent.

Our five-member Coalition of Local Governments, consisting of Atlanta, Decatur, Savannah, Athens-Clarke County, and DeKalb County, is united in our commitment to achieving 100 percent renewable energy, for most of us as soon as 2035. The decisions made in this proceeding will directly impact the ability of staff and our elected officials

to deliver on the goals supported by their constituents. Specifically, our testimony provides recommendations on four topics included in the Company's Rate Case filing.

The first is to support the company's expansion of its electric transportation programs and propose changes to the Make Ready Program to make smaller sites eligible for work. The Coalition supports the Company's request for $81 million over the next three years for the program and the expansion of critical charging infrastructure across our state.

This support from the Company is especially essential given the additional influx of federal dollars into electric vehicles in the state, which will primarily focus on the procurement of chargers, electric and alternative fuel school buses, and electric transit buses.

It will be necessary for the Company to provide the necessary grid investments to maximize the positive impacts of these programs and support the growth of the market for the electric vehicles that are or will be on the road in the short- and medium-term, including the increasing number of EVs that will be produced in Georgia.

The second is to propose changes to the

**Community Solar program to increase participation and to provide a viable option for those who cannot benefit from rooftop solar due to the ownership, condition, or shading of their home. The Coalition recommends that the Commission reject the Company's requested increase of the subscription price to $27.99 and order the Company to file a new price that is based on the cost of the program rather than lost revenues.**

**This pricing approach, we argue, would support increased participation in the program, accurately reflect the cost and the benefits of the customer's choice to subscribe, and provide participants the same opportunity to reduce their bills through renewable energy procurement that is afforded to rooftop solar owners.**

**The third is to ensure that all commercial customers have access to hourly interval data free of charge, consistent with the Commissions' order in the 2019 rate case. This data is vital for commercial customers looking to pursue energy efficiency and rooftop solar projects and is also essential for rate selection.**

**We specifically encourage the Commission to order the Company to replace or reprogram existing**

meters as necessary to support access to this data and to make sure customers can easily export their data in bulk as a .csv file.

The final recommendation is to reject the Company's request to maintain the Smart Usage tariff, which includes a confusing and punitive demand charge, as the default rate structure for new premises. Company data shows that customers on the tariff, especially low users, consistently pay higher rates for service than other residential customers despite having similar impacts on peak demand. By placing all new residential customers on the Smart Usage tariff, the Company will discourage electrification of end-uses, such as appliances, and place additional burdens on customers that cannot stagger loads or do not have the data to make informed decisions regarding their consumption patterns. Thank you.

MADAM CHAIR PRIDEMORE: Do you have another summary?

MS. BROWN: No, Madam Chair. At this time, the panel is available for questions from you and cross.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Brown.

Questions from Commissioners.

Commissioner Echols.

**VICE CHAIRMAN ECHOLS: Just a couple quick questions.**

**Regarding the smart usage rate, do you know of any signal that a utility could send to a Smart Usage customer that would make the rate beneficial or even tolerable?**

**MR. NIFONG: Well, I think that staff provided testimony to this point that, generally, the time-of-use rate does provide a price signal to customers to alter their consumption patterns.**

**But, also, if the Commission decides to maintain the Smart Usage tariff in some form, altering the demand charge to be reflective of kind of their peak on the system peak, I think could also send a better price signal rather than one-hour period over the entire month regardless of the time that it occurred.**

**VICE CHAIRMAN ECHOLS: All right. Last question: Do you know any GMA or let's just say MEAG cities that have an issue with Georgia Power's Make Ready or their Community Charging programs?**

**MR. DEFFLEY: That's not something --**

**MR. NIFONG: No, not our knowledge.**

**VICE CHAIRMAN ECHOLS: Okay. Thank you.**

**MADAM CHAIR PRIDEMORE: I need for the middle**

witness, please, if you would pull back from your mic. Don't speak so closely to it. We're having a YouTube issue right now with audio. And straighten your necks.

I'm going to have that put on a button, and I'm just going to wear it every hearing. Straighten your necks. Okay. All right. If it's still an issue, they'll come back to me. Thank you.

Any other questions from Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: All right. Georgia Public Service Commission?

MR. WALSH: No questions.

MADAM CHAIR PRIDEMORE: Okay. Anybody have questions for these witnesses? Any other intervenors?

Sierra Club? Ms. Ariza?

MS. ARIZA: Thank you.

MADAM CHAIR PRIDEMORE: Do me a favor -- that was you -- yeah, straighten your neck and just keep, like, a distance.

CROSS-EXAMINATION

BY MS. ARIZA:

Q For the record, Isabella Ariza on behalf of the Sierra Club. Gentleman, just a few questions for you.

On the bottom of page 4, lines 18 through 20, you say that you've received Make Ready funds for some of your cities; is that right?

A (Witness Deffley) That is correct.

Q And on page 4, you also state that the Make Ready Program has been a tremendous benefit to your member governments as you seek to transition your fleets; correct?

A (Witness Deffley) Correct.

Q So your government's fleets are benefiting from the Make Ready infrastructure that Georgia Power built; is that right?

A (Witness Deffley) Yes, we have actually had two different installations to the Make Ready Program in Savannah.

Q Okay. And are the current vehicles that are being served by that Make Ready infrastructure the only electric vehicles you expect to have in your fleet?

A (Witness Deffley) No, absolutely not. I mean, this is falling into our plan to really grow that fleet conversion but also use those same chargers for public use as well.

Q Thank you.

Would you support a utility program that would allow you to add more electric vehicles to your fleet?

A (Witness Deffley) Yes.

**Q And would you support having Georgia Power provide technical support for potential vehicle green charging for these buses?**

**A (Witness Deffley) Absolutely. Especially when you consider some of our school districts and our Chatham Area Transit buses that are now moving into electric. I think that's good candidate.**

**Q Speaking of schools, are you aware that several school districts in Georgia received Clean School Bus Program funds to purchase electric school buses?**

**A (Witness Deffley) Yes.**

**Q Are you aware that the Clean School Bus Program provides very limited funding for charging infrastructure?**

**A (Witness Deffley) Yes.**

**Q Is it your understanding that school districts may participate in and benefit from Georgia Power's Make Ready Program?**

**A (Witness Deffley) Yeah, absolutely. They're always trying to shift funds back to their core mission of education.**

**Q In your experience, do school districts feel the financial squeeze when gasoline prices go up?**

**A (Witness Deffley) You know, the school district is not connected to the City of Savannah, for instance, but I would imagine they must.**

Q Okay. Would you support having Georgia Power provide technical support to school districts for the electrification of their fleets?

A (Witness Deffley) Yes.

MS. ARIZA: Okay. No further questions. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Ariza. Anyone else?

(No response.)

MADAM CHAIR PRIDEMORE: Last call, Georgia Power?

MR. MARZO: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. MARZO:

Q Good morning, panel. I mean -- it's been one of those days. Feels that way. I have just a few brief questions for you.

To clarify the Coalition's position on TOU-RD, are you here representing the positions of the local government as a Georgia Power customer, or are you here on behalf of the constituents that live within those governments?

A (Witness Nifong) Both.

Q Okay. So if you're here on behalf of constituents, did you poll your constituents as it related

to TOU-RD?

A (Witness Nifong) We did not conduct any specific polling as to how many folks are on it, what their opinions of it are. But the data provided by the company shows that those customers are paying more than they would on the residential tariff.

Q Okay. But you've not polled your constituents? You haven't done anything to figure out which one of your constituents you're representing when you suggest TOU-RD shouldn't be considered the default rate; correct?

A (Witness Deffley) Well, I would say there's been no formal survey; however, we are out in the community all the time in the sustainability program, engaging with different communities through community centers and various other events, and we are hearing those stories very anecdotally, but it would not be a formal survey.

Q Now, you understand that Georgia Power is also out in the community as well and oftentimes does reach out to its customers and gets feedback? Does that surprise you?

A (Witness Deffley) No. They're, in fact, with us at some of our community engagement events.

Q Okay. And are you aware that the company has conducted several customer surveys regarding its residential rates and the satisfaction on the TOU-RD, and it's considerably higher than customers on the outdated R rate?

A (Witness Nifong) I am.

Q Okay.

A (Witness Nifong) That may or may not be true, and we don't know the kind of methodologies that the company uses when it selects who the -- who to send the surveys to.

Q Okay. Have you polled customers about their satisfaction on the R rate at all? Have you reached out and talked to --

A (Witness Nifong) We have not. That service is provided by the company.

Q So have you determined at all there's confusion from customers who were even on the R rate as to how the R rate works?

A (Witness Nifong) That may or may not be true. I could not attest to that fact.

Q Okay. I appreciate that.

MR. MARZO: That's all I have, Madam Chair. Thank you. Thank you, panel.

MADAM CHAIR PRIDEMORE: Okay. Redirect?

MS. BROWN: Yes, ma'am.

REDIRECT EXAMINATION

BY MS. BROWN:

Q Mr. Nifong, in your research, did you review the company's survey about rate satisfaction?

A (Witness Nifong) I did not personally; no.

Q Okay. Mr. Deffley, you talked about being out in the community.

What have you heard from some of the different individuals you've spoken to about their understanding of their rates and how to control it?

A (Witness Deffley) You know, the general feedback from residents, and especially in the community centers we go to, working with a lot of folks on fixed income or lower income residents, as well as moderate income households, I think they are all -- you know, we know more than they do, and we don't know -- I mean, we think we're experts, but we know enough to be dangerous in some ways, and I think that is even further exacerbated kind of further down the line.

So there are a lot of folks that just do not understand the rate structure at all, and they don't understand why their bill is the way it is.

MS. BROWN: Thank you.

May the witnesses be excused?

MADAM CHAIR PRIDEMORE: Yes, the witnesses may be excused. Thank you.

Georgia Interfaith Power & Light.

MS. WHITFIELD: Good evening, Commissioners. Georgia Interfaith Power & Light calls Mark Ellis to the stand.

MADAM CHAIR PRIDEMORE: Are we doing Mr. Ellis and Mr. Barnes separately?

MS. WHITFIELD: They are kind of unrelated, so we were planning on doing them separately, if that's okay.

MADAM CHAIR PRIDEMORE: Do you mind if they sit together, and you swear them in, you do the housekeeping things, the administrative things, together?

MS. KYSOR: Absolutely not, so long as the attorneys can handle them separately, that's fine.

MADAM CHAIR PRIDEMORE: Great. Thank you.

MS. WHITFIELD: Oh, and may we approach with demonstratives for Mr. Barnes and Mr. Ellis?

MADAM CHAIR PRIDEMORE: Yes, you may approach.

I realize it's late. The executive secretary brought out some waters, just...

MS. WHITFIELD: Mr. Barnes and Mr. Ellis, could you please both stand and raise your right hand.

Thereupon,

MARK E. ELLIS,
JUSTIN BARNES,

having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. KYSOR:

Q Mr. Ellis, please state your full name and your

employer for the record.

A (Witness Ellis) My name is Mark Ellis.

Q You can take a seat.

And, Mr. Barnes, please state your full name and employer for the record.

A (Witness Barnes) My full name is Justin Barnes. My employer is EQ Research, LLC.

Q On whose behalf are you both testifying today?

A (Witness Ellis) Georgia Interfaith Power & Light.

Q Mr. Ellis, on October 20th and 21st of this year, did you prefile or cause to be prefiled both a trade secret and a public disclosure version of 86 pages of direct testimony in question-and-answer format in this docket?

A (Witness Ellis) Yes.

Q And did you also cause to be prefiled, along with your testimony, an attachment marked as Exhibit MEE-1 and MEE-2?

A (Witness Ellis) Yes.

Q Mr. Ellis, do you have any corrections or changes to your errata direct testimony prefiled on October 22nd or the attachments at this time?

A (Witness Ellis) No.

Q If I were to ask you the same questions that appear in your prefiled testimony at the hearing today under

oath, would your answers be the same?

A (Witness Ellis) Yes.

Q Mr. Barnes, on October 20th of this year, did you prefile or cause to be prefiled a public disclosure version of 63 pages of direct testimony in question-and-answer format in this docket?

A (Witness Barnes) I did.

Q Did you also cause to be prefiled, along with your testimony, attachments marked as Exhibits JRB 1, 2, and 3?

A (Witness Barnes) I did.

Q Mr. Barnes, do you have any corrections or changes to your prefiled direct testimony or attachment at this time?

A (Witness Barnes) I have no corrections.

Q If I were to ask you the same questions that appear in your prefiled testimony at the hearing today under oath, would your answers be the same?

A (Witness Barnes) They would.

MS. WHITFIELD: Madam Chair, I move to have the public disclosure version of Mr. Barnes' and Mr. Ellis' testimony entered into the record as if given orally from the stand. And we'll begin with Mr. Ellis tonight.

MADAM CHAIR PRIDEMORE: So moved. So marked.

**(Whereupon, the prefiled direct testimonies of Justin Barnes and Mark E. Ellis follows:)**

PUBLIC DISCLOSURE VERSION
(October 21, 2022 Errata)

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the Matter of** | ) | |
| | ) | |
| **Georgia Power Company's 2022 Rate Case** | ) | **Docket No. 44280** |
| | ) | |
| | ) | |
| | ) | |

# DIRECT TESTIMONY OF MARK E. ELLIS

## ON BEHALF

## OF GEORGIA INTERFAITH POWER & LIGHT

**October 20, 2022**

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| **Exhibit** | **(Attached)** |
|---|---|
| Exhibit MEE-1. Mark E. Ellis professional background | |
| Exhibit MEE-2. *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) | |


[*Remainder of page intentionally left blank.*]

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND PROFESSIONAL AFFILIATION.**

A. My name is Mark E. Ellis. I am an economic and financial consultant. My business address is 8595 Nottingham Place, La Jolla, CA 92037.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am testifying on behalf of Georgia Interfaith Power and Light (GIPL).

**Q. DO YOU CERTIFY UNDER PENALTY OF PERJURY THAT, TO THE BEST OF YOUR KNOWLEDGE, THE TESTIMONY YOU WILL GIVE IN THIS PROCEEDING IS TRUE AND CORRECT?**

A. Yes.

**Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL WORK EXPERIENCE.**

A. I graduated from Harvard University with a Bachelor of Science in Mechanical and Materials Sciences and Engineering and from the Massachusetts Institute of Technology with a Master of Science in Technology and Policy.

I have over 25 years of professional experience in the energy industry. Before starting my consulting practice in 2020, I led the strategy function at Sempra Energy for fifteen years. My responsibilities included developing and implementing the enterprise-wide cost of capital estimation process. This critical corporate finance function entailed thorough and ongoing research of the academic and practitioner literature on the historical cost of capital and the various cost of capital estimation methodologies and models; creating a process to estimate, quarterly, the forward-looking, risk-adjusted cost of capital for Sempra's portfolio of companies spanning a variety of geographies and lines of business; and calibrating the results against historical data and reputable, objective third-party estimates.

Previously, I held various positions in strategy, project development, and engineering with McKinsey, ExxonMobil, Southern California Edison, and Sanyo Electric. Last year, I provided expert testimony on behalf of The Utility Reform Network (TURN) before the California Public Utilities Commission in PG&E's application (A.21-20-04-23) for a $7.5-billion wildfire cost securitization. Earlier in 2022, I provided expert testimony on behalf of The Protect Our Communities Foundation (PCF) before the California Public Utilities Commission in the three

California utilities' application (A.21-08-013 et seq.) to suspend the Cost of Capital Mechanism (CCM). I am currently working on or have completed other utility regulatory cases in New Hampshire, Hawaii, Georgia, and Wisconsin. Attachment MEE-1 contains more detail on my background.

## A. Summary of Conclusions

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. I have been asked by GIPL to assess Georgia Power Company's (GPC) test year 2023 cost of capital application to analyze and calculate the return on equity (ROE) and equity ratio that are (1) adequate to ensure that GPC, from 2023 to 2025, earns a return on its investments "commensurate with returns on investments in other enterprises having corresponding risk," and (2) "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[1]

**Q. GENERALLY, WHAT CONCLUSIONS DO YOU REACH FROM YOUR ANALYSIS AND CALCULATIONS?**

A. The Commission can substantially reduce the authorized ROE requested by Georgia Power, and thereby customer costs (by a billion dollars per year), while still enabling Georgia Power to attract debt and equity investment capital, fairly compensate investors for risk, and maintain Georgia Power's current credit rating.

**Q. WHAT ARE YOUR RECOMMENDED AUTHORIZED ROE AND EQUITY RATIO?**

A. I recommend an authorized return on equity (ROE) equal to Georgia Power's cost of equity (COE) and paired with an equity ratio that, together with my recommended ROE, minimizes customer costs while maintaining Georgia Power's financial integrity, fairly compensating debt and equity investors for risk, and *improving* Georgia Power's credit rating. My recommended authorized ROE is 5.54% at an equity ratio of 61.7%.

[1] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) (attached as MEE-2).

## B. Summary of Findings

### 1. Georgia Power's cost of capital testimony employs flawed models and assumptions that systematically produce upwardly biased ROE estimates.

**Q. THERE IS A SIGNIFICANT DIFFERENCE BETWEEN YOUR RECOMMENDATIONS AND GEORGIA POWER'S RECOMMENDED ROE AND EQUITY RATIO. HOW DO YOU EXPLAIN THAT?**

A. The divergence arises from differences in both the models and input assumptions used to determine our respective ROE and equity recommendations.

Georgia Power's cost of capital expert, Mr. James Coyne, uses four models in developing his recommended return on equity (ROE). Two of those models, the Risk Premium Analysis (RPA) and Expected Earnings Analysis (EEA), both suffer from a severe, invalidating conceptual flaw: they are based on utilities' authorized or forecast *return on equity*, not their actual *cost of equity* (COE), or the "the return *to the equity owner* … commensurate with returns on investments in other enterprises having corresponding risks."[2] Thus, these two models are not commonly used in finance outside of utility regulatory proceedings because they do not actually estimate the *cost* of equity. These models are akin to developing a nutrition recommendation based on what people *actually* eat, not on what they *should* eat to maintain a healthy weight.

The other two models used by Mr. Coyne – the discounted cash flow model (DCF) and capital asset pricing model (CAPM) – are widely used throughout finance to estimate the cost of capital. But Mr. Coyne's implementations of each suffer from numerous flaws which bias his results upward.

In implementing the DCF, Mr. Coyne uses unnecessarily long trailing price histories to calculate the dividend yield, which bias his figures upward, and he assumes demonstrably unrealistic, economically impossible long-term dividend growth rates.

In implementing the CAPM, he uses an interest rate forecast long and widely known to be systematically upwardly biased. He cherry-picks a beta calculation methodology that does not reflect current investor risk perceptions and applies the "Blume" adjustment that is not valid

[2] *Id*. (emphasis added).

for utilities, both of which upwardly bias his results. He fails to examine other, more robust beta estimation methodologies, investigate whether the pandemic-related changes in market conditions and investor perceptions of utility risk were temporary or have been sustained, or compare his results to the long-term history of utility betas.

Mr. Coyne's chosen methodology does not reflect the wide range of ways beta could be estimated, each of which could produce dramatically different results. As Nobel laureate Fischer Black, one of the pioneers of empirical testing of beta and the CAPM, famously admonished, "Watch out for data mining!"[3] – running an analysis several different ways but reporting only the outcomes that support one's conclusions.

To estimate the CAPM market risk premium, Mr. Coyne uses the same flawed implementation of the DCF used for his proxy group, again producing an economically impossible result.

Finally, Mr. Coyne fails to adjust his ROE estimates for differences in equity ratio among the proxy group members, and between the proxy group average and Georgia Power.

Mr. Coyne's capital structure recommendation is similarly deficient. While the testimony of Georgia Power's credit expert, Mr. David M. Fetter, refers to key metrics used in assessing credit quality, Mr. Coyne does not provide any analysis or calculations demonstrating how ROE affects those metrics, and how the impact of ROE on those metrics influences his proposed equity ratio. Regulators in other states have authorized ROEs that are substantially lower than those requested by Georgia Power, with comparable or lower equity ratios, without adversely impacting their utilities' credit ratings, suggesting the Commission can substantially reduce the ROE requested by Georgia Power, and thereby customer costs, while maintaining its credit rating.

[3] Fischer Black, *Beta and Return*, 20(1) J. Portfolio Management 8 (1993) (Available at hhtps://jpm.pm-research.com/content/20/1/8.)

**2. More rigorous, fact-based analysis of Georgia Power's COE and credit metrics yields a recommended ROE roughly 50% lower and an equity ratio slightly higher than Georgia Power's proposal.**

**Q. PLEASE SUMMARIZE THE MAIN FINDINGS OF YOUR ROE ANALYSES FOR GEORGIA POWER.**

A. Like Mr. Coyne, I use the DCF and CAPM, two models that are widely used throughout finance, to estimate the cost of capital. Unlike Mr. Coyne, I am careful to use realistic and rigorously supported assumptions about long-term dividend growth rates, current interest rates, and risk profiles and premia.

As I explain in Section III.A below, the equity ratio required to maintain any given level of credit quality depends on the ROE. Consequently, the ROE and equity ratio must be determined jointly. Instead of Mr. Coyne's crude equity ratio peer group comparison, which does not consider the most important metrics of credit quality, I model the inter-relationships between key credit metrics, ROE, and equity ratio to arrive at the optimal equity ratio that minimizes customer costs while meeting the return and credit quality requirements of both equity and debt investors.

Figure 1 summarizes the key findings of my review of Mr. Coyne's analysis, the modifications required to correct its deficiencies, the resulting COE estimates, and my ROE and equity ratio recommendations. More rigorous, fact-based, and accurate analyses result in a substantially lower recommendation for Georgia Power's ROE: 5.54%, roughly one half of Mr. Coyne's recommended 11.00%, and a slightly higher equity ratio, 61.7% vs. Mr. Coyne's 56%.

Based on my analysis of Georgia Power's general rate case filings, its proposed combined rate of return on both debt and equity, grossed up for taxes, accounts for more than 25% of its revenue requirement.[4] My recommended ROE and equity ratio would reduce Georgia Power customer costs by approximately 11%, over $1 billion, per year.

[4] M. Ellis analysis of data in 2022 Rate Case, Georgia Power Document Filing No. 190559, Ex. APA-SPA-ADH-MBR-1, Schedule 1 (June 24, 2022).

**Figure 1. Comparison of Coyne and Ellis ROE methodologies and results**[5]
Percent

| Model | Coyne | Ellis | Comment |
|---|---|---|---|
| **DCF** | **8.99** | **5.97** | |
| Dividend yield | 3.29 | 3.36 | Coyne: excessively long trailing price histories (up to 180 trading days) introduces upward bias<br>Ellis: one-month trailing price history (~21 trading days) |
| Constant growth rate | 5.61 | NA | Coyne: extrapolates DPS using analysts' 3-to-5-year EPS growth forecasts<br>• Economically impossible<br>• Estimates are upwardly biased<br>• Low correlation between EPS and DPS forecasts<br>• Inconsistency between EPS and DCF forecast starting periods<br>• Results are inconsistent with analysts' own return forecasts |
| Initial growth rate | NA | 5.49 | Analysts' EPS growth rates for three years to mitigate upward bias |
| Terminal growth rate | NA | 1.57 | Based on long-term historical utility DPS growth rate equal to inflation |
| **CAPM** | **13.55** | **5.41** | |
| Risk-free rate (30-year Treasury)<br>• Current<br>• Forecast | <br>2.72<br>3.40 | <br>NA<br>3.56 | Coyne: current (30-trading day average) and forecast from source known to provide systematically upwardly biased estimates for decades<br>Ellis: current (one-month trailing average) rate |
| Beta | 0.85-0.88 | 0.48 | Coyne: 5-year weekly; inflated due to early-2020 market turmoil and not reflective of current market conditions<br>Ellis: 5-year monthly; balances long-term historical trend and current market conditions |
| Market risk premium<br>• Historical<br>• Forward | 11.78-12.46<br>NA<br>11.78-12.46 | 3.86<br>4.86<br>2.87 | Coyne: forward-looking using flawed CG DCF<br>Ellis: average of forward-looking using MS DCF and long-term historical average; MS DCF long-term growth rate equal to pre-capita GDP |
| **Risk Premium Analysis** | **10.12** | **NA** | Conceptually invalid: equates COE to ROE |
| **Expected Earnings Analysis** | **11.03** | **NA** | Conceptually invalid: equates COE to ROE |
| **Mean** – Levered<br>– Unlevered | **10.92**<br>NA | **5.69**<br>4.78 | <br>59% proxy group average *market* equity ratio |
| **Flotation cost adjustment** | **0.08** | **NA** | Conceptually invalid: assumes M/B ratio = 1.0 |
| **Equity ratio** | **56** | **61.7** | |
| **Relevered COE/ recommended ROE** | **11.00** | **5.54** | |

[5] 2022 Rate Case Hr'g Tr. Vol. 1 at 659-660 (Sept. 28, 2022); Ex. JMC-4. (Transcripts from the GPC Direct Testimony Hearings on September 28-30, 2022 are marked as Volume 1.)

### C. Organization of testimony

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. First, I review a few key conceptual issues related to the cost of capital and capital structure. Next, I provide a detailed assessment of Mr. Coyne's cost of equity estimation methodology and implementation. For the DCF and CAPM, the two of Mr. Coyne's four cost of equity models that are valid, I explain various modifications to his methodology and assumptions to correct for the deficiencies in Mr. Coyne's analyses and then provide the resulting COE estimates. I then apply the capital structure concepts reviewed in the first part of my testimony to determine the optimal equity ratio that minimizes customer costs while satisfying the demands of equity and debt investors. Finally, I estimate the potential savings to customers from adopting my recommended ROE and equity ratio instead of Mr. Coyne's proposal.

## II. CONFUSION BETWEEN THE *RATE OF RETURN ON* CAPITAL AND *COST OF* CAPITAL HAS LED TO EXCESSIVE AUTHORIZED RETURNS.

### A. *Rate of return on* capital and *cost of* capital are not the same: rate of return on capital is a financial performance metric, whereas cost of capital is the measure of economic cost described in the *Hope* case.

**Q. WHAT IS THE OBJECTIVE IN SETTING A UTILITY'S AUTHORIZED RATE OF RETURN?**

A. The authorized rate of return is the amount of money, expressed as a percentage of capital invested, that a utility is allowed to recover in customer rates to compensate debt and equity investors for assuming the risks of investing in the utility

The Supreme Court provides the guiding ratemaking principles in its 1944 *Hope Natural Gas* case, in which it directs ratemakers to arrive at "just and reasonable rates" by a "balancing of the investor and the consumer interests."[6] Consumer interests are straightforward: they want to minimize costs and rates. Investors include holders of both the utility's debt and equity. A utility's debt investors expect to receive their contractual interest payments. Debtholders therefore have a "legitimate concern with the financial integrity of the company whose rates are being regulated,"[7] i.e., the utility's credit quality and anticipated ability to fulfill its

[6] 320 U.S. 591, 603.
[7] *Id.*

obligations to debtholders. Equity investors expect a fair return, defined in *Hope* as "commensurate with returns on investments in other enterprises having corresponding risks."[8]

**Q. HOW DOES THE RATE OF RETURN ON CAPITAL DIFFER FROM THE COST OF CAPITAL?**

A. The rate of return on capital, often shortened to "rate of return," is an accounting metric of financial performance, calculated by dividing the value *returned* to investors – e.g., interest, net income – by the amount of capital invested. The cost of capital is the return investors *expect* on their investment. It is referred to as a "cost" because it reflects what investors demand in return for assuming the risk of the investment and, therefore, what companies must pay for that investment. The *rate of return* on each form of capital, whether calculated retrospectively or estimated prospectively, may or may not equal its respective *cost of capital*.

**Q. HOW DOES THE *AUTHORIZED* RATE OF RETURN ON CAPITAL DIFFER FROM THE RATE OF RETURN AND THE COST OF CAPITAL?**

A. The *authorized* rate of return refers to a specific use of this accounting metric to determine a utility's revenue requirement and customer rates. According to long-established ratemaking principles, which will be explained in more detail below, the authorized rate of return should be set equal to the cost of capital. Figure 2 summarizes the differences between these three sets of metrics for debt, equity, and the combined return.

[*Remainder of page intentionally left blank.*]

[8] *Id.*

**Figure 2. Comparison of terminology: cost of capital, (rate of) return on capital, and authorized rate of return**

| | Cost | (Rate of) return | Authorized rate of return |
|---|---|---|---|
| **Capital** | *Cost of capital*<br>Economic concept: payment investors require to assume risk of investment | *(Rate of) return on capital*<br>Accounting concept: measured performance, historical or prospective | *Authorized rate of return*<br>Regulatory concept: profitability benchmark determined by regulators to set utility revenue requirement and customer rates, balancing customer and investor interests |
| **Equity** | *Cost of equity (COE)*<br>Forward-looking return, based on *market* value of equity, investors expect in compensation for risk assumed; not directly observable | *(Rate of) return on equity*<br>Profitability metric equal to net income divided by *book* value of equity | *Authorized return on equity (ROE)*<br>Per *Hope*, should equal cost of equity to ensure investors are adequately compensated at minimal customer cost |
| **Debt** | *Cost of debt*<br>Forward-looking market-based interest rate on debt with commensurate credit risk, adjusted for *expected* default and liquidity risk | *(Rate of) return on debt*<br>Contractual interest (coupon) rate, adjusted for *actual* default or transaction losses | *Authorized cost of debt*<br>Contractual interest rate; weighted average of current (for existing debt) and expected (for anticipated new debt) |

**Q. WHAT PRINCIPLES DO YOU USE TO DETERMINE YOUR RECOMMENDED AUTHORIZED RATE OF RETURN?**

A. As the National Association of Regulatory Utility Commissioners (NARUC) has explained, "Fundamental financial concepts demonstrate that the fair rate of return to use in ratemaking for a utility is its *cost of capital* in order to achieve the proper balance between customers and investors."[9] Mr. Coyne has also acknowledged, in ROE testimony in other jurisdictions, "that the allowed rate of return should equal the cost of capital."[10] The objective in setting a utility's authorized rate of return should, therefore, be to set the rate of return on each source of capital – debt and equity – as close as possible to the actual cost of each source of capital.

**Q. DOES THE APPROACH TO CALCULATING COST OF EQUITY DIFFER FROM THE APPROACH TO CALCULATING COST OF DEBT?**

A. Yes. The cost of outstanding debt can be directly determined from its contractual interest rates. Similarly, the cost of debt expected to be issued can be accurately determined from known interest rate indexes for debt of comparable credit quality, such as Moody's utility bond

[9] John D. Quackenbush, *Cost of Capital and Capital Markets: A Primer for Utility Regulators*, Nat'l Ass'n of Regul. Util. Comm's at 10 (2019) (emphasis added) https://bit.ly/3Th1lC8.

[10] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 65 (September 12, 2022).

indexes, which, in turn, are based on interest rates directly observed in the market. In contrast, the cost of equity, both existing and to-be-issued, cannot be directly observed and must be estimated using various models.

**Q. WHY IS THE DISTINCTION BETWEEN THE COST OF CAPITAL AND RATE OF RETURN IMPORTANT?**

A. The cost of capital and rate of return (on capital) are entirely different concepts. The rate of return is a financial performance metric. The cost of capital is an economic concept. Nonetheless, they are frequently referred to interchangeably in utility regulatory proceedings, perhaps in part because finance professionals commonly refer to the cost of capital as the *expected* return (on capital).[11]

The muddling of the difference between the cost of capital and the rate of return is not just of semantic concern, particularly for the cost of equity, which must be estimated using various models rather than directly observed (like the cost of debt).

This confusion between the *cost of* capital and the *return on* capital has infiltrated some of the models commonly used in utility cost of capital proceedings to estimate the cost of equity. These models' apparent influence on regulatory decisions, though, does not make them correct or mean they provide a suitable basis for estimating the cost of equity.

Models that rely exclusively on historical or forecast utility rates of return on equity, without reference to utilities' actual cost of equity, should be rejected outright. Mr. Coyne uses two such models, one relying exclusively on historical authorized ROEs, the other on forecast ROEs. These models incorporate no information about the actual cost of equity and are therefore inherently flawed and produce invalid results. Consistent with the fairness principle described by NARUC, and Mr. Coyne's own statements, only models that estimate the *cost* of equity should be used to determine the authorized ROE.

[11] *See, e.g.*, TIM KOLLER, MARC GOEDHART ET AL., VALUATION, 5TH ED. MCKINSEY & CO. 35 (2010): "The cost of capital is the price charged by investors for bearing the risk that the company's future cash flows may differ from what they anticipate when they make the investment. The cost of capital to a company equals the minimum return that investors expect to earn from investing in the company. That is why the terms *expected return to investors* and *cost of capital* are essentially the same. The cost of capital is also called the discount rate, because you discount future cash flows at this rate when calculating the present value of an investment, to reflect what you will have to pay investors" (emphasis in original).

## B. Multiple, diverse sources of evidence demonstrate that utilities' authorized ROEs far exceed their cost of equity.

**Q. DO AUTHORIZED ROES REFLECT THE ACTUAL COST OF EQUITY?**

A. No. Substantial, robust evidence suggests that authorized ROEs for nearly all U.S. utilities exceed their cost of equity. Georgia Power's ROE follows this national pattern. Below, I provide three diverse analyses that compellingly demonstrate, individually and collectively, the substantial gap between authorized ROEs and utilities' actual cost of equity: expected equity return forecasts produced by investment professionals, utility market-to-book ratios, and the increasing spread between authorized ROEs and interest rates.

### 1. Investment firms' expected return forecasts for the U.S. equity market as a whole – which is riskier, on average, than utilities – are consistently lower than utilities' authorized ROEs.

**Q. ARE THERE OTHER PUBLIC SOURCES FOR COST OF EQUITY ESTIMATES OUTSIDE UTILITY REGULATORY PROCEEDINGS?**

A. Utility cost of capital proceedings are not the only purpose for which expected returns on equity are estimated. Investment firms, such as JP Morgan, BlackRock, and T. Rowe Price, regularly publish capital market assumption reports (CMAs) – expected return forecasts for various asset classes. Figure 3 summarizes a survey of U.S. equity market return forecasts published by over thirty firms in 2021.

The CMA forecasts shown in Figure 3 are grouped by assumed investment horizon: less than ten years, ten years (the most common), and more than ten years.[12] The average across the longer-term 10-year and more-than-ten-year horizons, 5.7%, is approximately 40% less than the average ROE authorized for regulated utilities throughout the United States in 2021, 9.5%.[13] Not a single one of the forty-two expected return forecasts that I reviewed[14] is as high as the average ROE yielded by any of Mr. Coyne's models.

[12] Thirty-four CMA reports were reviewed, of which two were excluded due to insufficient data on investment horizon or return type (geometric or arithmetic).

[13] M. Ellis analysis of S&P Global Market Intelligence data, https://www.spglobal.com/marketintelligence/en/ (last accessed October 6, 2022). [Hereinafter referred to as "M. Ellis analysis of S&P GMI data."]

[14] Some CMAs included forecasts for multiple time horizons, so the number of forecasts exceeds the number of reports.

CMA equity market return forecasts are a relevant and useful benchmark for utility ROEs because U.S. utilities, including Georgia Power, are lower-risk – both historically and prospectively – than the market, and therefore investors have *lower* return expectations for utilities than for the market. The fact that authorized utility ROEs are so much higher than the expected returns on the overall market, which is higher risk, is a compelling indicator that authorized ROEs far exceed utility investors' expected returns, i.e., utilities' actual cost of equity.

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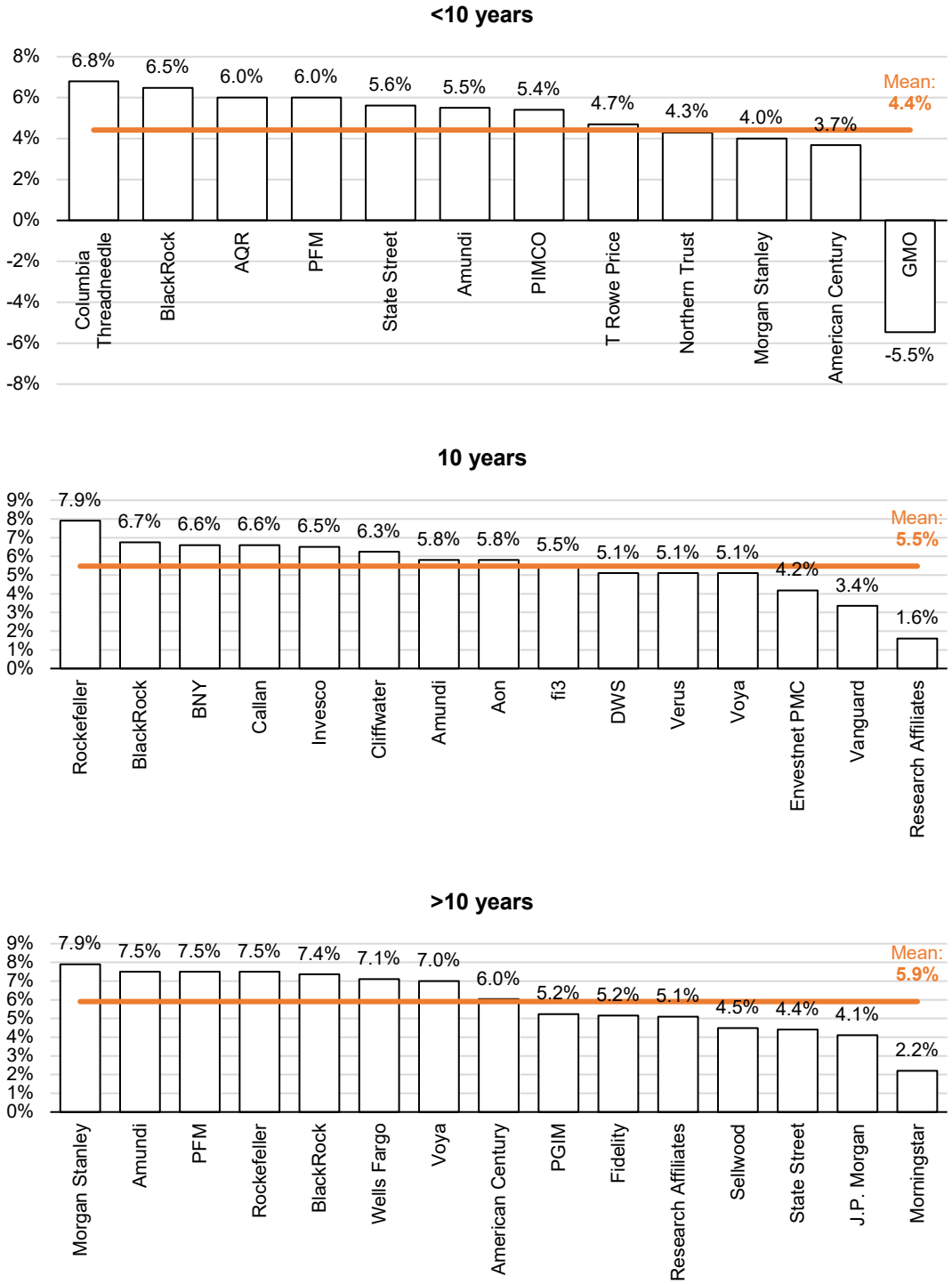
**Figure 3. U.S. equity market expected returns**[15]
Nominal, geometric




[15] M. Ellis analysis of investment firm CMA reports.

## 2. Market-to-book ratios reveal that utilities' cost of equity is substantially lower than authorized ROEs.

**Q. WHAT IS A MARKET-TO-BOOK RATIO?**

A. "Market" value refers to the price one must pay to purchase a share of a company's stock at any given time. "Book" value refers to the net equity invested in a company. In general, market value reflects the discounted value of a company's future cash flows, while book value reflects the historical investment in the company. The market-to-book ratio (M/B) is a commonly used financial metric that indicates the amount of shareholder value added in excess of shareholders' return expectations.

**Q. HOW DOES A MARKET-TO-BOOK RATIO RELATE TO RETURNS?**

A. It is a well understood financial principle that a market-to-book ratio greater than 1.0 indicates the company is expected to earn a return on its investment in excess of the actual cost of capital. A positive net present value (NPV), i.e., the value of a company minus its investments, is the signature indicator of a rate of return that exceeds the cost of capital. NPV is equal to investment multiplied by (M/B – 1.0), so M/B exceeding 1.0 indicates that NPV is positive.

**Q. WHAT DO UTILITY STOCK MARKET-TO-BOOK RATIOS REVEAL ABOUT ROES RELATIVE TO UTILITIES' COST OF EQUITY?**

A. It has long been recognized that utilities' market-to-book (M/B) ratios provide insight into the relationship between authorized return and the true cost of capital. Legendary regulatory economist Alfred Kahn[16] called attention to this phenomenon over fifty years ago in his 1970 classic, *The Economics of Regulation: Principles and Institutions*:

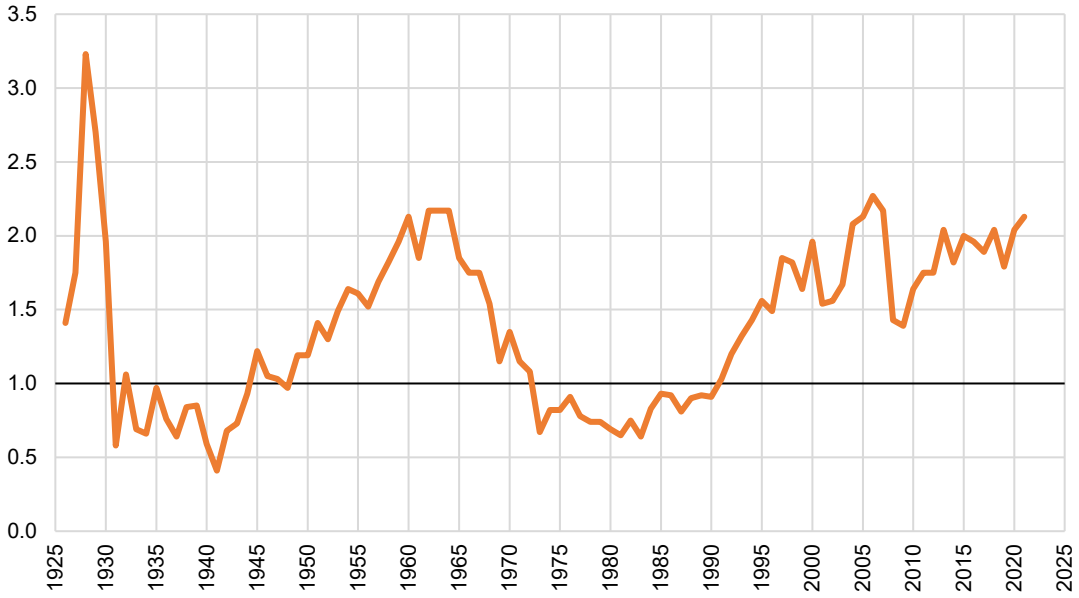
> [T]he sharp appreciation in the prices of public utility stocks, to one and half and then two times their book value during this period, reflected … a growing recognition that the companies in question were in fact being permitted to earn considerably more than their cost of capital. … The source of the discrepancy between market and book value has been that commissions have been allowing *r*'s [returns on equity] in excess of *k* [market cost of equity]; if instead they had set *r* equal to *k*, or proceeded at

[16] *See, e.g.*, Susan Lang, *Economist Alfred Kahn, 'father of airline deregulation' and former presidential adviser, dies at 93*, Cornell Chronicle (December 27, 2010) https://news.cornell.edu/stories/2010/12/alfred-kahn-father-airline-deregulation-dies-93.

> some point to do so … the discrepancy between market and book value … would have disappeared, or would never have arisen.[17]

Kahn was referring to the period of the late 1940s to 1965, but the observation that utilities trade above book value is equally valid today. As seen in Figure 4, the utility sector average M/B ratio has exceeded 1.0 for nearly thirty years and, except for a short period after the global financial crisis, has exceeded 1.5 since 1995.

**Figure 4. Utility sector average market-to-book ratio[18]**
Year-end




The average of Mr. Coyne's proxy group members' M/B ratios, listed in Figure 4, is even higher, at 2.1.[19] As Kahn observed, the utility sector trading at 1.5 to 2.0 times book value for decades clearly demonstrates that utilities have once again been "permitted to earn considerably more than their cost of capital."

[17] ALFRED KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, MASS. INST. TECH. 48, fn. 60, 50 (1970).
[18] M. Ellis analysis of French Data Library (FDL) data https://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html (last accessed October 2, 2022).
[19] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022); M/B ratio is the monthly average for September 2022.

**Figure 5. GPC proxy group market-to-book ratio and Value Line return on book equity**[20]
September 2022

| | | | Value Line return on book equity (%) | | |
|---|---|---|---|---|---|
| **Utility** | **Ticker** | **M/B** | 2022 | 2023 | '25-'27 |
| ALLETE | ALE | 1.22 | 8.0 | 8.0 | 9.0 |
| Alliant | LNT | 2.46 | 11.0 | 11.0 | 11.0 |
| Ameren | AEE | 2.37 | 10.0 | 10.0 | 10.5 |
| AEP | AEP | 2.12 | 10.5 | 10.5 | 11.0 |
| Duke | DUK | 1.69 | 9.0 | 9.0 | 9.5 |
| Edison Int'l | EIX | 1.82 | 11.0 | 11.0 | 12.0 |
| Entergy | ETR | 1.98 | 10.5 | 10.5 | 11.0 |
| Evergy | EVRG | 1.65 | 8.5 | 9.0 | 10.0 |
| Hawaiian Electric | HE | 1.87 | 9.5 | 9.0 | 9.5 |
| IDACORP | IDA | 2.02 | 9.0 | 9.0 | 9.5 |
| NextEra | NEE | 4.61 | 12.5 | 11.5 | 13.5 |
| OGE | OGE | 1.90 | 12.0 | 12.0 | 13.0 |
| Portland General | POR | 1.63 | 9.5 | 9.5 | 10.0 |
| Xcel | XEL | 2.50 | 9.5 | 9.5 | 10.0 |
| **Mean** | | **2.13** | **10.0** | **10.0** | **10.7** |

Another commonly referenced textbook on utility regulation, Kolbe, Read, and Hall's *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, recommends using a M/B ratio of 1.0 as a "guide for regulators" in setting the cost of capital:[21]

> The market-to-book ratio expresses the market value of the firm's outstanding common stock to the book value of its equity. If the two are equal the expected return on the book will equal the expected return on the market value of the company, which in turn will equal the cost of capital for a company of that degree of risk.

Kahn and Kolbe, et al., drew their conclusions from the basic financial concept of net present value (NPV) discussed above. Because utilities trade at a premium to book value (i.e., invested capital), they have positive NPVs – prima facie evidence that they are earning more than their cost of capital.

[20] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022); Company Response to STF-BAI-1-1 Attachment Coyne F.

[21] A. LAWRENCE KOLBE, JAMES A. READ, JR., GEORGE R. HALL, THE COST OF CAPITAL: ESTIMATING THE RATE OF RETURN FOR PUB. UTIL., CHARLES RIVER ASSOCIATES, INC. at 25 (1984).

**Q. IN PRACTICAL, DOLLARS-AND-CENTS TERMS, WHAT DOES IT MEAN FOR A UTILITY TO HAVE A MARKET VALUE THAT IS HIGHER THAN ITS BOOK VALUE?**

A. In practical terms, this means that, for every dollar of equity a utility invests, shareholders receive back not just their investment plus a reasonable return, which would be the case when M/B = 1.0, but additional value equivalent to their equity investment multiplied by (M/B – 1.0). At current M/B ratios near 2.0, authorized ROEs effectively double the value of utilities' equity investments, *on top of* returning their cost of equity. Such high returns are not necessary to attract capital and needlessly increase customer costs.

**Q. ARE YOU ABLE TO CALCULATE GEORGIA POWER'S MARKET-TO-BOOK RATIO?**

A. Georgia Power is not publicly traded, so its market value is not directly observable. Nonetheless, The Southern Company's market-to-book ratio, averaging 2.82 over the month of September 2022,[22] provides a reasonable estimate.

**Q. IS MR. COYNE AWARE OF THE RELATIONSHIP BETWEEN THE MARKET-TO-BOOK RATIO AND RETURNS?**

A Yes. Mr. Coyne has acknowledged that a market-to-book ratio greater than 1.0 necessarily implies that investors' expected return, i.e., the cost of equity, is less than their authorized return. In a recent cost of capital proceeding in California, Mr. Coyne testified to the following principles:

- "The terms 'expected return to investors' and 'cost of capital' are essentially the same."[23]
- "The allowed rate of return should equal the cost of capital,"[24] the NARUC fairness principle.
- "A typical [investor] expectation is the utility will earn its allowed return [on book equity]."[25] Mr. Coyne's Expected Earnings Analysis is predicated on this assumption,[26] and the Value Line reports from which the EEA draws

[22] M. Ellis analysis of S&P GMI data (last accessed Oct. 15, 2022).
[23] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 62 (September 12, 2022).
[24] *Id*. at 65.
[25] *Id*. at 70.
[26] Ex. JMC-7.

its input assumptions explicitly state that the reports' ROE forecasts are based on allowed returns.[27]

- "[I]nvestors can't buy shares at book value … They [investors] can only buy them [shares of utility stocks] at market value."[28]
- "[M]arket-to-book values [of] electric and gas utilities all hover in around 2.0; although there is variation between companies. It's been a long-term trend towards increasing the market-to-book ratio for utilities."[29]
- It "would be highly unusual" to find "any company in [Mr. Coyne's proxy group] sample that does not have a market value greater than the book value."[30]
- "When market-to-book ratio is greater than 1.0 that means that investors are willing to pay more than book value for the same stream of cash flows."[31]
- "[W]hen an investor pays more for the same stream of cash flows, that necessarily implies a lower return."[32]

The logical conclusions from Mr. Coyne's testimony are that (1) investors' expected returns on *book* equity are based on authorized ROEs (as can be seen in Figure 5, which shows the Value Line ROE data used in Mr. Coyne's EEA; the averages, which range from 10.0% to 10.7%, are in line with the national average ROE authorized for electric utilities in 2020-22, 9.4%[33]); (2) investors pay more than book value when they invest in utilities; (3) investors' expected return on *their* investment, i.e., the cost of equity, must be *less* than the authorized ROE; and (4) according to NARUC's fairness principle, under which the ROE should be set equal to the COE, historical, current, and forecast ROEs, because they systematically exceed the cost of equity, can provide no basis for determining the appropriate authorized ROE.

[*Remainder of page intentionally left blank.*]

[27] *See, e.g.*, Company Response to STF-BAI-1-1 Attachment Coyne F at 5; Value Line, "American Elec. Pwr." at fn. E. (March 11, 2022).
[28] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 72 (Sept. 12, 2022).
[29] *Id*. at 73.
[30] *Id*.
[31] *Id*.
[32] *Id*. at 74.
[33] M. Ellis analysis of S&P GMI data.

### 3. Authorized ROEs and interest rates have diverged without a corresponding increase in utilities' risk profile.

**Q. WHY DO REGULATORS APPROVE AUTHORIZED ROES IN EXCESS OF UTILITIES' ACTUAL COST OF EQUITY?**

A. A mathematical model called the Pólya urn can provide insight into why regulators have continued to approve authorized ROEs in excess of utilities' actual cost of capital.[34] Historical return on equity decisions can be thought of as balls in an urn. To decide on a new case, the regulator draws a ball from the urn. The ball is then replaced, along with a new ball – representing the current ROE decision – with the same value. This process of sampling-with-replacement-plus-duplication has a self-reinforcing property sometimes called the rich-get-richer or Matthew effect.

Of course, this model is over-simplified because regulators look at other information besides past authorized ROEs. The basic model can be modified to include additional balls in the urn representing new information, such as the estimated current cost of equity. Nonetheless, as long as regulators look at, much less rely on, past ROEs, changes in authorized ROEs will lag changes in the current true cost of equity.

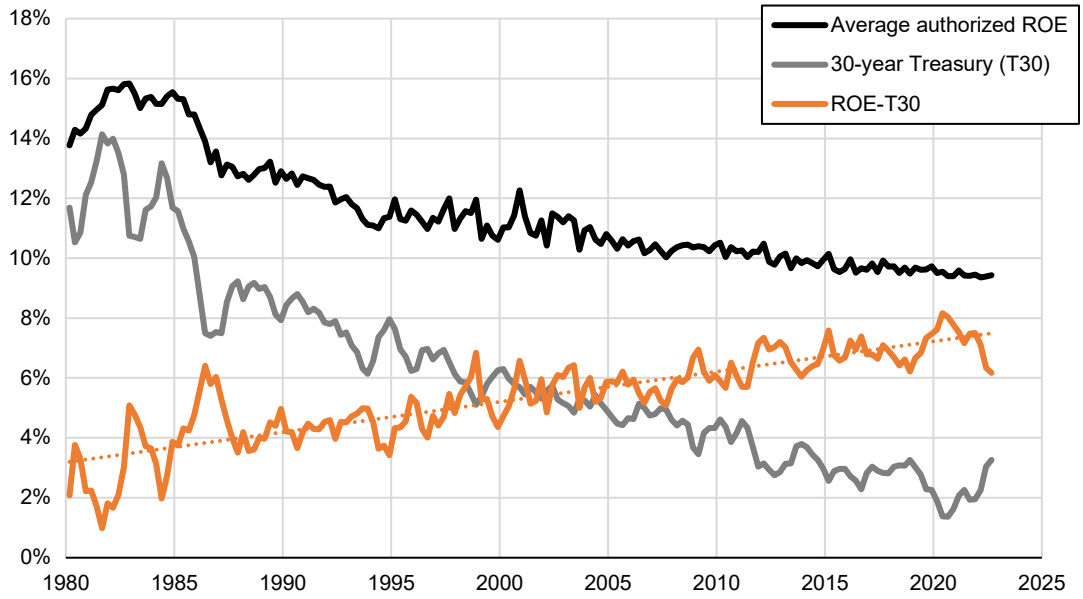
The basic utility regulatory model and risk profile have not changed significantly for decades, so the utility equity risk premium – the spread of the cost of capital over risk-free government interest rates – has remained stable. The Pólya urn model predicts that, in a market in which interest rates and, assuming a relatively stable utility equity risk premium, utilities' cost of equity have been trending downward for decades, authorized ROEs will consistently exceed the actual cost of equity, and the spread will widen over time.

The data confirm the Pólya urn model's prediction of such a widening spread between authorized ROEs and the actual cost of equity. Figure 6 shows the quarterly average authorized ROE for all U.S. utilities, the 30-year Treasury rate, and their difference. While interest rates have declined steadily since the mid-1980s, authorized ROEs have not kept pace. As a result, the ROE-Treasury spread has more than tripled, from approximately 2.3% in the early 1980s to 7.1% in the two years through September 2022. It can be estimated from the Pólya urn model

[34] *See, e.g.,* Learning Machines, *The Polya Urn Model: A simple simulation of "The Rich get Richer"* (Sept. 7, 2021) https://blog.ephorie.de/the-polya-urn-model-a-simple-simulation-of-the-rich-get-richer.

described above that, even under conservative assumptions, regulators, on average, assign no more than a 25% weight to the current cost of equity and at least 75% to recent ROEs. No evidence suggests that utilities' risk profile has systematically increased over this period, so setting ROEs higher and higher relative to utilities' actual cost of equity unnecessarily raises rates and costs to customers.

**Figure 6. Quarterly average authorized ROE and 30-year Treasury rate[35]**




Others have made similar observations about the growing divergence between authorized ROEs and utilities' actual COEs. In a study published in 2019 exploring potential explanations, Carnegie Mellon researchers David Rode and Paul Fischbeck concluded:[36]

[35] M. Ellis analysis of S&P GMI data (last accessed October 6, 2022); Federal Reserve Bank of St. Louis Economic Data (FRED) data (https://fred.stlouisfed.org/categories/115) (last accessed October 6, 2022).

[36] David C. Rode, Paul S. Fishchbeck, *Regulated equity returns: A puzzle*, 133 Energy Pol'y 1, 16 (2019) https://doi.org/10.1016/j.enpol.2019.110891 (emphasis in original).

> It would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms.
> …
> In the end, we may observe simply that what regulators *should* do, what regulators *say* they're doing, and what regulators *actually* do may be three very different things.

An analogy can be drawn between estimating the cost of equity and developing a nutrition recommendation. Looking at *actual* authorized ROEs to estimate the *required* ROE is akin to developing a calorie intake recommendation based on how much people *actually* eat, not what they need to maintain a healthy weight.

### 4. <u>These nationwide trends have been even more pronounced for Georgia Power.</u>

**Q. DO THESE NATIONAL TRENDS APPLY TO GEORGIA POWER?**

A. Yes. Authorized ROEs for Georgia Power have been set substantially higher than the national average authorized ROE for the last two decades, as seen in Figure 7, which shows the difference between GPC's authorized ROEs and the corresponding quarterly national average electric utility authorized ROE in GPC's last five cost of capital authorizations. On average, GPC's authorized ROEs have been 0.8% higher than the national electric utility average.

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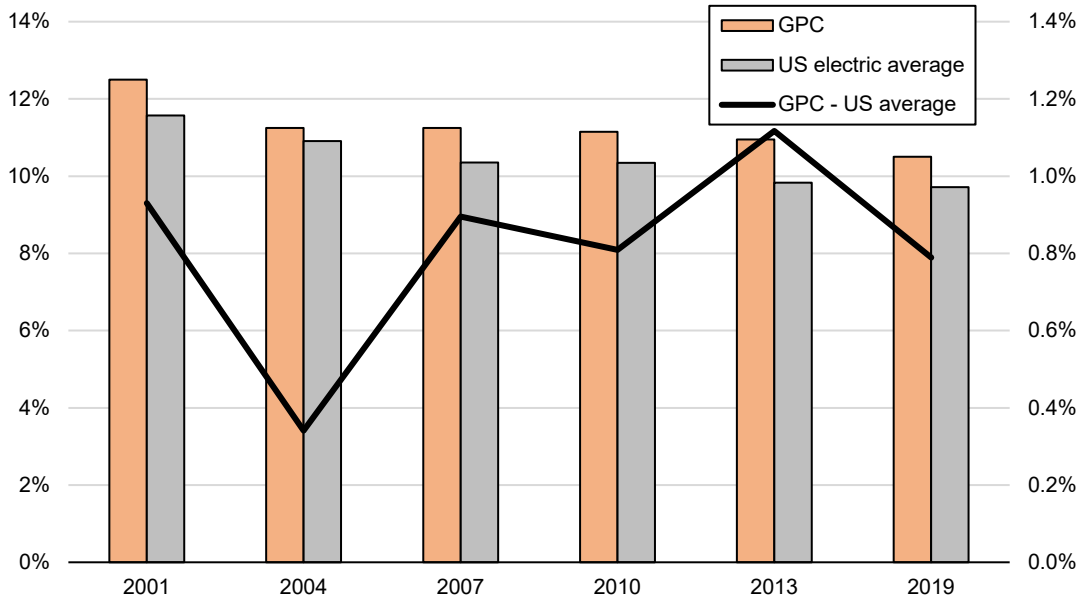
**Figure 7. GPC and average U.S. electric utility authorized ROE since 2000[37]**




## III. ROE AND CAPITAL STRUCTURE ARE INTERRELATED AND CANNOT BE DETERMINED SEPARATELY.

### A. ROE and capital structure are interrelated through ROE's impact on cash flow.

**Q. DOES THE CAPITAL STRUCTURE IMPACT CUSTOMER COSTS?**

A. Yes. Capital structure refers to the share of a utility's investment that is funded by debt and equity. Because equity generally has a higher cost than debt, assuming no change in authorized ROE, a higher equity ratio tends to increase customer costs.

**Q. DOES THE CAPITAL STRUCTURE IMPACT A UTILITY'S CREDIT QUALITY?**

A. Yes. A primary determinant of a company's credit quality – its anticipated ability to repay its debts – is the amount of debt outstanding relative to the total amount of capital, both debt and equity, invested in the company. In general, a higher equity ratio tends to improve a utility's credit quality. Equity ratio is not the only determinant of credit quality, though. As will be explained in more detail below, credit quality is also determined by the amount of cash available to service the debt.

[37] M. Ellis analysis of S&P GMI data (last accessed October 6, 2022).

**Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN ROE AND CAPITAL STRUCTURE.**

A. The testimony of Georgia Power's credit expert, Mr. Steven Fetter, reveals that ROE and capital structure are inextricably linked.

Mr. Fetter describes the importance of the ratio of funds from operations (FFO) to debt in rating agencies' assessments of utility credit quality.[38] FFO and similar cash flow metrics[39] measure the cash available to pay debt interest and principal. What he fails to clarify in his written testimony is that net income is a key component of FFO.[40] Net income, in turn, is the product of rate base, equity ratio, and ROE. Consequently, ROE and equity ratio are key determinants of FFO. During cross-examination, Mr. Fetter acknowledged the relationship between capital structure, ROE, and credit quality:

> Q. [Ms. Whitfield]: On page 14, you talk about key quantitative measures. Specifically, you reference FFO to debt and debt to EBITDA as two core financial ratios that are considered by credit agencies.
>
> A. [Mr. Fetter]: Yes.
>
> Q. Do both of those ratios include inputs that are affected by both capital structure and the return on equity?
>
> A. Well, it certainly factors in the equity/debt split because in one, the debt divides from the bottom and in the other, the debt is divided into by the EBITDA. As far as whether ROE gets factored into this, FFO – ROE ends up resulting in revenues and FFO is a certain measure and EBITDA is an earnings measure. And so ROE would impact those two items.[41]

In the context of the regulatory objective of setting a capital structure that appropriately balances customer and investor interests, as ROE increases, the amount of debt in the capital

[38] 2022 Rate Case Hr'g Tr. Vol. 1 at 799-800 (Sept. 28, 2022).

[39] Mr. Fetter refers to S&P's reliance on FFO; Moody's preferred cash flow metric is cash flow from operations (CFO). *See* GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* (October 13, 2021). Mr. Fetter also refers to the debt-to-EBITDA ratio. For utilities, debt-to-EBITDA is less important than FFO/D or CFO/D. For example, the only credit metric cited by Moody's in its "factors that could lead to an upgrade/downgrade" is CFO.

[40] The basic definition of FFO is net income + depreciation and amortization. *See, e.g.*, Corporate Finance Institute, *FFO – Funds from Operations: A measure of cash flow used in real estate* (Dec. 16, 2020) https://corporatefinanceinstitute.com/resources/knowledge/accounting/funds-from-operations-ffo/.

[41] 2022 Rate Case Hr'g Tr. Vol. 1 at 859 (Sept. 28, 2022).

structure can also increase while still maintaining the utility's credit quality; similarly, as the ROE declines, the equity ratio would need to increase to maintain the same creditworthiness.

Curiously, Mr. Coyne's capital structure analysis makes no reference whatsoever to any credit metrics. Instead, he bases his equity ratio recommendation, 56%, solely on a peer comparison.[42]

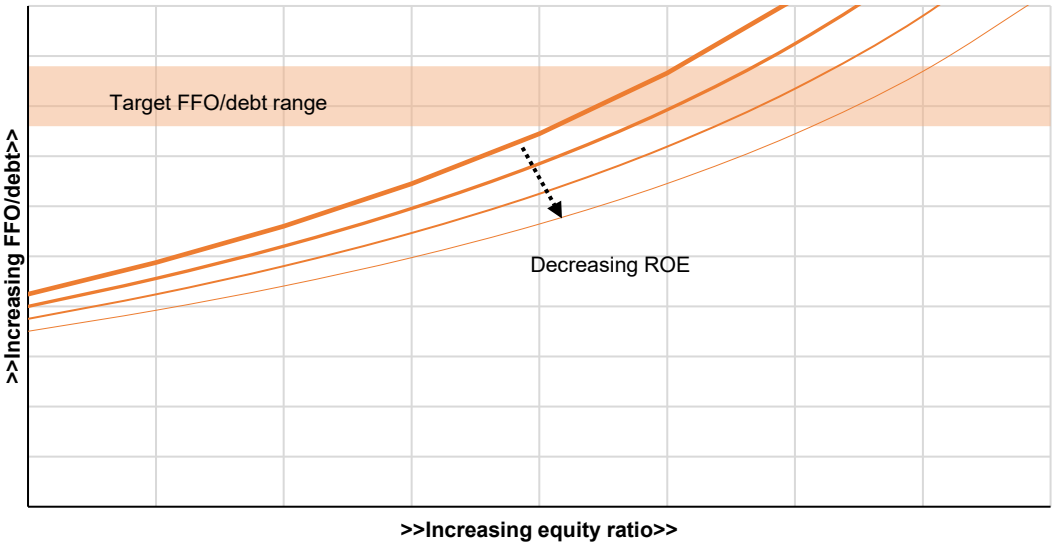
**Q. HOW SHOULD A UTILITY'S CAPITAL STRUCTURE BE DETERMINED?**

A. The appropriate capital structure can be determined more rigorously by using the analytical methods and metrics employed by credit rating agencies and as described by Mr. Fetter. The level of debt that can be accommodated in the capital structure will vary with ROE, because funds from operation (FFO), a key determinant of a utility's creditworthiness, is based on net income, and net income is based on ROE, for any given credit rating and its corresponding FFO/debt ratio.

Figure 8 illustrates the relationships between equity ratio, ROE, and FFO/debt. The horizontal axis is the equity ratio; the vertical axis is FFO/debt. The light orange horizontal band represents the range of FFO/debt that corresponds to the utility's desired credit rating. The dark orange arcing lines correspond to different levels of authorized ROE, with increasing line thickness representing increasing ROE. Holding the equity ratio constant, FFO/debt declines as the ROE is reduced (moving down from a thicker ROE line to a thinner line). But the decline in FFO/debt when ROE is reduced can be reversed by increasing the equity ratio (moving along the thinner ROE line up and to the right). Any number of combinations of ROE and equity ratio can meet the level of FFO/debt needed to maintain the utility's credit rating. A higher ROE requires less equity to maintain the same FFO/debt and credit rating; a lower ROE can maintain the same FFO/debt and credit rating if it is paired with a higher equity ratio.

[42] 2022 Rate Case Hr'g Tr. Vol. 1 at 672 (Sept. 28, 2022); Ex. JMC-10.

**Figure 8. Illustrative relationships between equity ratio, ROE, and FFO/debt**




Many observers see utilities' healthy credit ratings and low cost of debt and conclude that the best way to reduce customer costs is to increase the amount of debt in the capital structure. As explained above, current authorized ROEs far exceed utilities' actual cost of equity, so ample scope exists for the Commission to reduce Georgia Power's ROE without adversely affecting its ability to raise equity. At typical utility credit ratings, savings from a lower ROE, after grossing up for taxes, generally more than make up for the incremental cost of any additional equity required in the capital structure. For example, based on analysis of data provided in Moody's October 2021 Georgia Power credit opinion,[43] every 1.0% reduction in ROE reduces total customer costs by approximately 2.0%, *even after* accounting for the approximately 2.0% increase in equity ratio needed to maintain Georgia Power's current cash flow-to-debt ratio.[44]

Total customer costs can be reduced by decreasing the ROE while increasing the equity ratio to maintain the utility's creditworthiness (i.e., its cash flow-to-debt) because the trade-off is not one-for-one. Net income accounts for about 50% of GPC's FFO; other items, such as

[43] M. Ellis analysis of data provided in GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* at 10; Ex. 9; Ex. 10 (October 13, 2021).

[44] Moody's preferred cash flow metric is cash flow from operations (CFO), not FFO, and the analysis is based on Moody's CFO/debt data. The basic definition of CFO is net income + depreciation and amortization + changes in working capital, i.e., FFO + changes in working capital. *See* Corporate Finance Institute, *How to Calculate FCFE from CFO?* (Dec. 16, 2020) https://corporatefinanceinstitute.com/resources/knowledge/accounting/how-to-calculate-fcfe-from-cfo/.

depreciation and amortization, account for the rest. Consequently, a relatively large reduction in net income due to a sharp cut in ROE would reduce FFO by roughly half as much in percentage terms. In addition, ROE is grossed-up for taxes, which are not included in FFO, so the savings to customers from a lower ROE is amplified. Rather than "leverage up," i.e., reduce the equity ratio and increase debt, at current ROEs to reduce rates, it is more cost-effective to use any spare credit capacity to reduce the utility's ROE, or even to increase the equity ratio if necessary to maintain a target credit rating, than to increase debt.

Reducing ROE and increasing the equity ratio has the additional benefit of reducing debt-to-capitalization, another key metric used by rating agencies to assess credit quality.[45]

### B. Georgia Power's capital structure proposal does not address the interaction between ROE and capital structure.

**Q. DOES GEORGIA POWER'S CAPITAL STRUCTURE PROPOSAL TAKE INTO ACCOUNT THE INTERACTION BETWEEN ROE AND CAPITAL STRUCTURE?**

A. As Mr. Coyne acknowledged during cross examination, he developed his capital structure recommendation without incorporating the interrelationship between credit quality, ROE, and equity ratio.[46] Neither Mr. Coyne nor Mr. Fetter provides any analysis or calculations demonstrating how FFO/debt interacts with ROE and how that interaction influences GPC's proposed equity ratio. As a result, how much GPC's proposed ROE and/or the equity ratio could be reduced to lower customer costs while still maintaining its desired investment-grade credit rating cannot be assessed from the testimony and data GPC has provided.

GPC's analysis should have included a detailed analysis of the relationships between ROE, equity ratio, and creditworthiness and the impact of different combinations of equity ratio and ROE on customers, lenders, and shareholders so that the Commission could examine the ability of Georgia Power to obtain sufficient capital while minimizing customer costs. The Commission should require Georgia Power to provide a detailed analysis of the relationships between ROE, equity ratio, and creditworthiness so that the Commission possesses the facts it needs to come to fact-based conclusions about Georgia Power's authorized capital structure.

[45] *See, e.g.*, GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* at 3 (October 13, 2021).

[46] 2022 Rate Case Hr'g Tr. Vol. 1 at 764-66 (Sept. 28, 2022). Mr. Coyne acknowledges that his capital structure analysis did not involve any analysis of credit metrics like those cited by Mr. Fetter.

## C. Georgia Power's ROE and equity ratio can be modified to reduce customer costs without adversely affecting GPC's ability to raise capital.

**Q. CAN GEORGIA POWER'S PROPOSED ROE AND/OR EQUITY RATIO BE MODIFIED IN A WAY THAT REDUCES CUSTOMER RATES WHILE MAINTAINING THEIR CREDITWORTHINESS?**

A. Evidence from other states suggests both the ROEs and equity ratios proposed by Georgia Power can be reduced while maintaining their creditworthiness. Figure 9 summarizes recent utility rate cases in which the authorized ROE was 9% or less. All of the equity ratios are below the 56% proposed by Georgia Power, yet all of the companies listed in Figure 9 below nonetheless also have comparable or better credit ratings, maintaining their ability to attract capital.

**Figure 9. Recent authorized ROEs at or below 9%[47]**

| Company | State | Service type | Date | ROE (%) | Equity ratio (%) | Issuer credit rating | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | S&P | Moody's | Fitch |
| Orange & Rockland | NY | E/G | 3/19 | 9.00 | 48.0 | A- | Baa2 | BBB+ |
| Otter Tail Power | SD | E | 5/19 | 8.75 | 52.9 | BBB+ | A3 | BBB |
| Consolidated Edison NY | NY | E/G | 1/20 | 8.80 | 48.0 | A- | Baa1 | BBB+ |
| Central Maine Power | ME | E | 2/20 | 8.25 | 50.0 | A | A2 | BBB+ |
| NY State E&G | NY | E/G | 11/20 | 8.80 | 48.0 | A- | Baa1 | BBB+ |
| Rochester G&E | NY | E/G | 11/20 | 8.80 | 48.0 | NR | Baa1 | BBB+ |
| Corning Natural Gas | NY | G | 5/21 | 8.80 | 48.0 | NR | NR | NR |
| El Paso Electric | NM | E | 6/21 | 9.00 | 49.2 | NR | Baa2 | BBB |
| Brooklyn Union Gas | NY | G | 8/21 | 8.80 | 48.0 | BBB+ | Baa2 | BBB |
| KeySpan Gas East | NY | G | 8/21 | 8.80 | 48.0 | BBB+ | Baa1 | BBB+ |
| Arizona Public Service | AZ | E | 11/21 | 8.70 | 54.7 | BBB+ | A3 | BBB+ |
| Central Hudson G&E | NY | E/G | 11/21 | 9.00 | 50.0 | A- | Baa1 | BBB+ |
| Commonwealth Edison | IL | E | 12/21 | 7.36 | 48.7 | BBB+ | A3 | BBB+ |
| Ameren Illinois | IL | E | 12/21 | 7.36 | 51.0 | BBB+ | A3 | NR |
| Niagara Mohawk | NY | E/G | 1/22 | 9.00 | 48.0 | BBB+ | Baa1 | NR |
| Green Mountain Power | VT | E | 8/22 | 8.57 | 50.0 | A | NR | NR |

[47] M. Ellis analysis of S&P GMI; Moody's (https://www moodys.com/); FitchRatings (https://www fitchratings.com/) (last accessed October 6, 2022).

## IV. MR. COYNE EMPLOYS FLAWED MODELS AND ASSUMPTIONS THAT SYSTEMATICALLY PRODUCE UPWARDLY BIASED ROE ESTIMATES FOR GEORGIA POWER.

### A. Mr. Coyne's methodology relies, in part, on conceptually flawed models.

**Q. HOW DOES MR. COYNE ESTIMATE GEORGIA POWER'S ROE?**

A. Mr. Coyne employs four different models to estimate Georgia Power's ROE: (1) constant-growth discounted cash flow model (CG DCF); (2) capital asset pricing model (CAPM); (3) risk premium analysis (RPA); and (4) expected earnings analysis (EEA). In the CG DCF, CAPM, and EEA, Mr. Coyne estimates ROEs for a number of proxy group companies and bases his recommended ROEs on the proxy group average.

**Q. WHAT IS YOUR OVERALL ASSESSMENT OF MR. COYNE'S APPROACH?**

A. Although two of Mr. Coyne's models, the CG DCF and CAPM, are widely used by financial professionals and utility cost of capital experts to estimate the cost of equity, his implementations are deeply flawed. They rely on unrealistic, systematically upwardly biased assumptions that invalidate their results. I describe these deficiencies in more detail in Sections IV.C and IV.E below.

The other two models, RPA and EEA, while frequently used by utility cost of capital experts, are not commonly used elsewhere in finance outside utility regulatory proceedings, and both suffer a severe, invalidating conceptual flaw.

**Q. WHAT IS THE INVALIDATING CONCEPTUAL FLAW IN THE RPA AND EEA?**

A. Both the RPA and EEA confuse the cost of equity and the return on equity, estimating the cost of equity from historic or forecast returns on equity. The RPA consists of a linear regression model of historical quarterly-average authorized ROEs against historical quarterly-average 30-year Treasury yield. Mr. Coyne's EEA estimates the cost of equity using ROE forecasts provided by investment research firm Value Line. The primary drivers of Value Line's ROE forecasts for the proxy group companies, in turn, are the companies' most recent authorized ROEs.[48]

Both the RPA and EEA are essentially models of past ROE decisions, not the actual cost of equity. By design, therefore, they repeat the historic overearnings arising from the excess

[48] *See, e.g.,* GPC data request response STF-BAI-1-1 Attachment Coyne F at 5: Value Line, "American Elec. Pwr." (March 11, 2022), fn. E.

ROEs authorized in the past. As explained in Section II.A above, the cost of equity and the return on equity are two entirely different concepts; there is no basis to assume that they will or should be equal. In fact, as explained in Section II.B above, authorized ROEs have diverged dramatically from utilities' actual cost of equity, as reflected in the disparity between authorized ROEs and substantially lower forecast returns for the U.S. equity market as a whole, despite the latter's higher risk; utility market-to-book ratios exceeding 1.0 for decades; and the growing divergence between average authorized ROEs and interest rates. Basing a utility's authorized ROE on historically authorized ROEs without any reference to the *actual cost of equity*, as both the RPA and EEA do, merely perpetuates these errors.

A simple calculation illustrates the EEA's conceptual flaw in equating ROE and COE. ROE is the ratio of earnings to the book value of equity. But investors cannot buy shares at book value; they must pay market value. The market value of the stocks Mr. Coyne chose to include in his peer group tend to trade at a significant premium over book value, currently an average of 2.1x. Mathematically, if investors pay more than book value for the same stream of earnings, their expected return, i.e., the cost of equity, *must* be less than the ROE calculated using the book value.[49] For companies earning just their cost of equity, the *expected* return, i.e., the cost of equity, can be estimated by dividing earnings per share (EPS) by equity book value per share (BVPS).[50] EPS can be expressed as the product of ROE and book value per share, so COE can similarly be expressed as ROE divided by the market-to-book ratio.[51] COEs so calculated are dramatically lower than Mr. Coyne's EEA estimates. For example, Value Line's forecast '25-'27 ROE for Alliant Energy Corporation is 11.0%,[52] and as of September 30, 2022, Alliant's market-to-book ratio was 2.17,[53] so investors' expected return would be

[49] A simple example illustrates why this must be true. Suppose one pays $1 for an investment that guarantees a payment of $0.10 – a return of $0.010/$1.00 = 10% – every year into perpetuity. If instead the initial cost was $2 instead of $1 for the same perpetual stream of $0.10 per year, the return would be $0.10/$2.00 = 5%. If the initial investment for the *identical* cash flow stream is higher, the return is lower.

[50] Aswath Damodaran, *Implied Equity Risk Premium: Principles & Mechanics* at 5 https://pages.stern.nyu.edu/~adamodar/pdfiles/eqnotes/webcasts/ERP/ImpliedERP.pdf (last accessed July 22, 2022).

[51] COE = EPS / stock price = ROE x book value per share / stock price = ROE / M/B.

[52] GPC data request response STF-BAI-1-1 Attachment Coyne F at 2: Value Line, "Alliant Energy" (March 11, 2022).

[53] M. Ellis analysis of S&P GMI (last accessed October 2, 2022).

only approximately 11.0/2.17 = 5.07%.[54] As Kahn explained, and Mr. Coyne has acknowledged (see Section II.B.2 above), M/B ratios greater than 1.0 imply COE is less than ROE. It is simply mathematically impossible for COE to equal ROE when M/B is not equal to 1.0, yet Mr. Coyne's RPA and EEA are nonetheless premised on this mathematical impossibility.

FERC has also recognized the flaws in the RPA and EEA. In Opinion No. 569 (November 2019), FERC rejected the use of both the RPA and EEA to estimate the cost of equity. With regard to the EEA, FERC explained "that relying on the Expected Earnings model would not satisfy the requirements of *Hope*":

> In particular, we find that the record does not support departing from our traditional use of market-based approaches to determine base ROE. Under the market-based approach, the Commission sets a utility's ROE to equal the estimated return that investors would require in order to purchase stock in the utility at its current market price. In *Hope*, the Supreme Court explained that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." In order to determine this, we must analyze the returns that are earned on "investments in other enterprises having corresponding risks," but investors cannot invest in an enterprise at book value and must instead pay the prevailing market price for an enterprise's equity. As a result, the expected return on a utility's book value does not reflect "returns on investments in other enterprises" because book value does not reflect the value of any investment that is available to an investor in the market, outside of the unlikely situation in which market value and book value are exactly equal. Accordingly, *we find that relying on the Expected Earnings model would not satisfy the requirements of* Hope.[55]

FERC initially rejected the RPA for similar reasons:

[54] The EEA suffers other flaws, such as the growth adjustment to book value which does not account for new share issuance, but their effect is minor relative to the central conceptual flaw of confusing ROE and COE.

[55] Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc., Docket No. EL14-12-003, Opinion No. 569, 169 FERC at 103 ¶ 61,129 (emphasis added) (2019).

> [T]he Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, whose resulting ROE may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data. For example, previous ROE determinations may not involve an explicit determination as to whether an ROE is just and reasonable, but instead focused on whether to allow an ROE incentive adder or were approving a preexisting RTO-wide ROE for a new RTO member. Similarly, many previous ROE determinations used in the Risk Premium model were the product of rate case settlements. Such settlements often involve compromises on a variety of issues present in a rate case, of which the appropriate ROE is only one. Consequently, such settlements could include ROEs that are not representative of the market cost of equity because the ROEs were negotiated above or below that market cost of equity in order to form an overall settlement package, together with negotiated outcomes on other issues, that were acceptable to the parties.[56]

Although FERC subsequently reinstated the RPA in Opinion No. 569-A (May 2020), the D.C. Circuit Court of Appeals found that FERC's reinstatement of the RPA was arbitrary and capricious and has vacated Opinion 569-A.[57]

In the same California cost of capital proceeding referenced in Section II.B.2 above, Mr. Coyne acknowledged that his Risk Premium Analysis and Expected Earnings Analysis are not based on utilities' cost of equity:

[*Remainder of page intentionally left blank.*]

[56] Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc., Docket No. EL14-12-003, Opinion No. 569, 169 FERC at 166 ¶ 61,129 (2019).

[57] Van Ness Feldman, LLP, *D.C. Circuit Court of Appeals Decision Puts FERCs Revised Method for ROE Determinations in Question* (August 10, 2022) https://www.vnf.com/dc-circuit-court-of-appeals-decision-puts-fercs-revised-method-for-roe-determinations-in-question.

Q. Isn't it true that two of your models, the risk premium analysis, RPA, and the expected earnings analysis, EEA, are not based on the utilities' actual cost of equity?

A. Yeah.

Q. The RPA is based on historical authorized ROEs; correct?

A. It's based on an historic relationship between allowed return by regulatory commissions and Treasury yields.

Q. The EEA is based on forecast ROEs; correct?

A. Yes. That's based on a forecast of ROEs.[58]

Despite his acknowledgement that ROE systematically exceeds COE, Mr. Coyne's RPA and EEA nonetheless estimate COE based on historical and forecast ROEs – in direct contradiction to the NARUC fairness principle that he has endorsed. For these reasons, the results of Mr. Coyne's EEA and RPA models should be rejected outright.

### B. Mr. Coyne fails to account for differences in equity ratios among the proxy group members.

**Q. HOW DOES THE EQUITY RATIO AFFECT THE COST OF EQUITY?**

A. All else equal, a lower equity ratio tends to raise the cost of equity. This can be understood intuitively. The cash generated by a business is pledged to holders of its debt and equity, with debtholders having first priority. As the equity ratio declines, a smaller share of the cash goes to equity owners. To the extent there is uncertainty in the cash generated, it is amplified by a lower equity ratio, increasing the riskiness of those cash flows. This increased risk is reflected in a higher cost of equity.

The companies in Mr. Coyne's proxy group have different equity ratios, and their average, 53%,[59] is different from the 56% he proposes for Georgia Power, so their costs of equity cannot be used to estimate Georgia Power's under his proposed equity ratio. In addition, Mr. Coyne compares the equity ratios on a book basis; this is incorrect. When determining the cost of capital, the market value of equity should be used.[60]

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[58] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 65-66 (September 12, 2022) [edited for clarity].

[59] Ex. JMC-10.

[60] *See, e.g.,* TIM KOLLER, MARC GOEDHART ET AL., VALUATION, 5TH ED. MCKINSEY & CO. 204 (2010): "Where possible, you should estimate *market* values of the elements of the current capital structure" (emphasis added).

I will revisit adjusting the COE model results for differences in equity ratios among the proxy group members, and between the proxy group average and Georgia Power, in Section V.A below.

### C. Mr. Coyne's DCF model uses upwardly biased dividend yield calculations and unrealistically extrapolates analyst earnings growth forecasts into perpetuity, producing economically impossible results.

**Q. WHAT IS YOUR ASSESSMENT OF MR. COYNE'S DCF MODEL?**

A. Mr. Coyne uses the constant-growth version of the DCF model (CG DCF) in his analysis, with a growth rate equal to equity analysts' consensus 3-to-5-year EPS growth rate estimates. The key shortcoming in his implementation of the CG DCF is the assumption that dividends can grow at analysts' estimated EPS growth rates into perpetuity. This economically impossible assumption upwardly biases his results dramatically.

**Q. PLEASE DESCRIBE THE CONSTANT-GROWTH DCF MODEL.**

A. The constant-growth DCF is based on the well-known and widely used mathematical formula for the value of a growing perpetuity stream of cash flows. It assumes a single, constant rate of cash flow growth. In the constant-growth DCF model used by Mr. Coyne and many other modelers, the cash flows are expected dividends, and the perpetuity value formula can be expressed as:

$$M_0 = D_0 \frac{(1+g)}{(k-g)}$$

where $M_0$ refers to the current market value (stock price), $D_0$, the current dividend (typically four times the most recent quarterly payment), $g$, the forecast perpetuity growth rate, and $k$, the cost of equity. Rearranging terms, the cost of equity can be expressed as a function of the dividend yield, $d$ ($\frac{M_0}{D_0}$), and growth rate:

$$k = d(1+g) + g$$

In some implementations of the CG DCF, the first-year dividend yield is calculated by multiplying the current yield by $1 + \frac{g}{2}$, instead of $1 + g$, to account for the quarterly, not

annual, payment of dividends. Mr. Coyne uses this approach.[61] Typically, the cost of equity is estimated for each member of the proxy group, with the mean or median reflecting the cost of equity for the target company. Mr. Coyne uses the mean.

The general DCF model, which can allow for varying growth rates over time, is a particularly apt representation of stock returns because its assumptions realistically reflect several key features of share prices and expected returns. First, the DCF model's perpetual cash flow stream assumption mirrors equity's claim on a firm's cash flows into perpetuity. Second, the assumption of steady growth in dividends over time reasonably reflects their much greater stability relative to other potential measures of profitability, like earnings or cash flow. Third, the resulting single discount rate into perpetuity is consistent with the no-arbitrage principle of finance. If investors expected higher (lower) returns in the future, they would impute that into the price today and bid up (down) the price accordingly, such that near-term and long-term returns roughly equilibrate.[62]

But the *constant growth* version of the DCF used by Mr. Coyne is not well-suited for estimating the cost of equity for a utility or any other stock, for two reasons. First, it is not realistic to assume that a utility will maintain its current 3-to-5-year growth rate into perpetuity. At any given time, the 3-to-5-year growth rate will deviate from its long-term trend due to any number of factors, such as weather; economic conditions; new capital projects; regulatory, tax, and other policy changes; and unforeseen events like the Covid-19 pandemic. Second, the results of the CG DCF are particularly sensitive to the perpetuity growth rate assumption. The inaccuracy introduced by assuming a relatively short-term growth rate will be sustained forever invalidates the results of Mr. Coyne's CG DCF. Mr. Coyne's use of analyst estimates, a source

[61] 2022 Rate Case Hr'g Tr. Vol. 1 at 654 (Sept. 28, 2022). It can be demonstrated mathematically that, for dividend yields as of the starting time period of the model ($t_0$), the common method of using four times the most recent quarterly dividend is already slightly conservative relative to a more accurate quarterly model, and this adjustment is therefore not necessary.

[62] Some equity return projections vary with forecast horizon, generally due to a valuation-reversion assumption in the model, e.g., price-to-earnings ratios returning to their long-term historical average over an initial horizon and remaining at that level afterward. *See, e.g.*, BlackRock Investment Institute, *Capital market assumptions* (2022) https://www.blackrock.com/institutions/en-us/insights/charts/capital-market-assumptions. Whether variation in expected equity returns across different forecast horizons can be estimated with any accuracy is a subject of ongoing debate among academic and investment professionals. Some forecasters assume no mean reversion in their return forecasts. *See, e.g.*, AQR Capital Management, *2014 Capital Market Assumptions for Major Asset Classes* (2014) https://www.aqr.com/Insights/Research/Alternative-Thinking/2014-Capital-Market-Assumptions-for-Major-Asset-Classes).

widely known to be upwardly biased, for his growth rate assumption further invalidates his results.

### 1. Mr. Coyne's dividend yield calculations use unnecessarily long trailing price histories, introducing upward bias to his estimates.

**Q. HOW DOES MR. COYNE CALCULATE THE CURRENT DIVIDEND YIELD?**

A. To calculate the dividend yield, Mr. Coyne divides four times the most recent quarterly dividend by the trailing average share price over 30, 90, and 180 trading days.[63]

While it is advisable to use a multi-day average of the share price to reduce the effect of any day-to-day price fluctuations that are not reflective of investors' long-term expectations, *all three* of Mr. Coyne's averages are unnecessarily long. Because share prices have a general tendency to trend upward over time, the longer the backward-looking averaging period, the lower the share price will tend to be, introducing upward bias into the dividend yield. Averaging the most recent month of data, approximately 21 trading days, better balances the competing objectives of mitigating the potential short-term volatility cited by Mr. Coyne and reflecting current investor expectations.

### 2. Mr. Coyne's perpetuity growth rate is based on analysts' 3-to-5-year growth rate forecasts, producing economically impossible results.

**Q. HOW DOES MR. COYNE ESTIMATE EACH PEER UTILITY'S PERPETUITY GROWTH RATE?**

A. While estimating the current dividend yield is fairly straightforward (although, as just explained, the potential for bias exists even there), estimating the perpetuity growth rate is more subjective. Mr. Coyne uses analysts' consensus 3-to-5-year estimated earnings-per-share (EPS) growth rate provided by Value Line, Thomson First Call (as reported by Yahoo! Finance),[64] and Zacks.[65]

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[63] 2022 Rate Case Hr'g Tr. Vol. 1 at 653-54 (Sept. 28, 2022).

[64] The providers of EPS estimates have consolidated and changed their names numerous times over the last two decades. First Call was integrated with I/B/E/S in 2000 and discontinued in 2012 (https://libguides mit.edu/c.php?g=387236&p=2626822). I/B/E/S is now provided by Refinitiv (https://www refinitiv.com/en/financial-data/company-data/ibes-estimates). Refinitiv is the source of Yahoo! Finance's estimates (https://help.yahoo.com/kb/finance-for-web/SLN2310 html).

[65] Mr. Coyne's EPS growth rate forecast sources use the following forecast horizons: Value Line, '19-'21 to '25-'27 (*see, e.g.,* STF-BAI-1-1 Attachment Coyne F); Zack's, 3 to 5 years (https://www.zacks.com/stocks/); Yahoo! Finance, next 5 years (https://finance.yahoo.com/).

The DCF is a model of *dividends*, not earnings, so it would be preferable to use explicit dividend-per-share (DPS) forecasts. While some analysts, such as Value Line, provide DPS forecasts, they are less common, so EPS forecast are typically used instead.

**Q. IS IT REASONABLE TO ASSUME ANALYSTS' CONSENSUS GROWTH RATES INTO PERPETUITY IN A DCF MODEL?**

A. No. There are several problems with using analysts' estimates for the perpetuity growth rate. A wealth of academic research over decades has found that analyst forecasts tend to be optimistic.[66] Several other observations and analyses demonstrate the unreasonableness of using analysts' 3-to-5-year EPS growth rate estimates for the perpetuity dividend growth rate in the constant-growth DCF model.

**Q. WHAT IS YOUR FIRST OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?**

A. It is economically impossible for analyst earnings growth forecasts to be sustained even for one decade, much less into perpetuity. Figure 10 compares the forecast aggregate earnings of the U.S. publicly-traded companies for which analysts provide EPS growth forecasts[67] to forecast U.S. GDP.[68] Currently, these companies' combined earnings are equal to roughly 8% of U.S. GDP. Yet if analysts' growth projections were correct, they would exceed total U.S. GDP in just six years.

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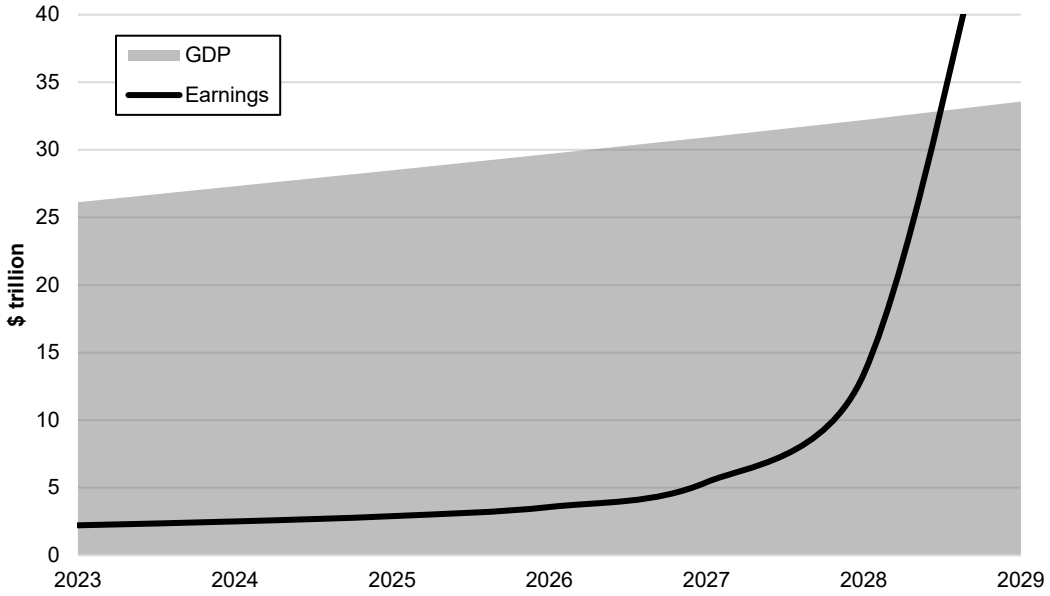
[66] *See, e.g.,* Marc Goedhart, Rishi Raj, Abjishek Saxena, *Equity analysts: Still too bullish*, McKinsey Quarterly (Apr. 2010), https://www mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/equity-analysts-still-too-bullish. For a more recent example, *see also* Stefano Cassella, Benjamin Golez, Huseyin Gulen, Peter Kelly, *Horizon Bias and the Term Structure of Equity Returns* (Nov. 2021), https://ssrn.com/abstract=3328970.

[67] M. Ellis analysis of S&P GMI data for 1,780 U.S. stocks. Excludes companies with growth rates less than -100%.

[68] Sum of the forecasts for each company. Analysts' EPS estimates and growth rates from S&P GMI as of June 30, 2022. GDP forecast is average of Congressional Budget Office, *The 2022 Long-Term Budget Outlook* (July 2022), https://www.cbo.gov/system/files/2022-07/57054-2022-07-LTBO.xlsx.; Energy Info. Admin., *Annual Energy Outlook 2022 Macroeconomic Indicators* (March 2022), Table 20 https://www.eia.gov/outlooks/aeo/excel/aeotab20.xlsx; Soc. Sec. Admin., *The 2022 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* (June 2022), Supplemental Single-Year Tables, https://www.ssa.gov/OACT/TR/2022/SingleYearTRTables_TR2022.xlsx.

**Figure 10. U.S. stock market forecast earnings vs. forecast GDP**




The Research Foundation of CFA Institute has made a similar critique of projecting analysts' estimates beyond their forecast horizon:[69]

> Consensus long-term earnings growth estimates routinely exceed sustainable GDP growth. The current consensus growth rate for earnings on the S&P 500, according to the Zacks Investment Research survey, is 10 percent, which, if we assume a consensus inflation expectation of 2-3 percent, corresponds to 7-8 percent real growth. Real earnings growth of 8 percent is six times the real earnings growth of the past century, however, and three times the consensus long-term GDP growth rate. This growth is not possible.

Mr. Coyne himself has acknowledged the potential unreasonableness of assuming analyst growth rates into perpetuity in his CG DCF model, testifying in a recent rate case, "the Multi-Stage DCF can be used when there is concern that short-term growth rates may not be sustainable over the longer-term."[70]

[69] Robert D. Arnott, *Equity Risk Premium Myths: Rethinking the Equity Risk Premium*, 2011(4) CFA Institute 97 (2011) https://bit.ly/3TjGiig.

[70] New Brunswick Energy and Utilities Board Docket No. 491, Liberty Utilities (Gas New Brunswick), *Prepared Direct Testimony: James M. Coyne*, at 39 (March 2021).

**Q. WHAT IS YOUR SECOND OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?**

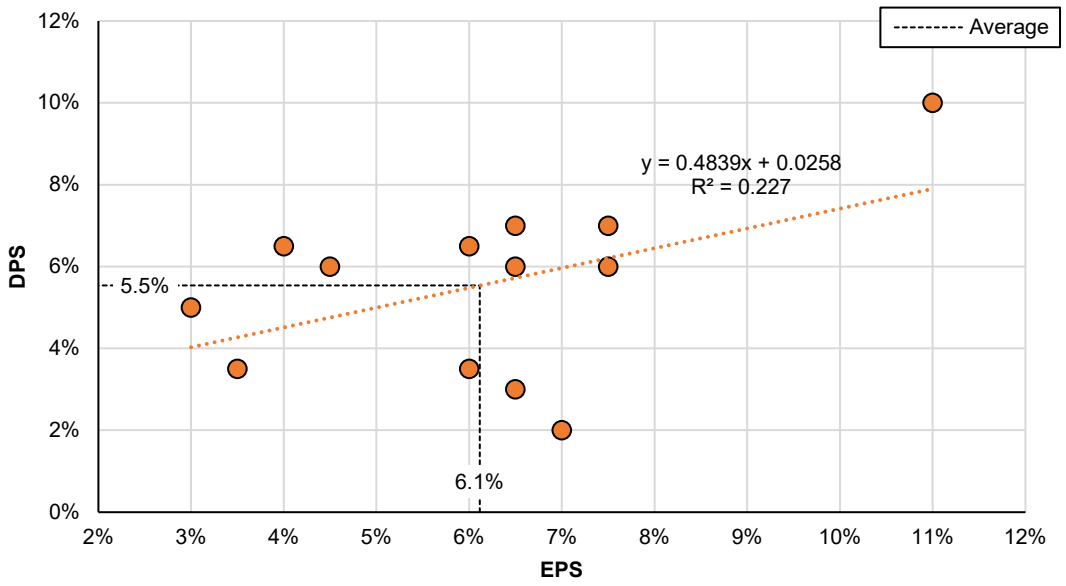
A. Mr. Coyne is correct that "[o]ver the long term … dividend growth can only be sustained by earnings growth,"[71] and EPS and DPS do tend to have similar growth rates over extended, multi-decade periods of time. Nonetheless, EPS growth rates are poor proxies for DPS growth over the 3-to-5-year horizon of analysts' EPS forecasts. This is observed in both forecast and historical data.

Few analysts provide both DPS and EPS projections, but Value Line, one source of Mr. Coyne's growth estimates, does provide both EPS and DPS growth forecasts, and its EPS and DPS projections vary considerably. Figure 11 compares Value Line's forecast EPS and DPS growth rates for the members of Mr. Coyne's proxy group. On average, the DPS growth rate is lower, 5.5% vs 6.1% for EPS; EPS overestimates expected dividend growth, introducing upward bias into Mr. Coyne's DCF results. More importantly, as shown in Figure 11, a cross-plot of Value Line's EPS and DPS growth rate estimates, the correlation between the two sets of numbers is low ($R^2$ coefficient of 0.23).

[*Remainder of page intentionally left blank.*]

[71] 2022 Rate Case Hr'g Tr. Vol. 1 at 654-55.

**Figure 11. Value Line forecast EPS and DPS forecast growth rates[72]**

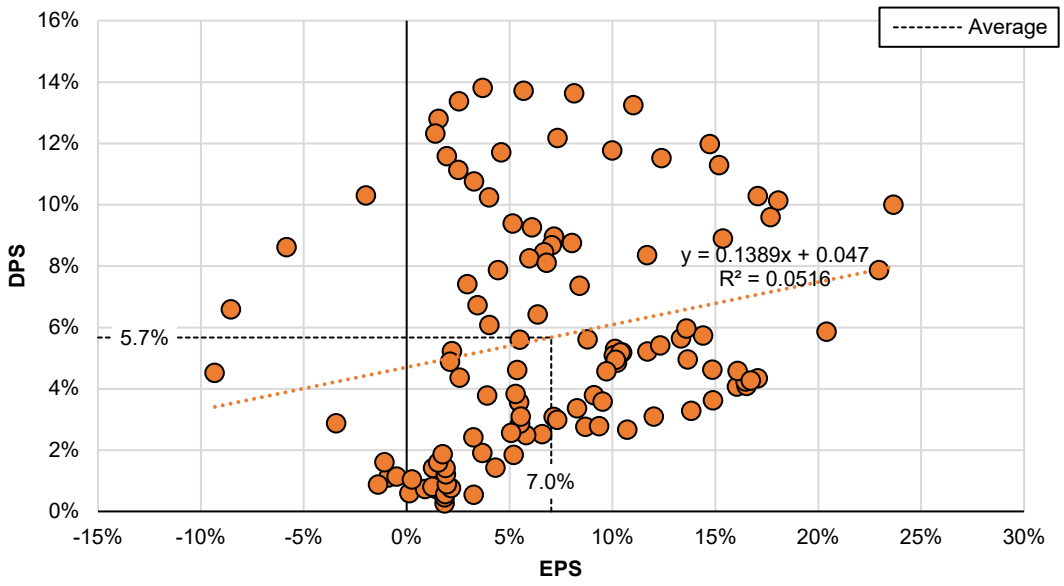



Historically, the variation between EPS and DPS is even greater. Figure 12 compares historical 5-year EPS and DPS growth rates for the S&P 500 from January 1988 through March 2022. Historically, average EPS growth has also been greater than DPS, 7.0% vs. 5.7%, and the correlation between EPS and DPS is even lower than for the forecast growth – $R^2$ coefficient of just 0.05.

[*Remainder of page intentionally left blank.*]

[72] M. Ellis analysis of data provided in GPC data request response STF-BAI-1-1 Attachment Coyne F: (Value Line reports for each member of Mr. Coyne's proxy group).

**Figure 12. Historical S&P 500 EPS and DPS 5-year growth rates[73]**




In both the historical and projected data, the average growth rate for EPS is higher than for DPS, seemingly contradicting Mr. Coyne's assertion that "earnings per share [and] dividends per share … grow at the same constant rate."[74] But EPS and DPS do, in fact, grow at roughly the same *compound* rate over the *long term*.[75] Nonetheless, analysts' 3-to-5-year forecast horizons are not long-term, and simply because earnings are more volatile than dividends, the figure reported for EPS growth over analysts' 3-to-5-year forecast period will tend to be higher than DPS, as both the historical growth rates in Figure 12 and the forecast growth rates in Figure 11 demonstrate.

This is due to the mathematical relationship between compound, or *geometric*, and *arithmetic* average growth rates.[76] An illustrative example demonstrates the principle. Suppose both EPS and DPS both grow at a compound average growth rate (CAGR) of 5% over 25 years, but they take different paths to get there. DPS grows at the same 5% every year, or

[73] M. Ellis analysis of data from S&P Dow Jones Indices, *S&P 500 Earning and Estimate Report* (September 30, 2022) https://www.spglobal.com/spdji/en/documents/additional-material/sp-500-eps-est.xlsx.
[74] 2022 Rate Case Hr'g Tr. Vol. 1 at 654.
[75] "Compound" refers to the single, constant growth rate at which an initial value would need to grow to reach a final value. Importantly, the initial value could follow any number of different growth paths to achieve the same compound growth rate. EPS and DPS can have the same compound growth rate over an extended, multi-decade period, but have very different growth rates over the intervening 5-year periods.
[76] *See, e.g.,* Educba, *Difference Between Geometric vs. Arithmetic Mean*, https://www.educba.com/geometric-mean-vs-arithmetic-mean/ (last accessed Oct. 20, 2022).

27.6% over each 5-year period. Annual EPS growth varies between -5% and +15% over each 5-year period, say 15% in the first 5 years, followed by -5%, 0%, 6%, and 10% over the next four 5-year periods. The average of the DPS growth rates over each of the 5-year periods is 5.0%, but the average of the EPS growth rates is 5.2%. The effect is relatively small, but it is another source of upward bias introduced by using EPS growth rates as a proxy for DPS growth.

For the two reasons observed in both forecast and historical data – overestimation on average and low correlation – EPS is a poor proxy for DPS, and it is inappropriate to assume that analysts' relatively short-term EPS growth estimates reasonably reflect investors' DPS growth expectations into perpetuity.

**Q. WHAT IS YOUR THIRD OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?**

A. EPS growth rate horizons are likely not compatible with the CG DCF's forecast horizon. The starting time periods of analysts' estimates are not specified with precision. S&P explains of its estimates:[77]

> Long Term Growth Rate (LTG) is a compound annual growth rate based on current and projected EPS values provided directly by the analysts. … Most analysts define LTG as an estimated average rate of earnings growth for the next 3-5 years. The exact time frame differs from broker to broker. Since the analysts providing LTG may differ from the analysts providing fiscal year estimates and the variation in time periods of 3-5 years, it is not possible to reconcile LTG with fiscal year estimates.

The starting points for Yahoo! Finance's estimates are similarly unknown:[78]

[77] *See* YCharts Financial Glossary, *Long Term Growth Rate*, https://ycharts.com/glossary/terms/eps_est_long_term_growth (last accessed July 22, 2022) (reporting estimates provided by S&P).

[78] *See* Stockopedia Financial Ratio Glossary, *Long Term Growth Forecast*, https://www.stockopedia.com/ratios/long-term-growth-forecast-5107/ (last accessed July 22, 2022) (Referring to Reuters, now Refinitiv, the source of Yahoo! Finance's estimates). *See also,* Yahoo!, *Exchanges and data providers on Yahoo Finance*, https://help.yahoo.com/kb/finance-for-web/SLN2310 html.

> [A]s most analysts do not provide the basis of the calculation of their growth rates, the estimates collected are assumed to include a combination of past and future years with at least one future period included, and are calculated on a compounded annual growth rate (CAGR) basis.

Value Line *does* specify the starting point and forecast horizon of its estimates. Nonetheless, Value Line's growth rate forecast horizons are virtually certain not to be consistent with the dividend yield used in the CG DCF, i.e., the end of the last trading day of the share price averaging period. The starting period for the Value Line growth estimates used by Mr. Coyne, for example, is '19-'21, the midpoint of which, June 2020, is almost three years before the first dividend payment in his DCF model.[79]

EPS can vary significantly from one year to the next, typically much more than the annual variation in DPS. Without knowing the forecast period, it is not possible to determine whether the estimate reflects the growth rate over the three to five years, much less the rate into perpetuity, from the starting point of the CG DCF. Following a year of poor performance, for example, expected growth would be elevated, potentially significantly above what could be sustained long-term.

The incompatibility of the growth estimates can be clearly observed in the data itself. For example, Value Line's growth rate for Edison International is reported as "not meaningful" because the company reported a loss in 2018, the first year of its growth forecast period. Yahoo! Finance's and Zacks's growth rates are both positive, presumably because the starting point of their growth rate forecasts are years in which Edison International reported a profit.[80]

[79] Mr. Coyne calculates average stock prices through April 30, 2022; *see* Ex. JMC-4, fn. 2. The CG DCF assumes annual dividend payments start one year later, or April 30, 2023.
[80] Ex. JMC-4.

**Q. WHAT IS YOUR FOURTH OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?**

A. The expected returns produced by a CG DCF model assuming DPS grows into perpetuity at analysts' 3-to-5-year EPS growth rates are inconsistent with analysts' own expected return forecasts.

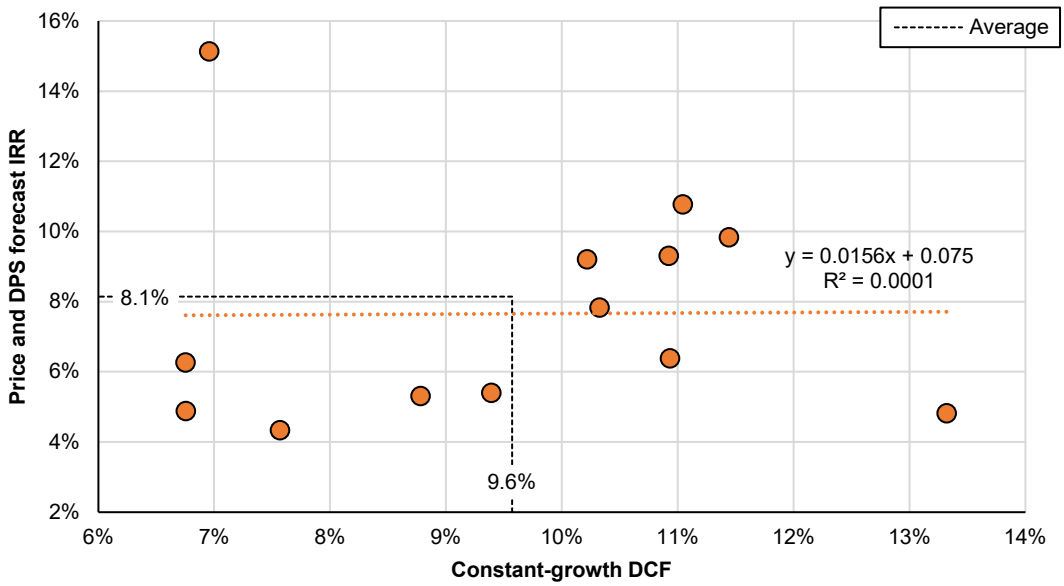
In addition to their EPS and DPS growth rates, Value Line publishes a variety of other forecasts, including for share prices.[81] These forecasts can be used to estimate Value Line's own expected return for each company, which can be compared to the CG DCF results using Value Line's dividend yield and EPS growth rate forecasts in Mr. Coyne's model.[82] Figure 13 compares the results of the two models. The horizontal axis is the COE estimated using Mr. Coyne CG DCF and Value Line's yield and EPS growth rate assumptions; the vertical axis is COE implied by Value Line's own dividend and price forecasts.

On average, the CG DCF COE estimates (9.6%) are significantly higher than the COE implied by Value Line's price and dividend forecast (8.1%). More importantly, there is virtually no correlation between the two sets of model results ($R^2$ = 0.0). A CG DCF COE based on Value Line's dividend yield and EPS growth bears almost no resemblance to the COE implied in its own dividend and price forecast. The analysts that provide 3-to-5-year EPS growth forecasts clearly do not assume those rates apply to dividends or will be sustained into perpetuity, as Mr. Coyne does. For Mr. Coyne's proxy group, Value Line assumes DPS will grow more slowly, on average, than EPS beyond its forecast horizon.

[81] Value Line reports do not include actual share price forecasts, but EPS and price-earnings multiple (P/E) forecasts. Price can be calculated by multiplying these two figures: P = EPS x P/E. *See* GPC data request response STF-BAI-1-1 Attachment Coyne F (Value Line reports for each member of Mr. Coyne's proxy group).

[82] A simple DCF model can be constructed from Value Line's most recent annual average price (investment), dividend forecast (with missing years interpolated assuming a constant growth rate), and'25-'27 price forecast (exit value). The COE is the internal rate of return (IRR) of this cash flow stream.

**Figure 13. COE based on Value Line CG DCF and price and DPS forecast IRR[83]**




**Q. WHAT IS YOUR FIFTH OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?**

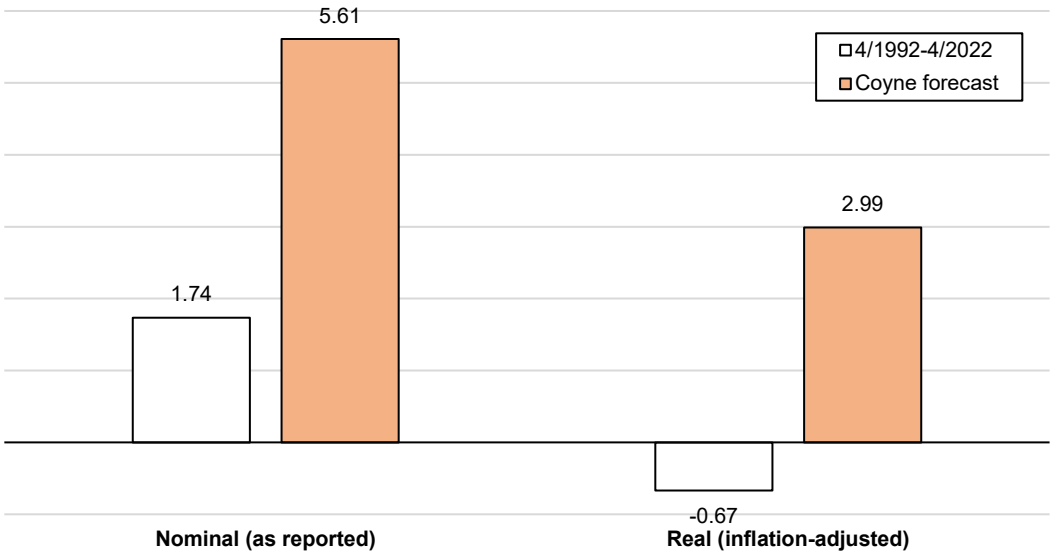
A. Analyst earnings (and, by assumption, dividend) growth forecasts tend to be higher than the companies' long-term historical results, additional evidence that analysts' 3-to-5-year growth forecasts are not sustainable into perpetuity and are therefore unreasonable assumptions in a CG DCF model.

Figure 14 compares the proxy group average growth forecasts to their historical 30-year (1992-2022) DPS compound annual growth rates (CAGR). On average, forecast rates are approximately 4% higher, in both nominal (as reported) and real (inflation-adjusted) terms, than the historical average. The ~4% difference between historical and forecast growth highlights the unreasonableness of assuming analysts' estimates into perpetuity.[84]

[83] M. Ellis analysis of data provided in GPC data request response STF-BAI-1-1 Attachment Coyne F (Value Line reports for each member of Mr. Coyne's proxy group).

[84] Forecast growth rates are adjusted by the monthly average Treasury-TIPS spread for April 2022, 2.54%, to correspond with Mr. Coyne's analysis.

**Figure 14. Proxy group average historical and Coyne forecast dividend per share growth[85]**
Percent




**Q. GIVEN THE NUMEROUS SHORTCOMINGS OF ANALYSTS' FORECASTS, SHOULD THEY BE USED AT ALL IN DCF MODELS?**

A. Discounted cash flow models can be a robust approach to estimating expected returns and are widely used throughout finance. The key shortcoming of the constant-growth version of the DCF model – assuming a relatively short-term growth rate into perpetuity – can be easily remedied by assuming that analysts' estimated growth rates apply only for a limited period, after which they converge toward a market- or sector-average terminal growth rate in a multi-stage DCF model (MS DCF), which I describe in more detail in IV.D below. Despite the various deficiencies in analysts' estimates even in the short-term, they are viewed as the best available estimates of near-term investor expectations. That said, relatively little weight should be placed on them in estimating the cost of equity, and the MS DCF model can weight them more appropriately.

[85] M. Ellis analysis of S&P GMI and U.S. Bureau of Labor Statistics (BLS) data (last accessed October 2, 2022); Ex. JMC-4.

### 3. Mr. Coyne's flawed DCF results should be disregarded.

**Q. WHAT IS YOUR CONCLUSION REGARDING MR. COYNE'S DCF RESULTS?**

A. Mr. Coyne's DCF model results should be disregarded completely. While, in principle, a constant-growth DCF model could be used to estimate the cost of equity, Mr. Coyne's implementation is deeply flawed. Its dividend yield calculations use excessively long historical price data series, introducing upward bias into the results. More critically, Mr. Coyne's DCF unrealistically assumes analysts' EPS growth estimates are valid for forecasting dividends into perpetuity. Several analyses demonstrate the invalidity of this assumption: the economic impossibility of sustaining EPS growth forecasts even for one decade, much less into perpetuity; the low correlation between analysts' EPS and DPS growth forecasts; the unknown starting period for analyst growth forecasts and therefore likely inconsistency with the DCF model's starting period; the inconsistency between the CG DCF results and analysts' own implied expected return estimates; and the wide disparity between analyst forecasts and utilities' long-term historical DPS growth rates.

## D. The Multi-Stage DCF should be used instead of the CG DCF because it allows more realistic cash flow projections, yielding more accurate results.

### 1. The multi-stage DCF model enhances the CG DCF by allowing different dividend growth rates over time.

**Q. WHAT IS THE MULTI-STAGE DCF MODEL?**

A. The multi-stage DCF model (MS DCF) enhances the CG DCF by allowing different dividend growth rates over time. As we saw previously, analysts' estimated 3-to-5-year growth rates are too high to be sustained in perpetuity, and may be biased. But analyst estimates should not be ignored completely. Analysts' estimated 3-to-5 year growth rates provide useful information about the relative expected growth across companies. Over the long term though, it is reasonable to assume investors expect growth rates, in real terms, to revert to their long-term historical trends. The MS DCF explicitly models different growth rates over time.

The MS DCF can incorporate any number of stages. For equity valuation, a three-stage model is commonly used, in which the initial stage uses analysts' estimates over their 3-to-5-year forecast horizon, and the terminal stage uses the long-term real historical growth rate plus current long-term inflation expectations. In between lies a transition phase, typically 5 to 15

years, in which the growth rate is the simple average of the initial and terminal rates. The MS DCF model can be expressed as:

$$1 = d\frac{1+g_1}{k-g_1}\left(1-\left(\frac{1+g_1}{1+k}\right)^{t_1}\right) + d\left(\frac{1+g_1}{1+k}\right)^{t_1}\frac{1+g_2}{k-g_2}\left(1-\left(\frac{1+g_2}{1+k}\right)^{t_2}\right) + d\left(\frac{1+g_1}{1+k}\right)^{t_1}\left(\frac{1+g_2}{1+k}\right)^{t_2}\frac{1+g_3}{k-g_3}$$

where $d$ is the current dividend yield; $g_1$, $g_2$, and $g_3$ are the initial, transition, and terminal growth rates, respectively (where $g_2 = \sqrt{(1+g_1)(1+g_3)} - 1$);[86] $t_1$ and $t_2$ are the initial and transition stage durations; and $k$ is the cost of equity such that the equation is true. Substantial precedent exists for the MS DCF model, in both its two- and three-stage forms, in both corporate finance and regulatory contexts.[87]

In my implementation of the MS DCF, I assume an initial growth stage of three years – the low end of analysts' EPS growth rate forecast horizon, to mitigate the effect of their upward bias – and a 10-year transition. To account for the quarterly distribution of dividends, I convert the reported rates to quarterly and multiply the number of periods in the initial and transition phases by 4.[88] The dividend yield is the most recent quarterly dividend divided by the average price over December 2021.

### 2. The MS DCF's initial growth rate can be estimated from analysts' EPS growth forecasts.

**Q. HOW DO YOU ESTIMATE THE INITIAL GROWTH RATE FOR THE MS DCF?**

A. I use an average of analysts' EPS growth forecasts from S&P Global Market Intelligence (S&P GMI), Yahoo! Finance, and Zacks.

### 3. The MS DCF's terminal growth rate can be estimated from expected inflation, based on utilities' long-term historical dividend growth.

**Q. HOW DO YOU ESTIMATE THE TERMINAL GROWTH RATE FOR THE MS DCF?**

A. The terminal growth rate is intended to reflect a sector-wide dividend growth rate toward which all stocks in the peer group are expected to converge over the long term. Figure 15 shows real

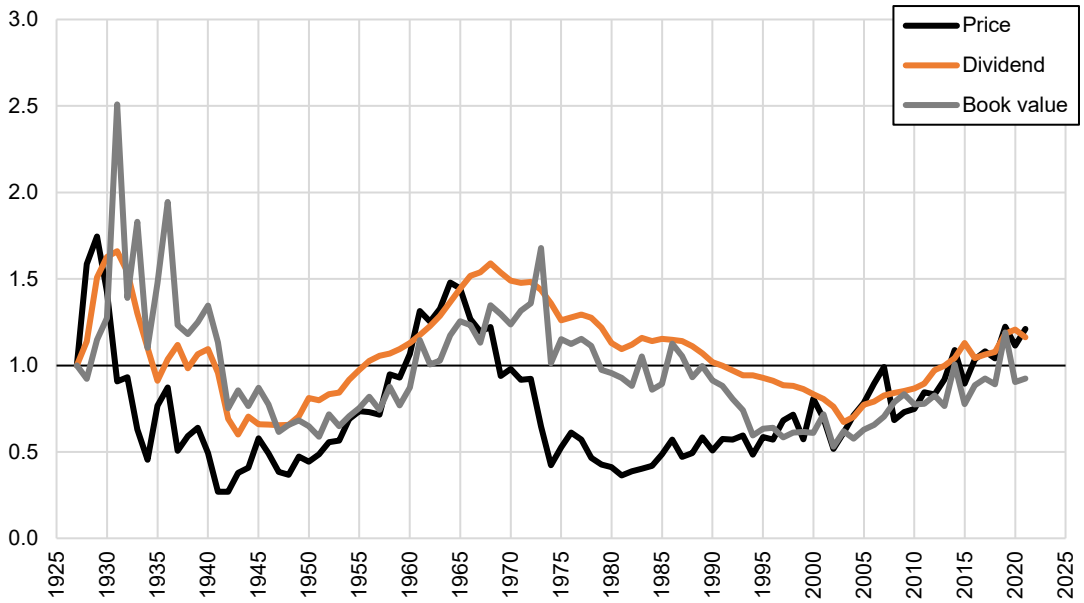
[86] The geometric mean of $g_1$ and $g_3$ is used to ensure consistency between annual and quarterly versions of the model.

[87] *See, e.g.,* RICHARD BREALEY, STEWART MYERS, FRANKLIN ALLEN, PRINCIPLES OF CORPORATE FINANCE, MCGRAW HILL/IRWIN 10TH ED. at 83-88 (2010).; Surface Transportation Board, *Use of a multi-stage discounted cash flow model in determining the railroad industry's cost of capital*, 73 Fed. Reg. 47642, 47642-47644 (2008) https://bit.ly/3s9fIMT.

[88] All rates are converted from annual ($r_a$) to quarterly ($r_q$) using the formula: $r_q = (1+r_a)^{\frac{1}{4}} - 1$.

utility-sector dividend, price, and book value per share from 1927 through 2020. While there have been periods of growth and decline, the long-term trend for both has been in line with inflation for over 90 years. Based on this long-term history, the terminal growth rate in the MS DCF for the GPC proxy group is assumed to be equal to long-term inflation.

**Figure 15. Utility sector real dividend and book value per share, 1927-2021**[89]
1927=1.0




For the market as a whole, long-term real DPS growth has tracked GDP per capita, about 1.9% per year.[90] At any given time, some sectors grow faster, some slower. The technology and healthcare industries, for example, have sustained DPS growth rates higher than the market average for decades. Utilities are a mature industry, though, and end-use demand for electricity, gas, and water has grown more slowly than GDP for decades, so it is not unreasonable for utility companies' per-share dividend growth to lag the market as whole. The long-term track record of essentially zero real dividend growth further highlights the unreasonableness of Mr. Coyne's assumption that analyst growth forecasts can be sustained into perpetuity.

[89] M. Ellis analysis of FDL and BLS data (both last accessed October 2, 2022).
[90] *See, e.g.,* ROGER IBBOTSON, JAMES HARRINGTON, STOCKS, BONDS, BILLS, AND INFLATION 2021 SUMMARY EDITION, CFA INSTITUTE RESEARCH FOUNDATION BOOKS at 157-60 (2021) (analysis is for total payout to account for the effect of net stock repurchases).

**Q. HOW DO YOU ESTIMATE EXPECTED LONG-TERM INFLATION?**

A. For expected long-term inflation, I use Treasury-TIPS spreads. TIPS are Treasury Inflation-Protected Securities, which provide investors a return equivalent to inflation plus the quoted TIPS yield. The difference in yield between Treasurys and TIPS of equal maturity is a current measure of the market's forward-looking inflation expectation over the life of the bonds.

The MS DCF uses inflation for the terminal, not initial or transition, growth rate, so inflation into perpetuity is estimated at the end of the transition phase, not from today. I use the expected inflation, $i_{lt}$, rate over the period from 20 to 30 years from now, as implied by the difference in the 30-year and 20-year Treasury-TIPS spreads:

$$i_{lt} = \left(\frac{(1+i_{30})^{30}}{(1+i_{20})^{20}}\right)^{\frac{1}{10}} - 1$$

Using average Treasury yields for the month of September 2022, the long-term inflation estimate is 1.45%.[91]

### 4. The MS DCF produces COE estimates substantially lower than Mr. Coyne's CG DCF.

**Q. WHAT ARE YOUR MS DCF COE RESULTS?**

A. Figure 16 summarizes the MS DCF results for the GPC proxy group. The average COE for the GPC proxy group is 6.0% – substantially lower than Mr. Coyne's corresponding CG DCF average results of 8%-10%.[92]

[*Remainder of page intentionally left blank.*]

[91] M. Ellis analysis of FRED data (last accessed October 2, 2022).
[92] 2022 Rate Case Hr'g Tr. Vol. 1 at 656 (Sept. 28, 2022).

**Figure 16. GPC proxy group multi-stage discounted cash flow COE[93]**
As of September 2022

| Utility | Price | DPS | Yield % | Initial growth rate (%) S&P GMI | Yahoo! | Zacks | Average | COE % |
|---|---|---|---|---|---|---|---|---|
| ALLETE | 57.42 | 2.60 | 4.53 | 6.11 | 8.70 | 8.15 | 7.65 | 8.25 |
| Alliant | 60.19 | 1.71 | 2.84 | 6.03 | 6.30 | 6.16 | 6.16 | 5.50 |
| Ameren | 90.72 | 2.36 | 2.60 | 7.25 | 6.37 | 7.20 | 6.94 | 5.36 |
| AEP | 99.21 | 3.12 | 3.14 | 6.25 | 6.25 | 6.11 | 6.20 | 5.92 |
| Duke | 104.95 | 4.02 | 3.83 | 5.64 | 5.62 | 6.09 | 5.78 | 6.70 |
| Edison Int'l | 66.00 | 2.80 | 4.24 | 4.15 | 4.35 | 2.97 | 3.82 | 6.61 |
| Entergy | 113.82 | 4.04 | 3.55 | 6.13 | 6.19 | 6.76 | 6.36 | 6.50 |
| Evergy | 66.72 | 2.29 | 3.43 | 6.37 | 3.71 | 5.24 | 5.11 | 6.00 |
| Hawaiian Electric | 38.13 | 1.40 | 3.67 | 5.28 | 1.30 | 2.57 | 3.05 | 5.73 |
| IDACORP | 107.90 | 3.00 | 2.78 | 4.62 | 2.70 | 2.67 | 3.33 | 4.78 |
| NextEra | 85.43 | 1.70 | 1.99 | 9.88 | 9.35 | 9.66 | 9.63 | 5.03 |
| OGE | 40.35 | 1.64 | 4.06 | 1.50 | 1.90 | 3.47 | 2.29 | 5.96 |
| Portland General | 49.99 | 1.81 | 3.62 | 4.25 | 3.16 | 4.63 | 4.01 | 5.93 |
| Xcel | 72.91 | 1.95 | 2.67 | 6.12 | 7.04 | 6.43 | 6.53 | 5.37 |
| **Mean** | | | **3.36** | | | | **5.49** | **5.97** |

**Q. DO YOU USE THE MS DCF ELSEWHERE IN YOUR ANALYSIS?**

A. Yes. I use it as one of two methods to estimate the market risk premium for the CAPM.

## E. Mr. Coyne makes unrealistic, upwardly biased assumptions for all three inputs into his CAPM.

**Q. WHAT IS THE CAPITAL ASSET PRICING MODEL?**

A. Mr. Coyne's analysis incorporates another well-known COE model, the capital asset pricing model (CAPM). It estimates the cost of equity, $k$, from the formula:

$$k = r_f + \beta(r_m - r_f)$$

where $r_f$ is the risk-free rate (typically a long-term U.S. Treasury), $r_m$ is the expected return on the market, and $\beta$ is a measure of risk of the company in question relative to the market. The market risk premium (MRP), the difference between the market return and the risk-free rate, $r_m - r_f$, reflects the additional return investors require as compensation for taking on equity market risk. The CAPM is a simple model of the fundamental financial risk-reward trade-off: investors demand higher returns as risk increases.

[93] S&P GMI; Refinitiv via Yahoo! Finance (https://finance.yahoo.com/); Zacks (https://www.zacks.com/) (last accessed October 2, 2022).

### 1. The source of Mr. Coyne's risk-free rate assumption has a long and widely known track record of upwardly biased interest rate forecasts.

**Q. WHAT RISK-FREE RATE DOES MR. COYNE USE IN HIS CAPM?**

A. Mr. Coyne uses the 30-year Treasury (T30). Because the models estimate the expected return on equity, which is a claim on cash flows into perpetuity, the longest-term rate available should be used. The 30-year Treasury is the longest-term risk-free rate, so the T30 is an appropriate term. Mr. Coyne calculates his CAPM COE estimates using both recent historical average and forecast Treasury rates.

**Q. DO YOU HAVE ANY CONCERNS WITH MR. COYNE'S RISK-FREE RATE ESTIMATES?**

A. Yes, I have two concerns. First, as with the average price calculation for the dividend yield in his DCF model, Mr. Coyne's historical T30 averaging period, 30 days, is too long. Curiously, Mr. Coyne provides no explanation for the use of different averaging periods in the two different models. One month of trading data, typically 20-22 days, is sufficient. Nonetheless, the difference in trailing averaging periods for interest rates generally does not introduce any bias in the results because, unlike stock prices, which tend to exhibit an upward trend over time, daily movements interest rates are random.

**Q. WHAT IS YOUR SECOND CONCERN WITH MR. COYNE'S RISK-FREE RATE ESTIMATES?**

A. My second concern involves his use of a forecast rate. Using a forecast rate creates inconsistencies with the time horizon of the DCF, which is estimated as of today (or, more precisely, as of the end of the trailing price averaging period). The mathematical formula for the present value of a periodic time series upon which the DCF is based discounts the stream of future cash flows to a "time zero" one period before the first payment. The resulting discount rate is as of that time zero. The first payment in the DCF model is typically assumed to occur one time step from today; therefore, the rate determined by the DCF model is as of today. Using an interest rate expected at some future date in the CAPM produces a COE as of that future date, not today, and that COE is not directly comparable to the DCF's COE.

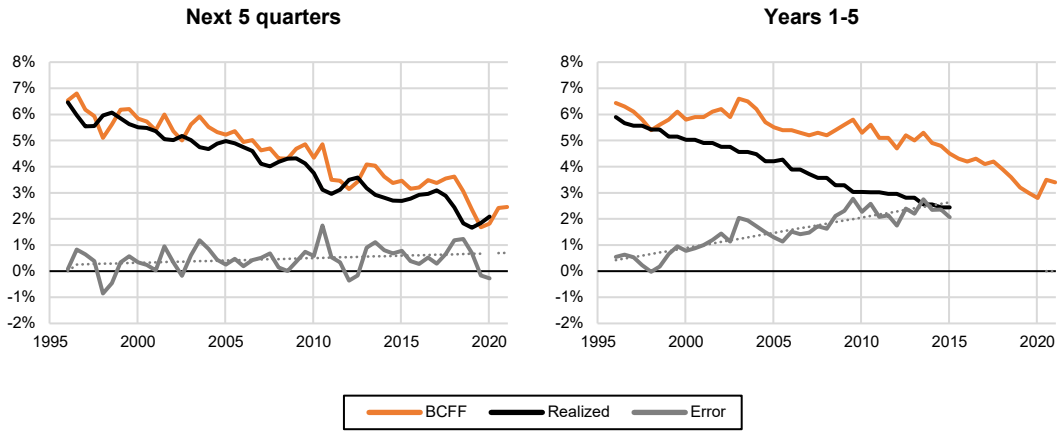
Ignoring the consistency concern, even if we did want to use a forecast rate, in general, commonly available interest rate forecasts are no better predictors of future interest rates than the current market rate. Most importantly, though, I am particularly concerned about Mr.

Coyne's chosen source for his interest rate forecast, Blue Chip Financial Forecasts (BCFF). BCFF's 30-year Treasury forecast has an exceptionally poor track record.

**Q. HOW ACCURATE HAVE THE BLUE CHIP FINANCIAL FORECASTS 30-YEAR TREASURY FORECASTS BEEN IN THE PAST/HISTORICALLY?**

A. BCFF has a multi-decade track record of producing systematically upwardly-biased forecasts, and the errors have only increased over time. Figure 17 compares the BCFF forecasts used by Mr. Coyne – the average of the next five quarters and years one to five – to their corresponding future average realized rates, going back to BCFF's first long-range forecast in December 1996. The chart shows that BCFF's 30-year Treasury forecasts have consistently overestimated future rates, and the forecast errors have tended to increase over time.

**Figure 17. BCFF 30-year Treasury forecast vs. average realized rate[94]**




**Q. HOW DOES MR. COYNE JUSTIFY HIS USE OF FORECASTS WITH SUCH A POOR TRACK RECORD?**

A. Mr. Coyne cites a Massachusetts regulatory decision to argue that "Blue Chip Financial Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate."[95] BCFF may be relied upon by *some* investors, but no basis exists for Mr. Coyne's claim that BCFF forecasts represent a reasonable proxy for investor expectations.

[94] M. Ellis analysis of BCFF and FRED data. From June 2002 through June 2005, BCFF forecast the long-term average of the 20-year Treasury instead of the 30-year. Those forecasts are used in this analysis and compared to subsequent actual 20-year Treasury rates.

[95] 2022 Rate Case Hr'g Tr. Vol. 1 at 660 (Sept. 28, 2022).

BCFF has no more than a hundred thousand subscribers,[96] less than 0.1% of the hundreds of millions of investors who are exposed to Treasury rates through direct investments or as a benchmark for other investments.[97] Although utility cost of capital experts routinely argue that these forecasts represent the "market's view," 0.1% in no way represents the market. The hundreds of millions of market participants respond to all kinds of information, and the small slice of the market used by Mr. Coyne, via BCFF, does not represent an adequate or reasonably proxy.

Mr. Coyne's argument also implicitly assumes that investors rely *only* on BCFF forecasts, to the exclusion of all other ways that investors might develop their expectations; that they rely on BCFF's forecasts as-is, with no adjustment for their historical inaccuracy; and that investors' only use of the forecasts is for investment decisions. None of Mr. Coyne's assumptions is true. The consistent errors in BCFF forecasts are well-known; the Congressional Budget Office has issued public reports on BCFF's interest rate forecasting errors for nearly twenty years.[98] Many investors undoubtedly take BCFF's forecasts "with a grain of salt" and inform their decisions with other forecasts and information. Finally, BCFF reports include dozens of other forecasts, as well as commentary and analysis. Investors might "rely" on the reports for that other content, not BCFF's interest rate forecasts, per se.

**Q. SUPPOSE WE IGNORED THE CONCERN YOU EXPRESSED ABOUT CONSISTENCY WITH THE DCF AND WANTED A FORECAST RISK-FREE INTEREST RATE ASSUMPTION FOR THE CAPM. WHAT SHOULD WE USE?**

A. It turns out that current interest rates generally provide an unbiased forecast of future rates. Figure 18 is a cross-plot of the 20-year Treasury rate one year ahead against the current rate. Current interest rates account for approximately 91% of the variation in future interest rates;

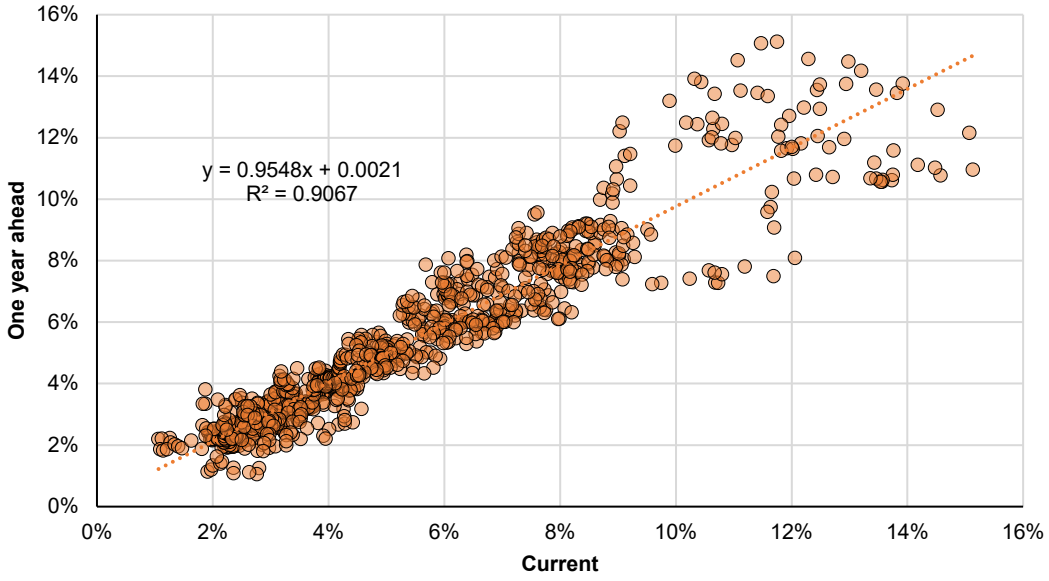
[96] In the 2020 annual report of Wolter Kluwers, BCFF's owner, $905 million of revenue was attributed to the Legal & Regulatory segment, of which BCFF is just 1 of 99 offerings. *See* https://www.wolterskluwer.com/en/legal/our-solutions. BCFF costs approximately $2,500/year. Even assuming BCFF accounts for 10% of segment revenue – roughly ten times the segment average – BCFF has no more than 40,000 subscribers.

[97] More than half of U.S. adults and households are invested in the stock market. *See, e.g.*, Kim Parker and Richard Fry, *More than half of U.S. households have some investment in the stock market*, Pew Research Center (March 25, 2020), https://www.pewresearch.org/fact-tank/2020/03/25/more-than-half-of-u-s-households-have-some-investment-in-the-stock-market/; Lydia Saad and Jeffrey Jones, *What Percentage of Americans Owns Stock*, Gallup (May 12, 2022), https://news.gallup.com/poll/266807/percentage-americans-owns-stock.aspx.

[98] *See, e.g.,* Congressional Budget Office, *CBO's Economic Forecasting Record* at 13, 18 (Nov. 2002), https://www.cbo.gov/sites/default/files/107th-congress-2001-2002/reports/11-07-economicforecast.pdf.

for rates two years in the future, current interest rates explain 83% of the variation in future interest rates, and for rates in three years, current interest rates explain 79%. Regardless of the forecast horizon, the current rate is unbiased – exhibiting no tendency to be systematically too high or too low.[99] Similar predictive validity is obtained for 30-year Treasury and corporate bonds.[100]

**Figure 18. Twenty-year Treasury rate, one year in the future vs. current[101]**
January 1925-September 2022




More intuitively, markets are forward-looking. If investors expect interest rates to rise, their expectations will be incorporated into current yields. Consider the alternative. Suppose an investor expects the yield on the 30-year Treasury to rise from its current ~3% to 4% over the next six months. There is an inverse relationship between a bond's value and a bond's yield; when the yield rises, the value falls, and vice versa. An investor who expects bond yields to rise would not buy a bond today, because to do so would be to invest expecting a loss; better not to buy the bond at all. But market participants *do* buy at the current 3%, implying that the

[99] The bias in a forecast can be assessed from the decomposition of the mean square error into bias, inefficiency, and random variation components. For the 20-year Treasury, bias accounts for less than 0.2% of forecast error at all three forecast horizons. *See, e.g.*, Jacob Mincer and Zarnowitz, *The Evaluation of Economic Forecasts*, Economic Forecasts and Expectations: Analysis of Forecasting Behavior and Performance at 3-46 (NBER, 1969), http://www nber.org/chapters/c1214.

[100] The 20-year Treasury is used here because much more historical data are available.

[101] M. Ellis analysis of FRED data (last accessed October 2, 2022).

market overall does *not* expect rates to rise in the future. Current yields are the best predictor of future yields, especially for longer-term bonds.

The predictive validity of current rates has been acknowledged among utility cost of capital experts. Reviewing the academic research, Roger Morin, author of the frequently cited practitioner text, *New Regulatory Finance*, concludes, "The literature suggests that on balance, the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change [from the current interest rate] model."[102]

BCFF's consistently poor track record, the high predictive validity of current interest rates, and economic intuition are consistent with an extensive body of research on the superiority of simple prediction models to both more complex models and expert judgment.[103]

Current interest rates are the most accurate and unbiased publicly available estimates for future interest rates that I am aware of. Conveniently, using the current rate also entirely skirts the potential concern about horizon inconsistency with the DCF.

### 2. Mr. Coyne cherry-picks his beta calculation methodology, ignoring the wide variety of valid potential approaches and best practice for choosing among them.

**Q. HOW DOES MR. COYNE ESTIMATE THE BETA IN HIS CAPM MODEL?**

A. Mr. Coyne uses beta estimates from two different financial data providers, Value Line and Bloomberg. He uses Value Line's betas as reported. Mr. Coyne overrides Bloomberg's default settings and uses only a subset of the beta estimates Bloomberg provides, such that the calculation methodology and resulting beta estimates he reports for Bloomberg are very similar to Value Line's.

Importantly, Mr. Coyne selects two nearly identical beta calculation methodologies among the multitude of methodologies commonly used by practitioners and academics, specifically the two that currently tend to produce the highest results.

**Q. HOW DO BLOOMBERG AND VALUE LINE ESTIMATE THEIR BETAS?**

A. Both Bloomberg and Value Line estimate beta from the slope of a linear regression model of a stock's returns against the returns of the market overall. Both calculate "raw" betas from a

[102] ROGER A. MORIN, NEW REGULATORY FINANCE, PUB. UTIL. REPORTS at 172 (2006).
[103] *See, e.g.*, DANIEL KAHNEMAN, OLIVIER SIBONY, CASS SUNSTEIN, NOISE: A FLAW IN HUMAN JUDGMENT, HACHETTE BOOK GROUP at 111-147 (2021).

regression of trailing weekly, price-only returns of the stock in question against the corresponding market returns. Both also report "Blume-adjusted" betas – a weighted-average of approximately 2/3 of the raw beta and 1/3 of the market average of 1.0 – to correct for an empirically observed tendency for betas, on average, to regress toward the market mean over time that I discuss in more detail below.[104] Other details of their respective methodologies differ, which is why their beta estimates are not exactly the same even after Mr. Coyne's modifications to Bloomberg's defaults. Figure 19 summarizes the key elements of Value Line's and Bloomberg's beta estimation methodologies.

**Figure 19. Value Line and Bloomberg beta estimation methodologies[105]**

| Parameter | Value Line | Bloomberg (default) |
|---|---|---|
| Return frequency | Weekly | Weekly |
| Trailing history | 5 years | 2 years |
| Index | NYSE Composite | S&P 500 |
| Return calculation | | |
| Price-only/total | Price-only | Price-only |
| Excess/absolute | Absolute | Absolute |
| Simple/logarithmic | Logarithmic | Simple |
| Blume adjustment parameters | 0.65 x raw + 0.37 | None (unadjusted)<br>2/3 x raw + 1/3 |
| Rounding | Nearest 0.05 | None |
| Updating frequency | Approximately quarterly | Daily |

**Q. MR. COYNE WRITES, "[I]T IS IMPORTANT TO EMPHASIZE THAT BETA COEFFICIENTS ARE CALCULATED OVER A FIVE-YEAR PERIOD." IS FIVE YEARS OF WEEKLY RETURNS WITH THE BLUME ADJUSTMENT THE ONLY WAY TO CALCULATE BETA?**

A. No. Academic studies commonly use five years of *monthly* returns, without the Blume adjustment. Other financial data providers, including some used by Mr. Coyne elsewhere in his analysis, calculate beta using different trailing histories, return frequencies, and without the Blume adjustment. Yahoo! Finance and Zacks – data sources for some of Mr. Coyne's other

[104] Value Line reports only the Blume-adjusted beta. Bloomberg reports both raw and adjusted beta.

[105] Value Line, "Estimation of Beta by Value Line"; Bloomberg Professional Workstation Guide; "BETA, HRA, BETA, HRA, and CORR Calculation FAQs." Simple price-only returns: $r = \frac{P_{t+1}}{P_t} - 1$; logarithmic price-only returns: $r = \ln \frac{P_{t+1}}{P_t}$.

cost of capital analyses[106] – use five years of monthly returns and are unadjusted, like many academic studies. S&P Global Market Intelligence (S&P GMI), another data source frequently cited by Mr. Coyne,[107] reports 1- and 3-year betas using daily returns, also without the Blume adjustment.[108]

Bloomberg's default trailing history is 2 years. Bloomberg allows users to override several of its calculation parameters, such as the trailing history, market index, and return frequency. Bloomberg also reports both raw and adjusted beta by default. Mr. Coyne apparently overrode Bloomberg's default trailing history parameter and simply ignored its raw beta estimates to arrive at the Bloomberg betas used in his CAPM, which are nearly identical to those provided by Value Line.

Figure 20 lists recent betas from S&P GMI, Yahoo! Finance, and Zacks for Mr. Coyne's GPC proxy group. The average betas are 0.43 and 0.76 for S&P GMI using 1 and 3 years of daily returns, and 0.48 for Yahoo! Finance and Zacks, both using 5 years of monthly returns. All four sources' beta estimates are lower than Mr. Coyne's 0.85-0.88 figures.[109]

**Figure 20. S&P GMI, Yahoo! Finance, and Zacks betas[110]**
As of September 30, 2022

| Utility | Ticker | S&P GMI 1-year daily | S&P GMI 3-year daily | Yahoo! Finance 5-year monthly | Zacks 5-year monthly |
|---|---|---|---|---|---|
| ALLETE | ALE | 0.44 | 0.88 | 0.61 | 0.61 |
| Alliant | LNT | 0.39 | 0.66 | 0.46 | 0.47 |
| Ameren | AEE | 0.40 | 0.72 | 0.36 | 0.35 |
| AEP | AEP | 0.42 | 0.61 | 0.34 | 0.34 |
| Duke | DUK | 0.32 | 0.71 | 0.35 | 0.35 |
| Edison Int'l | EIX | 0.53 | 0.82 | 0.68 | 0.67 |
| Entergy | ETR | 0.42 | 0.84 | 0.57 | 0.57 |
| Evergy | EVRG | 0.44 | 0.84 | 0.48 | 0.48 |
| Hawaiian Electric | HE | 0.41 | 0.66 | 0.32 | 0.32 |
| IDACORP | IDA | 0.38 | 0.73 | 0.56 | 0.56 |
| NextEra | NEE | 0.68 | 0.84 | 0.46 | 0.46 |
| OGE | OGE | 0.44 | 0.77 | 0.65 | 0.67 |
| Portland General | POR | 0.34 | 0.81 | 0.52 | 0.51 |
| Xcel | XEL | 0.37 | 0.68 | 0.35 | 0.34 |
| **Mean** | | **0.43** | **0.76** | **0.48** | **0.48** |

[106] Mr. Coyne uses Yahoo! Finance and Zacks EPS growth rates in his DCF model. *See* Ex. JMC-4.
[107] *See, e.g.,* Ex. JMC-9.
[108] M. Ellis analysis of S&P GMI data.
[109] Ex. JMC-5.2.
[110] M. Ellis analysis of S&P GMI data; Yahoo! Finance; Zacks.

**Q. WHY DO BLOOMBERG AND OTHER FINANCIAL DATA PROVIDERS USE DIFFERENT BETA CALCULATION METHODOLOGIES, PROVIDE MULTIPLE ESTIMATES, AND ALLOW USERS TO OVERRIDE THEIR DEFAULTS?**

A. Beta is intended to be a *forward-looking* measure of relative risk, so it is inherently uncertain. It cannot be measured directly (like an interest rate) and is usually estimated from *historical* data, as the slope of the regression of the returns of a stock against the returns of the market over a recently-ended historical period. Estimates based on historical data generally reasonably reflect future expectations, because most companies' risk profiles change slowly over time. Slowly changing risk profiles prove particularly true for the relatively stable and predictable utility sector.

But if a dramatic change in the market or in individual stocks occurs, as in the pandemic-related market turmoil of early 2020, that change will influence the beta estimate for as long as the period of change is included in the trailing data used in the beta calculation, even if investors' risk perceptions have returned to their level prior to the dramatic change. Analysts should always examine whether the change in market conditions was temporary or is sustained. Mr. Coyle's analysis suffers from his failure to examine whether the pandemic-related change in market conditions was temporary or has been sustained.

**Q. HOW CAN WE DETERMINE WHETHER THE CHANGE IN INVESTORS' RISK PERCEPTIONS WAS TEMPORARY OR HAS BEEN SUSTAINED?**

A. Determining whether the change in investors' risk perception was temporary or has been sustained is typically done by examining how betas calculated using different amounts of trailing data and returns calculated at different frequencies – for example, daily, weekly, or monthly – have changed over time.

**Q. IS THE NEED TO ESTIMATE BETA USING DIFFERENT METHODOLOGIES WELL KNOWN?**

A. Yes. Utility cost of capital expert witnesses Michael Vilbert and Bente Villadsen have written about the trade-offs of different methodologies, highlighting the need to consider shorter calculation intervals in the wake of abrupt disruptions such as was experienced first during and then immediately after the pandemic-driven bout of market turmoil in early 2020:

> The choices for the interval for the return data and the length of the beta estimation window involve trade-offs between obtaining more observations through the choice of a longer window and/or more frequent return data, ensuring that no structural change has occurred during the estimation window, and avoiding problems due to insufficient trading activity. … Balancing these considerations, economists typically recommend estimating beta using daily, weekly, or monthly returns over the most recent 2- to 5-year period, with weekly being the more common, *except if there are reasons to think that the industry might be subject to recent changes in systematic risk so that the use of a more recent data window is desirable*.[111]

The need to examine beta using different calculation methodologies is also reflected in data providers' offerings. As explained previously, Bloomberg allows users to easily override its default beta calculation parameters. S&P GMI, in addition to reporting betas calculated using 1 and 3 years of trailing data, provides its users with spreadsheet models that allow them to modify all of its beta calculation parameters.

In using both Value *and* Bloomberg betas, Mr. Coyne implicitly acknowledges that no single beta calculation methodology necessarily reflects current investor expectations. But the differences in the Value Line and (modified) Bloomberg beta methodologies he uses are immaterial. Their different market indexes – NYSE Composite for Value Line, S&P 500 for Bloomberg – are nearly perfectly correlated (0.96 correlation[112]), and their slightly different Blume adjustment weights yield differences in beta of 2% or less across the range of typical raw utility betas (0.4-1.0). Mr. Coyne's chosen methodologies hardly reflect the wide range of ways beta could be calculated, each of which could produce dramatically different results. As Nobel laureate Fischer Black, one of the pioneers of empirical testing of beta and the CAPM, famously admonished, "Watch out for data mining!"[113] – running an analysis several different ways but reporting only the outcomes that support one's conclusions.

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[111] BENTE VILLADSEN, MICHAEL J. VILBERT, DAN HARRIS, LAWRENCE KOLBE, RISK AND RETURN FOR REGULATED INDUSTRIES, ACADEMIC PRESS at 73-76 (2017) (emphasis added).

[112] Correlation between five years of weekly, simple, price-only, absolute returns for the S&P 500 and NYSE Composite Indexes, through February 25, 2022. M. Ellis analysis of S&P GMI data.

[113] Fischer Black, *Beta and Return*, 20(1) J. Portfolio Management 8 (1993), https://jpm.pm-research.com/content/20/1/8.

**Q. WHICH METHODOLOGICAL DIFFERENCES ACCOUNT FOR THE MOST VARIATION IN BETA ESTIMATES?**

A. The largest potential sources of variation in beta estimates arise from their trailing return history duration, return calculation frequency, and Blume adjustment parameters.

**Q. HOW DOES THE DURATION OF TRAILING RETURN HISTORY AFFECT BETA ESTIMATES?**

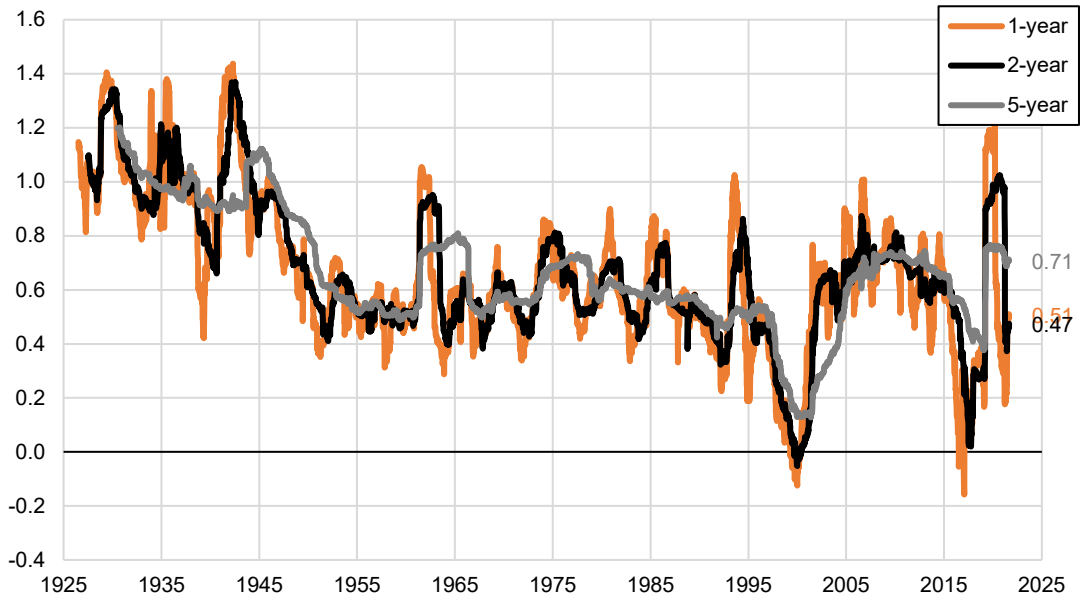
A. Following bouts of high market volatility, such as was experienced in the early days of the pandemic in February and March 2020, betas will be affected as long as the trailing history includes the volatile period, even if market conditions have stabilized. For example, S&P GMI reports unadjusted betas calculated from both 1 and 3 years of daily returns.[114] As of July 27, 2022, the average 1-year beta for the proxy group, which does not include the volatile period, was 0.28; the average 3-year beta, which does include the volatile period, was 0.72.[115] For comparison, on the same day, Yahoo! Finance's and Zacks's group average 5-year unadjusted betas using monthly returns were 0.45.[116]

Figure 21 plots the raw beta for the entire utility sector using 1, 2, and 5 years of weekly returns from June 1926 through May 2022. At any given time, beta can be very sensitive to the trailing history used. As of the end of August 2022, the betas using the 1-, 2-, and 5-year trailing histories were 0.51, 0.47, and 0.71, respectively.

[*Remainder of page intentionally left blank.*]

[114] Personal correspondence with S&P GMI (November 2021).
[115] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022).
[116] M. Ellis analysis of Yahoo! Finance data (last accessed October 2, 2022); Zacks data (last accessed October 2, 2022).

**Figure 21. Utility sector raw beta – trailing return history sensitivity**[117]
July 1926-August 2022




In general, betas calculated using longer return histories tend to be the more stable over time, as the effect of any short-term period of volatility is reduced by longer surrounding periods of stability. Because utility cost of capital proceedings seek a relatively long-term estimate, it might be tempting to conclude that a longer trailing history is preferred in estimating a utility's beta for purposes of authorizing an ROE. As Vilbert and Villadsen astutely recommend, though, "if there are reasons to think that the industry might be subject to recent changes in systematic risk … the use of a more recent data window is desirable."[118] The current 5-year beta of 0.71, driven by the market turmoil of early 2020, is higher than its historical average since 1955 of approximately 0.55. The 1- and 2-year betas, at 0.51 and 0.47, respectively, are in-line with their long-term historical averages. After the brief period of unusual market volatility in early 2020 not seen since the World War II era, investor perceptions of utility risk quickly settled to their pre-pandemic levels. Because of their shorter trailing histories, the 1- and 2-year betas are more reflective of *current* investor sentiment.

Figure 21 also betrays Mr. Coyne's claim that "the recent movement in betas captures a trend that began five years ago but has been accelerated by the recent market conditions" and

[117] M. Ellis analysis FDL (last accessed July 20, 2022).
[118] BENTE VILLADSEN, MICHAEL J. VILBERT, DAN HARRIS, LAWRENCE KOLBE, RISK AND RETURN FOR REGULATED INDUSTRIES, ACADEMIC PRESS at 73-76 (2017).

that "[t]he substantial increase in Beta coefficients for the proxy group companies represents a significant departure from how investors have typically viewed utilities relative to the broader market and is not just COVID-19 related."[119] Regardless of the duration of the trailing return used, utility sector betas were in a decade-plus-long decline before the pandemic. Once the early-pandemic period of market turmoil fell out of the trailing historical data, as with the 1- and 2-year betas, betas returned to their pre-pandemic levels.

The sharp declines in the 1- and 2-year betas in Figure 21 make it clear that Mr. Coyne's elevated 5-year weekly betas are not valid indicators of current investor expectations but purely artifacts of the inclusion of a transitory and short-term market anomaly.

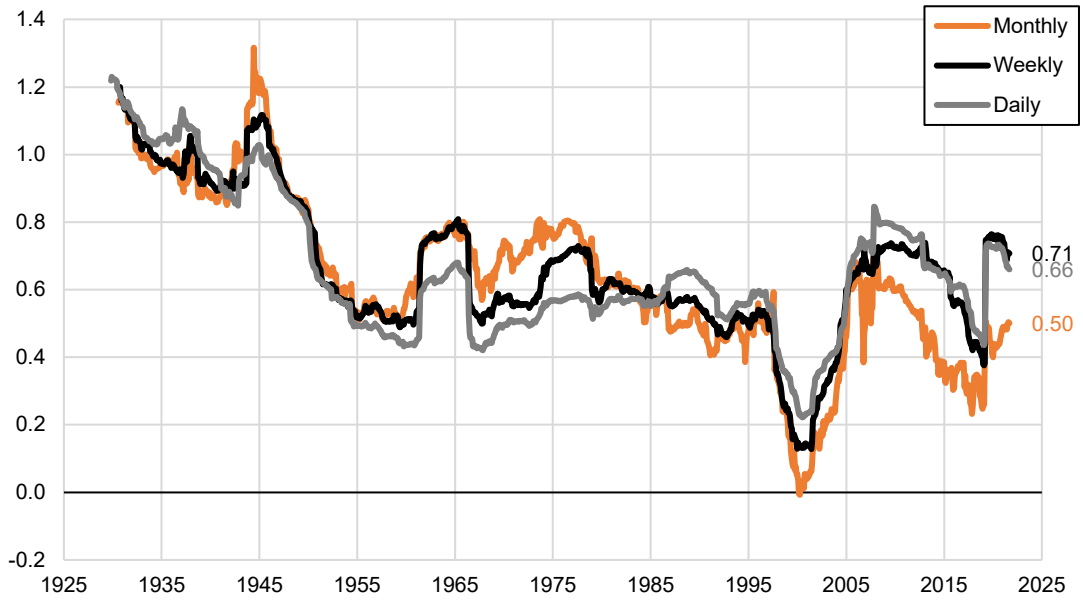
**Q. HOW DOES THE FREQUENCY OF RETURN CALCULATION AFFECT BETA ESTIMATES?**

A. Figure 22 plots the raw beta for the entire utility sector using 5 years of monthly, weekly, and daily returns from June 1926 through May 2022. As with the trailing history, at any given time, beta can be very sensitive to the return calculation frequency used. As of the end of August 2022, the betas using the monthly, weekly, and daily trailing histories were 0.50, 0.71, and 0.66, respectively. In general, betas tend to be more stable at higher return calculation frequencies. For any given trailing history duration (e.g., 1, 2, or 5 years), shorter return frequencies generate more data for use in the beta calculation: weekly returns generate approximately four times more data than monthly; daily approximately five times more than weekly. As the return frequency increases, any extreme data points are averaged with a larger number of "typical" data points, which tends to mitigate abrupt changes in beta over time.

This finding would tend to recommend using shorter return frequencies, due to their greater stability over time. But the choice of return frequency should reflect the time horizon of the analysis in which the CAPM-derived cost of equity will be used. Utility cost of capital proceedings seek to estimate a cost of equity that applies over a multi-year period. This consideration recommends a longer calculation frequency.

[119] 2022 Rate Case Hr'g Tr. Vol. 1 at 660-61 (Sept. 28, 2022).

**Figure 22. Utility sector 5-year raw beta – return calculation frequency sensitivity**[120]
July 1926-August 2022



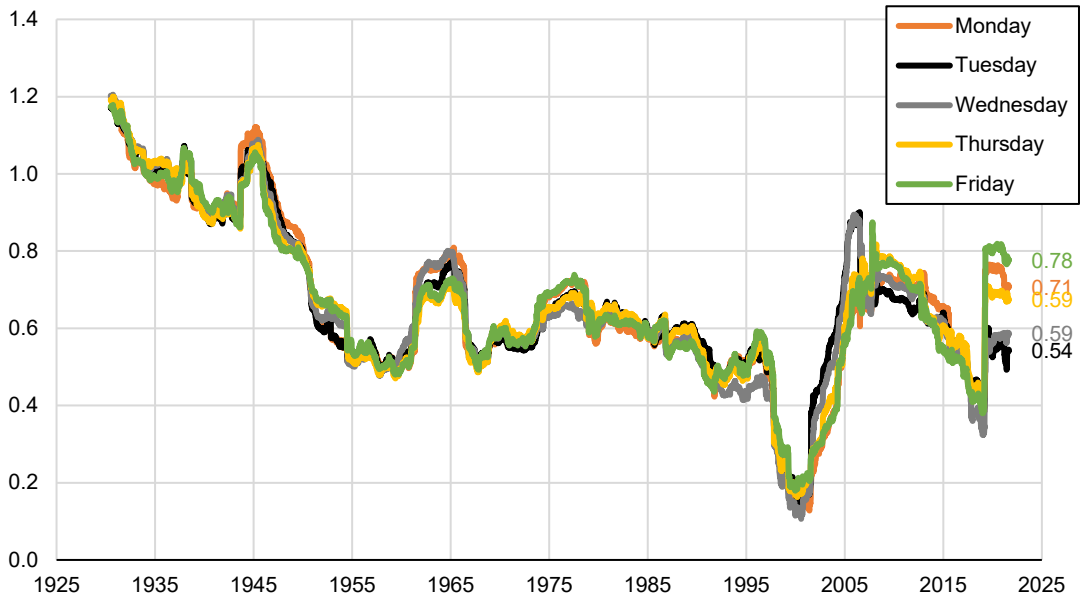

**Q. HOW DO OTHER BETA CALCULATION PARAMETERS IMPACT THE VARIATION IN BETA ESTIMATES?**

A. Even a beta calculation parameter as seemingly arbitrary as the day of the week on which weekly returns are calculated can materially affect the beta estimate. Figure 23 shows the 5-year trailing beta, i.e., raw Value Line-equivalent, with returns calculated on each weekday. Currently, Friday yields the highest beta, 0.78, but simply changing the calculation day to Tuesday reduces the beta to 0.54, 31% lower. This day-of the-week return calculation effect is only partially mitigated by averaging multiple utilities. The stock prices of individual companies within the sector tend to move together on any given day, so weekly returns calculated on the same day will tend to be similar.

This finding highlights the deficiency in Mr. Coyne's analysis in failing to examine alternative beta calculation methodologies and the potential arbitrariness of his selected methodologies. It also further highlights the need for caution in using the mechanically calculated betas provided by Value Line, Bloomberg, or other financial data providers, particularly betas calculated using weekly returns, without examining how they've changed over time or comparing them to long-term historical averages.

[120] M. Ellis analysis of FDL data (last accessed October 2, 2022).

**Figure 23. Utility sector 5-year weekly raw beta – return calculation day sensitivity[121]**
July 1926-August 2022




**Q. YOU LISTED THE BLUME ADJUSTMENT AS A THIRD SOURCE OF VARIATION IN BETA ESTIMATES. WHAT IS THE ORIGIN OF THE BLUME ADJUSTMENT?**

A. The Blume adjustment is based on an analysis conducted by Wharton professor Marshall Blume in the early 1970s. Analyzing beta-sorted portfolios, he found a tendency for betas, on average, to regress toward the market average beta, 1.0, from one time period to the next.[122] Based on this finding, some providers of beta estimates report adjusted betas that are a weighted average of the raw estimate and the market mean. The most common weighting is 2/3 on the raw beta, 1/3 on the market beta (1.0):[123]

$$\beta_{adjusted} = \frac{2}{3}\beta_{raw} + \frac{1}{3}.$$

For stocks with raw betas below 1.0, like most utilities historically, the effect of the adjustment is to increase the beta one-third of the way toward 1.0. For example, a stock with a raw beta of 0.4 would have an adjusted beta of 2/3 x 0.4 + 1/3 = 0.6. For its adjusted beta,

[121] M. Ellis analysis of FDL data (last accessed October 2, 2022).
[122] Marshall E. Blume, *On the Assessment of Risk*, 26:1 J. Finance at 1-10 (1971) https://onlinelibrary.wiley.com/doi/10.1111/j.1540-6261.1971.tb00584.x.
[123] The 2/3 and 1/3 weights are based on the regression coefficients Blume presented in his original paper, which regressed betas in one period against betas in the previous period.

Bloomberg uses the common 2/3 and 1/3 weights. Value Line's weights are similar: 0.67 and 0.35, respectively. Value Line also rounds to the nearest 0.05.[124]

As Vilbert and Villadsen note, "analysts have different views on whether to use raw or adjusted betas,"[125] hence the reporting of unadjusted betas by Bloomberg, S&P GMI, Yahoo! Finance, and Zacks.

**Q. IS THE BLUME ADJUSTMENT VALID FOR UTILITIES?**

A. No, it is not. The Blume adjustment is based on an observation of the tendency of betas, *on average*, to regress toward 1.0. But not every stock exhibits this tendency. Blume did not investigate whether and how this tendency might vary across stocks with different characteristics.

Rutgers professor Richard Michelfelder investigated the validity of the beta adjustment specifically for utility stocks and found no evidence of the average tendency observed by Blume.[126] This can be clearly seen in Figure 24, which shows the same 7-year monthly beta used by Blume in his original analysis for the entire utility sector going back to 1926. Since the 1950s, the beta for the utility sector as a whole has tended to regress toward 0.50-0.60, not 1.0.[127]

[*Remainder of page intentionally left blank.*]

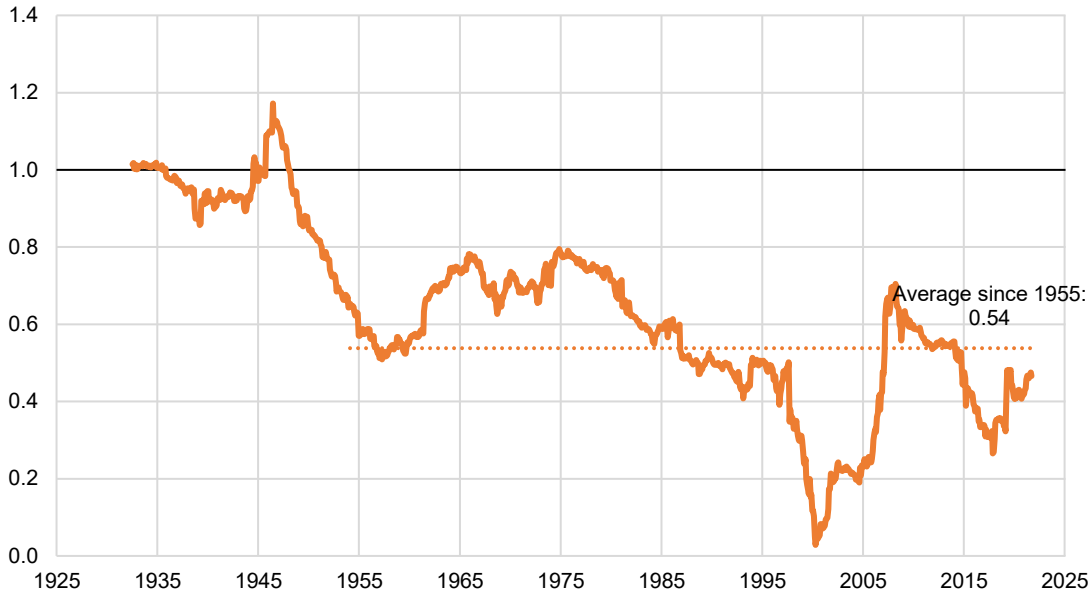
[124] Value Line, "Value Line's Estimation of Beta," personal correspondence (October 6, 2021).

[125] BENTE VILLADSEN, MICHAEL J. VILBERT, DAN HARRIS, LAWRENCE KOLBE, RISK AND RETURN FOR REGULATED INDUSTRIES, ACADEMIC PRESS at 80 (2017).

[126] Richard A. Michelfelder and Panayiotis Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings*, 26:9 The Electricity Journal at 60-68 (2013).

[127] One might ask whether the utility sector average reflects the tendency of individual utility stocks. Betas are additive, so a tendency for individual utility stocks to regress toward 1.0, on average, would be reflected in the industry beta. Blume used the same logic to extrapolate from the portfolios he analyzed to individual stocks. *See* Eugene F. Fama and Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, 18:3 J. Economic Perspectives 25, 31 (2004), https://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430.

**Figure 24. Utility sector 7-year monthly raw beta[128]**
July 1926-August 2022




Blume speculated as to why betas, on average, tend to regress toward 1.0 over time.[129] High-beta firms tend to be newer and smaller; as they mature and grow, they become more risk-averse. In contrast, low-beta firms tend to run out of low-risk investment opportunities and must accept more risk to stay in business. Neither of these causal explanations applies to utility operating companies, like Georgia Power and the publicly traded members of the GPC proxy group. They are large and mature, and their investments tend to have consistently low risk profiles over time. These attributes combine to keep utilities' betas sustainably and significantly below 1.0.

Empirical analysis specifically investigating utility betas, grounded in sound economic reasoning, demonstrates that utility betas do not have a tendency to regress toward the market average and therefore should not be Blume-adjusted.[130]

[128] Market capitalization-weighted average of all NYSE-, AMEX-, or NASDAQ-listed utilities. M. Ellis analysis of FDL data.
[129] Marshall E. Blume, *Betas and Their Regression Tendencies*, 30:3 The Journal of Finance 785-795 (1975), https://onlinelibrary.wiley.com/doi/abs/10.1111/j.1540-6261.1975.tb01850.x.
[130] Blume used mean squared error (MSQ) to assess the accuracy of his adjustment. It can be shown that the standard 2/3 and 1/3 weights increase the MSQ for utility betas by approximately 35%.

**Q. WHAT ARE YOUR CONCLUSIONS ABOUT MR. COYNE'S CHOICE OF BETA ESTIMATION METHODOLOGY?**

A. The variation in the three most recent beta estimates in Figure 21 suggests we should not unthinkingly use the most recent trailing betas from Value Line, Bloomberg, or any other data provider. It's important to keep in mind that all methodologies are intended to produce *estimates of investors' future expectations*. The elevated current 5-year betas used by Mr. Coyne are artifacts of arbitrary choices of calculation period; there is no reason to believe they reflect investors' current long-term expectations.

The seven-week bout of market volatility in early 2020 was an anomaly, and investor perceptions of utility risk quickly returned to their pre-pandemic levels. The 5-year return history used in Mr. Coyne's beta estimates does not accurately reflect current investor sentiment.

The betas used by Mr. Coyne are inflated because they are (1) Blume-adjusted and (2) incorporate an anomalous period that does not reflect investors' *current, long-term* expectations.

### 3. Mr. Coyne estimates his market risk premium using a constant-growth DCF model with the same flawed perpetuity growth assumption as his proxy group DCF analysis.

**Q. HOW DOES MR. COYNE ESTIMATE THE THIRD ASSUMPTION IN THE CAPM, THE MARKET RISK PREMIUM?**

A. Mr. Coyne estimates the market risk premium (MRP) using the same constant-growth discounted cash flow model he uses for the proxy group in his DCF analysis. As detailed in Section IV.C.2 above, Mr. Coyne's fatally flawed implementation of the CG DCF erroneously assumes analysts' 3-to-5-year EPS growth estimates can be sustained into perpetuity, a deficiency of which he is aware. This assumption is invalid for several reasons, perhaps the most compelling of which is that it is simply economically impossible for the market to sustain analysts' forecast growth rates for even a decade, much less forever. Since 1926, U.S. stock market dividend growth has averaged 4.9% (1.9% in real terms)[131] – roughly 40% of the 12.4%-14.2% range assumed by Mr. Coyne.[132] The market has never sustained 12.4% dividend

[131] M. Ellis analysis of FDL data (last accessed October 2, 2022).
[132] Ex. JMC-5.1.

growth for even seven years, much less into perpetuity – certainly raising a legitimate "concern that short term growth rates may not be sustainable over the longer-term." Mr. Coyne nonetheless ignores his own advice and uses the constant growth DCF to estimate his CAPM MRP. Consequently, Mr. Coyne's MRP results beggar belief: at 11.8%-12.5%, they are roughly 2.5 times the long-term historical average of approximately 5%.

#### 4. Mr. Coyne's flawed CAPM results should be disregarded.

**Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE CAPM AND MR. COYNE'S IMPLEMENTATION OF IT?**

A. The CAPM is conceptually sound and one of the most widely used COE models in corporate finance. But Mr. Coyne's implementation choices – a forecast, not current, risk-free interest rate; a cherry-picked adjusted beta that is not reflective of current market conditions or utilities' long term risk profile; and a flawed MRP model – yields systematically upwardly-biased results. His flawed CAPM results should be disregarded.

### F. Implementing the CAPM with more rigorously estimated assumptions produces substantially lower COE estimates.

**Q. PLEASE EXPLAIN YOUR IMPLEMENTATION OF THE CAPM.**

A. There are three components to the CAPM: the risk-free rate, beta, and the market risk premium. For the risk-free rate I use the current, not forecast, 30-year Treasury rate.

As explained above in Section IV.E.2, beta is the most subjective of the three CAPM parameters, and no single calculation methodology produces the most reasonable estimates in all market conditions. Based on my review of the latest research literature, I use the betas provided by Yahoo! Finance, calculated using five years of monthly returns. Five-year monthly betas are consistent with cost of capital proceedings' objective of estimating a multi-year cost of equity, and their current values strike a reasonable balance between current market sentiment and the long-term historical average for utilities.

I estimate the market risk-premium from the average of the long-term historical trend and a forward-looking estimate calculated using the MS DCF.

### 1. The risk-free rate, one of the three CAPM inputs, should be estimated from the current, not forecast, interest rate.

**Q. HOW DO YOU ESTIMATE THE RISK-FREE RATE?**

A. Like Mr. Coyne, I use the 30-year Treasury. I use the most recent full-month average 30-year Treasury rate, for September 2022, of 3.56%. As explained above in Section IV.E.1, current market interest rates provide an unbiased estimate of future rates and are generally superior to publicly available "expert" forecasts.

### 2. Betas calculated using five years of monthly returns are consistent with the objective of a cost of capital proceeding and strike an appropriate balance between recent market conditions and utilities' long-term historical risk profile.

**Q. HOW DO YOU ESTIMATE BETA?**

A. As explained in Section IV.E.2 above, no single, widely used approach to estimating beta exists. Beta estimates can vary substantially depending, in particular, on the historical trailing period used, return calculation frequency, and adjustment for long-term trend reversion. I use 5-year monthly betas such as those provided by Yahoo! Finance and Zacks and commonly used in academic studies. Five-year betas using monthly returns are consistent with cost of capital proceedings' objective of estimating a multi-year expected cost of equity. The current average of 0.48 for the GPC proxy group, shown in Figure 20, strikes an appropriate balance between the long-term historical range 0.5-0.6 and current subdued investor perceptions of risk, as reflected in 1-year betas using daily returns of approximately 0.4.

### 3. The market risk premium estimate should reflect both current market conditions and the long-term historical trend.

**Q. WHY CAN'T WE JUST LOOK UP THE MRP LIKE, SAY, WE CAN LOOK UP A STOCK PRICE OR INTEREST RATE?**

A. The market risk premium is the difference between investors' expectations of future stock returns and the risk-free (interest) rate. While interest rates are directly observable, expected future market returns are not. The MRP must therefore be estimated. A historical average is a useful check for reasonableness, but the cliché, "past performance is no guarantee of future results," applies. Instead, analysts use a variety of models and input assumptions to estimate the MRP.

**Q. HOW DO YOU ESTIMATE THE MARKET RISK PREMIUM?**

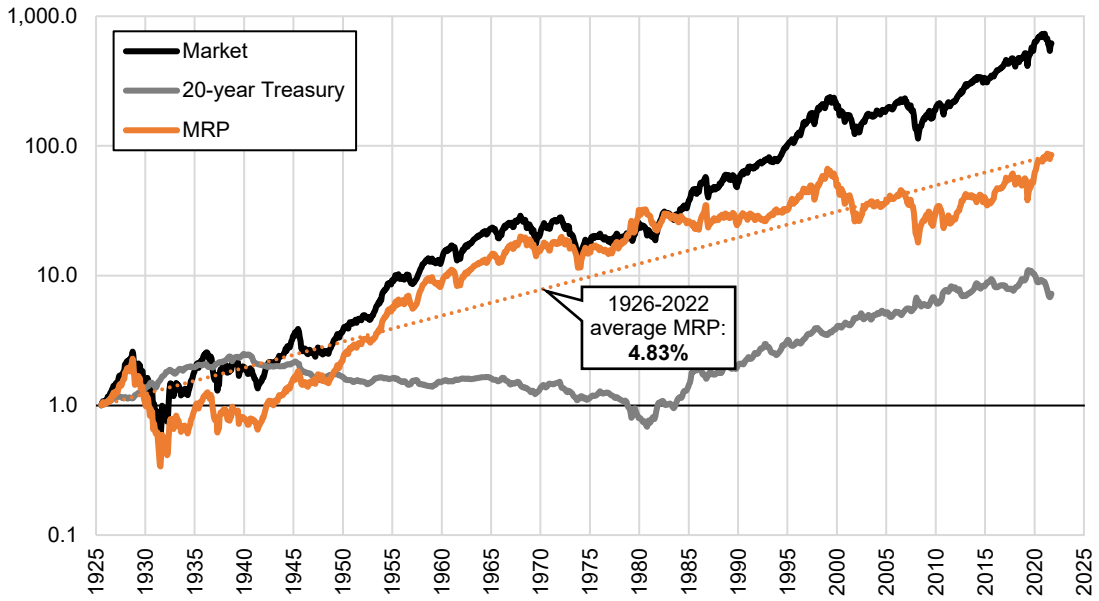
A. I use the average of two methods, one historical, the other forward-looking.

**Q. HOW DO YOU ESTIMATE THE HISTORICAL MARKET RISK PREMIUM?**

A. I use the long-term historical difference in the average real total returns on the market and long-term Treasury bond.[133]

Figure 25 shows the long-term historical real returns on the market and 20-year Treasury bonds, as well as the implied MRP, from June 1926 through August 2022. Over the last 96+ years, stocks have outperformed 20-year Treasurys by 4.83% per year.

**Figure 25. Market, 20-year Treasury, and MRP real total return index[134]**
June 1926=1.0 (log scale)




The historical MRP is calculated using 20-year Treasury data because that is the most extensive Treasury bond data set available.[135] Because I use the 30-year Treasury in my CAPM

[133] Total bond return is the monthly interest (the yield divided by 12) plus any capital gain or loss, estimated as the change in value from discounting the remaining interest payments (i.e., the previous time period's interest rate) and outstanding principal at the current time period's interest rate. This method is widely used, for example, by NYU finance professor Aswath Damodaran (*see, e.g.,* http://people.stern nyu.edu/adamodar/pc/datasets/histretSP.xls) and UCLA finance professor Ivo Welch (*see, e.g.,* Ivo Welch, *A Different Way to Estimate the Equity Premium (for CAPM and One-Factor Model Use Only)*, (2008) https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1077876).

[134] M. Ellis analysis of FDL data (last accessed October 2, 2022).

[135] The early historical monthly data available for long-term Treasurys is not specifically for the 20-year. A simple regression model is used to adjust the long-term Treasury data to estimate the 20-year yield.

analysis, though, the premium is reduced by the current difference in the inflation-adjusted 20- and 30-year Treasurys (TIPS), 0.08%, for a 30-year real MRP of 4.75%. Adjusted for the 30-year inflation rate estimated from the Treasury-TIPS spread, 2.24%, the nominal MRP is 4.86%.

**Q. HOW DO YOU ESTIMATE THE FORWARD-LOOKING MRP?**

A. I apply the same multi-stage DCF model I use for the GPC proxy group to the market as a whole, represented by the S&P 500 Index, and subtract the current 30-year Treasury.

**Q. HOW DO YOU ESTIMATE THE CURRENT DIVIDEND YIELD FOR THE S&P 500 INDEX?**

A. I use the same methodology I use for the proxy group members: the most recent dividend paid, through September 30, 2022, divided by the average price of the index over the month of September 2022. The current annualized yield is 1.73%.[136]

**Q. HOW DO YOU ESTIMATE THE INITIAL GROWTH RATE FOR THE S&P 500 INDEX?**

A. I use the weekly estimate provided in S&P's weekly S&P 500 earnings and estimate report. I use this source because it is publicly available, well-known, frequently updated, and produced by the party with the most intimate knowledge of the index. As of September 30, 2022, S&P's estimate for the S&P 500 Index's 3-to-5-year growth rate is 13.6%.[137]

**Q. HOW DO YOU ESTIMATE THE TERMINAL GROWTH RATE FOR THE S&P 500 INDEX?**

A. Many analysts incorrectly assume long-term dividend growth equal to nominal GDP growth. Historically, per-share payout growth, whether measured as dividends or dividends plus net share buybacks, has tracked GDP per capita.[138] I assume a terminal growth rate based on forecast real long-term per-capita GDP plus the current market forecast for long-term inflation, estimated as described in Section IV.D.3.

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[136] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022).

[137] S&P Dow Jones Indices, S&P 500 Earning and Estimate Report (September 30, 2022), https://www.spglobal.com/spdji/en/documents/additional-material/sp-500-eps-est.xlsx (last accessed October 2, 2022).

[138] *See, e.g.,* ROGER IBBOTSON, JAMES HARRINGTON, STOCKS, BONDS, BILLS, AND INFLATION 2021 SUMMARY EDITION, CFA INSTITUTE RESEARCH FOUNDATION BOOKS at 157-60 (2021) (Analysis is for total payout to account for the effect of net stock repurchases).

For long-term per-capita GDP growth, I use the average of the most recent long-term CPI-adjusted forecasts from three government agencies: the Congressional Budget Office (CBO),[139] the Energy Information Administration (EIA),[140] and the Social Security Administration (SSA).[141] I use the compound annual growth rate from 2042 to remove any near-term transitory effects, such as post-Covid economic recovery, and to align with the time period used to estimate long-term inflation (years 21 through 30 from today).

TIPS payouts are tied to CPI, so the Treasury-TIPS spread provides a forecast of *consumer* price inflation. In contrast, real GDP forecasts are deflated by the GDP deflator, which reflects the prices of all domestic expenditures, including by businesses and government. For consistency with the CPI forecast derived from the Treasury-TIPS spread, which reflects only the prices paid by consumers, I use each agency's nominal GDP forecast deflated by its CPI forecast, rather than its GDP deflator forecast. Figure 26 summarizes the three agencies' real long-term per-capita GDP forecasts.

**Figure 26. Real long-term per-capita GDP forecasts**
Percent

| | | GDP | | | | Nominal | | CPI-deflated |
|---|---|---|---|---|---|---|---|---|
| **Forecast** | **Horizon** | Real | Deflator | Nominal | Population | **GDP pc** | **CPI** | **GDP pc** |
| CBO | 2052 | 1.52 | 2.00 | 3.55 | 0.24 | 3.30 | 2.26 | 1.02 |
| EIA | 2050 | 1.99 | 2.28 | 4.32 | 0.33 | 3.98 | 2.40 | 1.55 |
| SSA[142] | 2100 | NA | NA | 4.09 | 0.42 | 3.65 | 2.40 | 1.22 |
| **Mean** | | 1.76 | 2.14 | 3.99 | 0.33 | 3.64 | 2.35 | 1.26 |
| + Treasury-TIPS long-term inflation | | | | | | **2.85** | 1.57 | |

The average of the CBO, EIA, and SSA (the agencies) CPI-deflated long-term per-capita GDP growth rates is 1.26%. Adding the same long-term inflation expectation, 1.57%, used to estimate the terminal growth rate in the proxy group MS DCF in Section IV.D.3 above gives a nominal rate of 2.85%.[143] The corresponding average of the CBO, EIA, and SSA long-term

[139] Congressional Budget Office, *The 2022 Long-Term Budget Outlook*, (July 2022), https://www.cbo.gov/system/files/2022-07/57054-2022-07-LTBO.xlsx.
[140] Energy Info. Admin., *Annual Energy Outlook 2022*, (March 2022), https://www.eia.gov/outlooks/aeo/excel/aeotab20.xlsx.
[141] Soc. Sec. Admin., *The 2022 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*, (June 2022) (https://www.ssa.gov/OACT/TR/2022/SingleYearTRTables_TR2022.xlsx).
[142] SSA does not forecast real GDP or the GDP deflator, only nominal GDP and CPI.
[143] Because these are compound growth rates, the geometric sum is used, $(1+g)(1+i)-1$.

per-capita nominal GDP growth rates is 3.64%. I use the market-implied long-term inflation rate rather than the agencies' for two reasons. First, although all three forecasts are the agencies' most recent, they are stale in comparison to the September 2022 average Treasury rates used to estimate inflation. Second, as demonstrated by the analysis of BCFF forecasts, market-derived data are generally considered less biased and more accurate indicators of investor expectations than expert forecasts.

**Q. WHAT IS YOUR FORWARD-LOOKING MRP?**

A. The S&P 500 MS DCF yields a forecast return of 6.43%. This result is consistent with the buy-side equity return forecasts summarized in Figure 3, which average 5.9% over the 10+-year horizon. Subtracting the current T30, 3.57%, gives an MRP of 2.87%.

**Q. AND YOUR COMBINED MRP?**

A. The average of my historical (4.86%) and forward-looking (2.87%) MRPs is 3.86%.

### 4. Implementing the CAPM with more rigorously estimated parameters yields COE estimates approximately one-third of Mr. Coyne's values.

**Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?**

A. The Yahoo! Finance and Zacks 5-year monthly betas for the GPC proxy group, listed in Figure 20, are both 0.48. The corresponding COE is 5.41%,[144] approximately 40% of the 13.55% average of Mr. Coyne's estimates.[145]

**Q. RECENT UTILITY BOND YIELDS ARE CLOSE TO, AND EVEN EXCEED, YOUR MS DCF AND CAPM RESULTS, 5.97% AND 5.41%, RESPECTIVELY. SHOULDN'T THE PREMIUM OVER BOND YIELDS BE GREATER?**

A. To compare my COE results to utility bond yields, we must use the monthly average yield that corresponds to the proxy group's average credit-rating, Baa1, for September 2022,[146] the averaging period of the inputs to my MS DCF and CAPM. Moody's provides several widely referenced utility bond yield indexes, but not specifically for Baa1-rated utility bonds. Nonetheless, the Baa1 yield can be estimated by interpolating between Moody's Baa and A

[144] COE = 3.57% + 0.48 x 3.86% = 5.41%
[145] 2022 Rate Case Hr'g Tr. Vol. 1 at 662 (Sept. 28, 2022).
[146] M. Ellis analysis of S&P GMI data (last accessed October 16, 2022). S&P credit ratings are used; it is assumed that, on average, the ratings are comparable to Moody's.

monthly average utility bond yields for September 2022, 2/3 x 5.61% + 1/3 x 5.28% = 5.50% – higher than my CAPM result of 5.41%.[147]

But a utility COE estimate – an expected return on equity – cannot be directly compared to the corresponding utility bond yield. Reported bond yields are yields to maturity, assuming no default. Default risk for bonds with a Baa1 rating reduces their expected returns by approximately 0.46%. Similarly, bonds are not as liquid as stocks and attract a liquidity premium of approximately 0.33%.[148] Deducting the default and liquidity premia from the Baa1 utility bond yield to maturity reduces it to approximately 4.74%, 1.24% and 0.67% lower than my MS DCF and CAPM COE estimates, respectively.

There is no hard-and-fast rule for what the spread of equity returns over the corresponding cost of debt should be. My MS DCF and CAPM results are consistent with my forward-looking MRP and beta estimates, third-party forecasts for total market returns, and the widely recognized low risk profile of utilities.

## G. Mr. Coyne's flotation cost adjustment is not analytically sound and is therefore unwarranted.

**Q. MR. COYNE ADDS A FLOTATION COST ADJUSTMENT TO HIS ROE MODEL RESULTS. IS A FLOTATION COST ADJUSTMENT WARRANTED?**

A. No. A flotation cost adjustment is not warranted. Mr. Coyne cites Roger Morin's *New Regulatory Finance* in support of adding a flotation cost adjustment,[149] but the application of the flotation cost adjustment provided in Morin's book is conceptually flawed. The math relied on by Mr. Coyne for his recommendation shows that shareholders make money from the issuance of new stock, so flotation cost adjustments are especially inappropriate.

[147] The ratings of Moody's A- and Baa-rated utility bond indexes are comparable to Moody's A2 and Baa2 ratings, respectively. The intermediate ratings are A3 and Baa1, so Georgia Power's Baa1 rating falls two-thirds of the way between A and Baa.

[148] Wolfgang Bühler and Monika Trapp, *Time-Varying Credit Risk and Liquidity Premia in Bond and CDS Markets*, CFR Working Papers 09-13, University of Cologne, Centre for Financial Research at 37 (2008), https://www.fdic.gov/analysis/cfr/2008/april/trapp-buhler.pdf.

[149] 2022 Rate Case Hr'g Tr. Vol. 1 at 669 (Sept. 28, 2022).

Mr. Morin's flotation cost adjustment assumes that the market price of the equity issued is equal to book value.[150] But, as shown in Figure 4 above, the average market-to-book ratio of the GPC proxy group is 2.1. As implied by the very formula provided by Mr. Morin, when the market price is greater than book value, new equity issuance is accretive to existing shareholders – that is, a share of the proceeds of the new issuance accrues to them.[151]

Morin derives the flotation cost adjustment from the formula for the extended DCF model under the assumption of continuous external stock financing:

$$k = \frac{D_1}{P} + br + sv,$$

where $b$ is the earnings retention ratio, $r$ is ROE, $s$ is the annual rate of new equity issuance (expressed as a share of existing book equity), and $v$ is the accretion factor, equal to $1 - \frac{B}{P}$. He then adjusts $P$ for flotation costs, $f$, so that $1 - \frac{B}{P(1-f)}$.[152] But as long as $(1 - f)$ exceeds $\frac{B}{P}$, i.e., the reciprocal of the market-to-book ratio, existing shareholders *gain* from new share issuance. Mr. Coyne estimates flotation costs to be 2.47%, so $1 - f = 0.98$, much greater than the reciprocal of the GPC proxy group average M/B ratio, 1/2.1 = 0.48.

**Q. UNDER THE NARUC FAIRNESS PRINCIPLE, ROE SHOULD EQUAL THE ACTUAL COST OF EQUITY. THIS WOULD IMPLY THAT THE MARKET-TO-BOOK RATIO EQUALS 1.0, IN WHICH CASE NEW EQUITY ISSUANCE WOULD NOT BE ACCRETIVE. IF THE COMMISSION ADHERES TO THE NARUC FAIRNESS PRINCIPLE, SHOULD ROE BE ADJUSTED FOR FLOTATION COSTS?**

A. No. Even if the M/B ratio is equal to 1.0, there is no reason to adjust the ROE for new equity issuance costs.

Purchasers of the newly issued equity know that a portion of proceeds will cover transaction costs, and the offering price reflects this information. There is no need to compensate new investors for issuance costs, which they knowingly pay when they purchase new shares, with an adjustment to the ROE. Similarly, existing shareholders know that the company may issue new equity over time. These costs, and their potential effect on expected

[150] ROGER A. MORIN, NEW REGULATORY FINANCE, PUB. UTIL. REPORTS at 328 (2006): "If $P_0$ is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, [if] $P_0$ equals $B_0$, the book value per share, …"

[151] MYRON J. GORDON, THE COST OF CAPITAL TO A PUBLIC UTILITY at 31-32 (1974).

[152] ROGER A. MORIN, NEW REGULATORY FINANCE, PUB. UTIL. REPORTS at 332-33 (2006).

returns, are likewise reflected in investors' willingness to buy, hold, or sell shares that determines share prices.

Mr. Coyne's flotation cost adjustment is small and is overwhelmed by the imprecision in his models. At 0.08%, it amounts to less than 2% of the 8.99%-13.55% range of Mr. Coyne's base ROE results.[153] To add a flotation cost adjustment is akin to the elementary school student, who, upon being asked what they learned during a field trip to the science museum, proudly says, "Earth is 4.5 billion years and [glancing at a clock] six hours and forty-three minutes old."

Mr. Coyne's flotation cost adjustment is conceptually flawed and not materially significant. It should be disregarded.

## V. GEORGIA POWER'S ROE AND EQUITY RATIO SHOULD OPTIMALLY BALANCE CUSTOMER AND INVESTOR INTERESTS.

### A. COE model results must be adjusted for differences in equity ratio.

**Q. IN SECTION IV.B ABOVE, YOU DISCUSSED ADJUSTING COE MODEL RESULTS FOR DIFFERENCES IN EQUITY RATIOS AMONG THE PROXY GROUP MEMBERS. HOW DO YOU DO THAT?**

A. The MS DCF and CAPM yield levered costs of equity. To account for differences in capital structure among the proxy group members, the COE results are unlevered to estimate the cost of equity assuming 100% equity financing.[154] The unlevered cost of equity, $k_u$, is typically expressed as an adjustment to beta in the CAPM:

$$k_u = r_f + \beta_u(r_m - r_f),$$[155]

where the unlevered beta, $\beta_u$, is expressed in terms of the levered equity beta, $\beta_e$:

[153] 2022 Rate Case Hr'g Tr. Vol. 1 at 668 (Sept. 28, 2022).

[154] The unlevered cost of equity differs from the weighted average cost of capital ("WACC"). The unlevered cost of capital assumes 100% equity financing; the WACC assumes the company's current capital structure. While under the Modigliani and Miller theorem of capital structure independence, the cost of capital should be the same regardless of capital structure, the WACC typically overstates the unlevered cost of equity because the *expected* return on corporate debt is lower than the yield due to default and liquidity risk.

[155] *See, e.g.*, ASWATH DAMODARAN, DAMODARAN ON VALUATION: SECURITY ANALYSIS FOR INVESTMENT AND CORPORATE FINANCE, WILEY 2ND ED. at 129 (2006).

$$\beta_u = \frac{E}{D+E}\beta_e.$$[156]

For consistency and comparability, I apply the same methodology – unlevering relative to the risk-free rate, not the company's cost of debt – to the MS DCF model results:

$$k_u = r_f + \frac{E}{D+E}\beta_l(r_m - r_f)$$

$$k_e - r_f = \beta_l(r_m - r_f)$$

$$k_u = r_f + \frac{E}{D+E}(k_e - r_f)$$

$$k_u = \frac{D}{D+E}r_f + \frac{E}{D+E}k_e,$$

where $D$ and $E$ refer to debt and equity, respectively. Best practice is to use market, not book, values for both debt and equity as market reflects investors' actual exposure; they buy and sell securities at market value, not book.[157] Market values for the debt carried by the proxy group members are not readily available, though, so book value is assumed.

[*Remainder of page intentionally left blank.*]

[156] Unlevered beta is sometimes adjusted for taxes (the "Hamada" adjustment). As explained in Damondaran in *Valuation*, when the capital structure is constant over time, as it is with utilities, then the value of tax shields tracks the value of operating assets. Thus, the risk of tax shields will mirror the risk of operating assets and have the same discount rate, i.e., the unlevered cost of equity. *Id*. at 790-93.

[157] *See, e.g.,* TIM KOLLER, MARC GOEDHART ET AL., VALUATION, 5TH ED. MCKINSEY & CO. 35 at 204 (2010): "Where possible, you should estimate *market* values of the elements of the current capital structure" (emphasis added).

**Figure 27. Proxy group levered COEs, equity ratios, and unlevered COEs[158]**
Percent, as of September 2022

| | Levered COE | | | | |
|---|---|---|---|---|---|
| **Utility** | MSDCF | CAPM | Average | **Equity ratio** | **Unlevered COE** |
| ALLETE | 8.25 | 5.92 | 7.08 | 56 | 5.52 |
| Alliant | 5.50 | 5.36 | 5.43 | 65 | 4.78 |
| Ameren | 5.36 | 4.93 | 5.15 | 61 | 4.53 |
| AEP | 5.92 | 4.87 | 5.40 | 57 | 4.61 |
| Duke | 6.70 | 4.91 | 5.81 | 52 | 4.73 |
| Edison Int'l | 6.61 | 6.17 | 6.39 | 42 | 4.75 |
| Entergy | 6.50 | 5.76 | 6.13 | 47 | 4.76 |
| Evergy | 6.00 | 5.41 | 5.71 | 56 | 4.77 |
| Hawaiian Electric | 5.73 | 4.80 | 5.26 | 62 | 4.62 |
| IDACORP | 4.78 | 5.72 | 5.25 | 74 | 4.81 |
| NextEra | 5.03 | 5.34 | 5.18 | 71 | 4.71 |
| OGE | 5.96 | 6.11 | 6.03 | 62 | 5.09 |
| Portland General | 5.93 | 5.55 | 5.74 | 56 | 4.78 |
| Xcel | 5.37 | 4.89 | 5.13 | 61 | 4.52 |
| **Mean** | **5.97** | **5.41** | **5.69** | **59** | **4.78** |
| *Standard deviation* | *0.87* | *0.48* | *0.57* | | *0.25* |
| *High* | *8.25* | *6.17* | *7.08* | | *5.52* |
| *Low* | *4.78* | *4.80* | *5.13* | | *4.52* |
| *High – low* | *3.47* | *1.37* | *1.95* | | *1.00* |

The variation in the unlevered COE estimates is much lower than in the levered COEs, with approximately half the standard deviation (0.25 vs 0.57) and range (1.00 vs. 1.95). The underlying businesses of the proxy group members are very similar, so their risk profiles and corresponding overall costs of capital are expected to be similar as well. Their equity ratios vary considerably, though, from 42% to 74%, which introduces variation in their levered costs of equity. This variation due to differences in equity ratios makes levered COEs an inappropriate basis for determining the ROE of a target company, like Georgia Power, which will likely have a different equity ratio.

**Q. HOW DO YOU USE THE PROXY GROUP AVERAGE UNLEVERED COE TO DETERMINE YOUR RECOMMENDATION FOR GEORGIA POWER'S ROE, WHICH IS LEVERED?**

A. The unlevered COE is "relevered" using the same formula described above, the terms of which can be rearranged as:

$$k_e = \frac{D+E}{E} k_u + \frac{D+E}{D} r_f.$$

[158] M. Ellis analysis of S&P GMI data; market equity ratio based on September 2022 average.

In Section III above, I explained that the equity ratio depends on ROE. ROE, in turn, depends on the equity ratio. They can be determined jointly, in an iterative calculation process that is easily performed in common spreadsheet software like Microsoft Excel or Google Sheets.

### B. ROE and equity ratio should be optimized to minimize customer costs while meeting investor requirements.

**Q. IN SECTION III.A ABOVE, YOU PROVIDED AN ILLUSTRATIVE ANALYSIS OF THE INTER-RELATIONSHIPS BETWEEN EQUITY RATIO, ROE, AND CREDIT QUALITY. CAN YOU CONDUCT THAT ANALYSIS SPECIFICALLY FOR GEORGIA POWER?**

A. Yes. Such an analysis can be conducted for Georgia Power using data provided in Moody's most recent credit update.[159]

Figure 28 applies the analysis illustrated in Figure 8 above to the financial data provided in Moody's October 2021 credit update for Georgia Power. As before, different levels of ROE are represented by the upward curving lines. As the equity ratio increases along the horizontal axis, so does the cash flow-to-debt ratio, depicted on the vertical axis. Here, cash flow from operations (CFO) is used instead of FFO, for consistency with Moody's preferred metric.[160] Black dashed horizontal lines have been added at the CFO/debt levels that correspond to potential target credit ratings: Georgia Power's current Baa1 ([redacted]% CFO/debt) and an upgrade to A3 ([redacted]%).[161]

The dark gray dot on the upper of the two ROE arcs represents Georgia Power's proposed 11.00% ROE and 56% equity ratio. The corresponding CFO/debt ratio is indicated by the

[159] GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, "Georgia Power Company: Update to credit analysis" (October 13, 2021). Data from Moody's is used, not the financial data in GPC's regulatory filing, because Moody's makes various adjustments to GPC's reported financials that are not explained in sufficient detail to replicate using GPC's data.

[160] *See* GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* (October 13, 2021). Moody's preferred cash flow metric is cash flow from operations (CFO), not FFO, and the analysis is based on Moody's CFO/debt data. The basic definition of CFO is net income + depreciation and amortization + changes in working capital, i.e., FFO + changes in working capital. *See* Corporate Finance Institute, *How to Calculate FCFE from CFO?* (Dec. 16, 2020) https://corporatefinanceinstitute.com/resources/knowledge/accounting/how-to-calculate-fcfe-from-cfo/.

[161] In the Moody's credit analysis provided in GPC data request Trade Secret response STF-NEC-1-1 Attachment AG, Moody's provides CFO/debt thresholds for up- and downgrades of [redacted]% and [redacted]%, respectively. The threshold for GPC's current rating is estimated as the midpoint, [redacted]5%.

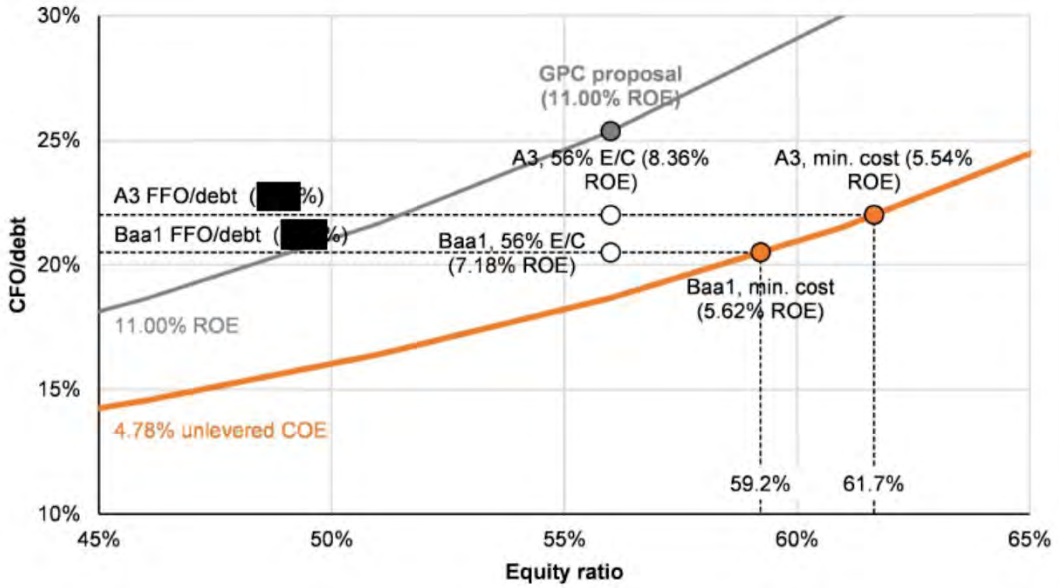
height of the dot on the vertical axis, [redacted]% – well above the [redacted]% required to maintain Georgia Power's current Baa1 credit rating. Either or both of Georgia Power's proposed ROE and equity ratio can be reduced to lower customer costs while still satisfying investor demands.

The lower of the two ROE arcs represents Georgia Power's 4.78% unlevered (100% equity) COE. As discussed previously, the corresponding levered ROE will increase as the equity ratio declines. To maintain Georgia Power's current Baa1 rating would require an equity ratio of 59.2%, slightly higher than GPC's proposal, and an ROE of 5.62%. If instead a higher A3 credit rating is targeted, the equity ratio and ROE would need to be 61.7% and 5.54%, respectively. The trade-off, in terms of customer costs, associated with these higher equity ratios will be quantified below.

The two white dots immediately below GPC's proposal illustrate scenarios in which an equity ratio constraint is imposed, here equal to GPC's proposed 56%. To maintain target credit ratings of Baa1 or A3, the ROE would need to be increased to 7.18% and 8.36%, respectively. The trade-off, in terms of customer costs, associated with an equity ratio constraint will also be quantified below.

[*Remainder of page intentionally left blank.*]

**Figure 28. Relationship between equity ratio, ROE, and credit quality for Georgia Power**




## C. An optimized ROE and equity ratio can significantly reduce customer costs while meeting the demands of both equity and debt investors.

**Q. HOW WOULD AN OPTIMIZED ROE AND EQUITY RATIO IMPACT CUSTOMER COSTS?**

A. Figure 29 compares the revenue requirement (pre-tax) weighted average rate of return for the five scenarios depicted in Figure 28. The ROE optimized for a Baa1 rating, 5.62%, is 49% lower than Mr. Coyne's proposed ROE of 11.00% (line 2). Even with the higher 59.2% equity ratio, after grossing up for taxes, the revenue requirement ROR, 5.92%, is 40% lower than GPC's 9.83% (lines 6-7). If a higher A3 credit rating is targeted, the additional cost of the required higher 61.7% equity ratio is almost completely offset by the lower levered ROE of 5.54%,[162] and the revenue requirement ROR increases only slightly to 5.95%.

Figure 29 also shows the average annual total revenue requirement under each of the five scenarios (line 8). Based on analysis of Georgia Power's general rate case filings, its proposed combined rate of return for both debt and equity, the latter grossed up for taxes, accounts for

[162] It is assumed that there is no change in the cost of debt at the higher A1 credit rating over the 2023-25 period. New issuance accounts for approximately 18% of Georgia Power's net long-term debt at the end of 2025. The difference in yield between A3- and Baa1-rated utility bonds is approximately 0.11%. The change in interest costs would therefore be approximately 18% x 0.11% = 0.02% by the end of the forecast period. M. Ellis analysis of data in Ex. APA SPA ADH MBR-3, Schedule 3, Workpaper 4.

more than 25% of its revenue requirement.[163] The total revenue requirement under GPC's proposal averages $9.14 billion per year from 2023 through 2025. Optimized ROEs and equity ratios, under either the Baa1 or A3 target credit rating, reduce total customer costs by over 11% (line 10) or more than $1.0 billion per year (line 9).

An equity ratio constraint would impose fairly substantial costs on customers, increasing the revenue requirement ROR to 6.96% and 7.84% under Baa1 and A3 credit rating targets, respectively – an increase of nearly 100 and 200 basis points relative to the corresponding minimum-cost scenarios. While total customer costs are lower than under GPC's proposal, they are only 50% to 70% of the reduction without an equity ratio constraint. These results further demonstrate the flaw in the "leverage up" (reduce the equity ratio) argument described in Section III.A above. It is much more cost effective to use any spare credit capacity to reduce ROE than to increase debt.

**Figure 29. Revenue requirement (pre-tax) rate of return under different weighted under GPC proposal, minimum cost, and equity ratio constraint scenarios**
Percent (except lines 8 and 9)

| | | GPC proposal | Minimum cost | | Equity ratio constraint | |
|---|---|---|---|---|---|---|
| | | | Baa1 | A3 | Baa1C | A3 |
| 1 | Equity ratio | 56.0 | 59.2 | 61.7 | 56.0 | 56.0 |
| 2 | ROE | 11.00 | 5.62 | 5.54 | 7.18 | 8.36 |
| 3 | Cost of debt | 3.59 | 3.59 | 3.59 | 3.59 | 3.59 |
| 4 | Rate of return | 7.74 | 4.79 | 4.79 | 5.60 | 6.26 |
| 5 | Tax rate | 25.3 | 25.3 | 25.3 | 25.3 | 25.3 |
| **6** | **Rev. requirement rate** | **9.83** | **5.92** | **5.95** | **6.96** | **7.84** |
| 7 | *ΔGPC proposal* | | *-40* | *-39* | *-29* | *-20* |
| **8** | **Rev. requirement ($ B)** | **9.14** | **8.09** | **8.10** | **8.37** | **8.61** |
| 9 | Customer savings ($ billion per year) | | -1.05 | -1.04 | -0.77 | -0.53 |
| 10 | *ΔGPC proposal* | | *-11.5%* | *-11.4%* | *-8.4%* | *-5.8%* |

**Q. WHAT ARE THE IMPLICATIONS OF AN OPTIMIZED ROE AND EQUITY RATIO ON RESIDENTIAL CUSTOMER BILLS?**

A. Average residential customer bills can be estimated from Georgia Power's total retail base rate revenue and sales of electricity forecast for the 12 months ending July 31, 2023,[164] and Budget

[163] M. Ellis analysis of data in Ex. APA-SPA-ADH-MBR-1, Schedule 1.
[164] 2022 Rate Case, Georgia Power Document Filing No. 190559, App. Ex. 1-2 Workpaper 1 (June 24, 2022).

2022 Load and Energy Forecast customer count projection.[165] Assuming the 11% cost reduction under either of the optimized ROE/equity ratio scenarios applies uniformly across customer classes, Georgia Power residential customers would save approximately $135 per year.

**Q. WHAT ARE YOUR ROE AND EQUITY RATIO RECOMMENDATIONS FOR GEORGIA POWER?**

A. I recommend the A3 target credit rating scenario for Georgia Power, 5.54% ROE and 61.7% equity ratio, for several reasons. Both the A3 and Baa1 scenarios are consistent with the Supreme Court's guidance provided in *Hope Natural Gas* to set "just and reasonable rates" through a "balancing of the investor and the consumer interests." In contrast, Mr. Coyne's recommendation and the two equity ratio-constrained scenarios are overly generous to investors at the expense of customers and therefore fail the *Hope* standard.

The A3 and Baa1 scenarios have the same estimated cost to customers over the 2023-25 timeframe. This is largely because the analysis assumes the improved credit rating does not materially reduce Georgia Power's average cost of debt during the 2023-25 timeframe. Beyond 2025, though, the average cost of debt would be materially lower under the A3 scenario, reducing customer costs relative to the Baa1 scenario. Figure 30 summarizes my COE analysis and ROE and equity ratio recommendations.

[*Remainder of page intentionally left blank.*]

[165] 2022 IRP, Georgia Power Document Filing No. 188519, PD Vol. 1, 4 PD Load and Energy Forecast, PD B2022 Load and Energy Forecast 2022 to 2041 at 18, Section 2 (January 31, 2022).

**Figure 30. Summary of Georgia Power COE analysis and recommended ROE and equity ratio**
Percent

| Model | COE | Key assumptions |
|---|---|---|
| **DCF** | **5.97** | |
| Dividend yield | 3.36 | Most recent quarterly dividend divided by one-month trailing price history (~21 trading days) |
| Initial growth rate | 5.49 | Analysts' EPS growth rates for three years to mitigate upward bias |
| Terminal growth rate | 1.57 | Based on long-term historical utility DPS growth rate equal to inflation |
| **CAPM** | **5.41** | |
| Risk-free rate | 3.56 | Current (one-month trailing average) 30-year Treasury |
| Beta | 0.48 | 5-year monthly balances long-term historical trend and current market conditions |
| Market risk premium<br>• Historical<br>• Forward | 3.86<br>4.86<br>2.87 | Average of forward-looking using MS DCF and long-term historical average; MS DCF long-term growth rate equal to pre-capita GDP |
| **Mean COE** – Levered | **5.69** | |
| – Unlevered | 4.78 | 59% proxy group average *market* equity ratio |
| **Equity ratio** | **61.7** | |
| **Relevered COE/ recommended ROE** | **5.54** | |

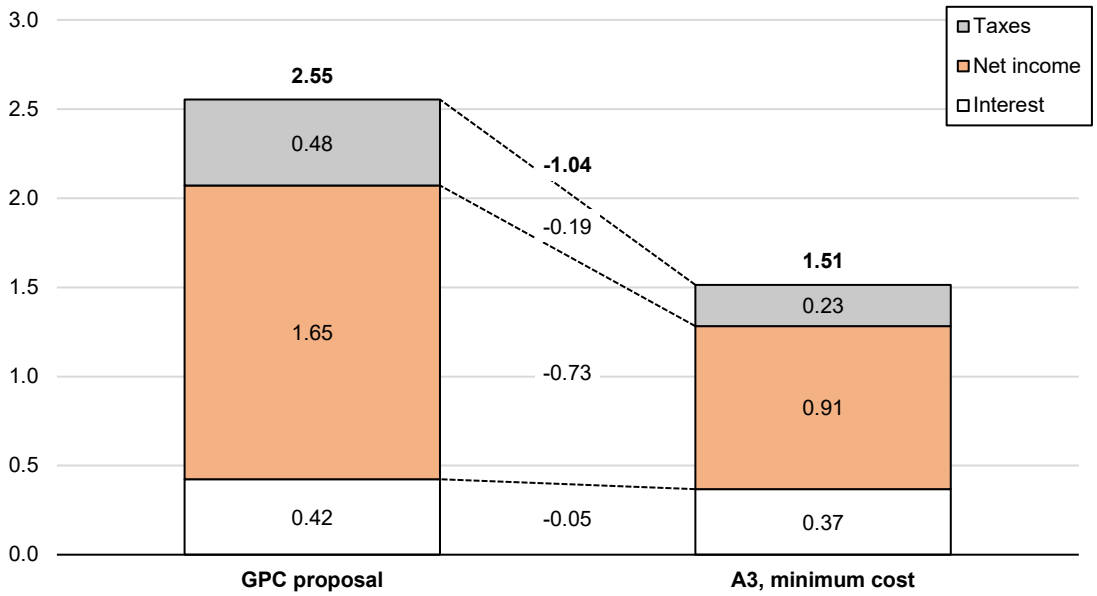
**Q. IF THE COMMISSION ADOPTS YOUR ROE AND EQUITY RATIO RECOMMENDATIONS, HOW WOULD THE SOUTHERN COMPANY'S SHAREHOLDERS BE AFFECTED?**

A. ROEs in excess of the cost of equity resembles a zero-sum game, with the interests of shareholders and customers in direct opposition. If the Commission adopted my recommended ROE and equity ratio, I would expect The Southern Company share price to experience a one-time downward adjustment as investors reset their expectations about future returns. Southern would still be able to access the equity markets, because Georgia Power's ROE, based on its actual cost of equity, i.e., investors' *expected* return,[166] would be sufficient to satisfy investors' demands. Investors who purchase shares after the one-time adjustment would earn returns comparable to the return current Southern shareholders expect.

[166] "Cost of equity" and "*expected* return on equity" are synonymous. *See supra* footnote 11.

I said that ROE above the cost of equity *resembles* a zero-sum game between shareholders and customers. It is not quite zero-sum between these two parties, though, because there is a third party: the tax authorities. ROE is grossed-up for taxes; to the extent ROE is reduced, taxes are also reduced. In aggregate, a lower ROE provides approximately one-third more benefit to customers than shareholders lose in foregone profit.[167] As shown in Figure 31, of the $1.04-billion reduction in revenue requirement return under the A3 scenario (Figure 29, line 9), the decline in Georgia Power's net income accounts for $740 million; $190 million is foregone taxes, of which approximately $150 million (77.5%) is Federal.[168]

**Figure 31. Interest, ROE, and income tax revenue requirement under GPC proposal and A3 minimum cost scenario**
$ billion




It is important to recognize that *Hope* established that regulators are not obligated to maintain utility stock market valuations, and that such an obligation would make a nonsense of regulators' consumer protection mandate:

> Ratemaking is indeed but one species of price-fixing. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact

[167] Georgia Power's marginal tax rate is approximately 25%. The tax gross-up is 1/(1 – 25%) = $1^{1}/_{3}$. *See* Ex. APA-SPA-ADH-MBR-1, Schedule 1 Total Company.

[168] Georgia corporate income tax rate of 5.75%, Federal, 21%. After deducting state taxes, the net Federal rate is (1 – 5.75%) x 21% = 19.79%; 19.79% / (19.79% + 5.75%) = 77.49%.

> that the value is reduced does not mean that the regulation is invalid. It does, however, indicate that "fair value" is the end product of the process of ratemaking, not the starting point, as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon "fair value" when the value of the going enterprise depends on earnings under whatever rates may be anticipated.[169]

The impact on Southern's stock price should not factor at all into the Commission's determination of the appropriate ROE and equity ratio.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

[*Remainder of page intentionally left blank.*]

[169] 320 U.S. 591, 601.

# Exhibit MEE-1

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

# MARK E. ELLIS

La Jolla, CA | mark.edward.ellis@gmail.com | 619-507-8892 | https://www.linkedin.com/in/mark-edward-ellis

## SUMMARY

Mark E. Ellis is a former utility executive now working as an independent consultant and testifying expert in finance and economics in utility regulatory proceedings.

Before establishing his own consultancy, Mark led the strategy function at Sempra Energy (parent of SDG&E and SoCalGas) for fifteen years. Previously, he worked as a consultant in McKinsey's energy practice, in international project development for ExxonMobil, and in industrial demand-side management for Southern California Edison. He has an MS from MIT's Technology and Policy Program, where he focused on utility policy and conducted research in the MIT Energy Lab, and a BS in mechanical engineering from Harvard.

## EXPERT TESTIMONY

| Client | Utility | Description | Docket No. | Date |
|---|---|---|---|---|
| Southern Environmental Law Center | Georgia Power | Cost of capital | 44280 | 8/22-ongoing |
| Clean Wisconsin | Wisconsin Electric Power, Wisconsin Gas | Cost of capital | 5-UR-110 | 9/22-ongoing |
| The Protect Our Communities Foundation | Pacific Gas & Electric, San Diego Gas & Electric, Southern California Gas | Cost of capital | A.22-04-008, et seq. | 4/22-ongoing |
| The Utility Reform Network | Pacific Gas & Electric | Wildfire liability self-insurance | A.21-06-021 | 11/21-ongoing |
| The Protect Our Communities Foundation | Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison | Cost of capital | A.21-08-013 et seq. | 11/21-ongoing |
| New Hampshire Department of Energy | Aquarion Water Company of New Hampshire | Cost of capital | DW 20-184 | 6/21-ongoing |
| The Utility Reform Network | Pacific Gas & Electric | $7.5-billion wildfire cost securitization | A.20-04-023 | 6/20-2/21 |

## EMPLOYMENT

| Company | Title | Location | Date |
|---|---|---|---|
| Self-employed | Independent consultant and testifying expert | La Jolla, CA | 2019-present |
| Sempra Energy | Chief of Corporate Strategy | San Diego, CA | 2004-2019 |
| McKinsey & Company | Engagement Manager | Houston, TX | 2000-03 |
| ExxonMobil | Venture Development Advisor | Houston, TX | 1996-2000 |
| MIT Energy Laboratory | Research Assistant | Cambridge, MA | 1994-96 |
| Southern California Edison | Staff Engineer | Irwindale, CA | 1994 |
| Sanyo Electric Company | Research Engineer | Osaka, Japan | 1992-93 |
| Los Angeles Department of Water & Power | Seasonal Waterworks Laborer | Chatsworth, CA | 1988 |

# MARK E. ELLIS

Independent consultant and testifying expert in utility finance and economics

## START-UP

| Organization | Title | Description | Date |
|---|---|---|---|
| Gridware | Advisor | Y Combinator graduate developing wildfire prevention technology for electric utilities | 2021-present |
| GATEMatrices | CEO & Founder | Created iOS app to prepare elementary-school children for gifted-and-talented education program admission tests | 2013-present |
| Apertur | CEO & Founder | Created a technology-enabled professional development platform of workshops, assessments, toolkit, and apps to help organizations improve their culture and decision-making by reducing cognitive bias | 2013-2020 |
| Climate Policy Initiative | Power Program Director | Climate change policy advisory non-profit funded by George Soros | 2010-13 |

## NON-PROFIT BOARD

| Organization | Date | Organization | Date |
|---|---|---|---|
| Harvard Club of San Diego | 2015-17 | Chabad Hebrew Academy | 2007-14 |
| Congregation Adat Yeshurun | 2005-12 | San Diego Agency for Jewish Education | 2005-07 |

## EDUCATION

| Institution | Degree | Date |
|---|---|---|
| Massachusetts Institute of Technology | MS, Technology and Policy | 1996 |
| Harvard University | BS, *magna cum laude,* Mechanical and Materials Sciences and Engineering | 1992 |

# Exhibit MEE-2

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

and Mr. Justice JACKSON concur in the result on the authority of Morton Salt Co. v. G. S. Suppiger Co., 314 U.S. 488, 62 S.Ct. 402, 86 L.Ed. 363.

320 U.S. 591

## FEDERAL POWER COMMISSION et al. v. HOPE NATURAL GAS CO.

## CITY OF CLEVELAND v. SAME.

Nos. 34 and 35.

Argued Oct. 20, 21, 1943.

Decided Jan. 3, 1944.

**1. Public service commissions ⇐7**

Rate-making is only one species of price-fixing, which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

**2. Public service commissions ⇐7**

Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

**3. Gas ⇐14(1)**

The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, §§ 4(a), 5(a), 6, 15 U.S.C.A. §§ 717c(a), 717d(a), 717e.

**4. Gas ⇐14(1)**

When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

**5. Gas ⇐14(1)**

Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

**6. Gas ⇐14(1)**

If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

**7. Gas ⇐14(1)**

An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

**8. Gas ⇐14(1)**

The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

**9. Gas ⇐14(1)**

As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

**10. Gas ⇐14(1)**

The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

**11. Gas ⇐14(1)**

Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

**12. Gas ⇐14(1)**

A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c (a), 717d(a).

**13. Gas ⇐14(1)**

There is no constitutional requirement that owner who engages in a wasting-asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c (a), 717d(a), 717e, 717r(b).

**14. Gas ⇐14(1)**

In fixing natural gas rate the basing of annual depreciation on cost is proper, since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S. C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

**15. Gas ⇐14(1)**

There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

**16. Commerce ⇐13**

The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

**17. Mines and minerals ⇐92**

Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

**18. Gas ⇐14(1)**

The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipe-line mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, §§ 4, 6–10, 14, 15 U.S.C.A. §§ 717c, 717e–717i, 717m.

**19. Gas ⇐14(1)**

Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, §§ 4, 5, and § 7, as amended, 15 U.S.C.A. §§ 717c, 717d, 717f.

**20. Commerce ⇐13**

A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural Gas Act, §§ 4, 5, and § 7, as amended, 15 U.S. C.A. §§ 717c, 717d, 717f.

**21. Gas ⇐14(1)**

The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or dis-

courage resales for industrial use. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c (a), 717d(a).

See Words and Phrases, Permanent Edition, for all other definitions of "Just and Reasonable Rates".

**22. Gas ⇐14(1)**

The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d (a).

**23. Courts ⇐383(1)**

Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

**24. Constitutional law ⇐74**

Congress has entrusted the administration of the Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, §§ 1 et seq., 19(b), 15 U.S.C.A. §§ 717 et seq., 717r(b).

**25. Gas ⇐14(1)**

Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S. C.A. § 717r(b).

**26. Gas ⇐14(1)**

Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

See Words and Phrases, Permanent Edition, for all other definitions of "Party Aggrieved".

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

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On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

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Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.

Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of Cleveland.

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Mr. William B. Cockley, of Cleveland, Ohio, for respondent.

Mr. M. M. Neely, of Charleston, W. Va., for State of West Virginia, as amicus curiæ by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.

The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. § 717 et seq., 15 U.S.C.A. § 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to § 19(b) of the Act, the

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Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases

are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state.[1] It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania.[2] In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March

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1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basis for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established "just and reasonable" average rates per m. c. f. for each of the five customer companies.[3] In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,N.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required

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to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11,910,947 annually since 1940.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the "actual legitimate cost" of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made

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[1] Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

[2] These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N. J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m. c. f. for 1940 may be classified as follows:

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|---|---|
| Local West Virginia sales | 11,000,000 |
| East Ohio | 40,000,000 |
| Peoples | 10,000,000 |
| River | 400,000 |
| Fayette | 860,000 |
| Manufacturers | 2,000,000 |

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

[3] These required minimum reductions of 7¢ per m. c. f. from the 36.5¢ and 35.5¢ rates previously charged East Ohio and Peoples, respectively, and 3¢ per m. c. f. from the 31.5¢ rate previously charged Fayette and Manufacturers.

certain adjustments not necessary to relate here and found the "actual legitimate cost" of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an "economic-service-life" basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses—about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended "original cost" estimate which exceeded $105,000,000. The latter was designed "to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898." 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the "per cent condition" method accrued depreciation at about 35% of

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reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was "not predicated upon facts" and was "too conjectural and illusory to be given any weight in these proceedings." Id., 44 P. U.R.,N.S., at page 8. It likewise refused to give any "probative value" to trended "original cost" since it was "not founded in fact" but was "basically erroneous" and produced "irrational results." Id., 44 P.U.R.,N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664–666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on "actual legitimate cost". It found that Hope during the years when its business was not under regulation did not observe "sound depreciation and depletion practices" but "actually accumulated an excessive reserve"[4] of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from "actual legitimate cost" in determining the rate base.[5] The majority of the

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Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to

[4] The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that "twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired." 44 P.U.R., N.S., at page 22.

[5] That contention was based on the fact that "every single dollar in the depreciation and depletion reserves" was taken "from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope." Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S. Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.



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lay "a sound basis for future regulation and control of rates." Id., 44 P.U.R.,N. S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation.[6]

Hope's estimate of original cost was about $69,735,000—approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended

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in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts.[7] The Commission refused to add such items to the rate base stating that "No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers." Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6½% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the "present fair value" of the

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property, that the Commission in determining the "value" should have considered reproduction cost and trended original cost, and that "actual legitimate cost" (prudent investment) was not the proper measure of "fair value" where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of "present fair value" of the property not on the basis of "actual legitimate cost".

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[6] The Commission noted that the case was "free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart." 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the "straight-line-basis" for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

[7] See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

*Order Reducing Rates.* Congress has provided in § 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission "shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful." Sec. 5(a) gives the Commission the power, after hearing, to determine the "just and reasonable rate" to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a "decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates." And Congress has provided in § 19(b) that on review of these rate orders the "finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." Congress, however, has provided no formula by which the "just and reasonable" rate is to be determined. It has not filled in the

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details of the general prescription [8] of § 4(a) and § 5(a). It has not expressed in a specific rule the fixed principle of "just and reasonable".

[1, 2] When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the "authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce." 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155–157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523–539, 54 S.Ct. 505, 509–517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that "fair value" is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon "fair value" when the value of the going enterprise depends on earnings under whatever rates may be anticipated.[9]

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[3-7] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of "pragmatic adjustments." Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order "viewed in its entirety" meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling. Cf. Los Angeles Gas & Electric Corp. v. Railroad

[8] Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, "The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property." Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the "original cost" of its property and shall keep the Commission informed regarding the "cost" of all additions, etc.

[9] We recently stated that the meaning of the word "value" is to be gathered "from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic question in a valuation for reorganization purposes is how much the enterprise in all probability can earn." Institutional Investors v. Chicago, M., St. P. & P. R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

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[8, 9] The rate-making process under the Act, i. e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that "regulation does not insure that the business shall produce net revenues." 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N. J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by

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the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7½%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i. e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the

company. It considered the financial history of Hope and a vast array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were "close to 3 per cent", 44 P.U.R.,N.S., at page 33. It stated that the company was a "seasoned enterprise whose risks have been minimized" by adequate provisions for depletion and depreciation (past and present) with "concurrent high profits", by "protected established markets, through affiliated distribution companies, in populous and industralized areas", and by a supply of gas locally to meet all requirements,

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"except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources." Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, "The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required." Id., 44 P.U.R., N.S., at page 33.

[10-12] In view of these various considerations we cannot say that an annual return of $2,191,314 is not "just and reasonable" within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an "inflation of the base on which the rate has been computed." Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L. Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to

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the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13-15] Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement "that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it." 315 U.S. at page 593, 62 S.Ct at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost.[10] By such a procedure the

[10] Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): "If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment un-

utility is made whole and the integrity of its investment maintained.[11] No more is required.[12] We cannot approve the contrary holding

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of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

*The Position of West Virginia.* The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order "brings consequences which are unjust to West Virginia and its citizens" and which "unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor."

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed.[13] Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate

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commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the "discovery value" of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes.[14] Secondly, it is pointed out that West Virginia has a production tax[15] on the "value" of the gas exported from the State. And we are told that for purposes of that tax "value" becomes under West Virginia law "practically the substantial equivalent of market value." Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1)

impaired, but to secure additional plant and equipment upon which the utility expects a return."

[11] See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259–288, 50 S.Ct. 123, 128–138, 74 L.Ed. 390, for an extended analysis of the problem.

[12] It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the Commission "may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas."

[13] See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

[14] West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

[15] W.Va.Rev.Code of 1943, ch. 11, Art. 13, §§ 2a, 3a.

exploratory development of new fields will be discouraged; (2) abandonment of low-yield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered.

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Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order.[16]

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16, 17] We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62 S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, "through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation." As stated in the House Report the "basic purpose" of this legislation was "to occupy" the field in which such cases as State of Missouri v.

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Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take "no authority from State commissions" and was "so drawn as to complement and in no manner usurp State regulatory authority." Id., p. 2. And the Federal Power Commission was given no authority over the "production or gathering of natural gas." § 1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the hands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies[17]. State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations.[18] These were the types of problems with which those participating in the hearings were pre-occupied.[19] Congress addressed itself to those specific evils.

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The Federal Power Commission was giv-

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16 West Virginia suggests as a possible solution (1) that a "going concern value" of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

en broad powers of regulation. The fixing of "just and reasonable" rates (§ 4) with the powers attendant thereto[20] was the heart of the new regulatory system. Moreover, the Commission was given certain authority by § 7(a), on a finding that the action was necessary or desirable "in the public interest," to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By § 7(b) it was given control over the abandonment of facilities or of service. And by § 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by § 7(c), as originally enacted, that it was "the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest." The latter provision was deleted from § 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, § 7(c) was broadened so as to require certificates

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of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions[21] contained in § 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under § 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not § 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over

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"the production or gathering of natural gas." § 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By § 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas.[22] The Commission was also

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[20] The power to investigate and ascertain the "actual legitimate cost" of property (§ 6), the requirement as to books and records (§ 8), control over rates of depreciation (§ 9), the requirements for periodic and special reports (§ 10), the broad powers of investigation (§ 14) are among the chief powers supporting the rate making function.

[21] Apart from the grandfather clause contained in § 7(c), there is the provision of § 7(f) that a natural gas company may enlarge or extend its facilities with the "service area" determined by the Commission without any further authorization.

[22] See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an "Interstate

directed to recommend further legislation appropriate or necessary to carry out any proposed compact and "to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas." § 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies.[23] But it left the protection of

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those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry[24] or to protect the interests of those who sell their gas to the interstate operator.[25] The return which

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Compact to Conserve Oil and Gas" between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

[23] As we have pointed out, § 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.

The bill amending § 7(c) originally contained a subsection (h) reading as follows: "Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served." See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: "The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection."

[24] We have noted that in the annual operating expenses of some $16,000,000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

[25] The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to § 1(b) which provides that the Act shall not apply to "the production or gathering of natural gas". But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed § 14(b) of the Act gives the Commission the power to "determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases."

the Commission
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allowed was the net return after all such charges.

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses.[26] No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. § 4.

[21,22] But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users[27] and domestic consumers. We hardly

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can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission.[28] But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix "just and reasonable" rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided "for regulation along recognized and more or less standardized lines" and that there was "nothing novel in its provisions". H.Rep. No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a "novel" doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that § 4(a) and § 5(a) contain only the conventional standards of rate-making for natural gas companies.[29] The
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Act of February 7, 1942, by broadening § 7 gave the Commission some additional authority to deal with the conservation aspects of the problem.[30] But § 4(a) and § 5(a) were not changed. If the stand-

[26] See note 25, supra.

[27] The Commission has expressed doubts over its power to fix rates on "direct sales to industries" from interstate pipelines as distinguished from "sales for resale to the industrial customers of distributing companies." Annual Report, Federal Power Commission (1940), p. 11.

[28] Sec. 1(b) of the Act provides: "The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas." And see § 2(6), defining a "natural-gas company", and H.Rep.No. 709, supra, pp. 2, 3.

[29] The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

[30] The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to re-

ard of "just and reasonable" is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

[23, 24] It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on § 4(b) of the Act which forbids natural gas companies from maintaining "any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service." The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. § 5(a). The Commission, however, made no findings under § 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not

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for us to advise the Commission how to discharge its functions.

*Findings as to the Lawfulness of Past Rates.* As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those "to be thereafter observed and in force." § 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates.[31] However that may be, we do not think that these findings were reviewable under § 19(b) of the Act. That section gives any party "aggrieved by an order" of the Commission a review "of such order" in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

[25, 26] The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22,

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1913, 28 U.S.C. §§ 45, 47a, 28 U.S.C.A. §§ 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where "the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action", it is not reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, "In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province." Id., 307

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strict the use of natural gas "by functions rather than by areas." Annual Report (1940) p. 79.

The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas "under boilers for the production of steam" is "under most circumstances of very questionable social economy." Ibid.

[31] The argument is that § 4(a) makes "unlawful" the charging of any rate that is not just and reasonable. And § 14(a) gives the Commission power to investigate any matter "which it may find necessary or proper in order to determine whether any person has violated" any provision of the Act. Moreover, § 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has "no authority to establish a rate governing the transportation or sale of such natural gas." And § 17 (c) directs the Commission to "make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies." For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles & S. L. R. Co., 273 U.S. 299, 309, 310, 47 S.Ct. 413, 414, 415, 71 L.Ed. 651; Shannahan v. United States, 303 U.S. 596, 58 S.Ct. 732, 82 L.Ed. 1039. These considerations are apposite here. The Commission has no authority to enforce these findings. They are "the exercise solely of the function of investigation." United States v. Los Angeles & S. L. R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414, 71 L.Ed. 651. They are only a preliminary, interim step towards possible future action—action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that "Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra [134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970], may fairly be claimed." That was the case in which a majority of this Court was finally induced to expand the meaning

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of "due process" so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, "That issue is not here in controversy." The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be "just

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and reasonable."[1] Section 6[2]

[1] Natural Gas Act, § 4(a), 52 Stat. 821, 822, 15 U.S.C. § 717c (a), 15 U.S.C.A. § 717c(a).

[2] 52 Stat. 821, 824, 15 U.S.C. § 717e, 15 U.S.C.A. § 717e:

"(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

"(b) Every natural-gas company upon request shall file with the Commission

throws additional light on the meaning of these words.

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P. R. Co. v. Minnesota, 134 U.S. 418, 461–466, 10 S.Ct. 462, 702, 703–705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment

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of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, "earnings produced by rates do not afford a standard for decision." 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost [3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value.[4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

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I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no

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an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction."

[3] "Reproduction cost" has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

"Prudent investment" is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

[4] It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate

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making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.

My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as

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the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty

years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota, 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be "just and reasonable". § 5 of the Natural Gas Act, 15 U.S.C. § 717d, 15 U.S.C.A. § 717d. Instead of making the Commission's rate determinations final, Congress

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specifically provided for court review of such orders. To be sure, "the finding of the Commission as to the facts, if supported by substantial evidence" was made "conclusive", § 19 of the Act, 15 U.S.C. § 717r; 15 U.S.C.A. § 717r. But obedience of the requirement of Congress that rates be "just and reasonable" is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be "just and reasonable" means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly bad prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as an entirety. See, for

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instance, §§ 4(a) (b) (c) (d), 6, and 11, 15 U.S.C. §§ 717c (a) (b) (c) (d), 717e, and 717j, 15 U.S.C.A. §§ 717c (a–d), 717e, 717j. Of course the statute is not concerned with abstract theories of rate-making. But its very foundation is the "public interest", and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the

total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided

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in determining that rates are "just and reasonable", and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co.[1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the "prudent investment" rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to "any single formula or combination of formulas" provided its order, "viewed in its entirety, produces no arbitrary result." 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the "prudent investment" theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved.[2] I disclaim this imputed

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approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad, bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service can be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own.[3]

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1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case "contains no express discussion of the Prudent Investment Theory" and that the concurring opinion contained a clear one, and said, "It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged." [134 F.2d 287, 312.] The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case—a very important distinction, as I shall try to make plain.

3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is

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available only to about 7,600,000 consumers.[4] Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69½ feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel.[5] The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 "wildcat" wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were "dry holes." About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only.[6] Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000.[7] Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

While for many years natural gas had been distributed on a small scale for lighting,[8] its acceptance was slow,

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facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry.[9] Soon monopoly of production or markets developed.[10] To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption.[11] The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by "wildcat" drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity.[12]

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With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a

[4] Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

[5] Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

[6] Id. at 62-63.

[7] Id. at 61.

[8] At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

[9] In that year Pennsylvania enacted "An Act to provide for the incorporation and regulation of natural gas companies." Penn.Laws 1885, No. 32, 15 P.S. § 1981 et seq.

[10] See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

[11] Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

[12] Id. at 63.

fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917.[13]

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry.[14] West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction

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from this Court.[15] Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas.[16] That Commission held that a company could not abandon a part of its territory and still serve the rest.[17] Some courts admonished the companies to take action to protect consumers.[18] Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion.[19] There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results.[20] Public service commissions of consuming states were handicapped, for they had no control of the supply.[21]

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13 Id. at 64.

14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N. Y., 407.

18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App. Div. 514, 189 N.Y.S. 478.

20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A.,N.S., 92, 18 Ann.Cas. 332; Village of Newcomerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D. C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

21 The New York Public Service Commission said: "While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If

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Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use.[22] After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price.[23]

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water

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heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel.[24] But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost.[25]

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial,

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38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7.[26] Although this spread is less than

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there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Potter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State." Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

[22] Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

[23] For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

[24] The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:

Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.

Use and Conservation of Natural Gas, issued by U. S. Fuel Administration (1918) 5.

[25] See Brief on Behalf of Legislation Imposing an Excise Tax on Natural Gas, submitted to N. R. A. by the United Mine Workers of America and the National Coal Association.

[26] Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

in other parts of the United States,[27] it can hardly be said to be self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use.[28]

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These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity.[29] Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems.[30] This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate

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subsidiaries,[31] the effect of which, if not the purpose, was to isolate

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[27] From the source quoted in the preceding note the spread elsewhere is shown to be:

| *State* | *Industrial* | *Domestic* |
|---|---|---|
| Illinois ..... | 29.2 | 1.678 |
| Louisiana ..... | 10.4 | 59.7 |
| Oklahoma ..... | 11.2 | 41.5 |
| Texas ..... | 13.1 | 59.7 |
| Alabama ..... | 17.8 | 1.227 |
| Georgia ..... | 22.9 | 1.043 |

[28] In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70¢ for the first 5,000 cu. ft. per month; 80¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.

The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35¢; second 5,000 feet, 45¢; third 5,000 feet, 50¢; all above 15,000, 55¢. This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75¢; next 4 m.c.f., 60¢; next 8 m.c.f., 55¢; over 15 m.c.f., 50¢. Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.

For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

[29] See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

[30] Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.

In 1915, so it was reported to the Governor of West Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

[31] This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission,

some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

The Natural Gas Act declared the natural gas business to be "affected with a *public interest*," and its regulation "necessary in the *public interest*."[32] Originally, and at the time this proceeding was commenced and tried, it also declared "the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate *consistent with the maintenance of adequate service in the public interest*."[33] While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when "necessary or desirable in the public interest," abandonment of facilities may be ordered when the supply is "depleted to the extent that the continuance of service is unwarranted, or that the *present or future public convenience or necessity*

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permit" abandonment and certain extensions can only be made on finding of "the *present or future* public convenience and necessity."[34] The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas "for resale for industrial use only,"[35] which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or *"any unreasonable difference in rates* * * * either as between localities *or as between classes of service."*[36] And the power of the Commission expressly includes that to determine the "just and reasonable *rate, charge, classification, rule, regulation, practice, or contract* to be thereafter observed and in force."[37]

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use.[38] I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as "broad powers of regulation."

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III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas "for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and *greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service*" (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of de-

292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

[32] 15 U. S. C. § 717(a), 15 U.S.C.A. § 717(a). (Italics supplied throughout this paragraph.)

[33] § 7(c), 52 Stat. 825, 15 U.S.C.A. § 717f(c).

[34] 15 U. S. C. § 717f, 15 U.S.C.A. § 717f.

[35] Id., § 717c(e).

[36] Id., § 717c(b).

[37] Id., § 717d(a).

[38] Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

livery. As to the allegation that the contract price is "greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio," Hope did not deny a price differential, but alleged that industrial gas was not sold to "favored consumers" but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not "unduly discriminatory."

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

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Hope is responsible for such discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, "(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes." The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and "Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company." This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to

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time with its approval in writing. It said, "It is believed that the price concessions contained in this letter, *while not based on our costs,* are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us [italics supplied]." [39]

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[39] The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

| *Ordinary Daily Requirements. Customer* | |
|---|---|
| Republic Steel Corporation | 15,000,000 cu. ft. |
| Otis Steel Company | 10,000,000 |
| Timken Roller Bearing Co. | 7,500,000 |
| Youngstown Sheet & Tube Co. | 7,000,000 |
| U. S. Steel Corp.—Subsidiaries | 6,500,000 |
| General Electric Company | 2,500,000 |
| Pittsburgh Plate Glass Co. | 2,000,000 |
| Niles Rolling Mill Company | 1,500,000 |
| Chase Brass & Copper Company | 700,000 |
| U. S. Aluminum Company | 400,000 |
| Mahoning Valley Steel Company | 400,000 |
| Babcock & Wilcox Company | 400,000 |
| Canton Stamping & Enameling Co. | 350,000 |

The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that "bona fide investment figures now become all-important in the regulation of rates." It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained

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the following: "In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question." H. R. 5423, 74th Cong., 1st Sess. Title III, § 312(c). Congress rejected this language. See H. R. 5423, § 213 [211(c)], and H. R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the "all important" formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such "excess earnings" to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation.[40] Of

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course, the

[40] To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that "As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts." He analyzes the hypothetical character of accounting and says "It was no eternal mold for pecuniary verities handed down from on high. It was—like logic or algebra, or the device of analogy in the law—an ingenious contrivance of the human mind to serve a limited and practical purpose." "Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making." As to capital account he observes "In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciа-

Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

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The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

## IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct by which to know the "reasonable" from the "unreasonable" in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise,

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I cannot learn. It holds that: "it is the result reached not the method employed which is controlling"; "the fact that the method employed to reach that result may contain infirmities is not then important" and it is not "important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at." The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases.[41]

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of "just and reasonable" rates and practices and of the "public interest" that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided "for regulation along recognized and more or less standardized lines" and that there was "nothing novel in its provisions." So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation,[42] and the purposeful

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tion, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account."

[41] See 2 Bonbright, Valuation of Property (1937) 1112.

[42] Bonbright says, "* * * the vice of

and deliberate innovation I
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would make to meet the necessities of regulating the industry before us.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence "value" to gas owned by the company and gives the pipeline company a large power over the marketability and hence "value" of the production of others.

The other part of the business—to reduce to possession an adequate supply of natural gas—is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

Is it necessary to a "reasonable" price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing "rate bases" in order to "value" something else? The method came into vogue
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in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The "value" or "cost" of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles—leaseholds and freeholds—operated and unoperated—of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The "present fair value" rate base, generally in ill repute,[43] is not even

traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so." Id., 1170.

[43] "The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered." 2 Bonbright, Valuation of Property (1937) 1190.

urged by the gas company for valuing its fields.

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The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and

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adapted to the ordinary utility business can serve the "public interest" as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, "In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree." 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below "gave careful consideration to the questions of the value of the property * * * at the time of the inquiry," and whether the rate "would be sufficient to provide a fair return on the value of the property." The Court said this method was "based upon principles thoroughly established by repeated decisions of this court," citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to

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regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were "due

chiefly to the difference in value ascribed by each to the gas rights and leaseholds." 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed 390. No one seems to have questioned that the rate base method must be pursued and the controversy was as to what rate base must be used. Later the "value" of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor—a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point

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if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform

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for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that "if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *." With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize "price" for what it is—a tool, a means, an expedient. In pub-

lic hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it—price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the

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field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio.[44] What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas?[45] Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has

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if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of "production or gathering of natural gas," and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

But there is nothing in the law which compels a commission to fix a price at that "value" which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, Block

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44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73 L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix

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a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates —a high one for domestic use and a lower one for industrial contracts.[46] The Commission can fix two prices for interstate gas as readily as one—a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the "public interest" is not unduly narrowed.

The Commission's concept of the public interest in natural gas cases which is carried today into the Court's opinion was first announced in the opinion of the majority in the Pipeline case. It enumerated only two "phases of the public interest: (1) the investor interest; (2) the consumer interest," which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner

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and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses

[46] I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? [47] And how much cheaper should industrial
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gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction
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of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the "public interest" requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order

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[47] The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: "The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.

"Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy." Twentieth Annual Report of the Federal Power Commission (1940) 79.

that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be

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at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the "public interest" and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as "all important" for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

320 U.S. 543

## UNITED STATES v. LAUDANI.

No. 71.

Argued and Submitted Dec. 16, 1943.

Decided Jan. 3, 1944.

**1. Master and servant ⇐84**

The purpose of the Kick Back Racket Act is to protect not only the legal form of employment contracts, but the substantive rights of workers to receive the benefit of wage schedules provided by Congress, except where diverted under authority of law or the workers' voluntary agreements. Kick Back Racket Act § 1, 40 U.S.C.A. § 276b.

**2. Master and servant ⇐84**

The Kick Back Racket Act, providing that "whoever" induces any person employed on any federally financed work to surrender part of wages by threat of dismissal shall be fined, etc., includes a foreman with authority to hire and discharge. Kick Back Racket Act § 1, 40 U.S.C.A. § 276b.

See Words and Phrases, Permanent Edition, for all other definitions of "Whoever".

On Writ of Certiorari to the United States Circuit Court of Appeals for the Third Circuit.

Convictions of Frank Laudani of violations of the Anti-Kickback Act were reversed by the Circuit Court of Appeals, which directed that the indictments be quashed, 134 F.2d 847, and the United States of America brings certiorari.

Reversed and remanded to the Circuit Court of Appeals for consideration and disposition of other questions.

Mr. Chester T. Lane, of Washington, D. C., for petitioner.

Mr. Harold Simandl, of Newark, N. J., for respondent.

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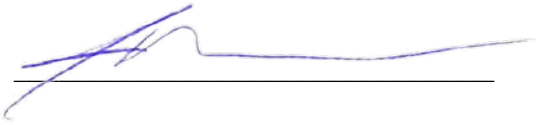
Mr. Justice BLACK delivered the opinion of the Court.

Indictments returned in a United States District Court in New Jersey charged that

## CERTIFICATE OF SERVICE

I certify that the foregoing **Errata to the Public Disclosure version of the Direct Testimony of Mark E. Ellis on behalf of Georgia Interfaith Power & Light** in Docket No. 44280 was filed with the Public Service Commission by electronic delivery on the 21st of October, 2022. An electronic copy of same was served upon all parties listed below by electronic mail as follows:



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**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In the Matter of** | ) | |
| | ) | |
| **Georgia Power Company's 2022 Rate Case** | ) | **Docket No. 44280** |
| | ) | |
| | ) | |
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# DIRECT TESTIMONY OF JUSTIN BARNES

## ON BEHALF

## OF GEORGIA INTERFAITH POWER & LIGHT

**October 20, 2022**

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## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.**

A. Justin R. Barnes. My business address is 1155 Kildaire Farm Road, Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

**Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?**

A. I am submitting testimony on behalf of Georgia Interfaith Power & Light ("GIPL").

**Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION ("THE COMMISSION")?**

A. Yes. I sponsored testimony in the 2019 Georgia Power Company ("GPC" or "the Company") rate case, Docket No. 42516.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.**

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the Database of State Incentives for Renewables and Efficiency ("DSIRE") project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

contribute to EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests.

**Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS IT RELATES TO THIS PROCEEDING.**

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in distributed generation ("DG") policy, rate design, and cost of service evaluation. For example, as part of my current duties overseeing EQ Research's general rate case tracking service, I have reviewed dozens of general rate case applications, including the methods used by different utilities to develop cost of service studies and different rate designs, as well as the decisions made by regulators in those proceedings.

Outside of Georgia, I have submitted testimony before utility regulatory commissions in Colorado, Hawaii, Kentucky, Michigan, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, South Carolina, Texas, Utah, Wisconsin, and Virginia, as well as the City Council of New Orleans, on various issues related to clean energy policy, rate design, and cost of service.[2] These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My curriculum vitae is attached as Exhibit JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My testimony addresses several specific aspects of the Company's Application that relate to residential rates. My testimony also includes a discussion of the general nature of cost of service, the existence of interclass and intraclass subsidies, the overall construction of residential rate options, and the Company's assertions regarding the purported "cost shift" associated with the monthly netting option under the Renewable and Non-renewable Resources ("RNR") tariff ("Schedule RNR"). The specific issues that I address in my testimony are as follows:

- The closure of the Residential Service Schedule ("Schedule R") to new premises established after December 31, 2022.
- The closure of the Time of Use – Residential Energy Only ("Schedule TOU-REO") rate to additional customers effective December 31, 2022.
- The continued use of the Time of Use – Residential Demand ("Schedule TOU-RD") as a default rate for new residential premises, which the Commission authorized in its decision in Docket No. 42516.
- The percentage-based design of the Environmental Compliance Cost Recovery Schedule ("Schedule ECCR") as applied to coal combustion residential ("CCR") compliance costs.
- The increase in the residential basic service charge ("BSC") from $0.4603/day to $0.492/day.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. My testimony is organized into the following sections:

- Section II: I discuss the nature of cost of service, rate design, and "cost shifts" or subsidies in general, as well as in the specific contexts of Schedule ECCR and the Schedule RNR monthly netting option.
- Section III: I address the collective issues associated with the availability of different residential rate options, including the Company's proposals to close Schedule R and Schedule TOU-REO, the reasonableness of using Schedule TOU-RD as the default rate new residential premises, and the overall residential rate options framework in terms of understandability and optionality.
- Section IV: I discuss the reasonableness of the proposed residential BSC and the use of the zero-intercept analysis to identify customer-related costs as it relates to setting BSCs.
- Section V: I provide closing remarks and summarized conclusions.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.**

A. I have grouped my recommendations according to subject matter categories aligned with the sections of my testimony, as follows:

Cost of Service and Cost Allocation – I recommend that the Commission:

- Modify the manner in which CCR compliance costs are allocated to customer classes and how those costs are recovered in rates because: (a) the current percentage-based adder design of Schedule ECCR fails to reflect that CCR compliance costs are primarily energy-related, and (b) results in those costs being borne disproportionately by the residential customer class. The revised Schedule ECCR should use an energy-based allocation factor and a uniform volumetric charge design.

- Pending any further information presented as part of the Company's supplemental testimony on this issue and subsequent responses by Staff and intervenors, disregard the Company's assertions regarding the alleged "cost shift" created by the Schedule RNR monthly netting option because the basic revenue erosion frame under which the Company presents the issue is flawed. The identification of the character, direction, and magnitude of a cost shift requires a far more extensive analysis of cost of service than the Company presents in its simplistic revenue erosion calculation. The only cost shift between Schedule RNR and non-RNR customers present in the Company's proposed rates is an object of the Company's own creation.

Residential Rate Options – I recommend that the Commission:

- Reject the Company's proposals to close Schedule R to new premises established after December 31, 2022 and to close Schedule TOU-REO to new customers because doing so would: (a) steer customers onto Schedule TOU-RD, which has been significantly more expensive for customers than other available rates during its tenure as the default rate for new premises, and (b) create inequities within the residential class between new and existing customers.
- Eliminate the use of Schedule TOU-RD as the default rate for new premises because: (a) it has been significantly more expensive to customers than other available rates, and (b) demand rate designs in general are inferior to volumetric time of use ("TOU") rates for providing economically efficient and consistent, actionable price signals to residential customers.
- Re-designate Schedule R as the default rate for new residential premises because it is demonstrably less expensive on average compared to Schedule TOU-RD. In the

alternative, should the Commission desire to retain a time-varying rate as the default rate for new residential premises, I recommend that it designate Schedule TOU-REO for this purpose.

- Pursue available options for presenting customers with clearer and more understandable information on available rate options, including but not limited to: (a) directing the rebranding the TOU-RD rate which is presently referred to as the "Smart Usage" rate by the Company, and Schedule Time of Use – Plug-In Electric Vehicle ("Schedule TOU-PEV"), which is not limited to customers with plug-in electric vehicles ("EVs"), and (b) directing GPC to develop a rates calculator tool to assist customers in selecting the rate best suited to their circumstances.

Residential BSC – I recommend that the Commission deny the Company's proposed increase and instead retain the current BSC because: (a) the current BSC already recovers costs in excess of the Company's truly customer-related costs, and (b) the Company's cost of service analysis shows a decrease rather than an increase in customer-related costs. Both of these facts, considered separately or in concert, render an increase in the BSC unjustified.

## II. COST OF SERVICE, COST ALLOCATION, AND SUBSIDIES

### *A. Background Discussion*

**Q. PLEASE DESCRIBE THE PRINCIPLE OF "COST CAUSATION" IN RATEMAKING.**

A. Cost causation refers to the ratemaking principle that costs should be allocated to customers who caused those costs to be incurred. Rates that allocate the cost of providing service to a customer are generally considered fair and equitable rates.

**Q. IN GENERAL, HOW DOES GEORGIA POWER CLASSIFY COSTS FOR THE PURPOSES OF ALLOCATING COSTS TO CUSTOMERS?**

A. Georgia Power classifies costs as belonging to one of three categories: demand-related, energy-related, or customer-related costs. Demand-related costs are those incurred to serve peak demand. Energy-related costs are those incurred to generate electricity. Customer-related costs are those costs associated with enabling customers to receive electricity service.

**Q. PLEASE PROVIDE SOME EXAMPLES OF THESE COST CLASSIFICATIONS.**

A. Customer-related costs are typically unrelated to a specific customer's energy consumption. Providing a customer with a meter or preparing and sending bills are costs incurred as part of a customer being able to receive electricity service. The amount, or level, of customer-related costs is unrelated to the amount of electricity an individual customer purchases. Overall, these types of costs increase for the utility based on the number of customers as opposed to the energy usage characteristics of customers.

Demand-related costs are incurred to supply customers with their maximum, or peak, power needs. These costs are driven by the amount of energy a customer uses during

one or more time increments, unlike energy-related costs which are driven by the amount of energy a customer uses over an extended span of time.

Energy-related costs are those costs the Company incurs from providing electricity to customers. These types of costs to the Company increase based on the volume of electricity the customers consume. For example, fuel is consumed to generate electricity, and the more electricity customers purchase, the more fuel is consumed, the higher the overall fuel costs. Other examples include regular equipment maintenance such as lubricating moving parts that is performed based on a set number of operating hours, or management of coal combustion residuals where combustion of some quantity of fuel results in the creation of some quantity of solid waste material. Any costs that increase in proportion to the quantity of electricity generated should be classified as energy-related costs.

**Q. IS IT POSSIBLE TO PERFECTLY ALLOCATE COSTS TO THE CUSTOMERS THAT CAUSED THEM?**

A. No, for a variety of reasons. To begin with, it is impractical to directly allocate costs to individual customers, so customers are grouped into different classes such as residential, commercial, industrial, etc. That grouping alone results in imperfect cost allocation among individual customers within each class, since not all customers within a customer class are identical. A circumstance in which some customers pay costs caused by other customers is often called a "cost shift" since the burden of costs that result from some customers' activity is effectively shifted onto other customers.

For instance, customers located in rural areas have fewer customers per mile of power line than customers in more densely populated urban areas, but both rural and urban

customers of the same customer class pay the costs for all power lines allocated to that customer class. The result in this example is that customers located in densely populated areas effectively subsidize customers located in areas with less population density. Similarly, multi-family customers tend to take service from larger capacity shared infrastructure that benefits from economies of scale, making their service on a per-customer basis less costly than service for more dispersed single-family homes. Multi-family customers may also differ considerably from single-family home customers in terms of their overall usage and demand, and the patterns of their usage and demand, due to differences in electric end uses and residence characteristics (e.g., prevalence of electric heating and water heating, smaller residences, etc.).

There are often cases where experts disagree on how costs should be classified, or the allocation methodology used to allocate costs, which can influence one's perspective on the existence and magnitude of any cost shift present in a utility's rates. For instance, the Company's practice of classifying a portion of costs of the shared distribution system as customer-related using its zero-intercept analysis and allocating those costs based on the number of customers within a rate class is not accepted in many jurisdictions.[3] Similarly, the measures of demand used to allocate production demand costs are often a source of disagreement in rates proceedings because the selection of a methodology invariably produces "winners" and "losers" and it is challenging to develop bright line tests that indicate which methodology is the most appropriate. In other words, the impacts of

[3] Because this methodology allocates a larger amount of costs to highly populated classes like the residential class, it results in the residential class producing a lower return (i.e., below "parity") and appearance that the residential class is being subsidized by other rate classes. Eliminating this element of the Company's cost of service study would result in the residential class showing a higher return and classes composed of larger non-residential customers showing lower returns.

classification and allocation decisions play a significant role in determining the amounts of costs that a group of customers is deemed to be responsible for causing, making the question of whether a cost shift is present a matter of perspective.

**Q. PLEASE ELABORATE ON THE NATURE OF COST SHIFT IN RATEMAKING.**

A. To some extent cost shifts are an unavoidable consequence of the ratemaking process. Details and nuances of cost causation are inevitably blurred as a result of the aggregation, classification, grouping, and allocation that occurs with both costs and customers. The technical and interdependent nature of components in the electric system also complicates achieving a perfect allocation of costs in accordance with the principle of cost causation.

However, there are multiple types of cost shifts that we can generally describe. The previous example of a cost shift or subsidization of rural customers by urban customers could be considered an intraclass cost shift, or a cost shift that occurs between members of the same customer class. Cost shifts can also occur between different customer classes as an interclass cost shift, when, for example, residential customers are paying for costs caused by industrial customers or vice-versa.

Other types of subsidization or cost shifts exist as well. There are intertemporal (a.k.a. generational) cost shifts in which costs caused during one time period are paid by customers in a different time period, either earlier or later. Another type of cost shift is an interparty shift, where costs or risks that might otherwise be the burden of the utility or its investors are shifted onto customers.

**Q. DO GEORGIA POWER CUSTOMERS EXPERIENCE COST SHIFTS?**

A. Cost shifts of various types exist throughout the Georgia Power system. Some, such as the previously described intraclass cost shift between urban and rural customers, could be

considered structural since they result from the design of the basic ratemaking process. Other cost shifts, however, are the result of more deliberate choices.

Consider, for example, some of the cost shifts associated with the Vogtle nuclear expansion project. Current customers are charged for Nuclear Construction Cost Recovery but may or may not receive future benefits from the construction for which they are paying. This is an example of an intertemporal cost shift where costs are charged to customers in one time period but benefits are received by customers in a different time period. Ratepayers in some future time will receive the benefits of electricity from this nuclear facility, but some of the ratepayers today who have been allocated these costs will never receive the benefits of electricity from this facility.

The cost recovery for the Vogtle expansion project could also be considered an interparty cost shift. Customer financing via construction work-in-progress ("CWIP") reduces the risk to other investors (e.g., equity and debt holders) and mitigates potential risks to the Company if the facility does not operate as expected in the future. A full pass-through of fuel costs presents a similar type of risk-shifting, as doing so places the entirety of fuel price risk on customers rather than sharing that risk between customers and a utility's shareholders.

**Q. ARE YOU OBJECTING TO THE COST RECOVERY MECHANISMS USED FOR VOGTLE COSTS OR FUEL COSTS?**

A. No, not in this testimony. I am simply pointing out that cost shifts: (a) exist in many forms, (b) can be caused by the necessity of using approximations to define cost responsibility, as well as intentional decisions, and (c) are inextricably linked to the perspective from which one views the accuracy of the mechanisms used to define cost responsibility.

### *B. Schedule RNR Monthly Netting and Schedule ECCR*

**Q. ARE THERE OTHER EXAMPLES OF POTENTIAL COST SHIFTS IN GEORGIA POWER'S RATE PROPOSAL THAT WARRANT THE COMMISSION'S ATTENTION IN THIS PROCEEDING?**

A. Yes. The Company alleges that the Schedule RNR monthly netting option creates a cost shift wherein monthly netting participants are being subsidized by non-participants. The Company has also proposed an adjustment to its proposed revenue requirement to recover a projected $1.4 million of revenue erosion which they have attributed to monthly netting compared to compensation for exports to the grid at avoided cost. This purported cost shift is the basis of the Company's position that the Schedule RNR monthly netting option should not be expanded to allow additional customers to enroll.

The Company also proposes to continue the current design of Schedule ECCR, which uses a percentage-based bill adder to charge customers for environmental compliance costs, the bulk of which relate to costs incurred for remediation of CCR storage sites.

**Q. HAS THE COMPANY ADEQUATELY DEMONSTRATED THAT THE SCHEDULE RNR MONTHLY NETTING OPTION CAUSES A COST SHIFT TO NON-PARTICIPANTS?**

A. Understanding that the Company has been directed to file supplemental testimony on this issue, it did not do so in in its initial direct testimony for two reasons.

First, revenue erosion should not be conflated with interclass or intraclass cost shifting. Absent the Company's proposed revenue adjustment, any revenue erosion would be borne by the Company's shareholders. Non-participant customers would be indifferent

because their own rates would not be affected. In other words, the purported $1.4 million cost shift to non-RNR ratepayers only exists because the Company created it by making this revenue adjustment.

Second, there are two facets to any question of cost shifting: (a) the costs to serve a group of customers, and (b) what they pay for service. The Company's revenue erosion projection addresses only one side of this equation. A complete picture is only possible with a more extensive evaluation of the long-term costs that monthly netting participants impose on the system, including the costs that they avoid for all customers or cause to be avoided for by customers within their rate class.

**Q. IS THERE A REASON FOR THE COMMISSION TO GIVE CONSIDERATION TO SHAREHOLDER INTERESTS IN REGARD TO THE PROJECTED REVENUE EROSION?**

A. No. The purported revenue erosion is one very small piece of potential variations in utility revenue, and the earnings band and sharing mechanism already adequately addresses the interests of shareholders by allowing the Company to petition for incremental cost recovery if its earned return on equity ("ROE") falls below 9.5%. The Company does not propose any changes to this mechanism in the current proceeding. This mechanism offers a global solution to the potential for under- or over-earning with recognition that variations in earnings are inevitable.

Carving out potential lost revenues from individual sources is counter to the purpose of the earnings band framework, which does not entitle the Company to any particular amount of revenue within the band. Stated another way, why should the Company be permitted to recover additional revenue for the benefit of shareholders if it is

already earning an adequate return for those shareholders as defined by the lower boundary of the earnings band?

**Q. PLEASE EXPLAIN WHY YOU ARE RAISING SCHEDULE ECCR DESIGN AS A MATTER FOR COMMISSION CONSIDERATION AS IT RELATES TO THE ISSUE OF COST SHIFTING.**

A. The design of Schedule ECCR is a matter for close Commission attention because: (a) the amount of costs associated with CCR remediation is large (and will continue to grow), and (b) the present design is inconsistent with cost causation. Total proposed ECCR revenue is $937,513,791, or 10.6% of proposed overall total revenue. Schedule ECCR is not subjected to a specific cost allocation protocol for the purpose of the distributing that revenue requirement between customer classes. Rather, the allocation is effectively based on class revenues because Schedule ECCR uses a standard percentage adder to customer bills. As a consequence, Schedule ECCR effectively "enhances" every component of base rates, such as fixed customer charges, demand charges, and the different varieties of energy charges (e.g., on-peak, off-peak, individual tiers within Schedule R). This suggests that the costs being recovered via Schedule ECCR are a mix of customer-related, demand-related, and energy-related costs. However, this is not the case in practice. Rather, the bulk of costs being recovered under Rider ECCR are for CCR remediation, which is energy-related in character.

**Q. WHY SHOULD CCR REMEDIATION COSTS BE CONSIDERED ENERGY-RELATED RATHER THAN DEMAND- OR CUSTOMER-RELATED?**

A. CCRs are produced when coal is burned as fuel. Every megawatt-hour ("MWh") of electricity generated from the combustion of coal generates a predictable quantity of CCRs.

Therefore, costs associated with CCRs are an energy-related cost and should be allocated on an energy basis. The creation of CCRs has no plausible connection to the number of customers on the system, nor does it have any relation to monthly demand peaks, maximum class demands, or levels of on-peak or off-peak energy use. The determinant of total CCR volume is total energy generated, therefore an energy allocator is appropriate.

**Q. IS THERE ANY MERIT TO THE ARGUMENT THAT CCR IMPOUNDMENTS ARE FIXTURES TO COAL-FIRED GENERATION UNITS, AND THEREFORE SHOULD BE SUBJECT TO THE SAME ALLOCATION METHODOLOGY AS THE PLANT ITSELF?**

A. No. The impoundment could be considered a fixture, but the CCRs themselves are not somehow tied to the plant. The very fact that in many cases CCRs must be relocated for disposal, and the costs of that relocation are directly related to the volume that must be moved, lends further support to their energy-related character. This is distinctly different from capital investments in pollution control equipment that are made in order to continue to allow a plant to operate to meet system demand and energy needs.

**Q. SHOULD THE FACT THAT SOME CCR REMEDIATION COSTS ARE ASSOCIATED WITH RETIRED PLANTS AFFECT THE COST ALLOCATION REGIME?**

A. No. Some amount of intergenerational cost shift will be present no matter how costs are recovered from present customers. Newer customers will always shoulder a portion of the burden of paying for the legacy costs of past users. There is no cost allocation regime that is inherently fairer for addressing this intergenerational issue. However, an energy-based allocation is fairer overall because: (a) a portion of the customer base did play a role in

causing those legacy costs due to their past energy use (i.e., there has not been 100% customer turnover), and (b) not all of the Company's coal-fired generation units are retired so CCRs that require disposal are still being produced.

**Q. HOW DOES THE CURRENT ALLOCATION OF CCR COSTS COMPARE TO AN ENERGY-BASED ALLOCATION?**

A. The Company's proposed rates allocate the residential rate group 50.6% of ECCR costs, of which the bulk are CCR remediation costs, resulting in a total allocation of roughly $474.1 million to residential customers. By contrast the residential customer class accounts for only 34.3% of total system energy requirements. If an energy allocator was used in place of the present regime, residential customers would be allocated roughly $321.4 million, or approximately $152.7 million less than the Company's proposal. The current framework that causes residential customers to bear a disproportionate share of CCR remediation costs is a clear cost shift in which residential customers are subsidizing customer classes who cause greater costs by consuming of greater amounts of energy.

**Q. HAVE REGULATORS IN OTHER STATES REACHED THE SAME CONCLUSION THAT CCR REMEDIATION COSTS ARE ENERGY-RELATED AND SHOULD THEREFORE BE ALLOCATED USING AN ENERGY FACTOR?**

A. Regulators in both Virginia and North Carolina determined that allocating costs associated with CCR remediation on an energy basis was consistent with the principle of cost causation. In Virginia, in a proceeding on the establishment of Dominion Energy Virginia's Rider CCR, the Hearing Examiner found "a direct connection between the volume of CCR materials to be remediated … and the volume of fuel that was burned at the four Power

Stations over many years."[4] Based on the established energy basis allocation of fuel-related costs and the consistency of applying "a uniform energy rate to recover all CCR remediation costs" with past fuel cost recovery "allocating … CCR costs on an energy basis is consistent with cost causation."[5] Elaborating on this finding, the Hearing Examiner observed: (a) that although an energy-related allocation may result in higher costs to high-load customers those high-load customers also experienced a greater share of energy-related benefits from the combustion of coal, and (b) that allocating CCR costs on an energy basis was therefore "reasonable and equitable."[6] The final order from the full Virginia State Corporation Commission agreed with and adopted this finding.[7]

In North Carolina, the North Carolina Utilities Commission ("NCUC") likewise concluded it was appropriate to "allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor."[8] Duke Energy Carolinas ("DEC") had initially proposed to allocate coal ash costs on a demand basis, a position opposed by several parties. After consideration, the NCUC ultimately agreed "with Public Staff witness Maness that the amount of coal ash correlates with the amount of energy produced from coal, and that the entire DEC system benefited from that energy."

[4] Va. Corp. Comm'n, Case No. PUR-2021-00045, Report of Mary Beth Adams, Hearing Examiner at 27 (Sept. 3, 2021) https://scc.virginia.gov/docketsearch/DOCS/5jsv01!.PDF.
[5] *Id.*
[6] *Id.*
[7] Va. Corp. Comm'n, Case No. PUR-2021-00045, Final Order at 5-6 (Oct. 26, 2021) https://scc.virginia.gov/docketsearch/DOCS/5vh901!.PDF.
[8] N.C. Util. Comm'n, Docket No. E-7, SUB 1146 Docket No. E-7, SUB 819 DOCKET No. E-7, SUB 1152 Docket No. E-7, SUB 1110, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction at 325 (June 22, 2018) https://starw1.ncuc.gov/ncuc/ViewFile.aspx?NET2022&Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

Accordingly, the NCUC ordered that coal ash costs be allocated system-wide on the energy-related factor.[9]

**Q. HOW DO YOU RECOMMEND THAT THE COMMISSION ADDRESS THE COST SHIFT CAUSED BY THE DESIGN OF SCHEDULE ECCR?**

A. The Commission should direct GPC to modify Schedule ECCR to use an energy-based allocation factor to determine class revenue requirements, and to modify the rate design from a percentage-of-bill based design to a uniform volumetric charge.

## III. RESIDENTIAL RATE OPTIONS

**Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSALS FOR REVISING THE RATE OPTIONS AVAILABLE TO RESIDENTIAL CUSTOMERS.**

A. The Company proposes to close two fully volumetric residential rates (Schedule R and Schedule TOU-REO) to certain residential customers after December 31, 2022. Schedule R uses a non-time-differentiated inclining block rate design during the summer (June – September) and a declining block structure during the non-summer months. Schedule TOU-REO uses a two pricing period design with an on-peak period during the summer months and a flat rate for summer off-peak and non-summer use. Schedule R would remain available to residential premises that established service prior to January 1, 2023.[10] However, unlike Schedule R, Schedule TOU-REO would only remain available for

[9] *See id.* at 324-325.
[10] 2022 Rate Case Hr'g Tr. Vol 1 at 911. (Sept. 28, 2022). (Transcripts from the GPC Direct Testimony Hearings on September 28-30, 2022 are marked as Volume 1.)

customers already on that rate prior to January 1, 2023.[11] With these changes, newly established residences would be left with a choice between the following rate schedules:

- Schedule TOU-RD (coined "Smart Usage"), which contains a monthly maximum demand charge applied during all months and a volumetric two-period TOU design with an on-peak period during the summer months and a flat rate for summer off-peak and non-summer use. Schedule TOU-RD was made the default residential rate for new premises starting January 1, 2021;
- Schedule TOU-PEV, (coined "Plug-In Electric Vehicle"), which is a fully volumetric whole-home TOU rate with three-period design during the summer months (on-peak off-peak, super off-peak) and a two-period design (off-peak and super off-peak) during the non-summer months. Despite its name, Schedule TOU-PEV is available to customers without electric vehicles; and
- The Pre-Pay and Flat Bill rates.

**Q. HOW DOES THE COMPANY JUSTIFY ITS PROPOSAL FOR THESE CHANGES TO ITS RESIDENTIAL RATE OPTIONS?**

A. Company Witness Legg describes two primary objectives. First, he describes the closure of Schedule R to new premises established after December 31, 2022 as "the logical next step in the Company's ongoing efforts to encourage residential customers to move toward more modern rate structures" and "toward more modern rate designs that send price signals that more appropriately reflect the cost of service."[12] Witness Legg further seems to be asserting that similar proposals from other utilities are common, stating "utilities across the

[11] *Id.* at 917.
[12] *Id*. at 910.

country are proactively moving away from more antiquated volumetric rate designs (such as the R tariff) and toward more modern rate designs that send price signals that more appropriately reflect the cost of service."[13]

With respect to Schedule TOU-REO, Witness Legg states that the proposal to close Schedule TOU-REO to new customers is motivated by a desire to "streamline the Company's tariff portfolio and avoid customer confusion."[14] He further notes that GPC has two additional time-varying rate schedules that would remain available to customers (Schedule TOU-RD and Schedule TOU-PEV), and relates his view that Schedule TOU-RD rate provides "customers the most accurate price signals while providing three opportunities to save (shifting usage out of on-peak times, staggering appliance use to reduce demand, and simply using less energy)."[15]

**Q. WHAT IS YOUR REACTION TO THE COMPANY'S PROPOSALS AND ITS STATED JUSTIFICATIONS?**

A. I urge the Commission to deny the Company's specific proposals with respect to Schedule R, Schedule TOU-REO and TOU-RD. I fundamentally disagree with Company Witness Legg's testimony that Schedule TOU-RD provides "the most accurate price signals" and that it provides most customers with reasonable opportunities to save money on their electric bills. As I discuss in in Section III(A) of my testimony, demand rates have considerable structural flaws that result in a misalignment with cost causation and economically inefficient price signals, in particular when they are applied to residential customers. Consequently, the Company's apparent desire to steer customers towards

[13] *Id.*
[14] *Id*. at 917.
[15] *Id*.

Schedule TOU-RD, which started with the Company's efforts in 2019 to designate Schedule TOU-RD as the default rate for new premises starting in 2021, rests on a weak foundation. This weak foundation is evidenced by the fact that, contrary to Witness Legg's assertions, there is no trend in utilities moving away from volumetric rate designs in schedules available to residential customers.

Furthermore, I object to the Company's proposals and stated justifications for the following reasons:

- The closure of Schedule R to new premises starting in January 2023 would create an undeniable inequity within the residential customer class based on the arbitrary distinction of living in a newly constructed home.
- During its tenure as the default rate for new residential premises, Schedule TOU-RD has proven to be significantly more expensive to participating customers than other available rate options, rendering further efforts to steer customers towards this rate not in the best interests of GPC's residential customers.

On the matter of the need to streamline the Company's residential rate offerings in order to avoid customer confusion, I agree that there is the potential for customers to become confused about their options, and be unable to determine the rate that best suits their needs. However, I disagree that the number of options is necessarily the core problem, or that the Company's customers' interests would be best served by reducing rate optionality in the manner the Company proposes. Rather, part of the problem lies in the confusing manner that the Company presents those options to customers, such as Schedule TOU-RD being presented with a positive connotation as the "Smart Usage" rate, and misnamed Schedule TOU-PEV being presented as the "Plug-In EV" rate when in fact it is

available to customers without EVs. Another part of the problem is a lack of tools and resources that could assist customers in selecting the rate most suitable for their needs.

**Q. AT SEVERAL POINTS YOU HAVE STATED THAT GPC IS ENGAGED IN EFFORTS TO "STEER" CUSTOMERS ONTO SCHEDULE TOU-RD. PLEASE ELABORATE ON THE BASIS FOR THAT ASSERTION.**

A. There are several actions that the Company has taken or proposes to take towards this objective, even if the rate itself remains "optional" as follows:

- The use of Schedule TOU-RD as the default rate for newly constructed premises effectively ensures enrollment growth and a steady supply of new prospective participants.
- Schedule TOU-RD is branded as the Smart Usage rate on the Company's website, which has a descriptive, positive connotation for customers seeking to manage their energy bills, and the marketing materials indicate that saving money on the rate requires only "small changes." Both claims are highly questionable.
- The Company now proposes to close the only two-period TOU rate option (Schedule TOU-REO) leaving customers that desire to take TOU service under a two-period TOU rate with one option, Schedule TOU-RD. Furthermore, the only other TOU rate option beyond Schedule TOU-RD that would be available is Schedule TOU-PEV, which is marketed as a rate for customers with Plug-In EVs. A customer without an EV reviewing the Company's website for rate options could easily overlook Schedule TOU-PEV as an option given how it is named and marketed.

- The Company now proposes to close off Schedule R to new residential premises, leaving customers principally with a choice between Schedule TOU-RD and Schedule TOU-PEV, which as noted they could only know that they qualify for by navigating to the tariff itself (which requires clicking through multiple layers on the Company's website that emphasize that TOU-PEV is for EV owners).

### *A. Flaws of Demand Rates*

**Q. PLEASE EXPLAIN IN GENERAL WHY DEMAND RATES ARE INCONSISTENT WITH THE PRINCIPLE OF COST CAUSATION.**

A. Grid infrastructure costs are caused by aggregate customer contributions to peak demands on different parts and levels of the system. A customer's monthly non-coincident maximum demand[16] only approximates their contribution to those costs for facilities in close proximity to the customer, such as secondary service lines and line transformers. Even line transformers will experience peaks that depart from individual customer peaks if they serve multiple customers because the peak demands of individual customers often do not occur at exactly the same time. The greater the number of customers (and different types of customers) served by a given piece of infrastructure, the greater this diversity benefit becomes.

Non-coincident demand charges fail to account for this diversity and fail to account for the time-differentiated nature of generation, transmission, and distribution capacity costs. The departure from cost causation is particularly pronounced at the generation capacity and transmission level where an enormous amount of load diversity is present, but

[16] Non-coincident demand refers to a customer's demand at any time rather than only during times that coincide with the collective peak demands on the system or a portion of the system.

it also exists at a significant level on the distribution system as individual distribution circuits often serve thousands of customers with different electricity usage patterns.

**Q. DO THE COST ALLOCATION METHODOLOGIES USED BY THE COMPANY REFLECT THIS DIVERSITY BENEFIT?**

A. Yes. In the Company's cost of service study, production demand costs are allocated based on class demands at the time of the 12 monthly peaks ("12CP"). Certain transmission costs are allocated based on only the monthly peaks during June – September ("Summer 4CP") while the balance of transmission costs are also allocated according to the 12CP methodology.[17]

Distribution cost allocation uses a hybrid system under which a portion of distribution costs are classified as customer-related according to the Company's minimum-intercept study and allocated based on the number of customers, and the remaining balance of costs are classified as demand-related and allocated based on non-coincident maximum class demand. This maximum class demand methodology assigns costs based on the maximum demand of a given customer class during any single hour of the year.[18] Although maximum class demand is sometimes referred to as a "non-coincident peak" allocator because the timing of the maximum demand of a given class may not be coincident with peak conditions on the broader system, this measure of demand still has a coincident character since it measures customer demands coincident with the maximum demand of the class as a whole. This is distinctly different from how a non-coincident demand charge functions because a non-coincident demand charge is based on an individual customer's

[17] 2022 Rate Case Hr'g Tr. Vol. 1 at 893-95 (Sept. 28, 2022).
[18] *Id.* at 896-97.

demand at any time, regardless of whether that demand occurs during times when aggregate class demand or system demand are at their highest.[19]

**Q. DOES THE DEMAND CHARGE COMPONENT OF TOU-RD REFLECT THE TIME-DIFFERENTIATED CHARACTER OF DEMAND-RELATED COSTS?**

A. No. The TOU-RD demand charge is based on a customer's maximum demand during a 60-minute interval each monthly billing period regardless of when that demand occurs. That demand may be offset from the time periods that are likely to produce a peak on the system or within the residential customer class, and by using a single hourly value, the demand charge fails to reflect the frequency of customer demands on the system during potential peak windows. Likewise, the demand charge does not reflect the summer-peaking character of the Company's system, which drives the Company's generation planning and is a component of the allocation methodology for transmission costs.

**Q. DOES THE TOU-RD RATE DESIGN PROVIDE A PRICE SIGNAL THAT PROMOTES EFFICIENT USE OF ELECTRIC SERVICE?**

A. No. There are two problems with the design. First, demand charges in general provide an inconsistent price signal to customers. Second, the price signal itself is not actionable for a typical residential customer.

**Q. PLEASE EXPLAIN HOW THE TOU-RD PRICE SIGNAL IS INCONSISTENT.**

A. The inconsistency in the price signal arises from the fact that the marginal cost of demand from a customer's standpoint is highly diluted by previously registered maximum demands

[19] The rationale for using maximum class demand for distribution cost allocation is that individual segments of the distribution system (e.g., a primary circuit) tend to primarily serve clusters of customers within the same rate class. In reality there can be considerable variations in the timing of peaks for individual substations or circuits in terms of both the time of year and the hour of the day.

within a billing period. During a billing period, any demand below the amount of previous maximum demand has a zero marginal cost. Even if a customer's maximum demand occurs during a peak window, they have no incentive to reduce their demands during future on-peak hours except as necessary to avoid exceeding a maximum demand amount registered earlier in the same billing period. Ultimately, this effect produces economically inefficient outcomes. For instance, during any given summer there are likely to be multiple heat waves with multi-day durations. An economically efficient rate design should incentivize a customer to reduce their demand as much as they can throughout the duration of peak conditions caused by these events. By contrast, demand rates progressively dilute the price signal hour by hour and day by day as a billing period progresses, and fail to account for the frequency and duration of high demands during peak periods.

**Q. DOESN'T THE VOLUMETRIC TIME OF USE COMPONENT OF SCHEDULE TOU-RD PROVIDE THIS TYPE OF CONSISTENT PRICE SIGNAL?**

A. It does, but the price signal should be stronger. At the Company's proposed rates, the fixed and demand components of Schedule TOU-RD account for roughly 82% of total rate revenue. The on-peak volumetric component accounts for only roughly 8.5% of total rate revenue.[20] For comparison, the on-peak volumetric component of Schedule TOU-REO accounts for approximately 20.2% of rate revenue[21] and the volumetric on-peak component of Schedule TOU-PEV accounts for roughly 20.7% of total rate revenue.[22]

[20] Based on Staff TAI 1-16 Attachment AJ.
[21] Based on Staff TAI 1-16 Attachment AK.
[22] Based on Staff TAI 1-16 Attachment AI.

**Q. PLEASE EXPLAIN WHY THE TOU-RD RATE DESIGN DOES NOT PROVIDE AN ACTIONABLE PRICE SIGNAL TO CUSTOMERS.**

A. The only way that a customer can reduce their costs under the TOU-RD rate design is to manage their electricity demand during every single hour of a monthly billing period, and ultimately do so consistently month after month. Such close attention to demand management is highly impractical for a typical residential customer, not to mention being unnecessary as a means of reducing system costs.

**Q. CAN YOU ELABORATE ON WHY IT IS IMPRACTICAL FOR RESIDENTIAL CUSTOMERS TO EFFECTIVELY MANAGE THEIR DEMAND DURING ALL HOURS?**

A. Yes. First, consider the summer months during which there are a total of 2,928 hours, each of which may require the customer's attention even if that hour falls outside of a peak period. The notion that customers should just avoid using major appliances at the same time is much harder to execute than it sounds, in particular because a single instance of relative inattention (or personal need) can produce an outsized bill impact. For instance, during the summer months when an air conditioner is likely to be cycling consistently, it is next to impossible to avoid using an electric dryer during the same time period when the air conditioner is operating. The same is true for other daily necessities, such as cooking with an electric range or oven, not to mention other things like using a dishwasher, coffee maker, toaster, or electric hair dryer. Furthermore, even relatively flexible needs are not infinitely flexible due to family needs and schedules. These challenges are not limited to the summer months. During the winter months any customer with electric heating is likely to experience the same scheduling difficulties, incurring high bills and utility charges

despite the fact the Company does not identify a winter period during which it desires customers to manage their electricity usage.

**Q. WHAT TYPES OF RATES PROVIDE A MORE CONSISTENT, ACTIONABLE PRICE SIGNAL THAN THE PRICE SIGNAL SENT BY DEMAND RATES, INCLUDING SCHEDULE TOU-RD?**

A. Time-differentiated volumetric rates improve the price signal to make it more consistent by effectively charging customers for their *average* contribution to peak conditions. This provides the customer with the same price signal during all potential peak hours, such that electricity demand during each individual on-peak hour has a meaningful marginal cost. This price signal should incent load shifting away from peak hours, not just those hours where a customer might register a demand above a previous maximum demand. The typical TOU price signal is also more actionable for customers because it presents a simple and predictable risk-reward calculation that can be readily planned around and managed using both technology adoption and behavioral changes.

On a practical level, consider again that the summer months during which there are a total of 2,928 hours. The on-peak period applied for five hours on weekday non-holidays would comprise only 14.5-14.9% of those hours depending on whether the holidays fall on a weekday or a weekend. Clearly, managing energy use during on-peak periods is a more manageable proposition than doing so during all hours. Moreover, managing an on-peak TOU pricing period also allows the customer to focus their efforts on the highest value hours from the standpoint of reducing stress on the system. This allows a customer to employ technologies such as programmable and smart thermostats and other smart appliances or devices (e.g., managed EV chargers) in support of their efforts, and adopt

consistent behavioral patterns for activities that are amenable to flexible timing (e.g., avoid using a dishwasher or an electric dryer).

**Q. DO SMART APPLIANCES REALISTICALLY OFFER CUSTOMERS OPPORTUNITIES FOR CUSTOMERS TO MANAGE DEMAND CHARGES?**

A. No. Smart appliances are not an effective means to manage demand charges. Smart devices are suited towards management of predictable TOU pricing windows and response to demand reduction dispatch during critical peak periods, but they do not function as a means of reducing demand during all hours of a day as is required to manage a demand charge. For example, a smart thermostat or smart EV charger can be: (a) programmed to concentrate operation during off-peak periods, and (b) respond to a demand reduction dispatch signal during critical peak periods. However, neither of these capabilities are sufficient to manage demand rate cost management because they depend on known, targeted use management periods and targeted dispatch during unpredictable critical peak periods. In fact, their use towards these ends would likely have the effect of concentrating demand during other periods (e.g., overnight low-cost periods) resulting in a higher charge to the customer, despite the fact that they are responding to a signal to reduce their consumption during on-peak periods.

Demand rate management requires integrated, coordinated operation during all hours among these end-uses, as all other electricity end-uses present in a residence. That is not something that smart appliances themselves can manage. Such coordinated management would require an entire "smart home" system where all end-uses are controlled under an overarching objective of limiting demand at all times. Establishing an

integrated smart home is highly impractical for the vast majority of residential customers, whether they reside in new premises or existing homes.

**Q. IS THIS VIEW OF RATE DESIGN AND ECONOMIC INEFFICIENCY SHARED BY OTHERS?**

A. Yes. The Regulatory Assistance Project ("RAP") recently published a Policy Brief ("RAP Policy Brief"), which I have attached to my testimony as Exhibit JRB-2. In examining the rationale for demand charges, RAP concludes that such charges have little or no place in modern rate design:

> Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60-minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general. For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are more efficient than peak window demand charges.[23]

[23] MARK LEBEL & FREDERICK WESTON, REGULATORY ASSISTANCE PROJECT, DEMAND CHARGES: WHAT ARE THEY GOOD FOR? AN EXAMINATION OF COST CAUSATION at 7 (2020), https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf.

**Q. WHY DO THE AUTHORS OF THE RAP POLICY BRIEF REACH THIS CONCLUSION?**

A. They raise the issues that I have also raised, specifically that what matters for cost causation is not a customer's individual peak, but their contribution to peak demands on the system (or a segment thereof), and that time-differentiated energy rates are more economically efficient than demand rates. They further observe that a significant portion of capacity investment is more properly classified as energy-related rather than exclusively demand-related because, "Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework."[24]

### *B. Modernization of Electric Rate Design*

**Q. APART FROM GPC, ARE THERE ANY OTHER INVESTOR-OWNED UTILITIES ("IOUS") IN THE NATION THAT USE A DEFAULT RATE FOR RESIDENTIAL CUSTOMERS THAT INCLUDES A DEMAND CHARGE?**

A. No. The Company is an outlier in this respect. To the extent that Company Witness Legg is implying that "antiquated volumetric rate designs" are being replaced with demand rate designs, he is incorrect.

[24] *Id.* at 21.

**Q. ARE THERE ANY OTHER IOUS IN THE NATION THAT HAVE CLOSED TRADITIONAL VOLUMETRIC RATE DESIGNS TO NEWLY CONSTRUCTED RESIDENTIAL PREMISES?**

A. No. I am not aware of any other utility that has made a proposal of this type in recent years, let alone one that has seen such a proposal adopted. A small number of IOUs have made proposals to establish a demand rate component within the standard residential rate, but none of those proposals have been adopted. There are no other IOUs in the country that either: (a) use rates with demand charge components as default rates for new or existing residential premises, or (b) otherwise apply them in a mandatory fashion in residential rates.[25]

**Q. WHAT WOULD BE A MORE ACCURATE CHARACTERIZATION OF TRENDS IN RESIDENTIAL RATE MODERNIZATION?**

A. Generally, the trend is towards greater availability of different rate options for the residential class, with an emphasis on making time-varying rates available as an additional option to flat or tiered rates. To be sure, the availability of different rate options has often included new optional demand rates, often with a time-varying element, in addition to volumetric TOU rates. However, there is no trend towards migrating residential customers to demand rates as GPC is seeking to do by using a demand rate as the default rate for new premises and closing other volumetric rate options. Any assertion that such a trend exists is simply inaccurate.

[25] Under cross-examination Company Witness Legg testified that he believed that some other IOUs have established demand rates that are mandatory for residential customers, although he could not name any specifically. 2022 Rate Case Hr'g Tr. Vol. 1 at 1048 ln. 2-19 (Sept. 28, 2022). Company Witness Legg's belief is mistaken.

Where time-varying rates have been adopted as default rates, such as in California, Colorado and Michigan, volumetric TOU rates (not demand rates) have been selected as the default rate. Furthermore, customers in those jurisdictions typically have access to one or more additional volumetric TOU rates beyond the default rate. Most commonly, movement towards TOU pricing for residential customers is to offer at least one relatively "simple" option (e.g., a two-period TOU rate) and at least one more complex option. TOU rates used as default rates tend towards the simple option with other features such as a limited on-peak, off-peak rate spread that help limit customer bill impacts.

**Q. ARE THERE ANY EXAMPLES OF REGULATORS RESPONDING TO CONCERNS ABOUT THE IMPACT THAT DEMAND RATES CAN HAVE ON SOME CUSTOMERS AND THEIR ALIGNMENT WITH COST CAUSATION?**

A. Yes. In Colorado, regulators recently ordered Black Hills Energy ("BHE") and Xcel Energy Colorado ("Xcel CO") to increase the availability of non-demand rates to small commercial customers. BHE was ordered to expand the eligibility for non-demand rate service to small commercial customers increasing by the maximum customer demand threshold for non-demand rates for small commercial customers from 10 kW to 50 kW.[26] Likewise, in 2021 Xcel CO was directed to increase the maximum customer demand eligibility threshold for its small commercial non-demand rate schedule from 25 kW to 50 kW.[27]

[26] Colo. Pub. Util. Comm'n, Proc. No. 17AL-0477, Decision No. C18-0445 at 25-26 ¶77 (June 15, 2018), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=887641.
[27] Colo. Pub. Util. Comm'n, Proc. No. 20AL-0432E, Decision No. C21-0536 at 16-17 ¶38 (Sept. 2, 2021), https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_dec=28531&p_session_id=.

In the same decision, the Colorado Public Utilities Commission ("COPUC") also required Xcel CO to offer a pilot rate for secondary voltage general service customers ("SG-TOU Pilot") that uses a primarily volumetric TOU-based rate design with a modest demand charge limited to secondary distribution costs. In establishing the SG-TOU Pilot, the COPUC found that there was insufficient evidence to make a broad determination on the virtues of a holistic shift away from demand rates in the proceeding, but noted significant concerns surrounding the cost causation attributes of demand rates, as follows:

> However, we do find the evidence and arguments in the record of this Proceeding demonstrate a clear need for further examination of the merits of developing an alternative approach to rates for the SG customer class that better reflects actual cost causation and the Commission's energy policy priorities. In particular, we recognize that COSSA/SEIA has raised significant and timely issues related to demand rates that warrant a much closer look in the Company's next Phase II rate case. *Those issues include, without limitation, the relationship of non-coincident demand charges to cost causation, and how the Commission should view rates that rely heavily on the demand component for recovery in light of: (a) the broad move to time differentiated rates for other major rate classes in an effort to send more accurate price signals*; and (b) the potential risk that the current design may be at odds with state policy goals related to both solar adoption, as well as electrification of smaller commercial facilities.[28] [Emphasis added.]

Beyond this example, in April 2020 the Delaware Public Service Commission ("DEPSC") ordered Delmarva Power (the state's only IOU) to notify all of their commercial customers of their eligibility for non-demand rates in response to petition from the Delaware Division of the Public Advocate ("DEDPA"). The issue arose due to Delmarva Power's implementation of the customer demand cap in the non-demand small general service rate, which over time resulted in many customers being involuntarily

[28] *Id.* at 9 ¶21.

switched to the medium general service rate, which uses a demand-based rate design. After registering demands below the threshold during the following year, customers that were switched to demand rate were not being switched back to the non-demand rate, or being notified of their eligibility to do so, resulting in many remaining on a rate that was more expensive for them.[29] At the time it was estimated that roughly 5,000 of Delmarva Power's 13,700 medium general service customers (36.5%) qualified for the non-demand small general service rate.[30]

**Q. HOW ARE THE EXAMPLES IN COLORADO AND DELAWARE RELEVANT TO RESIDENTIAL DEMAND RATES GIVEN THAT THEY ALL RELATE TO NON-RESIDENTIAL RATES?**

A. The use of demand rates in rate designs for non-residential customers has historically been common, in particular for larger customers, but the same is not true for residential rates. This is in part because the prevalence of high load factor customers who benefit from demand rate designs tends to increase with demand. In other words, many non-residential customers subject to demand rates are accepting of them because the rate design costs them less than a volumetric rate would. At the same time, demand rates applied to high load factor customers may have a somewhat better alignment with cost causation because relatively constant demands tend to make an approximation to a customer's contribution

[29] Del. Pub. Serv. Comm'n, Docket No. 20-0217, Order No. 9564 at 5, April 1, 2020, https://delafile.delaware.gov/CaseManagement/ViewFileNetDocument.aspx?Id=5e265e84-c955-4ee9-a58d-319ea565a901&Type=Docket.

[30] Del. Pub. Serv. Comm'n, Docket No. 20-0217, Petition of the DEPSC Staff and the Delaware Division of the Public Advocate at 6, March 10, 2020, https://delafile.delaware.gov/CaseManagement/ViewFileNetDocument.aspx?Id=02f1cc2e-8e3c-44cb-9599-b7424e21753d&Type=Docket.

to peak demands based on a monthly maximum demand measurement somewhat more accurate.

Residential customers in general are highly dissimilar to the types of high load factor customers for whom demand rates are beneficial and for whom cost causation may be fairly well-aligned (even if only incidentally). The Delaware and Colorado examples highlight the fact that, like most residential customers, not all small commercial customers fit this profile, and for those customers demand rates can be punitive and inconsistent with cost causation.

**Q. CAN YOU PROVIDE ANY EXAMPLES OF REGULATORS REDUCING THE ROLE THAT DEMAND RATES PLAY IN THE RESIDENTIAL RATE CONTEXT?**

A. No, because demand rates are not currently deployed as default or standard residential rates by any IOU in the country. As previously noted, none of the small number of utility proposals in recent years to introduce demand charges into standard or default residential rates have been adopted, so there is no role that demand rates play in residential rate design that could be reduced or eliminated.

**Q. ARE THERE ANY OTHER INDICATIONS OF MOVEMENT TOWARDS GREATER AVAILABILITY OF NON-DEMAND RATES TO DIFFERENT TYPES OF CUSTOMERS?**

A. Yes. There is a prominent trend is taking place in the context of rates charged for non-residential EV charging. Numerous utilities throughout the country now offer rates that allow volumetric charges to be substituted for demand charges, or establish limits or caps on demand charges for high capacity EV charging stations, in particular public direct

current fast charger ("DCFC") stations. GPC is proposing one such rate in the current proceeding in the form of Schedule Charge It-Electric Vehicle ("CIEV"). Although this trend is associated with a specific challenge faced by high capacity EV charging, at its core it acknowledges the fact that demand charges can be punitive to customers with low load factors.

### *C. The Schedule TOU-RD Default Rate Experience*

**Q. PLEASE DESCRIBE HOW SCHEDULE TOU-RD CAME TO BE DEPLOYED AS A DEFAULT RATE FOR NEW RESIDENTIAL PREMISES.**

A. In the Company's 2019 rate case, it proposed to make Schedule R unavailable to new residential premises beginning in January 2020. The Settlement Agreement adopted in the 2019 rate case did not adopt this proposal, but did allow the Company to use Schedule TOU-RD as the default rate for new residential premises starting in January 2021. This means that new customers are placed on Schedule TOU-RD unless they opt into another rate option when they begin service. The Settlement also obligated the Company to "report back to the Commission at the time of its next base rate case regarding the adoption of TOU-RD and its use as the default rate for newly constructed residential premises."[31]

**Q. HOW IS THE CUSTOMER RATE ELECTION, OR OPT-OUT OPTION, ACTUALLY IMPLEMENTED?**

A. The mechanics, such as how a customer specifically is presented with the choice of rates, how they are notified that they have a choice in rates, and how the merits and drawbacks

[31] Ga. Pub. Serv. Comm'n, Docket No. 42516, 2019 Settlement Agreement at 5 ¶21 (Dec. 11, 2019), https://psc.ga.gov/search/facts-document/?documentId=179169. Paragraph 21 of the settlement was incorporated into the Commission's Final Order in the case. *See* Ga. Pub. Serv. Comm'n, Docket No. 42516, Order Adopting Settlement Agreement as Modified (Feb. 6, 2020), https://psc.ga.gov/search/facts-document/?documentId=179856.

of different rate options are explained to customers are not very clear. For instance, the Schedule R and Schedule TOU-RD tariffs and webpages contain no mention that Schedule TOU-RD is the default rate for new residential premises. Likewise, the materials that the Company provides to customers of new residential premises related to the default rate contain no apparent mention of other rate options, considerations that should be made when selecting a rate, or guidance on how to execute a rate election at the time service is being requested, or a rate switch at a later date. The Company appears to provide the same materials to customers that pro-actively select Schedule TOU-RD as it does to those that reside in newly constructed premises. Exhibit JRB-3 contains the Company's response to a Staff data request for this information, which includes a welcome letter and an example of a seasonally sent postcard.[32]

It is possible that further information is provided to customers beginning service at a new premises via customer service agents or through others means, but if so the Company failed to clearly articulate this in written direct testimony, did not include the information in the above noted response or other responses to data requests, and failed to describe its approach to customer engagement with any specificity under cross examination.[33]

[32] Company Response to STF-PIA-2-3 and Attachments A and B.

[33] In response to cross-examination, Witness Legg stated that every time a customer calls into the call center to set up service, representatives discuss rate options available to them. 2022 Rate Case Hr'g Tr. Vol. 1 at 943 ln. 8-10 (Sept. 28, 2022). However, it is unclear if the Company has a conversation with every new customer – or whether this can happen online – and it is unclear how representatives are describing each rate option or whether customers are getting the same description based on consistent delivery of a standardized script.

**Q. HAS THE COMPANY FILED ANY REPORT WITH THE COMMISSION ON ITS EXPERIENCE WITH THE ADOPTION OF SCHEDULE TOU-RD AS THE DEFAULT RATE FOR NEWLY CONSTRUCTED RESIDENTIAL PREMISES?**

A. To the best of my knowledge there is no such formal report, or any evaluation whatsoever on the experience, lessons learned, improvements made, etc. The Company has responded to various data requests posed by Commission Staff, such as providing statistics on new enrollments and opt-outs, but as far as I can tell it has not conducted any research or analysis on its own initiative. I am not aware of any publicly filed report to the Commission that the Company has conducted in line with the provisions of the 2019 Settlement Agreement.

Witness Legg testified that, at least since before 2019, the Company has not conducted any specific analysis of whether new customers defaulted to TOU-RD have different usage patterns, load, or cost profiles that might differ from customers taking service under other residential rate options.[34] Likewise, Mr. Legg testified that the Company has not studied whether customers that have been on the TOU-RD tariff for at least one year have changed their behavior in response to price signals, or whether customers on the TOU-RD tariff have meaningfully different peak demand than residential customers at large.[35]

[34] 2022 Rate Case Hr'g Tr. Vol. 1 at 1054-55 (Sept. 28, 2022).
[35] *Id*. at 1057.

**Q. WHAT HAS BEEN THE EXPERIENCE OF CUSTOMERS ENROLLED ON SCHEDULE TOU-RD UNDER ITS USE AS A DEFAULT RATE FOR NEW RESIDENTIAL PREMISES?**

A. Customers on the TOU-RD rate paid more than they otherwise would have for electricity under another available rate. Figure 1 shows a comparison of monthly average bills from June 2021 to May 2022 for customers enrolled on Schedule TOU-RD versus what their bill would have been if they were enrolled on Schedule R. The average TOU-RD bill over this year was $15.98/month higher than it would have been under Schedule R, totaling roughly $192 over the course of this 12-month period.[36]

**Figure 1**

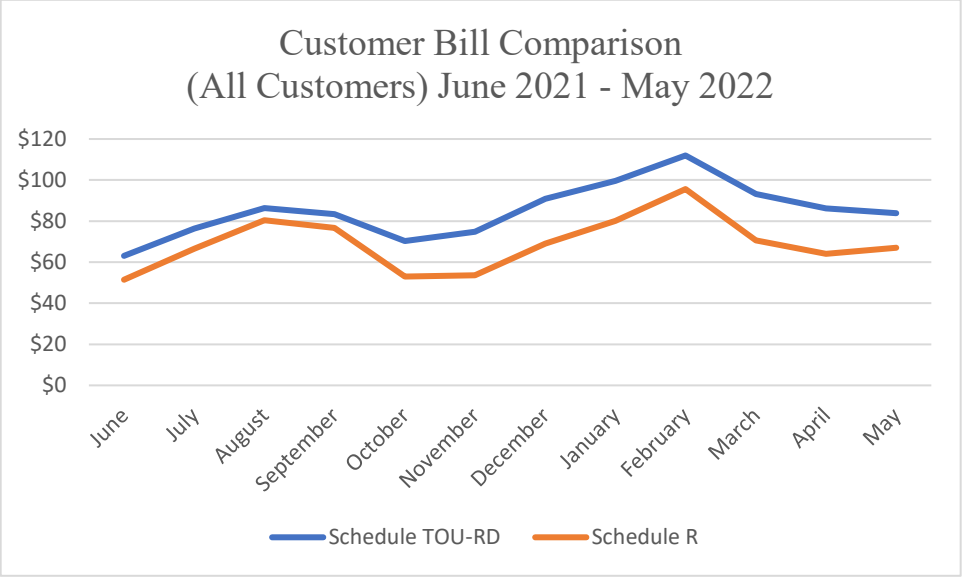


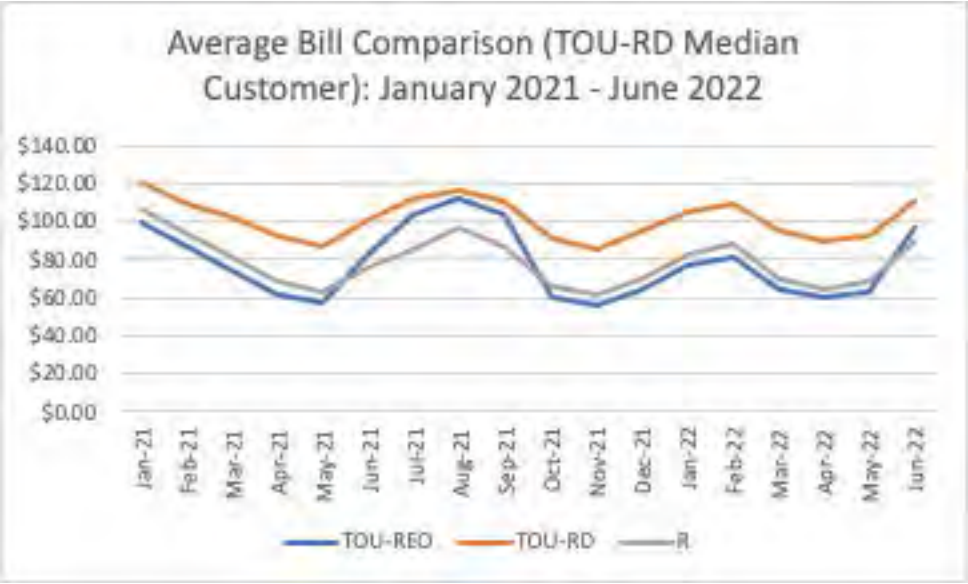

Figure 1 is simply a graphical representation of data provided by the Company in response to a data request. Figures 2 and 3 show comparisons from January 2021 to June 2022 between different rate schedules based on different data sets and my own calculations

[36] Figure 1 created used data provided in response to STF-PIA-2-1 (e.) and (f.), Attachment. It only uses Schedule R as the basis for comparison because the data request was limited to comparing Schedule R and Schedule TOU-RD.

of "shadow" bills under other rate schedules for the Schedule TOU-RD median customer. They also illustrate that Schedule TOU-RD is considerably more expensive for the typical customer than other available residential rate schedules.

Figure 2 shows a monthly shadow bill comparison between Schedules R, TOU-REO, TOU-RD using the demand and energy usage from the median Schedule TOU-RD customer while Figure 3 translates these amounts into average monthly volumetric rates.[37]

**Figure 2**




[37] Figures 2 and 3 are based on data provided in response to STF-PIA-6-41, Attachment. Schedule TOU-PEV is not shown in Figures 2 and 3 because it uses a different set of pricing windows than Schedules TOU-REO and TOU-RD, making it impossible to calculate a shadow bill based on the available data.

**Figure 3**

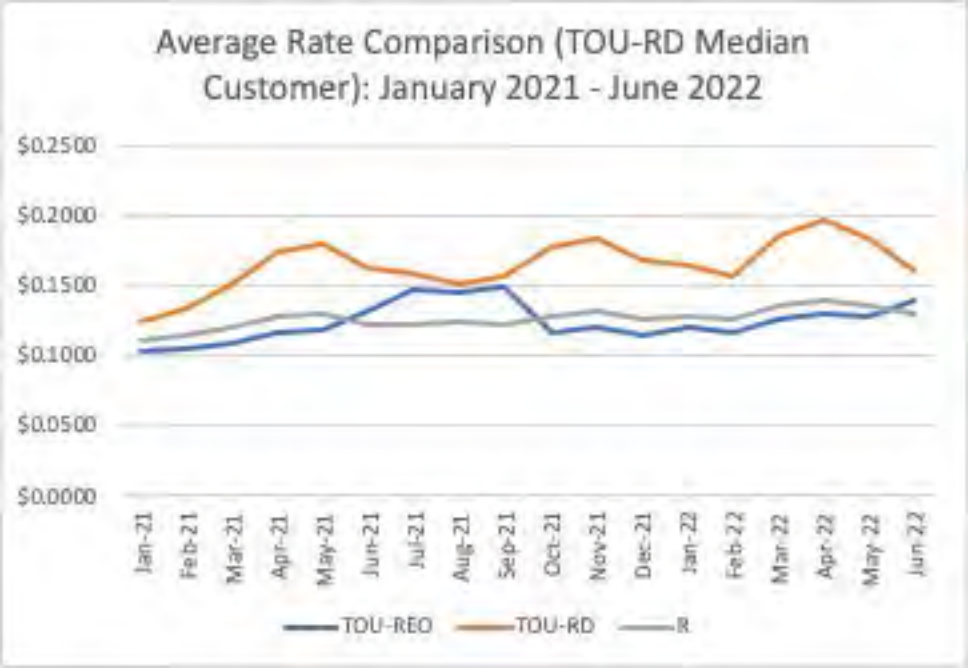
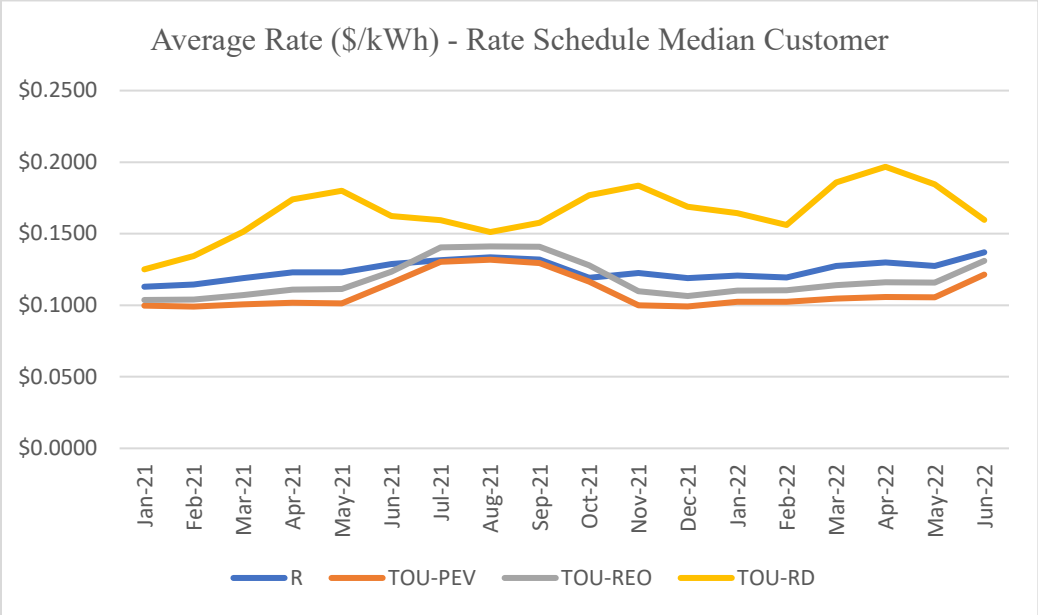



Figure 4 shows the monthly average rate (total bill divided by usage) paid by the class median customer for each of Schedules R, TOU-PEV, TOU-REO, and TOU-RD. Like Figure 3, Figure 4 illustrates that Schedule TOU-RD is an outlier in terms of the average rate it charges customers stated in volumetric terms, in particular during the non-summer months. The difference is significant. On an annual basis the TOU-RD rate is roughly 4.8 cents/kWh higher than the average of the other rates, while during non-summer months the difference increases to roughly 5.6 cents/kWh.[38] The difference between Figure 3 and Figure 4 is that Figure 3 shows the rate the median Schedule TOU-RD customer would have paid under other available rates, while Figure 4 shows the average rate actually paid by the median customer on each of those rate schedules.

[38] Figure 4 is based on data provided in response to STF-PIA-6-41, Attachment.

**Figure 4**




**Q. COULD THESE DIFFERENCES BE ATTRIBUTABLE TO CUSTOMERS THAT MORE ACTIVELY CHOSE SCHEDULE TOU-RD OR WERE ENROLLED ON THE RATE BEFORE JANUARY 2021?**

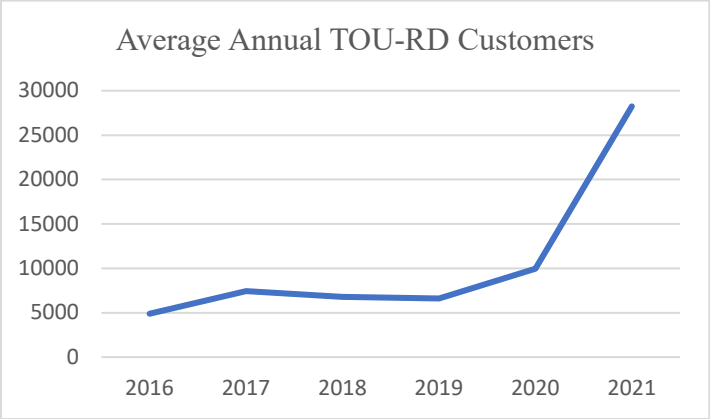
A. No. The vast majority customers on Schedule TOU-RD were enrolled during 2021 or later under the default rate implementation. The Company indicates that as of December 2019 there were 6,564 customers enrolled on Schedule TOU-RD. This increased by 50,853 to 57,417 in May 2022.[39] The Company enrolled a total of 49,809 customers on newly constructed residential premises from January 2021 to May 2022.[40]

[39] Company Response to STF-TAI-1-38 Attachment.
[40] Company Response to STF-PIA-2-1 Attachment, Tab A.

**Q. HAVE THE CHARACTERISTICS OF THE TYPICAL TOU-RD CUSTOMER CHANGED SINCE IT WAS ESTABLISHED AS THE DEFAULT RATE FOR NEWLY CONSTRUCTED RESIDENTIAL PREMISES?**

A. Yes. As the enrollment count for Schedule TOU-RD has gone up, average usage per customer has declined considerably.[41] Figure 5 shows the recent uptick in enrollment, which is flat from 2017 to 2019, jumps somewhat in 2020, and then increases dramatically in 2021. The 2020 increase in customer enrollment is not explained by the start of the default rate system, but could be attributable to Company efforts to support its goal of moving more customers onto Schedule TOU-RD. In any case, 2020 marks the start of a shift in enrollment and participating customer usage characteristics which then becomes even more pronounced in 2021 with the implementation of the Schedule TOU-RD as a default rate for new customers.

**Figure 5**




Figures 6 and 7 illustrate that the increase in enrollment in TOU-RD starting in 2020 coincides with: (a) a significant decrease in average annual customer energy use among participants, and (b) a significant increase in the average cost of electricity. Over

[41] Figures 5, 6, and 7 are based on data from the Company's FERC Form 1 filings.

the course of two years, average usage per customer declines by nearly 50% and the cost of electricity goes from being 1.14 cents/kWh cheaper than Schedule R during 2019 to 1.49 cents more expensive in 2021. This indicates that not only were 2021 enrolled customers distinctly different from the historic participant base in terms of average annual electricity use, but also that the customers added in 2020 were a departure from the historic norm.

**Figure 6**

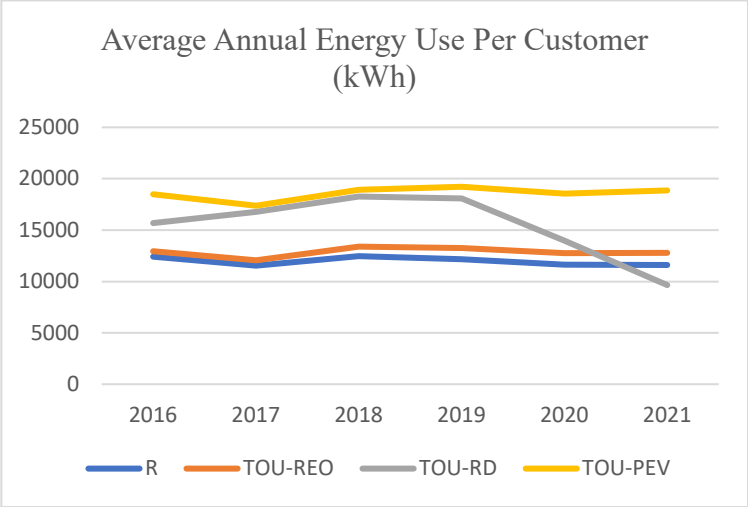
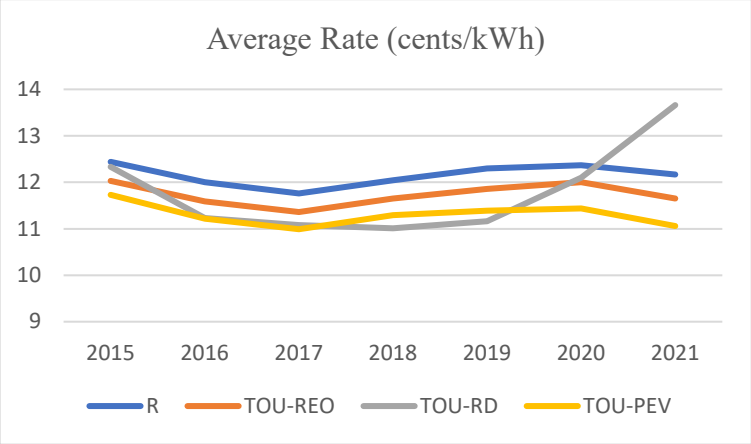



**Figure 7**



**Q. WHY WOULD THE SCHEDULE TOU-RD ENROLLEE USAGE PROFILE HAVE CHANGED SO SIGNIFICANTLY DURING 2020 AND 2021 RELATIVE TO PRIOR YEARS?**

A. Customers with relatively higher average usage tend to be customers with high load factors, for whom demand rates are less costly than volumetric rates. High usage customers that benefited from being on the rate were the norm prior to 2020, as one would expect with an optional rate since participants self-select. Such a profound change in the customer composition strongly suggests that at best, customers were unaware that Schedule TOU-RD was not a good fit for their usage patterns, and at worst, they were steered towards service under a rate that is not in their best interest from a cost standpoint.

**Q. IF THE TOU-RD IS MORE EXPENSIVE THAN ANOTHER AVAILABLE RATE OPTION, WHY WOULD MOST CUSTOMERS REMAIN ON THE SCHEDULE TOU-RD INSTEAD OF SWITCHING TO ANOTHER OPTION?**

A. Assuming that they even know they have the option to change to a different rate, there are two possible reasons. First, Schedule TOU-RD has a one year minimum initial contract term, which presumably prevents a customer from switching until they have received service under Schedule TOU-RD for at least one year. It is not clear specifically how the Company is enforcing this restriction for defaulted customers, but the letter of the tariff is quite clear on this point, stating, "The Customer is required to remain on the TOU-RD

tariff for a period of twelve (12) months from the contract date. … The customer may change tariffs at any time after the initial twelve (12) month term expires."[42]

A second reason could be that they simply do not know any better. Recall that the customers being defaulted are residing in newly constructed premises. Customers may be moving from outside the Company's service territory and be wholly unfamiliar with the Company's rates, or from within the service territory from a dissimilar prior residence (e.g., apartment to single-family home, a different apartment building, or a single-family home with different electric end-uses and/or square footage). Those customers do not have the benefit of being able to compare bills under Schedule TOU-RD to a bill under a different rate because they lack a suitable point of comparison.

**Q. ARE THERE ANY OTHER NOTABLE PATTERNS PRESENT IN YOUR EVALUATION OF HOW TOU-RD HAS AFFECTED PARTICIPANTS DURING RECENT YEARS?**

A. Yes. The excessive costs are concentrated during the non-summer off-peak months, in particular the "shoulder" spring and fall seasons. This is illustrated in Figures 3 and 4, which show that the difference between the effective volumetric rates that Schedule TOU-RD customers pay compared to what customers would pay with the other rate options is at its highest during the shoulder months. These shoulder months are characterized by lower overall demands on GPC's system, meaning that demand during these periods is not a driver of system costs. The fact that the effective rates for Schedule TOU-RD customers

[42] Witness Legg appeared to say that the Company does not always require customers to stay on the tariff for a full 12 months if they call and complain to a customer service representative. 2022 Rate Case Hr'g Tr. Vol. 1 at 1053 (Sept. 28, 2022). Even so, at best this gives a limited pool of customers an opportunity to leave the tariff early on a case-by-case basis at the discretion of the Company. Some customers might read the tariff and believe the Company would not allow them to switch rates, and so would not bother to make the attempt.

are at their highest during such low cost periods of the year illustrates the misalignment between Schedule TOU-RD and cost causation. Customers on other available residential rates pay higher rates during the highest cost summer months, whereas the reverse is true for Schedule TOU-RD customers.

**Q. IS THERE ANY JUSTIFICATION FOR THESE HIGH NON-SUMMER RATES BEING PAID BY SCHEDULE TOU-RD CUSTOMERS, SUCH AS ADDRESSING WINTER PEAKS?**

A. No, for several reasons. First, the highest effective rates appear during the shoulder months, not the winter months. Second, the Company has expressly stated that it does not believe there is a need for a winter peak period in its residential TOU rates at present.[43] Third, such a justification would conflict with the design of Schedule R and the Company's two other available TOU rates, which offer lower rates during non-summer months. It is unreasonable for such a material difference in price signal to exist between available residential rates, and Schedule TOU-RD is the outlier in this respect. The problem is not the design of other available residential rates. The problem is the design of Schedule TOU-RD.

**Q. IS THERE ANY EVIDENCE THAT INDICATES THAT THE HIGHER RATES AND HIGHER BILLS THAT THE CURRENT ENROLLEES ON SCHEDULE TOU-RD CUSTOMERS NOW FACE ARE JUSTIFIED BASED ON DIFFERENCES IN COST OF SERVICE?**

A. No. The Company's assertions that Schedule TOU-RD is the most cost-based residential rate design are based on generalized assertions that are wholly unsupported by any analysis.

[43] Company Response to STF-TAI-1-31.

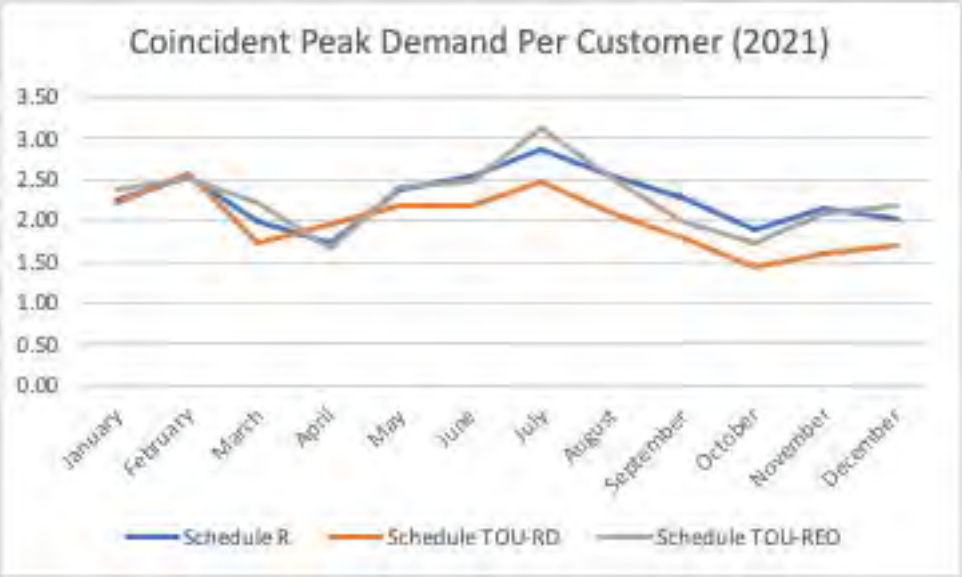
In fact, my own analysis indicates that even though Schedule TOU-RD customers pay overall higher rates and higher bills than they would pay under other available residential rates such as Schedule R and Schedule TOU-REO, on a per-customer basis they contribute lower amounts to the 12CP and Summer 4CP, and, at most, an equivalent amount to maximum class demand.

**Q. PLEASE ELABORATE ON HOW THE CURRENT SUITE OF SCHEDULE TOU-RD CUSTOMERS, AS AFFECTED BY THE DEFAULT RATE POLICY FOR NEW PREMISES, ARE LOWER COST CUSTOMERS ON AVERAGE.**

A. Figure 8 below shows demand per customer coincident with the monthly system peak for the 2021 historic test year. As illustrated in Figure 8, Schedule TOU-RD customers consistently contribute less on a per-customer basis to peak demands than Schedule R and Schedule TOU-REO customers. This difference grows over time as Schedule TOU-RD becomes more populated with defaulted new construction customers. The data underlying Figure 8 show an average 12CP contribution to peak demand of 1.92 kW/customer for Schedule TOU-RD customers, compared to 2.27 kW/customer for both Schedule R and Schedule TOU-REO customers. A Summer 4CP comparison shows an even larger difference with Schedule TOU-RD customers averaging a 2.11 kW/customer contribution to peak demand, Schedule R customers averaging 2.56 kW/customer, and Schedule TOU-REO customers averaging 2.53 kW/customer.[44]

[44] Monthly peak demand by rate schedule was sourced from the Company's Response to STF-TAI-1-3 Attachment. Monthly customer numbers used to make the per customer calculation were sourced from STF-TAI-2-1 Attachments A, B, C, and G providing the number of customer bills by rate schedule each month.

**Figure 8**




I also evaluated whether Schedule TOU-RD customers may have contributed more to the maximum residential class demand. I determined that the average contribution to peak demand per Schedule TOU-RD customer was virtually identical (slightly less) to contributions from Schedule R customers, at 3.04 kW/customer, and significantly less than the contributions of Schedule TOU-REO customers (3.61 kW/customer).[45]

**Q. WHAT CAN THE COMMISSION CONCLUDE BASED ON THE CUSTOMER EXPERIENCE WITH SCHEDULE TOU-RD AS THE DEFAULT RATE FOR NEW RESIDENTIAL PREMISES?**

A. The use of Schedule TOU-RD as a default rate for new residential premises has not been in the best interests of GPC's customers because it has caused a significant number of affected customers to pay more for electric service than they would have paid under other

[45] *Id*. This calculation used customer numbers for July 2021 to align with the timing of the residential class demand during 2021.

available residential rates. The reasons for this are unavoidable flaws with demand rate designs, which are particularly prominent when applied to residential customers.

### *D. Conclusions and Recommendations on Residential Rate Options*

**Q. WHAT ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE IN RESPONSE TO THE EXPERIENCES OF CUSTOMERS WHO WERE DEFAULTED TO SCHEDULE TOU-RD?**

A. The Commission should eliminate the use of Schedule TOU-RD as the default rate for new residential premises and instead return to the use of Schedule R as the default rate for new residential premises. In the alternative, should the Commission desire to retain a time-varying rate as the default rate, it should designate Schedule TOU-REO as the default rate because it is the simplest TOU rate currently available to residential customers. I am recommending Schedule TOU-REO as a secondary alternative to Schedule R because my analysis shows that summer bill volatility is likely to be higher under Schedule TOU-REO than it is under Schedule R, although annual customer bills would remain similar. By extension, the Commission should deny the Company's requests to close Schedule R to newly constructed residential premises.

**Q. SHOULD SCHEDULES R AND TOU-REO REMAIN OPEN TO NEW CUSTOMERS EVEN IF THE COMMISSION DECLINES TO ADOPT EITHER AS THE DEFAULT RATE FOR NEW RESIDENTIAL PREMISES?**

A. Yes. Both should remain available to new customers —including those occupying new residential premises —on an opt-in basis even if Schedule TOU-RD remains the default rate for new residential premises. Both of these rates offer relatively simple structures that are more consistent with cost causation than Schedule TOU-RD, as both charge relatively

higher total rates during the summer peak months and lower rates during the non-summer months, whereas Schedule TOU-RD does the opposite.

**Q. HOW CAN THE COMMISSION ADDRESS POTENTIAL CUSTOMER CONFUSION REGARDING A SUITE OF AVAILABLE RESIDENTIAL RATE OPTIONS, AS THE COMPANY CONTENDS IS NECESSARY?**

A. There are multiple options at the Commission's disposal. The simplest and most obvious is to ensure that the Company's marketing and branding of these rate options accurately reflects their design. That is to say, at a minimum, the misnamed and mis-marketed Schedule TOU-PEV should be rebranded with a more accurate name and description given that it could be a highly viable option for customers who do not have EVs. For instance, it might be rebranded as the "Advanced Time of Use Overnight Discount" rate, which more accurately describes its most notable features of being somewhat more complex than Schedule TOU-REO with the added element of a super off-peak rate during overnight periods. The description could continue to reference its particular suitability for EV customers (e.g., "this rate may be particularly advantageous for EV owners that charge their vehicles at home overnight") without implying that the rate is exclusively for EV customers.

In addition, Schedule TOU-RD should be rebranded as something other than the "Smart Usage" rate because the present branding inappropriately steers customers who desire to manage their energy bills towards it, even though most customers will find doing so highly difficult given the prominent role that the non-coincident demand charge plays in determining their bill. A more accurate nomenclature should reflect the most notable characteristic of the rate: the fact that the largest component of a customer's bill is the

demand component. For instance, it might be referred to as the "Managed Demand" rate with a description indicating that accruing bill savings requires customers to manage their electricity demands during all hours.

The Commission could also direct the Company to develop a rate comparison calculator that would allow customers to download their usage history and through a model provided by the Company, calculate what their historic bills would have been under different available rate options. At present, customers can access granular data on their electricity usage, but it remains up to them to perform the bill modeling necessary to identify the most cost-effective rate for their usage patterns. It is unreasonable to expect the average (or even more sophisticated) residential customer to possess the capabilities to perform this type of modeling themselves. Some customers, in particular lower-income customers, may not have access to the necessary software (e.g., Microsoft Excel), and many others likely lack the skills to develop a rate model.

**Q. HOW DO YOU RECOMMEND THAT THE COMMISSION PURSUE YOUR RECOMMENDATIONS FOR PROVIDING RESIDENTIAL CUSTOMERS MORE ACCURATE AND ACTIONABLE INFORMATON THAT ALLOWS THEM TO SELECT THE MOST APPROPRIATE RATE OPTION?**

A. Within 90 days of an order in this proceeding, the Commission should direct GPC to file a residential rates marketing, education, and outreach ("ME&O") plan which would, at a minimum, address the appropriate branding of all of the Company's residential rate options and provide a detailed plan and timeline for developing a rate calculator to allow customers to easily identify the best rate for them. The Commission may further wish to identify additional minimum contents and parameters for the ME&O plan, such as comprehensive

materials detailing the information provided to new customers generally and customers occupying a new premises (e.g., fact sheets, welcome letters, and customer service scripts), and a detailed, step-by-step description of how the default rate opt-out process functions for customers taking service at a new premises. The overarching objective should be to ensure that customers are not enrolled on a rate schedule that is disadvantageous to them through ignorance of their options or the inability to make informed decisions due to a lack of appropriate information.

## IV. RESIDENTIAL BASIC SERVICE CHARGE

**Q. WHAT IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BSC?**

A. The Company proposes to increase the nominal residential BSC from $0.4603/day, or roughly $14.00/month, to $0.492/day, or $14.97/month. By "nominal," I am referring to the amount of the BSC as reflected in the various residential rate schedules. The effective BSC rate is higher due to the impacts of percentage-based riders which incrementally increase the rates for all components of a customer's bill. Inclusive of the effects of current and proposed percentage-based riders (i.e., Schedules NCCR, ECCR, DSM, and MFF),[46] the Company proposes an increase in the effective residential BSC from $17.69/month to $18.85/month. Under the proposed rates, the riders account for an additional effective fixed charge of $3.89/month.

[46] The current percentage based riders total 26.38% while the proposed percentage based riders total 27.78%.

**Q. HOW DID THE COMPANY DETERMINE THE AMOUNT OF THE PROPOSED INCREASE IN THE RESIDENTIAL BSC?**

A. GPC applied the same percentage increase equally across all residential rate components, approximately 6.9%.[47]

**Q. WHAT IS THE GENERAL PURPOSE OF THE BSC IN THE COMPANY'S RATES?**

A. Fixed monthly charges, or "customer charges," like the BSC, have traditionally been employed to recover costs that vary in proportion to the number of customers served by the utility system. As previously noted, some classic examples of these types of customer-related costs are meters and customer service drops (generally one per customer), and expenses related to monthly meter reading and billing.

**Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE RESIDENTIAL BSC JUSTIFIED FROM THE STANDPOINT OF COLLECTING COSTS THAT VARY IN PROPORTION TO THE NUMBER OF CUSTOMERS?**

A. No. The Company's cost of service study erroneously classifies a portion of the costs associated with the shared distribution system as customer-related based on its Minimum Distribution System ("MDS") analysis. By "shared distribution system" I am referring to infrastructure logged in FERC Accounts 364-368 pertaining to poles, overhead and underground conductors, underground conduit, and line transformers. This classification also flows down into expense categories associated with the shared distribution system.

Consistent with my 2019 testimony, my position continues to be that all costs associated with the shared distribution system should be classified as demand-related and

[47] 2022 Rate Case Hr'g Tr. Vol. 1 at 907, ln. 7-9 (Sept. 28, 2022).

therefore should not be lumped in with costs which truly vary directly in relation to customers (e.g., meters and service drops) when setting the residential BSC. This position is shared in many other jurisdictions throughout the country.

**Q. WHAT WOULD THE RESIDENTIAL CUSTOMER-RELATED UNIT COSTS BE IF THE MDS ASSUMPTION IS REMOVED FROM THE COMPANY'S COST OF SERVICE STUDY.**

A. For the residential class as a whole, I estimate that the amount is $13.77/month per customer. This is $1.20/month less than the proposed tariffed residential BSC ($14.97/month) and $5.08/month less than the effective fixed charge would be under GPC's collective proposal. In order to create an effective BSC equivalent to the $13.77/month amount, the nominal BSC would need to be reduced to $10.78/month at the Company's proposed percentage rider amounts. If Schedule ECCR is modified to use a volumetric rate structure, as I recommend, the nominal BSC amount necessary to yield an effective BSC of $13.77/month is $12.88/month.

**Q. PLEASE EXPLAIN HOW YOU MADE THIS CALCULATION.**

A. I arrived at this figure first by eliminating the MDS component from the Company's historic test year 12CP version of the Company's cost of service study, and then modifying the amount of customer-related rate revenue to the point where the customer-related revenue requirement produced a return equivalent to the overall residential class return. I then divided the required revenue amount by the number of customer bills during a year to

produce a monthly revenue need per customer. This approach is equivalent to how Company Witness Vogt developed a customer-related unit cost in the 2019 rate case.[48]

In addition to eliminating the MDS element, I made several adjustments to exclude certain expenses that should not be considered customer-related for the purpose of setting the residential BSC. These exclusions in aggregate reduced the monthly residential customer-related cost by $0.42/month. The specific exclusions I made are as follows:

- Pre-Pay program expenses, which are attributable to the pre-pay program itself rather than the broader residential customer class.
- Selling and Demonstration expenses, which relate to the promotion of utility services.
- Expenses associated with the Company's membership in the Electric Power Research Institute ("EPRI").

**Q. IS THE PROPOSED INCREASE IN THE RESIDENTIAL BSC JUSTIFIED EVEN IF THE EFFECTS OF THE MDS ARE INCLUDED WHEN SETTING CUSTOMER-RELATED COSTS?**

A. No, for two reasons. First, the Company's estimated residential customer-related costs have actually decreased relative to the amounts the Company specified in its 2019 rate case. In the 2019 rate case Company Witness Vogt sponsored testimony indicating that its residential customer-related costs were $24.36/month.[49] I have calculated that the residential customer-related costs based on the cost of service study filed in the current proceeding, without excluding the MDS assumption or making any other adjustments, are $22.34/month, a decrease of $2.02/month.

[48] Ga. Pub. Serv. Comm'n, Docket No. 42516, Document Filing No. 177523, Direct Testimony of Lawrence J. Vogt, Ex. LJV-9, https://psc.ga.gov/search/facts-document/?documentId=177523.
[49] *Id*.

Second, embedded cost studies are more useful for determining the amount of revenue to be collected in total and from different groups of customers, not how to collect it in the form of rate design. Using customer-related unit costs produced by an embedded cost study in a deterministic fashion to set a residential BSC ignores the wealth of other ratemaking considerations and objectives. I also discussed the application of these other considerations and objectives at length in my 2019 testimony.

**Q. WHY DID THE CUSTOMER-RELATED UNIT COSTS DECLINE IN THE PRESENT CASE RELATIVE TO THE 2019 RATE CASE?**

A. The primary factor that changed is a decrease in the customer-related component the Company calculates for shared distribution system infrastructure using its MDS analysis. The customer-related component of shared distribution plan decreased from 46.9% in the 2019 MDS analysis to 32.6% in the current version.[50] The customer-related percentages decreased significantly for three Federal Energy Regulatory Commission ("FERC") accounts in the present study relative to the 2019 study, as follows:[51]

- Account 364 (poles): 47.8% (2019) to 32.2% (2022)
- Account 365 (overhead conductors): 56.5% (2019) to 43.4% (2022)
- Account 368 (line transformers): 90.2% (2019) to 49.7% (2022)

[50] Company Response to STF-PIA-8-9(c).
[51] Sourced from Company Response to STF-TIA-1-2, Attachment, Summary Tab for 2022 values, and Company response to STF-PIA-8-9, Attachment, Summary Tab for 2019 values.

**Q. WHAT SPECIFICALLY CHANGED IN THE HOW THE COMPANY CONDUCTED THE MDS EVALUATION IN THE PRESENT CASE RELATIVE TO THE 2019 RATE CASE?**

A. The most significant change the Company made is to how it develops current costs for line transformers based on past booked costs. In the current case the vintage adjustment to booked costs for line transformers used GPC-specific estimates rather than South Atlantic region Handy Whitman Indices of component cost inflation over time.[52] This change addresses a significant problem that I identified in the 2019 MDS study that produced customer-related percentages for pad-mounted transformers in excess of 100% (e.g., 219% for single-phase pad-mounted transformers), which is a clear impossibility.[53] This change is the primary reason that the estimated customer-related percentage for line transformers decreased so dramatically, from roughly 90% to 50%.

The Company also made a change in how it determines the customer-related component for certain accessory equipment. In the 2019 MDS study it classified this "Other Unitized Equipment" relating to overhead conductors (FERC Acct. 365) as 100% customer-related, whereas in the current MDS analysis the allocation was revised to base it off the customer- and demand-related split for primary overhead conductors.[54] This change also partially addresses a critique from my 2019 MDS analysis.

[52] Company Response to STF-PIA-8-9(b).
[53] *See* Company Response to STF-PIA-8-9, Attachment, Acct 368 Tab, cell U57.
[54] Company Response to STF-PIA-8-9(b).

**Q. ARE YOU ENDORSING THE COMPANY'S MDS ANALYSIS FOR DETERMINING CUSTOMER-RELATED COSTS IN THIS CASE GIVEN THE CORRECTIONS THAT THE COMPANY HAS MADE TO ITS EVALUATION RELATIVE TO THE 2019 STUDY?**

A. No. The Company's present MDS study is more reasonable than its 2019 evaluation because some errors have been addressed, but it does not change the fact that the MDS concept itself rests on shaky methodological ground. Moreover, the changes in the 2022 results relative to the 2019 study underscore the subjective nature of the entire exercise.

**Q. WHAT IS YOU RECOMMENDATION TO THE COMMISSION REGARDING THE LEVEL OF THE RESIDENTIAL BSC.**

A. I recommend that the Commission deny the Company's proposed increase and instead leave the residential BSC unchanged from its present amount, contingent on the Commission also adopting my recommendation to modify Schedule ECCR from using a percentage-based structure to a volumetric structure. With this change, the difference between the effective BSC at the current $14.00/month rate and the effective BSC that reflects a cost-based rate that does not reflect the use of the MDS would be small. In fact, the Commission would be justified to reduce the residential BSC by $1.12/month ($0.039/day) to achieve this outcome, but retaining the current charge produces a similar result and could be viewed as maintaining greater consistency in rates.

**Q. WOULD RETAINING THE CURRENT RESIDENTIAL BSC STILL BE APPROPRIATE IF THE COMMISSION ACCEPTS THE USE OF MDS AS AN ELEMENT OF CALCULATING CUSTOMER-RELATED COSTS?**

A. Yes, because even with the inclusion of the MDS, the decrease in customer-related costs since the 2019 rate case allows the Commission to retain the current charge while at the same time providing an incremental, gradual movement towards the Company's supposed "cost-based" residential BSC.

## V. CONCLUSION

**Q. DO YOU HAVE ANY CLOSING REMARKS TO MAKE TO THE COMMISSION ON THE MATTERS THAT YOU HAVE ADDRESSED IN YOUR TESTIMONY?**

A. Yes. I ask that the Commission take note of several key conclusions that I have reached in my evaluation of the Company's application and implement my associated recommendations.

1. The design of Schedule ECCR, including the cost allocation regime and the rate design, is inconsistent with cost causation and results in significant cost shifting to the residential class. Accordingly, it should be modified to allocate costs based on an energy factor and charge customers for those costs using a uniform volumetric charge.
2. The only cost shift associated with the Schedule RNR monthly netting option that the Company has identified thus far is of the Company's own creation via a proposed $1.4 million revenue adjustment that benefits its shareholders. This proposed revenue adjustment is inappropriate because the existing earnings band and revenue sharing mechanism already adequately addresses shareholder interests.

3. The use of Schedule TOU-RD as a default rate for new residential premises has not been in best interest of the Company's customers because Schedule TOU-RD has proven to be poorly suited as a cost-reflective rate for residential customers and has been significantly more expensive on average for the current suite of Schedule TOU-RD customers than other rate options. The Commission should act based on this new information by eliminating the use of Schedule TOU-RD as the default rate for new residential premises and redesignating Schedule R as the default rate, or in the alternative Schedule TOU-REO if it wishes to retain a time-varying price signal as part of the residential default rate.
4. In line with conclusion (3) above, and in the interest of allowing the diverse class of residential customers greater opportunities to control their energy costs through selecting the best rate for their individual circumstances, the Commission should deny the Company's proposals to close Schedule R to new residential premises and close Schedule TOU-REO to new enrollments.
5. The manner in which the Company presents rate options to residential customers is confusing and fails to promote effective customer understanding and rate selection. Most specifically, the branding of Schedule TOU-RD as the "Smart Usage" rate and Schedule TOU-PEV as a rate for customers that own EVs, even though non-EV customers may enroll in Schedule TOU-PEV, are problematic. In order the remedy this problem, I recommend that the Commission direct the Company to file, within 90 days of an order in this proceeding, a residential rates ME&O plan that at a minimum addresses the appropriate branding of all of the Company's residential rate options and

contains a detailed plan and timeline for developing a rates calculator that allows customers to easily identify the rate that best suits their circumstances.

6. The current residential BSC is already sufficient to recover truly customer-related costs, and the Company's cost of service analysis shows a decrease rather than an increase in customer-related costs. Both of these facts, considered separately or in concert, render an increase in the residential BSC unjustified.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

# Exhibit JRB-1

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

# JUSTIN R. BARNES

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## EDUCATION

**Michigan Technological University** Houghton, Michigan
*Master of Science,* Environmental Policy, August 2006
Graduate-level work in Energy Policy.

**University of Oklahoma** Norman, Oklahoma
*Bachelor of Science,* Geography, December 2003
Area of concentration in Physical Geography.

## RELEVANT EXPERIENCE

**Director of Research**, July 2015 – present
**Senior Analyst & Research Manager,** March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

**Senior Policy Analyst**, January 2012 – May 2013;
**Policy Analyst**, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

## SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

## TESTIMONY & OTHER REGULATORY ASSISTANCE

**Wisconsin Public Service Commission. Docket No. 5-UR-110**. September 2022. On behalf of RENEW Wisconsin. Wisconsin Electric Power Company general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

**Wisconsin Public Service Commission. Docket No. 6690-UR-127**. September 2022. On behalf of RENEW Wisconsin. Wisconsin Public Service Corporation general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

**Wisconsin Public Service Commission. 3270-UR-124**. September 2022. On behalf of RENEW Wisconsin. Madison Gas and Electric general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit. (*Note: Exhibit was introduced at the hearing and testimony on the methodology provided orally at the hearing; written testimony was not filed).*

**Michigan Public Service Commission. Case No. U-20836.** May 2022. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Addressed the utility's proposal for changes to its DG Tariff, including excluding generation capacity value from the export rate and requiring DG customers to take service under a newly proposed residential demand rate. Also evaluated the cost causation and other rate attributes of the proposed residential demand rate.

**Virginia State Corporation Commission. Docket No. PUR-2021-00171**. January 2022. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Evaluation of the cost basis for the residential customer charge, AMI deployment and the timeline for deployment of TOU rates, class allocation of distribution and production demand costs, and the Company's proposal for a DSM/EE pilot program and cost recovery rider.

**Michigan Public Service Commission. Case No. U-20963.** June 2021. On behalf of the Michigan Energy Innovation Business Council and the Institute for Energy Innovation. Consumers Energy Company general rate case. Provided an evaluation of the utility's proposed home battery program and offered recommendations for modifications to the program to improve its cost-effectiveness and delivery of benefits to participants and non-participants through changes to battery operational plans, elimination of restrictions on consumer use of the batteries, battery sizing modifications to fit actual customer needs, and use of solar-paired storage to provide greater resiliency.

**Colorado Public Utilities Commission. Proceeding No. 20AL-0432E.** March 2021. On behalf of the Colorado Solar and Storage Association and the Solar Energy Industries Association. Public Service Company of Colorado (Xcel Energy Colorado) general rate case. Provided analysis and recommendations on several non-residential rate design issues, including the utility's practice of switching small commercial customers to demand rates, relaxing the demand threshold at which commercial customers are subject to demand rates, the utility's proposal for modifying time-varying pricing windows, and the establishment of a pilot time-of-use rate for Secondary General (SG) commercial customers intended to remedy the misalignment between the SG non-coincident demand rate design and cost causation and set a foundation for a default time-varying rate option for SG class customers.

**Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350**. March 2021 (Phase 1) and July/August 2021 (Phase 2). On behalf of the Kentucky Solar Energy Industries Association. Kentucky Utilities and Louisville Gas and Electric general rate case applications. Provided an analysis of the utilities' current tariffs governing purchases from qualifying facilities and recommended changes to align them with state regulations, recent precedent, and accepted methodologies of energy and capacity pricing.

**South Carolina Public Service Commission. Docket Nos. 2020-264-E and 2020-265-E.** February 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Duke Energy Carolinas and Duke Energy Progress. Provided testimony in support of a stipulated settlement discussing the critical role that a proposed smart thermostat rebate and enabling technologies more generally play in the successfully meeting the legislative objectives for Solar Choice tariffs.

**South Carolina Public Service Commission. Docket No. 2020-229-E.** January 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Dominion Energy South Carolina. Provided an analysis of the proposed Solar Choice tariff from the standpoint of NEM successor best practices, alignment with the enabling statute, and cost of service basis. Offered an alternative Solar Choice tariff proposal based on

this analysis. Surrebuttal testimony provided an evaluation of solar customer cost of service correcting erroneous assumptions used by the Office of Regulatory Staff in its direct testimony.

**Virginia State Corporation Commission. Docket No. PUR-2020-00134**. January 2021. On behalf of the Behind the Meter Solar Alliance. Docket for Dominion Virginia's 2020 RPS Plan. Offered testimony supporting the designation of small-scale resource carve-out eligibility being limited to behind the meter resources, based on the underlying Virginia statute and other public policy reasons.

**South Carolina Public Service Commission. Docket No. 2019-182-E.** October 2020. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a cost-benefit analysis methodology and protocols for net metering and DERs. Provided discussion of historic regulatory use of DG cost-benefit and cost of service studies, how results should be viewed, and a discussion of the role of economic benefits and resiliency in DER cost-benefit analyses.

**Kentucky Public Service Commission. Docket No. 2020-00174**. October 2020. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Provided an evaluation and critique of the cost of service support for, and design of, Kentucky Power's proposed net metering successor tariff and offered recommendations for developing cost-based DER rate designs. Also recommended changes to the utility's QF tariff and calculation of capacity costs.

**New Jersey Board of Public Utilities. Docket No. EO18101111**. September 2020. On behalf of Sunrun, Inc. Public Service Gas and Electric energy storage deployment plan proposal. Offered alternative proposal for a program utilizing non-utility owned energy storage assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

**Virginia State Corporation Commission. Docket No. PUR-2020-00015.** July 2020. On behalf of Appalachian Voices. Appalachian Power Company general rate case. Analysis of the cost basis for the residential customer charge, the Company's winter declining block rate proposal, and a proposed Coal Asset Retirement Rider (Rider CAR) providing for advance collection of anticipated accelerated depreciation of coal generation assets. Provided an alternative residential customer charge recommendation and an alternative rates proposal for addressing winter bill volatility for electric heating customers.

**North Carolina Utilities Commission. Docket No. E-2 Sub 1219**. April 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

**North Carolina Utilities Commission. Docket No. E-7 Sub 1214**. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

**Virginia State Corporation Commission. Docket No. PUR-2019-00060.** November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

**Georgia Public Service Commission. Docket No. 42516.** October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general

rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

**Hawaii Public Utilities Commission. Docket No. 2018-0368**. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

**Virginia State Corporation Commission. Docket No. PUR-2019-00067**. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

**New York Public Service Commission. Case No. 19-E-0065.** May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

**South Carolina Public Service Commission. Docket No. 2018-318-E.** March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

**South Carolina Public Service Commission. Docket No. 2018-319-E.** February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

**New Orleans City Council. Docket No. UD-18-07**. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

**New Hampshire Public Utilities Commission. Docket No. DE 17-189**. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

**North Carolina Utilities Commission. Docket No. E-7 Sub 1146**. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system

study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

**Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO**. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

**North Carolina Utilities Commission, Docket No. E-2 Sub 1142**. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

**Public Utility Commission of Texas, Control No. 46831**. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

**Utah Public Service Commission, Docket No. 14-035-114**. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

**Colorado Public Utilities Commission, Proceeding No. 16A-0055E**. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

**Public Utility Commission of Texas, Control No. 44941**. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

**Oklahoma Corporation Commission, Cause No. PUD 201500274**. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

**South Carolina Public Service Commission, Docket No. 2015-54-E**. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

**South Carolina Public Service Commission, Docket No. 2015-53-E**. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

**South Carolina Public Service Commission, Docket No. 2015-55-E**. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

**South Carolina Public Service Commission, Docket No. 2014-246-E**. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

## AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Masters Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

# Exhibit JRB-2

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

RAP®

REGULATORY ASSISTANCE PROJECT

NOVEMBER 2020

# Demand Charges: What Are They Good For?

## An Examination of Cost Causation

Mark LeBel and Frederick Weston, with contributions from Ronny Sandoval

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- Jim Lazar, Carl Linvill and Ann McCabe, RAP

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The analysis in this paper rests on the shoulders of earlier RAP publications, in particular:

Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Linvill, C., Lazar, J., Dupuy, M., Shipley, J., & Brutkoski, D. (2017). *Smart non-residential rate design.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

Weston, F. (2000). *Charging for distribution utility services: Issues in rate design.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design/

That said, responsibility for the information and views set out herein lies entirely with the authors.

# Executive Summary

Demand charges, rates that are applied to an individual customer's maximum short-term usage (typically 15, 30 or 60 minutes) in a billing period, have existed since nearly the beginning of the electric industry. While utilities often favor demand charges, economists have continually questioned whether they are an efficient form of pricing. With the widespread adoption of advanced metering, this is an opportune time to reconsider demand charges, even for industrial customers, and replace them with more efficient time-varying energy (kilowatt-hour) rates.

Traditional monthly demand charges have always provided a perverse incentive that does not reflect cost causation for shared system costs. Individual customer noncoincident peaks (NCPs) do not reflect the coincident peaks that drive *shared* generation and delivery capacity costs. The price signal that demand charges send — to lower individual customer NCP and to level a customer's load over time — is substantially different than a price signal to reduce usage at the time of coincident peaks. As a result, demand charges penalize customers for usage at times that do not impose particularly high costs and encourage them to waste effort and money shifting loads off their own maximum hour (and sometimes onto high-load system hours).

The historic exception to this rule is a customer that has a nearly 100% coincidence factor with the relevant peaks. The prototypical example of this in the mid-20th century was an industrial customer with very high load factors. Demand charges could be reasonable in the past only as applied to this specific category of customers. But, in today's electric system, even this justification for demand charges falls away. High penetrations of nondispatchable but variable renewable generation means that a 100% load factor is unlikely to be, from a system perspective, the most desirable load shape. Rather, flexible load — load that can respond to swift changes in the availability of supply, perhaps in the middle of the day for solar and late at night with wind — becomes cheaper to serve than unvarying loads in systems marked by high penetrations of variable supply.

Historically, demand charges have frequently been sized to recover most or all shared system capacity costs. Again, this may have been reasonable enough in the mid-20th century for certain customers, but it does not reflect the economics and engineering of a modern electric system. The choices that system planners make are trade-offs between different types of costs. Much "capacity" investment today aims to reduce energy costs and is not incurred to meet peak reliability needs. This means that a significant portion of investment in generation, transmission and distribution plant (and the associated operation and maintenance expense) cannot be reasonably described as demand-related or driven by peak reliability needs. Any pricing structures that reflect the marginal costs of peak system capacity should be sized properly to reflect these distinctions. That includes

demand charges, if appropriate, as well as time-varying energy pricing.

It is fair to ask whether a properly sized "peak window" demand charge solves these issues. Although such a charge is superior to traditional demand charges for the pricing of shared capacity costs, peak window demand charges nonetheless retain many of the shortcomings of their traditional counterparts. Customers who have high usage at many times throughout the peak period should be charged more for capacity than customers who have a single high usage interval in that same window. Time-varying energy pricing provides superior incentives to optimize usage at all relevant times. Simple time-of-use rates are fairer and more efficient than peak window demand charges and can be made even more so by overlaying them with pricing that is responsive to critical peak conditions.

A few analysts and economists have identified several narrower applications where pricing structures akin to demand charges could be appropriate and reasonably efficient: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. While more research into these applications might be merited, demand-based pricing would only be a second-best approximation of a more efficient but potentially more administratively complex time- and location-based pricing system.

# 1. Introduction

Demand charges have existed almost since the beginning of the electric industry in the 1880s. They were originally called Hopkinson rates after John Hopkinson, a British engineer who described the concept in 1892. Hopkinson believed that costs of "plant and conductors"[1] — namely capacity costs — for an electric utility should be charged to customers based on the "greatest rate of supply the consumer will ever take."[2] Shortly thereafter, a meter was developed that could capture the highest kW power draw from the customer, defined over a period of an hour or half-hour, during an entire billing period (now typically a month). These rates became prevalent for industrial customers in the early 1900s.[3]

It did not take long, however, before economists called into question their putative cost-causation rationale. In 1941, future Nobel Prize winner in economics W. Arthur Lewis argued that the cost-causation case for demand charges was often based on "a simple confusion. … The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak."[4] In 1970, prior to becoming chairman of the New York Public Service Commission, Cornell University professor Alfred E. Kahn wrote that demand charges are "basically illogical."[5] More recently, University of California professor and California Independent System Operator board member Severin Borenstein opined that "it is unclear why demand charges still exist."[6]

Electric utilities and some consultants still make broad arguments for demand charges that are, at their core, the same as those made more than a century ago. In 2016, the Edison Electric Institute (EEI) asserted that "demand charges provide accurate price signals" and "better collect capacity costs [than other kinds of prices]."[7] EEI made this

[1] Hopkinson, J. (1901). *Original papers: Vol. 1, Technical papers*, p. 257. Cambridge University Press.

[2] Hopkinson, 1901, p. 261.

[3] There was a debate within the electric utility industry about rate design in the 1890s. A time-of-use meter was invented nearly simultaneously with the demand meter, and some industry participants argued that time-of-use rates would be superior. See Hausman, W. J., & Neufeld, J. L. (1984). Time-of-day pricing in the U.S. electric power industry at the turn of the century. *The RAND Journal of Economics, 15*(1). This time-of-use meter disappeared from discussion relatively quickly, however, as an industry consensus formed around demand charges. Neufeld argues that demand charges were a part of utility strategy to discourage industrial customers from relying on distributed generation, known as "isolated plants" at the time. Neufeld, J. (1987, September). Price discrimination and the adoption of the electricity demand charge. *Journal of Economic History, 47*(3), 693-709. In addition, Samuel Insull, president of Chicago Edison (later Commonwealth Edison) and a major player in the industry, happened to own a part of the patent for the demand charge meter. See Yakubovich, V., Granovetter, M., & McGuire, P. (2005). Electric charges: The social construction of rate systems. *Theory and Society, 34,* 597-612.

[4] Lewis, W. A. (1941). The two-part tariff. *Economica, 8*(41), 252.

[5] Kahn, A. E. (1970). *The economics of regulation: Principles and institutions: Vol. 1, Economic principles*, p. 96. John Wiley & Sons.

[6] Borenstein, S. (2016). The economics of fixed price recovery. *The Electricity Journal, 29*(7), 10.

[7] Edison Electric Institute. (2016, February). *Primer on rate design for residential distributed generation,* p. 6. https://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/2016%20Feb%20NARUC%20Primer%20on%20Rate%20Design.pdf

argument simultaneously for two different types of demand charges: (1) the traditional monthly noncoincident peak (NCP)[8] demand charge, based on an individual customer's NCP across an entire billing period, and (2) a peak window demand charge,[9] based on an individual customer NCP within a defined multihour interval, similar to the on-peak period for a time-of-use (TOU) rate.[10] In addition, there has been a push by EEI and many utilities to expand the application of demand charges beyond just the industrial and large commercial customer classes to small business and even residential customer classes.

Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60-minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general.[11] For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are more efficient than peak window demand charges.

If there is a role for demand charges in today's electric system, it is much narrower than the one it performs for industrial customers in many jurisdictions. Modern versions of

[8] A customer's noncoincident peak is its highest demand, in kilowatts, measured at the meter during the period in question. This customer demand can be measured based on different intervals, typically 15, 30 or 60 minutes. "Noncoincident" means that this demand does not necessarily occur at the time of a system peak.

[9] There is no standardized terminology for this type of demand charge where determination of the maximum demand for the billing period considers only a limited number of peak hours, similar to the peak period for a time-of-use rate. We find the "peak window demand charge" description more apt than the other alternatives.

[10] Less commonly, daily-as-used demand charges are part of the discussion, which we raise later in this paper. As the name implies, it is a demand charge for a customer's individual NCP in a given 24-hour period, sometimes limited to a peak window within that day and sometimes excluding weekends and holidays. This means that the ratchet feature of a daily-as-used demand charge is reset every day and not every billing period, as with other demand charges. In this paper, we do not focus on contract (ex ante) demand charges, although they share many features with these other alternatives.

[11] There are other issues at play in the debate around demand charges, particularly whether residential and small business customers can understand and manage these types of rates and the related potential for inequitable bill impacts. See Chernick, P., Colgan, J., Gilliam, R., Jester, D., & LeBel, M. (2016). *Charge without a cause? Assessing electric utility demand charges on small consumers.* (Electricity rate design review paper No. 1). https://votesolar.org/files/6414/6888/3283/Charge-Without-CauseFinal_71816.pdf; and Lazar J. (2015). Use great caution in design of residential demand charges. *Natural Gas & Electricity*. https://www.raponline.org/wp-content/uploads/2016/05/lazar-demandcharges-ngejournal-2015-dec.pdf. The question of understandability of demand charges by residential and small business customers is a longstanding one. D. J. Bolton notes that a 1948 report by a government commission in Great Britain rejected demand charges for residential customers on two bases: (1) understanding of the rate and (2) the potential reaction to an overload encouraging higher usage levels going forward. Bolton, D. J. (1951). *Electrical engineering economics: Vol. 2, Costs and tariffs in electricity supply*, p. 255. (2nd ed. rev.). Chapman & Hall. We do not delve into these issues at length in this paper.

these charges need to be more rigorously fashioned to achieve economic efficiency and advance the public good than they have been historically. We examine three more nuanced cases where demand charges have been identified as a potentially efficient pricing mechanism: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. In these situations, pricing structures with some similarities to demand charges may be appropriate. In each of these cases, demand-based pricing would only be a second-best approximation of a more efficient time- and location-based pricing system.

Unless we reexamine fundamental ratemaking practices critically in light of the modern electric system and new technologies, we will miss major opportunities to optimize system costs, ensure reliability and improve societal outcomes. While utilities and some consultants have been pushing for new applications for demand charges, regulators and utilities should be moving in the opposite direction by replacing demand charges for industrial customers with more accurate pricing mechanisms.

# 2. Historic Cost-Causation Argument for Demand Charges

A frequently used but inaccurate cost-causation argument for demand charges begins with the observation that several of the most important cost categories can be denoted in kilowatts (kW) or megawatts (MW).

- Generation capacity is denominated in kW or MW, reflecting the maximum instantaneous power output of a given unit.
- Transformers are rated in kilovolt-ampere (kVA) or megavolt-ampere (MVA), a unit of apparent power[12] closely related to kW or MW.
- Conductors are rated in amps for the level of current that they can handle. For a given voltage, this leads to a maximum kW or MW power flow for that conductor (power equals current times voltage).[13]

From these engineering descriptions, which are accurate but potentially misleading, some analysts conclude that, because generation and delivery capacity can be measured in units of power (kW or MW), their costs are demand-related. Making the leap to retail rate design then becomes easy: Capacity costs are rated in kW, so prices should be reflected

[12] Apparent power is the combination of active and reactive power in an alternating current circuit that needs to be supplied to serve load. This includes the power components that are needed to energize the circuit but don't transfer useful power to the load.

[13] For three-phase power, power is current times voltage times the square root of 3.

in kW.[14] This is the essence of the argument made by EEI, but it rests on several fallacies.

Some earlier writers, including W. Arthur Lewis, D. J. Bolton and James Bonbright, are open to demand charges to a certain extent but are quite candid about their limitations and significant downsides. Important factors in this more nuanced determination include:

- The diversity and coincidence factors[15] of any group of customers who might face a demand charge.
- The relative metering costs for flat kilowatt-hour (kWh) rates, demand rates and time-varying rates.
- The ability (or lack thereof) for customers to economically shift certain types of load.
- The broad similarity of capacity and fuel costs for many generation alternatives (typically thermal steam units) prior to 1960.

Lewis acknowledged the metering problem in his 1941 article, "The Two-Part Tariff." He stated that "the two-part tariff [a demand charge and an energy charge] is superior to having a single undifferentiated price which discourages off-peak consumption, *but inferior to charging different prices at different times*, though it may sometimes be more convenient than the latter if the measurement and timing of consumption are costly."[16] In the early and mid-20th century, only simple kWh metering was economic for small customers (that is, the system benefit from the response to time-differentiated pricing did not exceed the cost of the metering necessary to support it), while more sophisticated metering could be justified for industrial customers.

In 1951 Bolton noted, with some approval, that demand charges were much more common for industrial customers than residential.[17] He observed that residential customers' peaks are more random, that is to say more diverse (spread out in time) and less likely to be correlated with system peaks: "A metered demand system for such a [residential] consumer would mean making a high charge for payment at times when it was most unlikely to matter."[18] He opined that the load of many large industrial customers is not

[14] It is worth noting that these "kW" demand measurements are actually measured in units of kilowatt-hours per hour and simplified to be presented as measures of kW demand.

[15] Diversity of demand for a utility reflects the temporal differences in usage among customers. Peak coincident demand at any level of the system is less than the sum of customers' individual peaks because of these temporal differences. The calculated "diversity factor" provides a quantitative measure of these differences; conversely, a "coincidence factor" measures the extent to which these individual peaks do line up. These concepts are defined and discussed further in Section 3.1.

[16] Lewis, 1941, pp. 255-256 (emphasis added). Even in 1941, Lewis thought that it was no longer the case that demand metering would be cheaper than time-based metering, with one alternative being simple timers and another being "ripple control," where a utility sends a high frequency signal to flip an equipment switch.

[17] Bolton, 1951, p. 255. Bolton's proposed ideal "scientific tariff" features a TOU rate and no demand charges, where the on-peak price recovers demand-related costs. See Bolton, 1951, pp. 249-250.

[18] Bolton, 1951, p. 255.

particularly susceptible to shaping, because it is "motive power" (i.e., motors to run large equipment), and the electricity costs represent a small fraction of overall costs for these firms.[19] This type of industrial customer has strong incentives, given a set amount of productive capacity, to have the highest operating factor possible and thus a high load factor.[20] This industrial load pattern implies a significant likelihood that an individual customer's peak in a given month or year is closely linked to the customer's demand at the time of system peak.

Bonbright, writing originally in 1961, stated that traditional demand charges provide some benefits from "a tendency of existing customers to spread their loads over a longer period in order to minimize their demand charges, instead of bunching them during short period likely to coincide with the heavy loads of other customers."[21] Bonbright then went on to observe that electric rate design in those days "[was] far from ideal, and practical rate makers will do well to consider seriously its alleged infirmities viewed from the standpoint of its critics among the academic economists." He noted in particular that there was little sense in "the imposition of demand charges which penalize consumers for high individual demands even though these demands come at hours or seasons that fall well off the peak loads imposed on the system as a whole or even on any major part thereof."[22]

Up until 1960, most generation options, with the exception of hydroelectric power, had very similar cost characteristics. Steam generation was the predominant capacity type, and there were few differences in cost among coal, oil and natural gas units. Even fuel prices were broadly similar. In such a system, there is a better case that all capacity is similarly situated to serve peak reliability needs and thus can be considered demand-related. As discussed later, this issue goes to the sizing of any demand charges if they can be shown to be a reasonable solution (in limited circumstances at best).

This combination of factors — (1) an industrial customer base with a relatively small number of customers, most of whom had high load factors, high peak-coincidence factors and high levels of consumption and (2) a large number of residential customers with lower coincidence factors and relatively low consumption per customer — provided a rough rationale for the rate designs that prevailed throughout most of the United States in the 20th century and are now lingering into the 21st. In pricing, this typically manifested itself in significant demand charges for large industrial classes to recover nearly all capacity costs and in fully volumetric energy rates for residential and small business customers.

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[19] Bolton, 1951, p. 238.

[20] Load factor is the ratio of an end user's actual energy usage in a period to its maximum potential usage in that period. It is calculated as follows: kWh/(peak demand x total hours), within the specified period.

[21] Bonbright, J. (1961). *Principles of public utility rates*, p. 311. Columbia University Press. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/

[22] Bonbright, 1961, p. 316.

In this historical context, this could be relatively fair and efficient for a narrow slice of customers that meet the relevant description. To the extent that other customers that could share capacity (e.g., churches and schools; offices and movie theaters) were faced with demand charges, these customers were treated unfairly and often paid significantly more costs than they caused.

# 3. Why Demand Charges Are Inefficient

Some of these arguments for demand charges held sway in the past, even though the better case for time-varying energy charges was well understood. Today, the features of the modern electric system undermine even the more nuanced historic case for demand charges altogether. This is true for large industrial customers as well as for residential and small business customers.

The original advocates of demand charges often focused on what they thought was a fair and efficient division of historic accounting costs. Modern economists, even those who still advocate for demand charges, recognize that this older perspective is in error and argue (correctly) that rate structures should be designed to efficiently optimize *future* costs.[23] This perspective leads one to the conclusion that rates should be reflective of forward-looking marginal costs. In utility regulation, this concept is translated into different operative regulatory language in different jurisdictions, calling variously for rates that discourage wasteful usage, reflect actual costs or ensure the causer pays those costs. But in each case, the underlying microeconomic principle is the same: Rate design should ensure that the actions customers take to minimize their own bills are consistent with the actions they would take to minimize system costs. The nitty-gritty of designing rates in this framework is how to fairly and efficiently reflect marginal costs in prices. The best way to conceptualize this is to examine how the customer responds to a given rate design — both its form and its magnitude. An efficient rate design will lead to customer behavior that optimizes system costs.

The marginal consumption incentives for customers in any system of time-varying rates are fairly straightforward: (1) discourage usage in periods of relatively high rates and (2) encourage usage in periods of relatively low rates. Prices that achieve these outcomes are charged in a way that is both (1) consistent (all kWh at a given time or system condition are treated the same) and (2) symmetric: If an increase in consumption causes a bill to rise by $10, then the same sized decrease causes a bill to decline by $10.

The incentives presented by a typical demand charge structure are somewhat more

[23] See, for example, Boiteux, M. (1960). Peak-load pricing. *The Journal of Business, 33*(2), 157-179. (H. W. Izzzard, Trans.); Kahn, 1970; and Crew, M. A., & Kleindorfer, P. R. (1979). *Public utility economics.* St. Martin's Press.

complex.[24] If a customer is perfectly flexible (indifferent as to when they take electricity from the grid) and has perfect foresight, a demand charge would clearly incentivize a 100% load factor within the relevant time frame (e.g., each month). Of course, such customers do not exist in the real world,[25] although there are some customers that come close to having 100% load factors because of the nature of their operations: 24-hour supermarkets, data centers and certain types of factories.

Because customers do not have perfect foresight and infinite flexibility, it is only possible to talk about the incentives created by a demand charge at a certain level of generality. The most obvious features of a demand charge are that it directly (1) discourages higher individual customer NCP demand and (2) encourages levelization of load within the relevant time period. The related key feature of all types of demand charges is that they act as a ratchet, even if the ratchet is not applied across multiple billing periods.[26] Once a certain level of demand has been reached, customers then face a *lower* marginal cost for the remainder of the period to which the demand charge applies, as long as they have a power draw between zero and their previous individual demand peaks.

When the demand charge impacts a particular consumption decision, it can be quite punitive — imagine paying $5 to $10 to make toast for a family, which is exactly what can happen with a poorly designed residential demand charge.[27] This shows up as a high marginal cost for a subset of hours and consumption decisions. But otherwise, if a particular consumption decision does not pose a substantial risk of setting the demand charge, then consumption becomes cheaper — defined solely by the other charges without any demand charge implications. This means that optimal customer decision-making under a demand charge is quite complex and depends on the level of foresight and the value of consumption across all of the relevant time periods. Of course, most customer decision-making will not necessarily be optimal but rather based on rules of thumb, particularly for residential and smaller commercial customers.

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[24] Sandford Berg and Andreas Savvides did some theoretical work that incorporated the granular incentives of a demand charge into a traditional economic model of consumption. See Berg, S. V., & Savvides, A. (1983, October). The theory of maximum kW demand charges for electricity. *Energy Economics (5)*4, 258-66. However, this was a two-period model with numerous simplifying assumptions. Such a simplified theoretical model does illuminate certain features of a demand charge, but the authors note numerous areas for further work. To our knowledge, this line of theoretical research has not been pursued.

[25] This is true in particular because customer "utility" from electricity is not solely about the amount of consumption. Customers also enjoy significant convenience benefits for certain usage timing, again assuming that on-site storage and energy management are not cheap and convenient enough to smooth these features out.

[26] Some rates that do not meet this criterion are occasionally described as demand charges, such as annual system coincident peak capacity charges. These types of charges may, however, be better thought of as a type of time-varying rate or perhaps in a third category of their own.

[27] A toaster is approximately 1 kW demand; see Home Energy Saver & Score: Engineering Documentation. (n.d.). *Default energy consumption of MELs*. http://hes-documentation.lbl.gov/calculation-methodology/calculation-of-energy-consumption/major-appliances/miscellaneous-equipment-energy-consumption/default-energy-consumption-of-mels. If a customer uses it for 15 minutes straight at the time of the customer's individual peak, the monthly demand billing determinant increases by 1 kW with a corresponding bill increase.

As the analysis in the subsections that follow shows, demand charges — whether of the traditional monthly variety or the peak window variety — are inefficient and inequitable for the pricing of shared system costs, as is the continued reliance on them. There are three interrelated reasons for this:

1. Traditional monthly demand charges provide an inaccurate price signal that is unrelated to high-cost periods for nearly all customers and which leads to inefficient customer efforts and investments in response to its incentives. The changes in the electric system due to dramatic increase in wind and solar generation mean that, from a system perspective, very high industrial load factors are not necessarily optimal.
2. Even in cases where a traditional demand charge could be justified, the sizing of demand charges to recover nearly all generation and delivery capacity costs reflects an outdated perspective of the engineering and economics of the electric system. Modern cost allocation and rate design must reflect the trade-offs between different types of expenses and investments. Much capacity investment is designed to reduce energy costs and line losses and should be charged on that basis.
3. Although a reasonably sized peak window demand charge is superior to a traditional monthly demand charge, time-of-use and other kinds of time-varying rates remain more efficient and equitable. These time-varying rate options are enabled by the dramatic decrease in the cost of sophisticated metering over the past two decades.

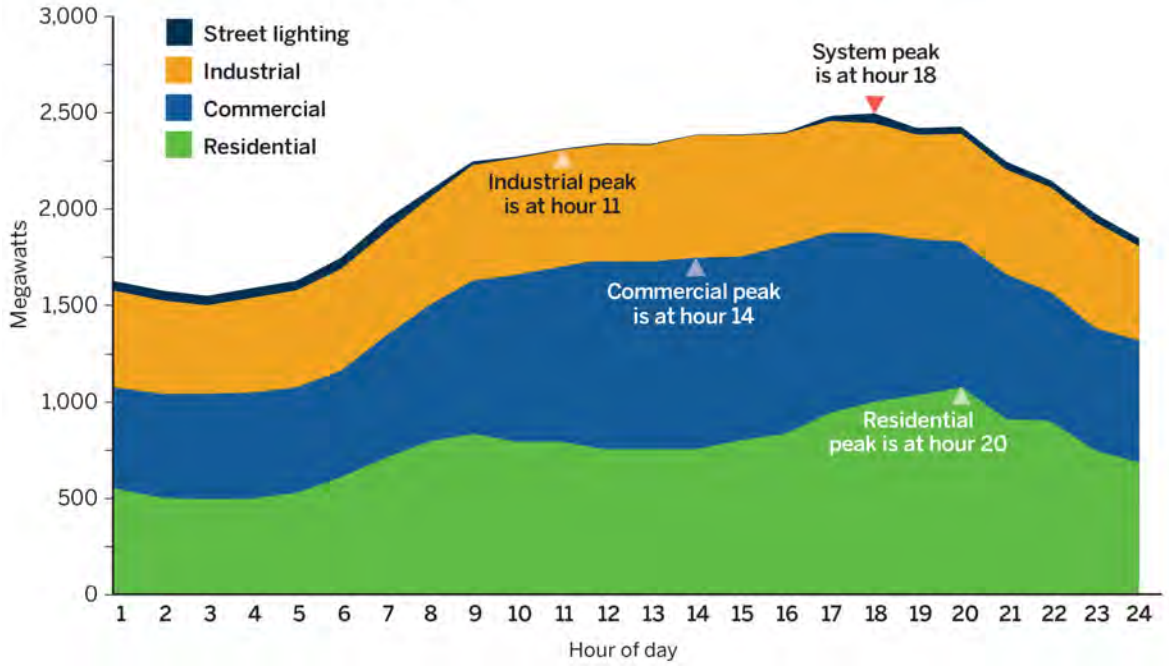
## 3.1 Individual Peaks Are Not the Same as System Peaks

Virtually all of the electric system consists of capacity that is shared among customers. With the exception of facilities that serve one or a very few customers, each component of the system is sized to meet an expected peak coincident demand of the customers it serves. The costs incurred to meet peak coincident demand, both short-run variable costs and capacity investment, are a significant portion of overall system costs. As a matter of economic efficiency, it is crucial that prices reflect the marginal costs of meeting the coincident system peak. Peak coincident demand is not simply the sum of the customers' individual peak demands but is rather something less, often significantly so. This phenomenon is known as *diversity* of demand and reflects the temporal differences of usage across the relevant customer base.

Customer loads are diversified at every level of the utility system. At the system level, the peak is determined by that combination of customer class loads that produces the highest instantaneous demand. That system peak might, or might not, coincide with the peak demand of any one customer class, and that system is likely interconnected to other systems with slightly different loads, through a shared transmission network. Figure 1 shows illustrative customer class loads on a system peak day. Each of the customer classes has a highest load hour at a different time: hour 11 for industrial, hour 14 for commercial

and hour 20 for residential. The load for the lighting class is roughly the same across many different hours when the sun is down. The overall peak is at hour 18, which is different than any of the class peaks.

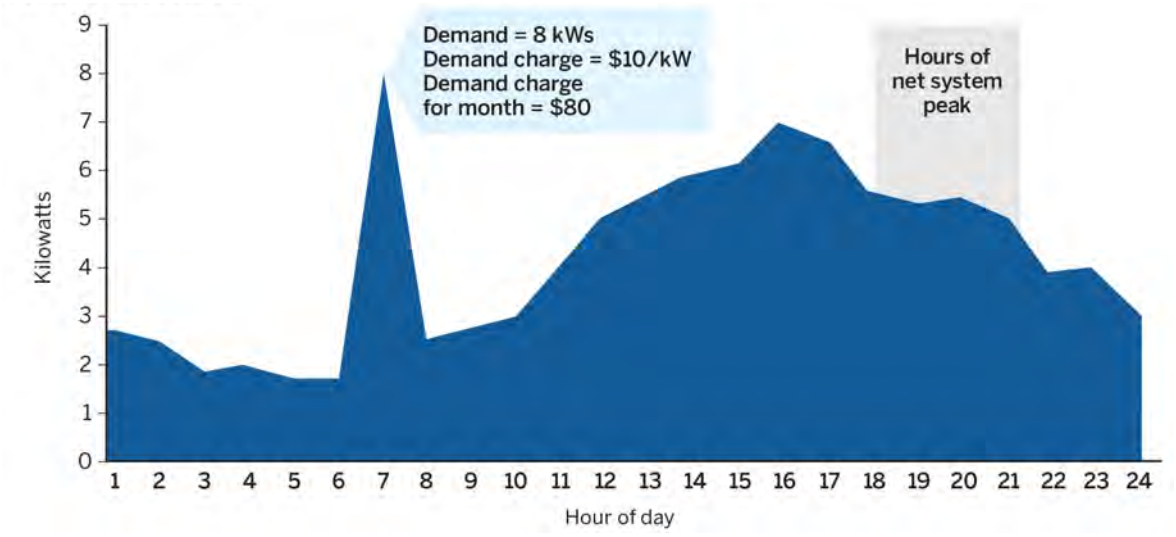
**Figure 1. Diversity at the customer class level**




Diversity can be quantified as the ratio of the sum of the subgroup peaks to the relevant coincident peak — the diversity factor. In this illustrative example, the diversity factor of the customer classes is 1.1. Diversity factors cannot go below 1 because in the extreme case where all subgroups peak at the same time, the sum of the subgroups equals the overall coincident peak. As long as customers peak at different times, diversity factors are higher as you consider smaller subgroups. Load diversity across individual customers is even greater than across customer classes.

Traditional monthly demand charges impose a rate on each customer that is independent of the system peak, as illustrated in Figure 2 on the next page. These demand charges provide little, if any, incentive to minimize a customer's contribution to system peak, unless a strong correlation exists between the customer's peak and the system's, a circumstance known as a high coincidence factor. In this illustrative example, a residential customer has an electric water heater that runs for nearly a full hour in the morning and a substantial cooling load in the afternoon.

**Figure 2. Illustrative monthly noncoincident peak demand charge for an individual residential customer**




Demand charges encourage customers to flatten their own load curves relative to their individual maximum usage but do not necessarily encourage them to consume energy in ways that optimize system costs. If we assume that Figure 2 shows customer usage before a traditional monthly demand charge is imposed, we could expect significant changes in usage after application of this charge. It would be reasonable to expect this customer to attempt to reduce the 8 kW demand reached at 7 a.m. In the case of an electric water heater, the individuals living in the house could change their behavior or adjust the settings on the water heater. If the customer could reduce that morning peak, then there would be some incentive to reduce the afternoon peak caused predominantly by cooling load. In this case, the customer would benefit by moving some portion of that load away from hour 16 to other hours, including possibly during the system peak from hours 18 to 21. Furthermore, this customer could increase overall kWh consumption since the marginal cost would be lower at times (often including the system peak) when there is little risk of triggering a higher demand charge.

More generally, a flat individual customer load shape may not, in fact, be what is best for the system and is in fact worse than a low load factor with predominantly off-peak usage. The clearest illustration of this is street lighting load, which, for most systems, falls entirely outside the system peak hours and has a roughly 50% load factor. If we designed and sized a demand charge for street lighting on the same basis as a typical demand charge for industrial customers, it would force this low-cost off-peak load to pay as much for system capacity as an industrial customer using the same amount of power during the peak periods. This is virtually never done, however, and street lighting is treated as a separate rate class without any demand charges.

D. J. Bolton summarized the basic problem facing utilities and regulators in the middle of the 20th century:

> The aim should always be the improvement of the *system* load factor, and the only justification for an elaborate tariff is that it shall contribute directly to this end. … If these costs are passed on to the consumer as they stand, in the form of a two-part [maximum demand] tariff, the fixed charge will be levied on the consumer's individual [maximum demand] instead of his effective demand on the system. The consequence will be that low-load-factor consumers will be overcharged (since they are given insufficient credit for their greater diversity) whilst the high-load-factor consumers are under-charged.
>
> The weakness of such a tariff when applied to the small individual consumer is that it treats load factor as a variable and diversity factor as a constant. … But, in practice, diversity factors vary from consumer to consumer almost as much as load factors, and moreover, in the opposite direction.[28]

In other words, diverse customers can efficiently *share* capacity, and rate design should recognize this fact. As Bolton mentioned, it is often the case that small users have *lower* load factors but more diversity and thus less impact on peak. This is still true today because many small residential users have lower levels of heating and cooling usage (smaller residences) and often have similar appliances (microwaves, toasters, dishwashers and dryers) that are used more sporadically than larger residential customers. This means that the load factor for each individual appliance is lower, but the power characteristics are similar for each usage of an appliance.

As described in Section 2, demand charges may present a rough price signal to control peak system demand for customers with a high system-peak coincidence factor. In that case, controlling a customer's individual peak does systematically reduce the overall coincident peak. One case where this could be true historically is large industrial customer classes, where individual customer usage is driven by large equipment that is constantly used throughout every working day of the year. Even for this type of customer, however, there remains the question of whether load can be shifted from peak hours to off-peak hours. A critical peak energy price would produce a superior price signal, to actively reduce usage at critical peak hours, rather than maintain steady usage at those hours if such a shift is possible. Indeed, industrial customers in Texas, faced with significant, narrowly focused transmission charges based on four coincident peak hours, use specialized consultants to help them identify, in advance, the hours to which those

[28] Bolton, 1951, p. 107-108 (emphasis in original). Bolton was writing at a time when, in operations, customer demand was taken largely as a given and much of the resource mix was dispatchable thermal generation. In those circumstances, improvement of system load factor would, all else again being equal including overall kWh consumption, lead to a reduction in total system costs.

charges will be applied and reduce usage sharply in those hours.[29]

For a diverse customer class, however, the share of customers who face this demand charge price signal at system peak times is random and inconsistent. In almost any hour, whether near system peak or the lowest-load hours of the year, some customers will face the demand charge price signal. Also, a substantial number and, at times, a majority of customers (e.g., those customers who have already hit their peaks in the billing period) face a lower marginal cost at system peak times. While this is very blunt and inaccurate, it could be a sharper price signal than a traditional flat kWh rate in some circumstances, although a customer's likelihood of facing those circumstances would vary randomly. In contrast, a well-designed TOU rate provides the broadly correct incentive for all marginal consumption choices by all customers, sending a consistent price signal for on-peak and off-peak periods; a critical peak pricing rate can be even more precise, focusing on specific hours when the electric system is under stress.[30]

The undesirable effects of demand charges are made worse by ratchets across billing periods — the mechanism by which a maximum demand in one period becomes the basis for minimum billed demand in subsequent periods. For example, billing demand may be the greater of this month's noncoincident maximum load and 80% of maximum in the previous 12 months. Once a maximum demand is hit, the customer has little incentive to reduce demand in the following periods. Unless individual customer peak is closely linked to system peak, there remains little incentive to minimize usage at a time of system peak.

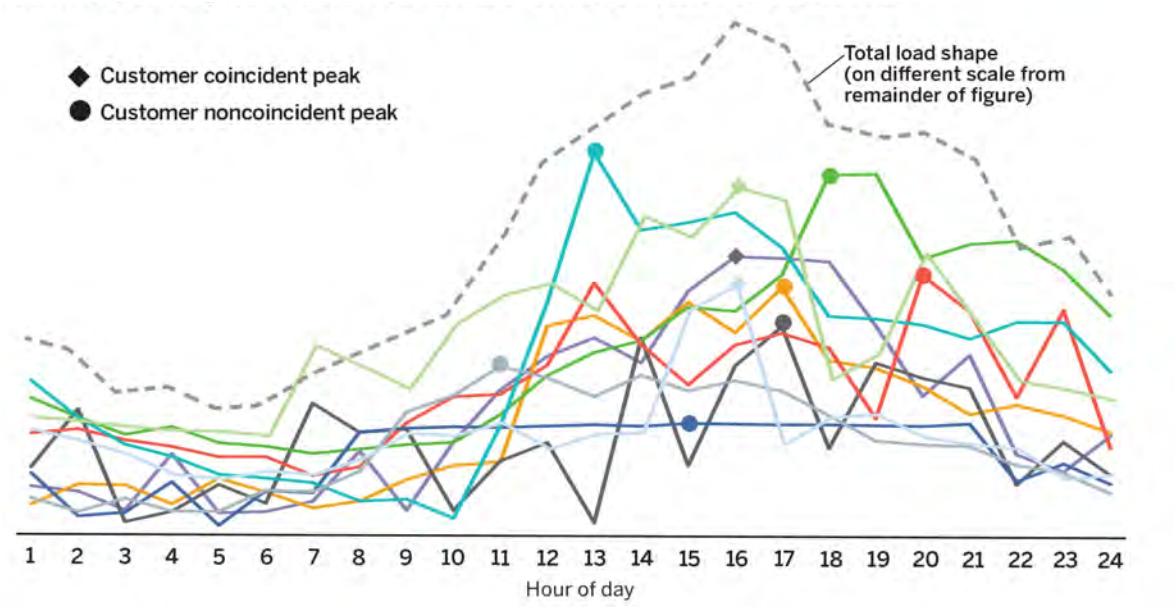
It is only when one gets close to the end user that the components of the system — the final line transformers, secondary distribution lines and service lines — are sized to meet a very localized demand that can be directly attributed to a small number of customers. Even at this level, there can be significant diversity among customers sharing a single transformer.

[29] Zarnikau, J., & Thal, D. (2013, September). The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market. *Utilities Policy, 26*, 1-6.

[30] To be more precise, we should say a "relevant component of the system" since different components of the system may hit peaks at different times. It's not unusual to see a systemwide peak occur at a particular hour on a particular day, but for individual elements of the subtransmission and distribution systems to hit peaks at other times. Expressing these peaks in prices and capturing each user's causal relationship to them is a challenge of time-varying rate design and, to the extent that this reflects different peaks in different areas of the system, may require locational distinctions as well. Precision is valuable, but complexity may produce inferior customer response.

Figure 3 shows actual data from a confidential load research sample on a summer peak day for 10 residential customers who share a line transformer. The total load shape is on a different scale than the individual customer loads.

**Figure 3. Summer peak day load from 10 residential customers on one line transformer**

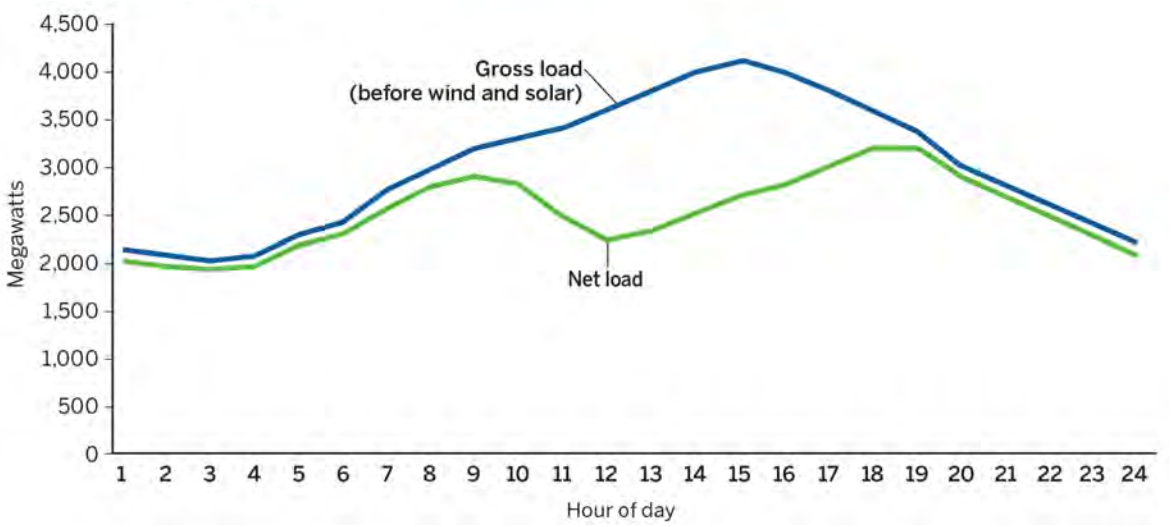



Source: Confidential load research sample

This demonstrates how diversity determines the need for the sizing of system elements. Only three of the 10 customers peak at the same time as the 4 p.m. coincident peak for the group, and the coincident peak is only 86% of the sum of the individual peaks on this day, which translates into a diversity factor of 1.16. This is just the variation on a particular high-load day. Although not shown in this figure, this coincident peak is only 64% of the sum of the annual NCPs for the individual customers, which translates into a diversity factor of 1.56.

At least two features of the modern electric system are changing the traditional argument that high-load-factor industrial customers should be subject to demand charges. First, the timing of traditional peaks and valleys, and by extension their effect on both short-run variable costs and longer-term capacity needs, is changing due to the increased prevalence of variable renewable resources. In regions where solar generation has increased rapidly, the "duck" curve is now a familiar phenomenon, as shown in Figure 4. Second, relatively low-cost on-site energy storage means that *all customers* have the potential for economically shiftable load and can respond to time-based price signals.

**Figure 4. Illustrative net load curve**




In such a situation, the benefits of shifting energy intensive industrial load from early evening to midday could be quite large. But this could mean *an increase* in the customer load factor, which is substantially discouraged by demand charges.

## 3.2 A Significant Portion of Capacity Investment Is Not Demand-Related

Traditional cost allocation terminology makes a distinction among demand-related, energy-related and customer-related costs. This terminology may obscure more than it illuminates. In particular, the term "demand-related" is often used to imply that demand charges are a proper pricing method for recovering costs so designated. Moreover, "demand-related" has typically referred to system peak demand and not individual customer peaks.[31] Other terminology, such as "peak-related," is more descriptive of the concept and avoids confusion with the use of "demand" in other contexts (such as "demand for energy").

[31] See Bolton, 1951, p. 132 (describing demand-related costs as "a cost proportional to system demand") and pp. 143-144 (describing how to spread costs across a wide number of potential system peak hours). In rate design, these same costs might be recovered through demand charges for certain customer classes. When determining the rate in dollars per kW, the total costs are then divided over the larger denominator of individual NCP demand, without accounting for load diversity within the class. This reduces the dollars per kW as charged to each customer from the dollars per kW used to assign costs to each class. This reduction is labeled differently in different jurisdictions, such as an "effective demand factor." However, this reduction is passed through to all customers and does not correct for differences in the timing of individual customer peaks. Customers who have demand highest at peak times receive a discount, and those who have demand highest at other times are overcharged.

Advocates for demand charges sometimes assert that most or all capacity costs are demand-related, which maximizes the size of the demand charge (if one is at all justified).[32] This leads to the large magnitude of the demand charges for industrial customer classes in many states. However, significant portions of capacity costs are not demand-related but are in fact incurred to meet energy needs. Investments in generation, transmission and distribution in the modern electric system may serve either of the two primary objectives of system planners, but the degree to which demand plays a role in each objective is different. These two goals are: (1) ensuring reliability (in both operational and investment time frames) and (2) meeting year-round system load at least cost. In many respects, reliability concerns arise predominantly at peak system hours.[33] Meeting system load at least cost, by its very nature, must consider usage patterns across every hour of the year. To meet these two objectives, system planning, investment and operation must jointly consider not only the engineering and physics of the electric system but also the economics of the relevant choices. We see this tension in the evolving landscape of capacity resources.

With respect to generation, most capacity costs may have been demand-related prior to the invention of the modern combustion turbine in the 1960s. In an electric system dominated by largely homogenous steam generation capacity, a MW of capacity built for peak demand could be used equivalently year-round.[34] In such a situation, generation capacity costs could be allocated and charged predominantly at peak times.

The existence of multiple different types of generation capacity, storage and demand response changes this analysis significantly.[35] Aggregate supply (generation, storage and demand response) must be sufficient for systemwide coincident peaks, as well as contingencies across many other hours of the year, such as when outages (unforced and even planned, such as nuclear refueling) combine with other circumstances (e.g., unusual weather) to push demand up against the limit of available resources.

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[32] See Faruqui, A., & Davis, W. (2016, July). Curating the future of residential rate design. *Electricity Daily*, 23. http://files.brattle.com/files/7137_curating_the_future_of_rate_design_for_residential_customers.pdf. The authors state that "a large share of a utility's costs are actually driven by investment in infrastructure, such as generation capacity and transmission and distribution (T&D) networks. These costs are not directly related to the amount of energy that is consumed; they are, instead, driven by various measures of maximum electricity demand." See also the description of an idealized rate design that "recover[s] capacity costs through demand charges" in Faruqui, A. (2019, June 1). 2040: A pricing odyssey. *Public Utilities Fortnightly*, p. 56.

[33] Reliability can be thought of as having two dimensions, in terms of both system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

[34] Even this historic scenario is a substantial oversimplification due to significant level of hydro generation in many areas.

[35] Bonbright recognized this briefly in a footnote; see Bonbright, 1961, 354, fn 15. By 1970, this was a better understood and less theoretical concept so that Kahn spent multiple pages discussing it; see Kahn, 1970, pp. 97-98. M. A. Crew and P. R. Kleindorfer formalized mathematical models of optimal pricing with multiple different types of generation capacity; see Crew & Kleindorfer, 1979.

The optimal mix of resource types depends on the broader load patterns. Different generation technologies have different capabilities and different cost characteristics and should not be blindly lumped together as "capacity" for cost allocation and rate design purposes. The kind of capacity that one would build to meet short-term coincident peak needs, as well as reserves on short notice throughout the year, is much different than the kind of capacity that one would build to generate year-round. Indeed, for very infrequent needs, demand response (paying customers to curtail usage for a short period) is proving much cheaper than building *any* kind of generation resource that is seldom used. In order to be economic, capacity that serves only short-term needs must have low upfront investment costs, such as combustion turbines or demand response, but can have higher short-term variable costs when it is used. The combustion turbine is cheap to build but relatively inefficient and expensive to run. In contrast, a larger investment can only be justified by lower expected short-run variable generation costs and a higher expected capacity factor. As a result, this high-upfront-cost capacity lowers the total cost of both meeting peak demand and serving energy needs over the planning horizon.

So there is a trade-off between capacity costs and energy costs. Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework.[36] Under any reasonable version of the demand-related classification, it is important to recognize that the capacity costs placed here are to serve relatively short-period peak reliability needs.

Even the appropriate short-period peak reliability capacity costs should be charged on a broader basis than the absolute peak hour of the year for several reasons. One is that, while planners and operators generally have a good idea of when a system peak is likely to occur, they by no means know for sure. Consequently, there is a reliability value to capacity in many hours that should be reflected in prices.[37] A second is that the actual peak can be influenced by pricing structures. For example, if a system peak could be reliably predicted for the 5 p.m. hour on a given day, charging a higher price at that single hour could just push that same peak to 4 p.m. without a meaningful reduction. This is the "whack-a-mole" problem. Taking both of these issues into account, some writers have referred to the relevant set of peak hours as the "potential peak" period.[38] This is a major consideration in the determination of on-peak hours for a TOU rate or a peak

[36] See Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.) (2020). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[37] The operating reserves demand curve mechanism in the ERCOT wholesale market is one means of establishing that value across the entire year. In many areas, the loss of load probability is relatively high for only 50-100 hours per year, which is the typical design criteria for critical peak pricing and demand response programs.

[38] Bolton, 1951, p. 143.

window demand charge. A related challenge is that different elements of the system (e.g., generation, transmission and distribution) may peak at different times, which should be accounted for to the extent possible.

Generation capacity also has some reliability value in off-peak hours. Generation reliability issues may come primarily at peak times but certainly not exclusively. This can be because of generator outages (both planned and unplanned), unusual weather, transmission outages, other operating constraints or a combination of the above. D. J. Bolton commented in 1951 that there had been several times that load needed to be shed in off-peak seasons because of generator maintenance, which was "a definite indication of demand-related expenses on account of generating plant" even in off-peak seasons.[39] A loss-of-energy-expectation study calculates the year-round generation reliability risks and is one of the best ways to allocate demand-related generation capacity costs (but not energy-related generation capacity costs) over the entire year.[40] A probability-of-dispatch method, alternatively, assigns the total costs of generation resources to the hours in which each resource provides service.

Many of these same considerations apply to the transmission and distribution system, and an analyst should look to the underlying purposes and benefits of system investments to allocate and charge them properly. Several different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs. The transmission segment that connects a generating unit to the broader transmission network can be properly thought of as a generation-related cost and charged on the same basis as the underlying generator. In many situations, long transmission lines are needed to connect low-cost generation resources, such as remote hydroelectric facilities or mine-mouth coal plants, to the network. These long lines are built to facilitate access to cheap energy and should be classified on that basis. Last, transmission lines built to facilitate exchanges between load zones are not necessarily most highly used at peak times but are used to optimize dispatch and trade energy across many hours of the year.

Other parts of the transmission and distribution network do need to be sized to meet peak demand and other reliability contingencies. But there are several different engineering options for transmission and distribution networks that have implications with respect to line losses, another clear energy-related benefit.[41] There are generally two types of losses incurred across the transmission and distribution system: no-load losses and load losses. No-load losses are incurred primarily to energize transformers (both station transformers

[39] Bolton, 1951, p. 143.

[40] Lazar et al., 2020, p. 132.

[41] See generally Lazar, J., & Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

and line transformers). Smaller transformers consume less energy in this respect, but overloaded transformers incur high load-related losses, so optimal transformer sizing saves energy.

The system planning considerations for load losses, also known as resistive losses, are more complex. These losses occur as electrical current flows through each element of the system. These losses manifest themselves in the form of heat and reduce the amount of useful power that can supply customer loads. This relationship is represented by the formula:

Load losses (in kW) = $I^2$ x R

Where I = current (in amps) and R = resistance (in ohms)

Load losses can be decreased by reducing the resistance or reducing the current. Installing conductors with thicker metal wires is a simple way to reduce resistance, but these larger conductors are more expensive. Investments that reduce the current can, however, be much more effective because losses go up with the square of current. Any investment that reduces the current by 50% will reduce load losses by 75%, and any investment that reduces the current by 90% will reduce load losses by 99%. Since the current required to supply load is highest during peak demand periods, system losses are greatest during peak demand periods. There are several different types of capacity investments that reduce current substantially:

- Higher voltage lines: There is a direct relationship between the voltage of a line, the current passing through the line and the power delivered.
    - Current (in amps) = power (in kW)/voltage (in volts)
    - As a result, increasing the voltage by a factor of 10 reduces the current by 90%, which in turn reduces load losses by 99%.
- Siting substations closer to loads: By siting substations closer to loads, one can reduce the losses incurred by having conductors at lower voltages supply loads across long distances — the latter condition resulting in higher currents and relatively higher losses.
- Converting single-phase distribution lines to three-phase power: Three-phase power requires one additional conductor and additional space for the arrangement of the lines. For three phase lines, current = power/(voltage x √3). At the same voltage, current drops by 42.3% and load losses are reduced by two-thirds.
- Distribution level control of voltage and reactive power: Capacitor banks, smart PV inverters, voltage regulators and other more distributed assets across the system can compensate for voltage and reactive power needs at a local level that would

otherwise need to be met through the supply of upstream resources delivered through the grid — the latter condition resulting in higher currents and greater incurred losses.

- Optimizing the location and size of line transformers: Siting transformers closer to customers allows for shorter secondary lines that have low voltage and thus higher losses per foot. For some areas, this may require additional transformers, which comes at a cost. Smaller transformers also have lower no-load losses. Unfortunately, smaller transformers have lower rated capacities and thus higher load losses for a given level of current. Conversely, larger transformers have higher no-load losses but lower load losses. These complex economics should be analyzed to account for trade-offs between capital costs and energy losses. Modern advanced metering infrastructure (AMI) systems provide the ability to prepare heat maps on each transformer, enabling optimal sizing to minimize costs and losses.[42]

All of these factors should be accounted for in both cost allocation and rate design. Energy-related benefits from transmission and distribution capital investments are quite extensive. In a relevant sense, nearly all transmission lines are built with a substantial purpose of minimizing line losses for the delivery of large volumes of energy. Choice of the voltage level for a transmission line, either for a new line or upgrading an old line, involves higher capital costs for higher voltages with the counteracting benefit of lower losses. These costs are energy-related costs, not capacity-related costs. Furthermore, many of these energy benefits from investments to minimize line losses are not static over the course of the year. They increase dramatically at times of system peak because current delivered over the system is much higher, and marginal system losses at the time of peak can be 15-20% in many utility systems.[43] In addition, these benefits can be compounding because they are not limited to fuel costs or wholesale purchases. A more efficient transmission and distribution system can lower generation capacity requirements as well, including reserves.

All of these economic and engineering phenomena should be properly reflected in any analyses of cost causation. More specifically, these distinctions must be passed into rate design or else it gives rise to opportunities for customers to take inappropriate advantage by gaming the rates, with bill savings that far exceed any long-term reduction in system costs. The experience of the British Central Electricity Generating Board, a wholesale provider, provides a stark example of this in the late 1960s. The central board charged the regional boards for generation capacity costs based solely on a narrow peak window. In response, the regional area boards built their own combustion turbines at significantly lower cost to generate during these peak hours. This forced the central board to change its

[42] See Lazar, J. (2018, October 18). *Smart grid and community benefits — with no rate increase? How Burbank made it happen.* Regulatory Assistance Project. https://www.raponline.org/blog/smart-grid-and-community-benefits-with-no-rate-increase-how-burbank-made-it-happen/

[43] Lazar & Baldwin, 2011, p. 4.

wholesale rates, charging for only marginal capacity costs in a short peak and charging for the bulk of capacity costs in a broader period.[44] The key insight in this scenario is that demand-related costs charged to peak times should only reflect the marginal costs of relatively cheap generation, storage or demand response capacity costs incurred for short-period peak reliability purposes.

Modern examples of this pricing problem can be found in the current practices of several independent system operators and generation and transmission suppliers. For example, ERCOT currently charges on the basis of the highest hour in each of the four summer months for recovery of embedded transmission system costs to distribution service providers. This type of pricing mechanism is inappropriate for transmission costs and furthermore distorts the operation of the wholesale energy markets by over-incentivizing a wide range of customer actions.[45] Similarly, many electric cooperatives, charged by their generation and transmission suppliers on the basis of NCP demand imposed on the wholesale supplier, have installed water heater control systems to mitigate this demand at much lower cost than the avoided demand charges. Since the generation and transmission demand charges include the cost of baseload units and transmission, they greatly overstate the value of localized NCP load reductions. While these are wholesale examples, the same economic proposition also extends to retail rates.

## 3.3 Time-Varying Energy Rates Are More Efficient Than Peak Window Demand Charges

Once one acknowledges the time-dependent nature of cost in the generation and delivery of electricity to end users on a shared system, one must necessarily acknowledge the superiority (as matters of economic efficiency and fairness) of prices that reveal to those end users that temporal variability in cost to those that do not. The question, then, is simple: What should those prices look like? In some sense, a peak window demand charge does recognize this time dependency. However, a comparison of the incentives presented by time-varying demand charges and time-varying kWh charges reveals why time-varying kWh charges are the better approach.

There are several types of time-varying energy rates to be considered today.[46] Key design choices for these rates include the number of time periods, whether the price for each time period is set long in advance or can itself vary based on system conditions and market

[44] Kahn, 1970, pp. 97-98.

[45] See Hogan, W., & Pope, S. (2017, May). *Priorities for the evolution of an energy-only electricity market design in ERCOT*, pp. 69-79. Harvard University and FTI Consulting. https://hepg.hks.harvard.edu/publications/priorities-evolution-energy-only-electricity-market-design-ercot-0. We do not endorse the proposed solution of Hogan and Pope but agree with the transmission pricing problem that they describe.

[46] From this definition we exclude seasonal rates and kWh prices that vary from billing period to billing period. These kinds of rates can also reflect the cost-causation basis of rates but provide little or no incentive to manage usage within a billing period.

outcomes, and the actual prices for each time period.[47] The simplest is known as a time-of-use or time-of-day rate, which utilizes a small number of preset time periods and prices within each billing period. The most sophisticated time-varying rates are typically described as real-time prices, which are updated at short, regular intervals (e.g., hourly) based on prices in wholesale energy markets.

There are also options that combined preset time periods with pricing that varies based on system conditions in a predictable manner. With critical peak pricing, or the related peak-time rebate alternative, higher prices for times when the grid is stressed are set well in advance, but the days (and perhaps the hours) where these higher prices apply are actively chosen in response to system conditions. Variable peak pricing, as currently offered by Oklahoma Gas & Electric,[48] adds another layer of price differentiation by allowing more preset options for the on-peak price period. The on-peak price depends on market conditions: low, standard, high and critical. This choice between four different alternative on-peak prices allows for a higher level of precision in marginal incentives. All of these variations share a common goal — to improve the load shape for a utility by decreasing peak period load and shifting some of that to off-peak periods.

In this context, it is most natural to compare peak window demand charges with simple TOU rates because many of the key parameters can be kept constant. For both of these options, the peak time periods and the prices charged are set well in advance and can be set to recover the same categories of costs. Holding those two variables constant, peak window demand charges are inferior to time-varying kWh charges in that same peak window, as a general method for charging peak capacity costs, for two related reasons:

1. The inefficiency of the ratchet that all demand charges impose, which incorrectly underprices usage in the rest of the peak window within the billing period.
2. Unfair intraclass cost allocation, with those customers with demand diversity subsidizing those with more continuous usage.

Peak window demand charges can certainly elicit customer response and incentivize them

[47] The options that are available in practice depend on metering technology, which has evolved substantially over time. In the early part of the 20th century, TOU rates could be implemented with meters that operated on timers, where one track would record on-peak usage every day and another track would record off-peak usage every day. No distinction based on weekends or holidays was possible. By 1941, more sophisticated versions were available with remote controls that could switch the meters between tracks on command. Since that time, many more innovations have occurred to enable different types of time-varying rates. Three-period TOU rates became common for large industrial customers in France beginning in the 1950s. With advanced metering infrastructure and a sophisticated data collection and billing system, the possibilities are nearly endless. Even without AMI, simple TOU meters have long been available that track on-peak and off-peak usage based on programmed timers, which can exclude weekends and holidays from on-peak periods.

[48] Oklahoma Gas & Electric. (2018, June 18). *Standard pricing schedule: R-VPP variable peak pricing.* https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

to shift load from inside to outside that window.[49] Nevertheless, peak window demand charges share many of the faults of traditional monthly demand charges, just on a different scale. Once again, the key distinction is between the consistent and symmetric marginal incentive of a time-varying kWh rate and the arbitrary effects driven by the demand charge's ratchet.

A close examination of customer behavior reveals why energy-based prices are preferable to demand charges even within a peak window. In any system with significant customer diversity, a large number of customers will not have their individual peaks at the time of the system's peak. Still, it could be that a substantial number of customers peak at the time of the system peak. The proportion of one to the other matters if demand charges are to have a significant linkage to the system peak. Customers who are at risk of setting the individual peak for the demand charge face a high marginal price for consumption, but those who are not face a lower marginal price. This proportion will vary from service territory to service territory and over time as technology evolves.

Customer behavior under a peak window demand charge would likely even vary based on completely arbitrary factors. That could be whether certain customers are at the beginning of their billing period or whether a significant event that led a customer to incur a largely unavoidable peak (e.g., hosting a party during a peak window) happened before that very high-load time. This randomness can be entirely avoided. The fair and efficient solution is to continue to treat all consumption as marginal, a condition that is achieved by time-varying kWh rates.

In the absence of technology that automates response to changes in prices, the ratchet problem for peak window demand charges may be diminished by the inability of customers to respond accurately to its incentive structure. It is unlikely that people going about their daily lives can do more than respond to the broad incentives provided by either an on-peak kWh price in a simple TOU rate or a peak-window demand charge. In both cases, the easiest answer may very well be just "consume less during the peak window period."[50] This could mitigate the harm posed by the ratchet, but it also begs the question about the underlying rationale if there is no customer response.

A modest subset of residential customers may be able to respond to the next rule of thumb presented by a peak window demand charge: to operate as few end uses as possible simultaneously. Fully responding to the incentives posed by a demand charge requires

[49] See, for example, Stokke, A., Doorman, G., & Ericson, T. (2009). *An analysis of a demand charge electricity grid tariff in the residential sector.* (Discussion Paper No. 574). Statistics Norway, Research Department. https://ideas.repec.org/p/ssb/dispap/574.html

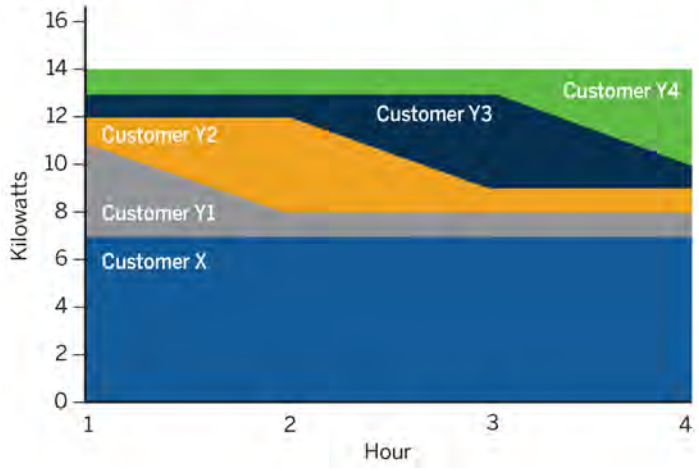
[50] For example, the Mid-Carolina Electric Cooperative has a three-hour peak window demand charge for residential customers. On the relevant page of its website, the peak window demand charge is labeled as an "on-peak charge." None of the advice given to manage this rate is specific to the actual working of a demand charge and could equally apply to a three-hour on-peak kWh rate. Mid-Carolina Electric Cooperative. (n.d.). *Rate structure.* http://www.mcecoop.com/content/rate-structure

customers to track their demand and know whether they are currently at risk of setting a high demand for the billing period — too much to ask of many residential and small business customers.

However, energy management technology, enabled by software and "supercharged" by on-site storage, will be able to adjust usage in a far more responsive manner than ordinary people could manage alone. Such energy management is likely feasible today for larger customers and could very well be widely feasible for smaller customers in the next few years. At least one company, Energy Sentry (http://energysentry.com/index.php), has developed a residential "demand controller" that automatically sheds less critical loads (water heaters, clothes dryers) when priority loads (microwaves, coffee makers, hair dryers) are activated. Such technology would allow customers to respond more effectively — *from their perspective* — to the incentives provided by a demand charge. But that is not to say that the overall efficiency of the electric system will be improved, since customer responses to demand charges do not typically optimize use of the system.

Peak window demand charges also create intraclass cost allocation problems, which are linked closely to the above efficiency concerns. Peak window demand charges still overcharge the low-load-factor customer and undercharge the high-load-factor customer. This is illustrated in the case of several smaller customers whose aggregate consumption adds up to the load of a single larger customer. Such a hypothetical is shown in Figure 5 for a four-hour peak period.

**Figure 5. Customer load comparison illustrating ability to share capacity**




Customers Y1, Y2, Y3 and Y4 have, in the aggregate, the same load profile as Customer X. Each of the Y customers has a peak of 4 kW for a total billing determinant of 16 kW under a peak window demand charge. However, Customer X has a peak of 7 kW, which translates into a billing determinant of 7 kW under a peak window demand charge. This means that Customer X is charged less than half the amount that the Y customers are for the *exact same aggregate load pattern*. The four diverse customers can efficiently share capacity and should not be penalized by a price structure that fails to account for their diversity. Time-varying energy-based charges solve this problem.

Peak window demand charges, though an improvement on monthly NCP demand charges,

still come up short in the effort to send accurate information to consumers about peaks and other high-cost events. The occurrence of a peak cannot be known in advance, and, indeed, its timing depends in part on price structure. Shifting hours within a peak period does not necessarily lower the overall peak. Figure 6 is a comparison of two customers with equal kWh consumption in the peak period, one with a flat consumption throughout that period and another that varies.

**Figure 6. Comparison of two customers**

Compared with Customer X with a flat load pattern, Customer Z with the varying load pattern likely increases the chance of a system peak in hour 2, but by the same token likely decreases the chance of a system peak in hour 3. But the reverse can be said for Customer X compared with Customer Z: Customer X raises the likelihood of a system peak in hour 3 and decreases the likelihood of a system peak in hour 2. Advocates of demand charges consistently fail to explain why these types of discrepancies are justified by cost considerations.

Even well-designed TOU rates do not necessarily reflect critical peak times very well. For example, a four-hour weekday on-peak window for only the highest demand months will include around 200-400 hours annually. These will necessarily contain some days with higher peaks than others and only a limited number of hours that define utility capacity needs for reliability purposes at peak. Simple TOU rates do not distinguish in this regard between the moderate peaks (e.g., ordinary days in the summer) and the very highest peaks (e.g., extremely hot days in the summer). In short, the implication is that simple TOU rates do not provide a sharp enough incentive on actual peak days.[51] In any case, we are no longer bound to simple TOU pricing. Dynamic rates, including critical peak pricing, peak-time rebates, variable peak pricing and real-time pricing, all better address peaking issues because they provide higher marginal prices at the times of maximum system stress. By concentrating customer attention on the hours that actually drive costs, the more dynamic rates produce better results for the electric system and society.

By its very nature, a demand charge cannot present symmetric and consistent marginal incentives in the same way as a time-varying kWh charge. Compared to traditional demand charges, properly sized peak window demand charges have a better cost causation

[51] This is referred to as the needle-peaking problem in Crew & Kleindorfer, 1979, p. 186.

basis because they can be linked to the time periods that drive higher system costs. Daily as-used demand charges[52] applied to peak windows could be a further improvement on peak window demand charges, and, better yet, these peak window daily-as-used demand charges could fluctuate according to system conditions. However, this is only an improvement because it converges on the better solution, a system of time-varying kWh rates. Given the rate design possibilities that AMI offers, what reason is there to retain demand charges at all?

# 4. What Might Be Left for Demand Charges?

The foregoing demonstrates that the typical argument for demand charges, as used for generation, transmission and shared distribution capacity, is substantially flawed. Even so, we want to investigate if there are any circumstances, however limited, for which demand charges are an efficient rate design.

Some theorists have identified a different and, in our minds, much narrower set of rationales for demand charges. The case for time-varying rates relies substantially on the diversity of load and the lack of a direct relationship between individual customer peaks and the system peaks that drive costs. A diverse set of customers may, in the aggregate, create a predictable load profile much of the time. But what if this diversity goes away in an unpredictable manner? Or, for that matter, in a predictable one? Is there something about the causation of costs in special and *limited* circumstances that warrants charging for peak incurrences of short-term (e.g., 15-minute) demand for individual customers? To answer this question, we consider three cases that, on their faces, might present a marginal-cost justification for demand charges. The first is one that we have carved out from the beginning: capacity costs that are not shared, such as dedicated transformers and service drops, which we term "dedicated site infrastructure."[53] This illustrates some important issues relevant to any broader theoretical case for demand charges. The second is the cost associated with uncertainty in customer behavior. The third is timer peaks, a phenomenon where customers shift usage in response to hours with lower prices.

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[52] RAP authors, writing with partners from Synapse Energy Economics, previously recommended daily-as-used demand charges for standby service to large combined heat and power customers, as an alternative to monthly standby demand charges. The purpose was to recognize that different combined heat and power customers would have scheduled and forced outages on different days and could share the same capacity to provide their standby service. This was certainly an improvement on monthly demand charges for such customers, but, in light of the progress made in metering and time-varying energy-based rate structures, there's every reason to think today that such time-varying energy rates are equally appropriate to customers with on-site generation. Johnston, L., Takahashi, K., Weston, F., and Murray, C. (2005, December 1). *Rate structures for customers with onsite generation: Practice and innovation*. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy06osti/39142.pdf

[53] RAP has previously recommended a small transformer or site infrastructure demand charge for secondary voltage customers, particularly those customers with dedicated site infrastructure. See Lazar, J., & Gonzalez, W. (2015, July). *Smart rate design for a smart future*, pp. 53-54. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

## 4.1 Dedicated Site Infrastructure

Dedicated transformers and service drops for individual customers are, by definition, not shared infrastructure. The relative importance of this category of cost will vary by customer class. Larger commercial and industrial customer classes, as long as they are taking secondary voltage service, will often have dedicated transformers for each customer or a dedicated transformer bank for customers taking three-phase power. Dedicated transformers will be rare for residential customers in urban and suburban areas, but single-family homes will almost always have a dedicated service drop. The largest industrial customers may have their own primary line (effectively serving as a dedicated service drop) or a dedicated substation (effectively serving as a dedicated transformer). In rural areas, each customer will typically have a dedicated transformer, at which point transformers are customer-specific site infrastructure.

For these customer-specific site infrastructure costs, there is no diversity of demand between the customer meter and point of connection with the shared system. As a result, individual customer NCPs are certainly relevant to the sizing of these components. One might conclude from this that a demand charge can provide a reasonable pricing incentive here. The time period for such a demand charge should have nothing to do with a shared peak since there is no sharing of the infrastructure. Nor should it be limited to peak windows since the peak for an individual customer could occur at any time. The cost of these components may be no more than about $1/kW/month, a fraction of typical demand charges.[54]

There are also other ways of efficiently pricing this category of costs. A similar set of customer incentives may be presented by a connected load charge for a set amount of local capacity. Such a connected load charge can help with efficient sizing, but only if it's accompanied by a fee for overages or the automatic tripping of circuits when demand would cause an overage. Even then, a connected load charge provides no incentive for customers to manage their usage efficiently; that is, there are no cost savings to be gained by keeping their demand below the level of the predetermined connected load. A charge that establishes the relationship of the customer's individual peak demand to the sizing of these components might, however, give the customer some incentive to minimize peaks.

It is worth examining this issue at the level of engineering and planning. What type of customer behavior would minimize the risk of transformer overload and degradation? Or what type of customer behavior would allow utilities to size dedicated transformers more efficiently?

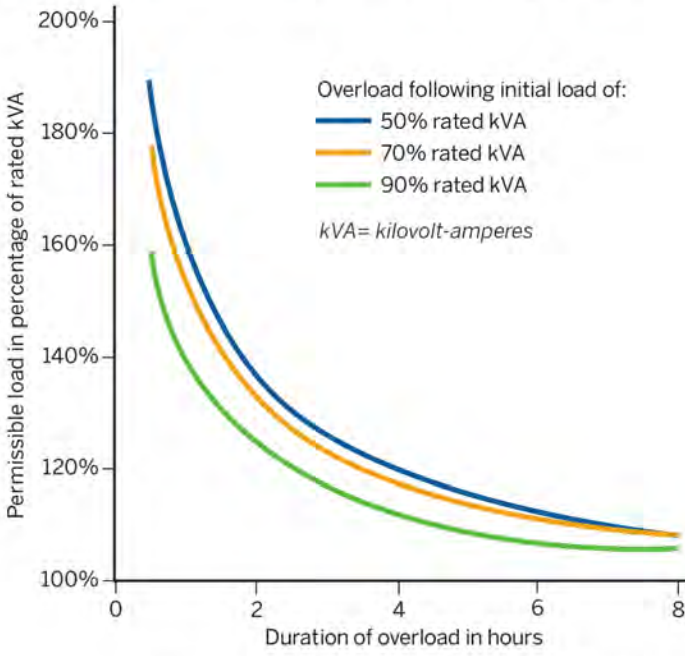
Capacity ratings for the different elements of the electric system are set with many

[54] Seattle City Light, for example, has a large general service rate with specific charges for transformer investment; these are $0.27/kW/month. Seattle City Light. (n.d.). *City Light rates*. https://www.seattle.gov/light/rates/summary.asp

engineering limits in mind. Many of the most important considerations revolve around the heating — and overheating — of components, particularly transformers and conductors. This has a number of different implications. For example, effective delivery capacity can be higher in the winter than the summer or higher in the cool nighttime than during the sunny daytime. The capacity ratings for individual system elements are for sustained loads in typical conditions, but loadings can exceed those ratings on a regular basis without necessarily incurring significant damage. As Tom Short colorfully puts it, a conductor rated 480 amps "will not burst into flames at 481 [amps]."[55]

Figure 7[56] demonstrates the maximum overload that a transformer can take without shortening its operating life, by examining two primary variables: (1) the initial load prior to any overload and (2) the duration of an overload. If a transformer has had light loads (50% of its rating), it can sustain a short-term overload of nearly 190% or a four-hour overload of just over 120%.

**Figure 7. Permissible transformer overloads for varying periods**




Source: Bureau of Reclamation. (1991). *Permissible Loading of Oil-Immersed Transformers and Regulators*

The important question then is what kind of rate design incentivizes optimal customer behavior with respect to this equipment. Panagiotis Andrianesis and Michael C. Caramanis have developed an algorithm for dynamic nodal locational marginal costs for distribution systems that offers an intriguing approach to pricing for these customer-specific facilities. For line transformers, the pricing formula is a real-time price per unit of energy that follows the transformer thermal response dynamics, which is essentially the temperature of the cooling oil in each transformer.[57] Similarly, a critical peak energy charge could apply for the few hours per year when a transformer is

[55] Short, T. A. (2004). *Electric power distribution handbook*, Section 3.5, p. 140. CRC Press.

[56] Bureau of Reclamation. (1991). *Permissible loading of oil-immersed transformers and regulators.* https://www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf

[57] Andrianesis, P., & Caramanis, M. (2019). *Distribution network marginal costs: Part 1, A novel AC OPF including transformer degradation.* arXiv. https://arxiv.org/abs/1906.01570

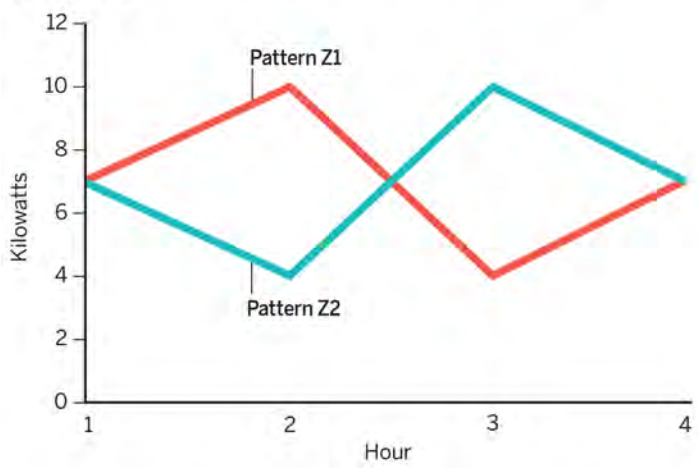
stressed but would require real-time monitoring and pricing to be applied on a transformer-by-transformer basis.

This type of short-run marginal cost pricing does not resemble a demand charge and has the virtue of linking closely in time the incurrence of high marginal costs to the prices charged. These approaches are quite sophisticated and could be costly to administer. To achieve a rate that is more feasible now, a simpler structure would be necessary. A daily-as-used demand charge or a traditional monthly demand charge, based on 15-minute or 30-minute peaks, could certainly discourage the extremely high short-term peaks that would damage a transformer. Those options might not do enough, however, to discourage a sustained, multihour overload.

## 4.2 Risks of Customer Variance at Peak Times

Load diversity isn't static and can fluctuate in ways that are both predictable and unpredictable. Predictable changes often occur around the weather, one of the few variables that simultaneously affects all customers in a given area. Regarding unpredictable changes, consider a simple hypothetical illustrated in Figure 8.

**Figure 8. Two hypothetical load patterns randomly chosen by customers**




If there are 10 "random-load" customers who flip a fair coin to determine whether their load profile corresponds to either Z1 (heads) or Z2 (tails) in Figure 8, the average load in each hour across a large number of trials will be 70 kWh.[58] However, system planning must not only deal with the expected average load but rather the chances of higher load. Unfortunately, in any given trial of this scenario, the probability of five heads and five tails — leading to a demand of 70 kW in every hour — is only 24.6%. There is a small but nonzero chance that every customer gets either heads or

[58] In this illustrative example, we consider each customer to have a flat load within each hour. This means that kW and kWh are largely interchangeable as units. Similar examples could, however, be constructed with demand varying in smaller increments (e.g., 30, 15 or 5 minutes), and similar results could be obtained.

tails, leading to a 0.2% probability of a peak load of 100 kW. The full spectrum of potential results for this hypothetical scenario with 10 random-load customers is shown in Table 1.

**Table 1. Peak load and probabilities for 10 random-load customers**

| Coin flip result | High load: Number of customers | Low load: Number of customers | Peak load (kWs) | Probability |
|---|---|---|---|---|
| **10 heads or 10 tails** | 10 | 0 | 100 | 0.2% |
| **9 heads or 9 tails** | 9 | 1 | 94 | 2.0% |
| **8 heads or 8 tails** | 8 | 2 | 88 | 8.8% |
| **7 heads or 7 tails** | 7 | 3 | 82 | 23.4% |
| **6 heads or 6 tails** | 6 | 4 | 76 | 41.0% |
| **5 heads and 5 tails** | 5 | 5 | 70 | 24.6% |

The cumulative odds of a peak of 88 kWh or higher is 10.9%, and a peak of 82 kWh or higher is 34.4%. In this hypothetical scenario, it is clearly beneficial to have customers flatten their load curves to 7 kW every hour within this time period. Table 2 shows the range of possible results and associated probabilities for six random-load customers corresponding to either pattern Z1 or Z2 and four flat-load customers with a demand of 7 kW in each hour.

**Table 2. Peak load and probabilities for six random-load and four flat-load customers**

| Coin flip result | High load: Number of customers | Low load: Number of customers | Flat load: Number of customers | Peak load (kWs) | Probability |
|---|---|---|---|---|---|
| **6 heads or 6 tails** | 6 | 0 | 4 | 88 | 3.1% |
| **5 heads or 5 tails** | 5 | 1 | 4 | 82 | 18.8% |
| **4 heads or 4 tails** | 4 | 2 | 4 | 76 | 46.9% |
| **3 heads and 3 tails** | 3 | 3 | 4 | 70 | 31.3% |

The risk of a peak of 88 kW or higher drops from 10.9% to 3.1%, and the risk of a peak of 82 kW or higher drops from 34.4% to 21.9%. If the customer choices are uncorrelated, this type of risk goes down as the number of customers increases.[59] However, if the customer choices are correlated, between hour 2 and hour 3 in this hypothetical, the risk does not necessarily decrease with a higher number of customers.

[59] The ratio of the variance to the expected total decreases in proportion to the square root of the number of customers.

This simple example is the essence of the argument made by Michael Veall.[60] He demonstrates that, for a given level of average customer demand during a peak, higher variance customers lead to a risk of higher peaks, particularly if they are correlated. This, in turn, results in a need for higher capacity planning margins. Veall constructs a detailed economic model of optimal peak period pricing. He states that the traditional monthly demand charge does not reasonably address this issue, but rather a peak window demand charge can serve as marginal price on a customer's variance. He notes additional caveats: "If there are many small users with uncorrelated demands, the effects of an individual user's variation on total system variation will be small. But if users are large or their demands are correlated, variance charges are important."[61] Finally, Veall's result demonstrates that, if a peak window demand charge is to be imposed, it should be paired with an on-peak kWh rate.[62] The logic around risk and Veall's theoretical model present an argument for a peak window demand charge that is substantially different from those that utilities put forward. And again, we see a more defensible justification for peak window demand charges for larger-volume customers. But the key question of correlations and *levels of risk* has been neglected in the discussion around demand charges and is only a theoretical possibility in Veall's model. Furthermore, Veall's model does not consider the possibility of more granularly dynamic time-varying kWh rates.

Marcel Boiteux, the influential French economist and executive for Électricité de France (EdF), does discuss risk and uncertainty in a 1952 paper, written jointly with his colleague Paul Stasi.[63] When it comes time for tariff design, Boiteux and Stasi describe two different zones of the shared electric system: (1) the "collective network" and (2) the "semi-individual network, whose capacity depends particularly on the uncertainties of consumption of each customer."[64] With respect to the collective network, they find that the "uncertainties of individual consumption" are small enough to be ignored.[65] And, finally, their analysis of the "semi-individual network" is dominated by risk and the irregularities of individual customer's loads. This leads them to a justification for a complex system of subscription-based contract demand charges, with higher prices for contracted demand in

[60] Veall, M. (1983). Industrial electricity demand and the Hopkinson rate: An application of the extreme value distribution. *The Bell Journal of Economics, 14*(2), 427-440.

[61] Veall, 1983, p. 429.

[62] Veall, 1983, p. 431. Veall notes that this on-peak kWh price could, in principle, even be negative, which would be a curious result.

[63] Boiteux, M., & Stasi, P. (1964). The determination of cost of expansion of an interconnected system of production and distribution of electricity. In J. Nelson (Ed. & Trans.). *Marginal cost pricing in practice.* Prentice Hall. (Original work published in 1952).

[64] Boiteux & Stasi, 1964, p. 117.

[65] Boiteux & Stasi, 1964, p. 117

peak periods and lower prices in other periods. However, Boiteux and Stasi offer little but generalities as to the demarcation of the semi-individual network:

> The extent of the zone within which the uncertainties of individual demands have a very marked influence on the collective cost is greater in proportion to the irregularity of the demands considered, and to the correlations among these demands. This extent depends also on the density of consumption, for the number of customers supplied from a given node plays an important role in the "reduction of uncertainties."[66]

Based on these considerations, Boiteux and Stasi largely describe the generation and transmission system (150-220 kV) as the "collective network" and the distribution system (15-60 kV) as the "semi-individual" network.[67] They are discussing these issues in the context of the then-new Tarif Vert for high voltage industrial customers, and the discussion could be read in a manner that is limited to those customers. This could mean that the dividing line for the semi-individual network could vary by the size of customer. Whether residential customer fluctuations are correlated in a significant and pertinent way is another empirical question Boiteux and Stasi do not address. It is unclear whether the irregularities of individual residential customers would ever be significant enough to matter at a level higher than a shared transformer.

## 4.3 Timer Peaks

Michael A. Crew and Paul R. Kleindorfer (1979) raise another area where a demand charge could theoretically be efficient, which they describe as the secondary preferences of customers, given the structure of time-varying rates, and the shifting of demand to notionally off-peak times. This is colloquially known as a timer peak. This occurs if customers increase their usage substantially during hours with low rates or more specifically right at the time when low-priced hours begin.[68] In the worst-case scenario, TOU rates can theoretically just shift the system peak without reducing it if enough usage is shifted to hours with low prices. The same is true of coincident peak window demand charges. This outcome can be avoided by managing the number of periods in the rate, the hours covered by each period and the relative prices. One utility has designed a TOU rate in which each customer chooses a three-hour peak period of 4-7 p.m., 5-8 p.m. or 6-9 p.m. All of these customers have 6-7 p.m. in their peak period; two-thirds of them have 5-6 p.m. and 7-8 p.m. in their peak period; and one-third have either 4-5 p.m. or 8-9 p.m. in their

[66] Boiteux & Stasi, 1964, p. 123

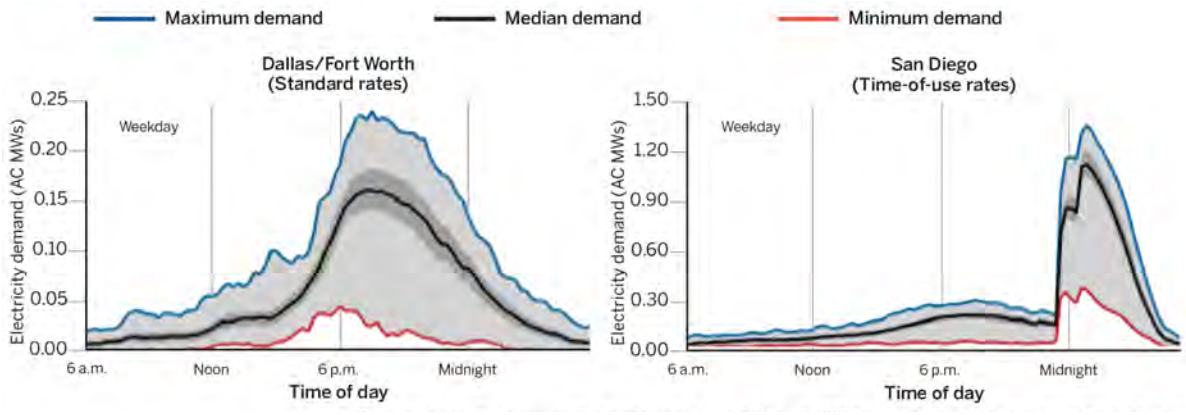
[67] Boiteux & Stasi, 1964, p. 110.

[68] Bonbright mentions this as a possible objection to time-of-use rates. See Bonbright, 1961, p. 362, fn 23: "In Chapter 10 of his book already cited in footnote 10, Davidson suggests this type of rate [time of day and time of season] as preferable to the familiar Hopkinson-type rate. But among the objections to it is the danger that its sharp breaks will create surges in the loads imposed on a power station or on a distribution line."

peak period. This provides the utilities with the most powerful pricing signal during the most likely peak hour but substantial peak reduction in the adjacent hours.[69] Another simple solution is to apply different hours to different classes or subclasses. For example, single-family residences may have their tariff shifted one hour earlier than apartments, or secondary general service one hour later than primary general service.

If the more general system peaks are not impacted significantly enough by this phenomenon to warrant changing the structure of the rate, more granular and local issues can theoretically arise. Figure 9 shows a set of results from a San Diego Gas and Electric rate for electric vehicles, where the "super off-peak" rate begins at midnight.[70]

**Figure 9. Real-world illustration of timer peak with EV charging on TOU rate**




Source: Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the Electric Vehicle Market*

This is a rational customer response to a TOU rate, at least for specific end uses. If an electric vehicle is parked at home in the evening and will not be used again until morning, then the customer has a significant amount of flexibility to choose when charging will begin. The very beginning of the lowest price period is an obvious time to start charging. While this may not present an issue at the generation and transmission level, assuming midnight remains an off-peak period, bunching of EV charging could lead to issues at the more local level.

Again, thinking about a line transformer helps focus the analysis. If five single-family homes are served by one shared transformer and all five of those homes have EVs that start charging at midnight, then impacts at the line transformer level are a possibility. Furthermore, what if those houses have other timed usage that starts at the beginning of the lowest price period? Sending a secondary price signal that discourages households

[69] Salt River Project. (n.d.). *SRP EZ-3 price plan*. https://www.srpnet.com/prices/home/ez3.aspx

[70] Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the electric vehicle market*, p. 16. M.J. Bradley & Associates. https://www.mjbradley.com/sites/default/files/MJBA_Accelerating_the_Electric_Vehicle_Market_FINAL.pdf

from turning on all of their major end uses at midnight could be effective. A daily-as-used demand charge can send such a signal if it were applied across 24-hour periods. A more traditional monthly demand charge, however, will send that signal in a much more attenuated way. A connected load charge based on a contract demand for the cost of connection, with fees for overages, similar to the Électricité de France Tempo rate for residential customers,[71] would send a similar price signal as well.

There are other ways to deal with this phenomenon besides price signals with demand-charge features. The beginning of the off-peak period with the lowest price could be staggered for different customers, for example, beginning at 10 p.m. for one-third of customers, midnight for another third and 2 a.m. for the last third. For customers with long-duration controlled loads, like water heaters or electric vehicles, this would be easy for the customer to manage and beneficial to the utility. To maximize the benefits of such an approach, one would need to have a relatively even split among those three options for the customers on each shared transformer. Load management programs and smart devices could deal with this type of issue as well. For some loads, particularly water heating and EV charging, we anticipate advanced devices that will enable the utility to manage loads to minimize costs and enable customers to benefit from even lower off-peak rates for enabled devices.

One could even question how much of a problem this poses to the longevity of the shared transformers in question. The ambient temperature has almost always cooled off by midnight, and several hours of low or moderate loads could allow the transformer to cool from significant levels of usage during the day or early evening. In certain circumstances, it could be more convenient and cost-effective to upgrade any potentially affected transformers, particularly where multiple water heaters or EV chargers are served from a single transformer.

# 5. Conclusion

Demand charges, of either the traditional monthly NCP or peak window variety, are not efficient, as a general matter, for shared system capacity costs because:

- For the vast majority of customers, any peak reduction signal in a traditional monthly demand charge is weak and inaccurate.
- Traditional calculations for demand charges have included far too many costs as demand-related. Ideally, utility commissions will adopt a new time-based classification

[71] Electricite de France. (n.d.). *Tarif Bleu: Regulated sale tariff for electricity*. https://particulier.edf.fr/en/home/energy-and-services/electricity/tarif-bleu.html

and allocation framework for generation, transmission and shared distribution costs.[72] Failing that, the numerous energy benefits from capacity investments should be properly accounted for — that is, reflected in energy, not demand, charges.

- Simple TOU rates are superior to peak window demand charges in their own right, but AMI enables time-varying energy charges, such as critical peak pricing, peak-time rebates and variable peak pricing, that much more accurately target times of system stress and reward end users for shifting their loads to off-peak times.

Although we have shown the significant downsides to using current forms of demand charges, in very limited circumstances there might be cost- and efficiency-related justifications for certain types of demand charges. But such charges would be significantly lower than those prevailing for industrial customers in the United States today. Dedicated site infrastructure is a small portion of utility system costs, and typical demand charges would not necessarily provide an optimal signal to control these costs. The primary concerns around timer peaks are almost certainly limited to local infrastructure.

As for the general risk of customer variance and correlation, little work has been done to investigate the statistical bases of this more sophisticated case for demand charges. We think that it is unlikely that such an analysis would find that a substantial demand charge would be fairer or more efficient than time-varying energy charges. Lastly, there is a better case for demand charge-like structures for large customers, who are more likely to have significant dedicated site infrastructure. One might also argue that high variance at peak times among these customers has a more significant chance of influencing the overall system peak. Any such demand charges may not look like Hopkinson rates and would likely be only a second-best solution to a sophisticated system of time-varying energy charges.

The economic and regulatory principles that underlie these judgments are not new. The inescapable essentials of microeconomic theory are at work here. Boiteux, Bonbright and Kahn follow these principles and theories, as do the other scholars and practitioners we cite. In 1964, Paul Garfield and Wallace Lovejoy[73] also stepped into the fray. They converted principles of economic efficiency and fairness into straightforward criteria for assessing the merits of cost allocation methods and rate designs for generation and delivery capacity costs:

- All utility customers should contribute to capacity costs.
- The longer the period of time that customers preempt others' use of capacity, the more they should pay for the use of that capacity.

[72] Lazar et al., 2020.

[73] Criteria adapted from Garfield, P., & Lovejoy, W. (1964). *Public utility economics,* pp. 163-165. Prentice Hall.

- Any service that makes exclusive use of a portion of capacity should be assigned all of the costs for that portion of capacity.
- The allocation of capacity costs should change gradually with changes in the pattern of usage.
- More capacity costs should be allocated to on-peak usage than off-peak.
- Interruptible service (or other forms of utility restrictions and control) should be allocated less in capacity costs as the degree of restriction increases.

Only time-varying energy charges can meet all of these objectives simultaneously. Demand charges for shared costs are demonstrably less efficient and less equitable than they.

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# Exhibit JRB-3

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

**GEORGIA POWER COMPANY**
**Docket No. 44280**
**Georgia Power Company's 2022 Rate Case**
**Staff Data Request No. STF-PIA-2**

**STF-PIA-2-3**

Question:

Please provide informational materials provided to customers of new residential premises related to the default rate (TOU-RD).

Response:

New customers to the Smart Usage rate (TOU-RD) receive a welcome letter that confirms their enrollment and provides helpful information to educate them on how to take advantage of the rate's design. This information is provided to all customers who enroll in the rate – regardless of whether they reside at a newly established premises or at an existing premises. This information is provided via email if an email address is available; otherwise, it is provided by direct mail.

Additionally, customers enrolled in Smart Usage receive multiple seasonal postcards that highlight the on and off-peak pricing differences. The message includes specific reminders to shift usage to capitalize on the TOU design as well as emphasizing the importance of managing demand.

The materials provided also encourage customers to visit the Georgia Power website for more information on the Smart Usage rate and for tips on managing their energy usage.

Examples of the welcome letter and postcard communications are provided in STF-PIA-2-3 Attachment A and STF-PIA-2-3 Attachment B, respectively.

DropDateLS

Endorsement Line*****SP-Sort Position T-Tray Number P-Bundle Number
Full Name
Business
Address Line 1 Address Line 2
City, State ZIP Code

# Smart Usage

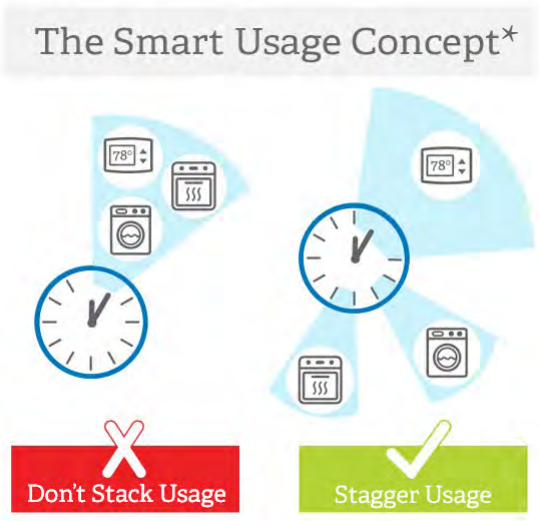
## Your account #AccountNumber is now enrolled in Smart Usage.

With Smart Usage, the power to save is in YOUR hands.

Customers on Smart Usage can save on their energy bill by making small changes to how and when they use energy. In fact, this rate plan provides 3 ways to save:

### 1. How you use energy matters.

Certain appliances – like clothes dryers, ovens, and dish washers – are some of the biggest energy users in your home. By just using these appliances at different times of the day, you can reduce your demand on Georgia Power's system and lower your monthly energy bill.*




### 2. When you use energy matters.

During summer months, our customers use the most energy and it costs the most to produce. By shifting some usage outside of the peak period that occurs from 2 – 7 p.m. on summer weekdays, customers can enjoy lower cost energy –which can lead to savings on their bill.

### 3. Less is always more.

As with all rate options, the less energy you use the more you can save. Find ways to reduce usage – such as converting to LED light bulbs or installing a programmable thermostat – to stay comfortable and spend less.

Visit **georgiapower.com/smartusage** for even more information, FAQs, and a short video about your rate plan. Thank you for being a valued Georgia Power customer and we hope you enjoy your experience on Smart Usage.

# Smart Usage Rate Plan

## Terms and Conditions

By choosing to participate in the residential Smart Usage rate plan, you agree to pay the monthly Smart Usage charges for electric service to the service address associated with the account number used in online enrollment for at least twelve months, beginning with the first bill rendered on the Smart Usage rate.

Your Smart Usage rate does not include fuel, taxes, and other charges, nor does it include Georgia Power security lights, or other Georgia Power products and services should you have any.

These Smart Usage terms apply only for electric service to the designated account(s) and address. If you transfer service to another address, you will need to reapply for the Smart Usage rate.

Georgia Power offers the Smart Usage rate plan pursuant to the current residential rate filing, which is on file with the Georgia Public Service Commission.

For further terms, conditions, and information, please visit the Smart Usage section of GeorgiaPower.com.

# Smart Usage

## Small changes can bring savings during the summer

Georgia Power

# Electricity prices are higher from 2 p.m. – 7 p.m. on weekdays, June 1 – September 30

Thank you for participating in **Georgia Power's Smart Usage** program. We wanted to remind you that you may enjoy savings on your electric bill by shifting some of your summer electric usage to the "off peak" evening and weekend hours when our energy prices are much lower. Specifically, consider reducing your usage between the hours of **2 p.m. and 7 p.m. Monday through Friday (June – September).**

Also, remember that it is always important to use your major appliances – like clothes dryers, oven, and dishwasher – at different times to reduce your demand on Georgia Power's system and lower your monthly energy bill.

By taking these steps, the power to save is in your hands! Visit our website at **www.georgiapower.com** for helpful tips in reducing and shifting usage.

Thanks again for being a part of the **Smart Usage program**.

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MS. WHITFIELD: And, finally, I would ask that each witnesses' attachments be marked for identification. Mr. Ellis' attachments MEE-1 and MEE-2 are attached to his prefiled direct testimony. We ask that they be marked for identification as GIPL Exhibits 9 and 10.

MADAM CHAIR PRIDEMORE: So moved.

(The documents referred to were marked for identification as GIPL Exhibits 9 and 10.)

MS. WHITFIELD: And Mr. Barnes' attachments JRB-1, 2, and 3, which are attached to his direct testimony, we ask are marked as GIPL Exhibits 6, 7, and 8.

MADAM CHAIR PRIDEMORE: So moved.

(The documents referred to were marked for identification as GIPL Exhibits 6, 7 and 8.)

MADAM CHAIR PRIDEMORE: Since I suspended roll call for cross, so we will just do it once, but then that way I'll keep track for you so that cross doesn't get confusing.

MS. WHITFIELD: Sure.

BY MS. WHITFIELD:

Q Mr. Ellis, did you prepare a summary of your testimony?

A Yes.

**MS. WHITFIELD: Madam Chair, may Mr. Ellis read his summary?**

**MADAM CHAIR PRIDEMORE: Please go ahead, Mr. Ellis.**

**MR. ELLIS: Thank you.**

**Thank you and good evening, Madam Chair and Commissioners. I am grateful for the opportunity to be here today.**

**My name is Mark Ellis. I have 25 years of professional experience in the energy industry. I began consulting in 2020, and I have provided testimony in several rate cases. Before 2020, I led the strategy function at Sempra Energy, a gas and electric utility with the largest customer base in the United States. At Sempra, among other responsibilities, I developed and implemented the enterprise-wide cost of capital estimation process.**

**In this case, Georgia Interfaith Power and Light has asked me to calculate Georgia Power's cost of equity, coupled with the appropriate capital structure, that are adequate to ensure that Georgia Power, from 2023 to 2025, earns a return on its investments commensurate with returns on investments and other enterprises having corresponding risk and are sufficient to assure confidence in the financial**

integrity of the enterprise so as to maintain its credit and to attract capital.

This analysis requires balancing the financial interests of the utility with the interests of customers, consistent with the US Supreme Court's opinion in Hope Natural Gas.

To meet these goals, I recommend an authorized ROE of 5.54 percent and an increased equity ratio of 61.7 percent. My recommendation would save customers over $1 billion each year in rates and preserve Georgia Power's financial integrity and ability to raise capital.

I applied basic finance principles to calculate the return required to adequately compensate investors for the risk of investing in Georgia Power's equity. My testimony is based on finance theory and calculations that are commonly used by finance professionals. The two most critical to takeaways from my testimony are:

First, Hope instructs us to consider the cost of equity, which is a distinct term and financial concept from the rate of return on equity. The differences in terminology are summarized in Figure 2 on page 9 of my testimony and have been provided as a handout.

**This is important because two of the models relied on by Georgia Power's expert, Mr. Coyne, do not estimate the cost of equity. Instead, they're designed to estimate a rate of return on equity, which is not the financial goal prescribed by Hope.**

**Mr. Coyne's implementation of his two other models, the discounted cash flow, or DCF model, and capital asset pricing model, CAPM, are deeply flawed. The growth rate assumptions in his DCF are not valid beyond five years and are economically impossible to sustain in perpetuity, as his model assumes. All three inputs into his CAPM model, the risk-free rate, beta, and market risk premium, are demonstrably upwardly biased and do not reflect current investor expectations.**

**The second key takeaway in my testimony is that capital structure and ROE cannot be determined independently from one another. They work together, and I would urge this Commission to consider their impact on each other.**

**This is important because capital structure and ROE jointly determine how much cash is flowing to the utility, how credit worthy a utility is, and how high customer rates will be.**

**Figure 29 of my testimony, which has been**

provided as a demonstrative, provides four different ROE equity ratio scenarios. These varying options are seen in the top rows, highlighted in orange. All four are optimized to minimize customer costs while satisfying the demands of equity and debt investors.

This chart shows how much money customers could save, per year, in billions of dollars. That's in the bottom row that is highlighted in orange.

As you can also see, I have calculated how these ROE and equity ratio recommendations, or combinations, impact a key creditworthiness metric for Georgia Power, FFO to debt. And I have indicated whether the cash flows to the company would qualify for its current credit rating of Baa1 or whether the cash flows to the company would qualify it for a higher credit rating of A3.

Critically, the savings for customers range from over $500 million to over $1 billion each year. I urge the Commission to reject Georgia Power's proposed ROE and capital structure because it is significantly more expensive than necessary for Georgians.

MS. WHITFIELD: I'd like to make one correction, if I may, Commissioners, to Mr. Ellis' summary, which is we have chosen not to provide

Figure 2 on page 9 as an handout in the interest of expediency.

BY MS. WHITFIELD:

Q Mr. Barnes, have you prepared a summary?

A (Witness Barnes) Yes, I have.

MS. KYSOR: Madam Chair, may Mr. Barnes proceed with his summary?

MADAM CHAIR PRIDEMORE: Please go ahead with your summary, Mr. Barnes.

MR. BARNES: Good evening, Madam Chair and Commissioners. I appreciate the opportunity to be here today.

As part of my participation in this case, I've reviewed the Company's cost of service studies and rate design proposals and recommend several changes, focused on aspects of the rates paid by residential customers, including the availability of different rate options for residential customers. I'll summarize three of my core recommendations now, but welcome questions on any recommendations detailed in my testimony.

First, I recommend that the Commission reject the Company's proposals to close the standard volumetric rate, Schedule R to new premises, and to close the two-part time-of-use rate, Schedule

TOU-REO, to new enrollments altogether. Eliminating these options would steer customers onto a more complicated demand charge tariff, Schedule TOU-RD. This is problematic for several reasons:

One, customers on the demand charge rate use less electricity and pay more. Referring to the demonstrative, the top figure shows how customers on the demand rate consistently pay more on their monthly bills, roughly $16 a month more on average from June 2021 to May 2022.

Figure 4 on page 43 of my testimony shows that the average rate paid by customers on several residential rate schedules -- on several residential rate schedules is on average 4.8 cents lower than the rates paid by customers on Schedule TOU-RD, the demand rate.

The bottom figure in my demonstrative shows how Schedule TOU-RD customers actually used less electricity on average during 2021 while also illustrating how average annual consumption changed as Georgia Power made efforts to increase Schedule TOU-RD enrollment.

Beyond the significant cost impacts on customers, demand rates also suffer from deficiencies that create misalignments with cost causation, in

particular when applied to residential customers.

Finally, demand rates do not provide consistent or actionable price signals to residential customers. All of these are reasons why the Commission should reject the company's proposals to close the other residential rates.

Second, and for the same reasons, I recommend that the Commission stop using the residential demand charge tariff, Schedule TOU-RD, as the default rate for new residential premises. Instead, the Commission should redesignate Schedule R as the default rate for new residential premises.

Or in the alternative, should the Commission desire to retain a time-varying rate as the default rate for new residential customers, I recommend that it use Schedule TOU-REO, a two-part volumetric time-of-use rate, which is the simplest of the Company's available TOU rate options.

Third, I recommend that the Commission deny the Company's proposed increase in the residential basic service charge and instead retain the current residential basic service charge because: One, the current basic service charge already recovers costs in excess of the Company's truly customer-related costs; and, two, the Company's cost of service

**analysis shows a decrease rather than an increase in customer-related costs relative to its last rate case.**

**Finally, my testimony also contains recommendations for ensuring that residential customers are presented with sufficient information to make an informed decision on their best rate option, recommendations for revisions to the cost allocation and rate design for recovery of coal ash mitigation costs to improve the alignment with cost causation, and a generalized discussion of cost causation and the nature of cost shifts in ratemaking.**

**That concludes my summary. I look forward to answering your questions.**

**MS. WHITFIELD: Madam Chair, Mr. Ellis and Mr. Barnes are available for questions from the Commission and for cross-examination from the parties.**

**MADAM CHAIR PRIDEMORE: Thank you very much.**

**So let's -- questions from Commissioners first.**

**Questions for Mr. Ellis?**

**Commissioner Echols?**

**VICE CHAIRMAN ECHOLS: Madam Chair, thank you.**

**Mr. Ellis, good to see you.**

MR. ELLIS: Thank you.

VICE CHAIRMAN ECHOLS: You went to Harvard and MIT, huh?

MR. ELLIS: Yes.

VICE CHAIRMAN ECHOLS: You didn't get much away from Cambridge, huh? You like the place?

MR. ELLIS: I did. I also took some courses at Texas A&M.

VICE CHAIRMAN ECHOLS: Well, you did get away.

I guess this is the lowest recommendation I've ever seen an expert make for the company, and maybe the highest capital cost. Is this -- this seems unusual.

Is this something you've seen work in other places, at Sempra, or other places?

MR. ELLIS: Yeah. So as I mentioned in my introduction, I was responsible for the cost of capital for the entire enterprise, and so that was the basis on which the company made its own internal investment decisions, and the numbers that we used internally were substantially lower than those that the utility's subsidiaries, SDG&E and SoCalGas, petitioned for in front of the Commission.

In fact, one year our internal estimates were actually produced -- actually, for several years were

produced in our SEC filed proxy statements. And I noticed -- you know, highlighted that, hey, we're going to have in the public domain our own internal estimates that are quite a bit lower, less than half of what we were asking for from the Commission.

They decided to publish them anyway. They were confident that the Commission would never look at those figures, or if they did, that they would not connect the dots on that.

VICE CHAIRMAN ECHOLS: Last question: It seems like, if we did something like that, it's so different than anything we've ever done before that it would -- you don't think that would incite panic in New York and wonder what's going on down here? I mean, it just seems drastic.

MR. ELLIS: Well, there would -- in my testimony, I describe towards the end of it the impact on the Southern Company's shares, share price, and there would be negative impact. Hard to estimate what it would be. The company would continue to be able to raise capital. Many utilities -- I come from California, so we have a poster child of a utility that has gone through bankruptcy twice in my career, and they've always been able to raise capital.

So the reduction in the ROE would not -- as

long as it's above the actual cost -- or equal to the actual cost of equity, the utility will be able to continue to raise equity and continue to operate fine. There will be a one-off impact on the share price, but investors who buy after that point would continue to get the same return that investors today expect.

VICE CHAIRMAN ECHOLS: Thank you.

MADAM CHAIR PRIDEMORE: Any Commissioner questions for Mr. Barnes?

VICE CHAIRMAN ECHOLS: Oh, for Barnes or Ellis?

MADAM CHAIR PRIDEMORE: That was Mr. Ellis.

And questions for Mr. Barnes?

VICE CHAIRMAN ECHOLS: Yes, I have one for Mr. Barnes.

MADAM CHAIR PRIDEMORE: Go ahead with your questions for Mr. Barnes.

VICE CHAIRMAN ECHOLS: Mr. Barnes, I've asked other witnesses this today.

Do you know what price signal that the company could use to make the TOU-RD work for customers, be a positive experience, a positive rate that would save them money?

MR. BARNES: Not really. You know, the customers that are going to save money on that rate

are the customers whose loads typically -- those high-load-factor customers are already conducive to a demand rate. So, you know, even without -- they would be structural savers.

So even without doing anything different than what they were already doing, because they have high load factors, that demand rate is less expensive for them than other available rates. I mean, you mentioned earlier the possibility of, like, notifications via your cell phone or something like that.

You know, managing a demand rate for residential customers, it's not a question of being smart or even understanding it, even though most of them don't. It's the lack of the amount of mental energy it would take day in and day out, every hour, to actually kind of implement what was necessary in order to actually save money.

So, like, you know, a notification on your cell phone, you would be getting those constantly, you know, you would grow tired of it, and there would be times when you couldn't actually respond to it in any effective way. And all it takes is once, you know, during a month, and that's it. You lost.

So I think it's -- demand rates for residential

customers will benefit some customers. It just so happens that those are the customers that are structurally kind of aligned with that rate. Most customers typically will not benefit from that rate.

VICE CHAIRMAN ECHOLS: Thank you.

MADAM CHAIR PRIDEMORE: Mr. Ellis, you said that you're from California, but I'm certain everybody in this room knows it, but you never know; people might be watching this on YouTube instead of ESPN.

Where is Sempra? What state is Sempra in?

MR. ELLIS: So Sempra is headquartered in San Diego, California. It is the parent company on the utility side of San Diego Gas and Electric, Southern California Gas, and also Oncor a Texas, distribution utility for TXU wires business.

MADAM CHAIR PRIDEMORE: So when this ROE and capital structure was -- the basis of it, though, is in a California utility context; correct?

MR. ELLIS: No. I used the exact same proxy group as Mr. Coyne.

MADAM CHAIR PRIDEMORE: No, I'm saying it's the same proxy group, but you said that's where your experience is, and that's where you worked for an employer that had a similar capital structure.

MR. ELLIS: No, the capital structure I developed for Georgia Power is based on analysis of Georgia Power's financial statements that they provided.

MADAM CHAIR PRIDEMORE: Okay. Thanks for the clarification.

MR. ELLIS: Yeah, it's not based anything at all on California.

MADAM CHAIR PRIDEMORE: On Sempra?

MR. ELLIS: No, not at all.

MADAM CHAIR PRIDEMORE: Okay. That makes you feel a little bit better about life. Okay. Here we go.

Any intervenor questioning for Mr. Ellis?

(No response.)

MADAM CHAIR PRIDEMORE: All right. Any intervenor questioning for Mr. Barnes?

Okay. Georgia Power, Mr. Ellis.

CROSS-EXAMINATION

BY MR. MARZO:

Q Good evening, gentleman. Good evening, Mr. Ellis. I will be asking you questions. My partner will be asking Mr. Barnes questions, Mr. Hewitson.

Mr. Ellis, earlier -- I just want to clarify what I think I heard, and it's late, so you'll have to

forgive me if I misheard, but is it your position that your experience in California knowing that you can bankrupt a utility, and let's see whether the utility can still actually access capital, is that the foundation of experience that you provided to Commissioner Echols a response to his question?

A (Witness Ellis) No, that's not what I said at all. I just observed that California had a utility that did go bankrupt that was able to continue to raise capital, emerged from bankruptcy.

Q Okay.

A (Witness Ellis) It has nothing to do with my recommendations here. There was a question about would reducing the ROE cause a panic and prohibit somehow and adversely impact the customers of Georgia Power, and I gave an example where a company -- a utility did much worse, they went bankrupt, and customers were not adversely impacted.

Q Okay. And that utility, did they have a ROE lower than your recommendation in this case?

A (Witness Ellis) Their authorized -- their realized ROE was, in fact, much lower, yes.

Q Okay. Their realized?

A (Witness Ellis) Yes.

Q But they're authorized by a commission ROE, was it lower than what you're recommending in this case?

A (Witness Ellis) The authorized ROE is not relevant to the bankruptcy.

Q Okay.

A (Witness Ellis) The bankruptcy was not caused by a lower ROE. It was caused by its wildfire liabilities in the most recent instance.

Q Okay. But if we take your recommendation --

MADAM CHAIR PRIDEMORE: I would like to say it was also caused by really bad California policy.

MR. MARZO: Yeah. I can't go there.

MR. ELLIS: I really would agree with you.

Thank you.

BY MR. MARZO:

Q Now, your ROE recommendation is approximately 500 basis points from Mr. Coyne's recommendation of 11 percent in this case and 496 basis points from the company's currently set 10.5 percent ROE; is that correct?

A (Witness Ellis) Subject to check, yes, that's correct.

Q And you're aware that your 5.4 percent ROE is also 391 basis points below the next lowest ROE recommendation in this case?

A (Witness Ellis) My ROE is based on an estimate of the utility's cost of -- cost of equity. It is not based on peer analysis or peer comparison or what the national

average is.

Q And I'm just asking you a question, Mr. Ellis. I mean, your ROE at 5.4 percent is 391 basis points below the next lowest ROE recommendation in this case.

A (Witness Ellis) I did not conduct that analysis, so I can't confirm that.

Q And if I look at your resume, you have only testified in five cases on cost of capital; is that correct?

A (Witness Ellis) Yes, although I was responsible for over a decade for a cost of capital function at a major U.S. utility.

Q Including this case? You're counting this case in your five; correct?

A (Witness Ellis) Yes.

Q Okay. And in all those cases you listed, they're still, in your resume, listed as being ongoing; is that correct?

A (Witness Ellis) Some of them have subsequently closed. One of them in -- the New Hampshire case has been closed.

Q Okay. And have any of them adopted your recommendation?

A (Witness Ellis) I don't know.

Q And am I correct that, in each of those cases,

your ROE recommendation has been lowest by at least 300 to 400 basis points?

A (Witness Ellis) I did not conduct that analysis. I don't know.

Q Now, you've been testifying in five cases, but you're aware that Mr. Coyne and other expects in this case have multiple case experience, maybe in the hundreds of cases experience over you in terms of testifying; correct?

A (Witness Ellis) That may be true. I would also note that Mr. Coyne uses models and methodologies that are not accepted in finance and are not widely used in finance. And, in fact, two of them have recently been rejected by FERC.

Q Okay. But --

A (Witness Ellis) My testimony goes into detail of the numerous flaws in Mr. Coyne's methodology.

Q And Mr. Coyne has been testifying for over 15 years, correct, in cost of capital?

A (Witness Ellis) I don't know how long he's been testifying.

Q Okay. And if I look out in the world of ranges of ROEs, and I look for ranges of Mr. Coyne, I can find some examples. But when I look for ranges of your ROEs, I'm having a real difficulty finding that example.

A (Witness Ellis) I'm sorry? I don't --

Q When I'm looking around for authorized ROEs by commissions, if I look around at Mr. Coyne's recommendations that he's made throughout his history, his long career, and I look at what you've done in just the last five cases of your short career, I can't find those types of recommendations.

I can't find that 5.4 percent recommendation for an authorized utility ROE; correct?

A (Witness Ellis) As I explained in detail in my testimony, authorized ROEs have far exceeded utilities' actual cost of equity for decades, and this is a well-known fact in the industry.

Q Now, as you mentioned, you start -- before starting your consultant practice in 2020, you worked at Sempra Energy, and I think the Chair asked you some questions about your role there. And you've touted that you were the enterprise-wide cost of capital function. You worked in that group; correct?

A (Witness Ellis) I headed the strategy group, and one of my responsibilities was the cost of capital function.

Q Okay. And the enterprise strategy for Sempra was to get an ROE at 5.4 percent?

A (Witness Ellis) I was not involved -- like other utilities, SDG&E and SoCalGas and Oncor hired third

parties to provide their rate of return testimony. I was not involved actually in the utility proceedings.

Q And I assume that was intentional by Sempra; is that correct?

A (Witness Ellis) Yes, yes.

Q And I'm not trying to be aggressive here. It's obviously late, but at the same time, I'm assuming that's -- that was intentional.

Now, if I look out into the world of Sempra utilities, I look at San Diego Gas & Electric and Southern California Gas, currently, or at the time that you were there in 2019, their ROEs were at the lowest level, 10.05 percent. That's their authorized ROE, and some of -- and, actually, one of their utilities had a higher ROE than that; correct?

A (Witness Ellis) I don't know what their most recent authorized ROEs were. I can assert that I actually just finished testimony in two ROE proceedings in California at SDG&E, SoCalGas.

Q Now, are you aware that utility debt yields have recently been in the range of approximately 50 to 100 basis points above your 5.54 percent recommendation?

A (Witness Ellis) Yes, I covered the incomparability of debt yields and authorized utility cost of equity in my testimony.

Q And are you --

A (Witness Ellis) And you can't compare them directly.

Q I'm sorry. I didn't mean to interrupt you, Mr. Ellis.

A (Witness Ellis) They can't be compared directly. I covered that in my testimony.

Q Now, are you aware utility debt yields have recently been in the range of approximately 6 percent to 6.5 percent?

A (Witness Ellis) I have not looked at the latest figures. I used data as of September 2022.

Q And you state in your testimony on page 74, "There is no hard and fast rule for what the spread of equity return over the corresponding cost of debt should be," but can you and I agree that spread should be one that can reasonably attract capital?

A (Witness Ellis) The cost of debt and the cost of equity are determined independently. So as I said, there's no hard and fast rule, so you can't just look at the cost of debt and say, oh, the cost of equity has to be the nominal cost of debt, right, the yield of maturity, which is actually not the expected return, as I explained in my testimony, and then compare it to the estimated cost of equity and compare them apples to apples. It's not apples

to apples. I explain why in my testimony.

Q And at the most fundamental level, what I'm asking you, Mr. Ellis, is that when someone is looking at the risk-free rates and looking at a utility to invest in, even if you set the equity level at a hundred percent or 80 percent, or whatever you want to set it at, you've got to find equity investors who are actually willing to make that investment; correct?

A (Witness Ellis) So my analysis is based on the expected return that equity investors and utility shareholders expect, and that number currently, based on current market values and current estimates of beta, is on the order of 5 percent, and that's how I developed my cost of equity estimate for the utilities.

Q Let's me ask you a couple questions that follow up on the question that was asked about how people would react.

If adopted, Mr. Ellis, your 5.45 percent ROE recommendation would introduce significant regulatory risk, increasing the cost of capital; correct?

A (Witness Ellis) I don't agree with that.

Q Are you familiar with Moody's credit rating methodology?

A (Witness Ellis) Yes. I used it in my analysis.

Q Is it your understanding that 50 percent of

Moody's rating methodology for regulating utilities relates to the regulatory environment?

A (Witness Ellis) I don't know the exact figure. I know that regulatory environment is a factor.

Q Okay. Wouldn't it be important to know that if you're going to suggest that there won't be significant impacts to utilities from adopting a recommendation that's 500 basis points?

A (Witness Ellis) I admitted that regulatory environment is important. I didn't know the exact fraction in Moody's methodology.

Q And, in fact, Mr. Ellis, you admit in your testimony that you expect that if the Commission were to adopt your recommendation, that Southern Company's stock price would decline and that there would be equity investors that would flee from that stock; correct?

A (Witness Ellis) I did not say equity investors would flee from the stock. I did say there would be a decline, but as I also mentioned in my testimony, there's no -- in fact, Hope specifies regulators have no obligation to protect stock prices of utilities.

Q But you understand that Hope and Bloomfield also are about trying to meet investors' expectations and comparable risk utilities.

So if the result of your recommendation is a

flee away from the stock, isn't that, by definition, indicating that your recommendation is not consistent with Hope and Bloomfield and is, in fact, the result of being inconsistent to Hope and Bloomfield?

A (Witness Ellis) I did not say investors would flee the stock. That was your statement.

Q Okay. So stock price decline is a different term for you in your testimony? Because I believe that's what you used.

A (Witness Ellis) Yes. The stock price would decline.

Q Okay. Now, if your recommendation is inconsistent with investors return expectations, doesn't that indicate it does not reflect the cost of equity?

A (Witness Ellis) My recommendation is precisely consistent with investor return expectations. That's the whole basis of my analysis.

Q And that's why it is currently 500 or more basis points away from even the lowest recommendation?

A (Witness Ellis) As I described in detail in my testimony, the authorized ROEs is a very different concept from the cost of equity or the investors' expected return.

Q Okay. In the interest of time, Mr. Ellis, I think I will go ahead and conclude my cross now.

MR. MARZO: But thank you, Madam Chair.

Thank you, Mr. Ellis.

MR. ELLIS: Thank you.

MADAM CHAIR PRIDEMORE: Ms. Whitfield, just so it's fresh in your mind, do you have any redirect for Mr. Ellis?

MS. WHITFIELD: I don't have any redirect. Thank you.

MADAM CHAIR PRIDEMORE: Okay.

Mr. Barnes. Mr. Hewitson, Mr. Barnes is your witness.

MR. HEWITSON: Thank you.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Good evening, gentlemen. Mr. Barnes, good to see you again.

A (Witness Barnes) Evening.

Q Steve Hewitson on behalf of Georgia Power Company. I want to start with your recommendation that the company not be allowed to adjust for the $1.4 million revenue erosion -- or the revenue erosion from the RNR monthly netting pilot.

Do you agree that when the rates were designed in 2019 and approved by this Commission, they did not account for the potential revenue erosion from the monthly netting pilot?

A (Witness Barnes) Yeah, I don't believe they did.

Q And recognizing that you disagree with the company as to how to address the issue, would you agree with me that, at the outset, the company collected less revenue from the monthly netting pilot participants than it had originally designed in its rates?

A (Witness Barnes) It collected less revenue. The question, though, is what revenue was it entitled to collect, you know, in order to earn a reasonable return. I would say that that 1.4 million did not cause the company to earn an unreasonable return and, therefore, itself is not necessary.

Q But the difference in what was planned for and what was collected is the revenue erosion for which the company is asking to make the adjustment; right?

A (Witness Barnes) I'm sorry. Could you repeat that?

Q Sure.

The difference in what was planned for and then what was actually collected is the revenue erosion that the company is requesting the adjustment be made for?

A (Witness Barnes) So I guess it would apply going forward into rates, but you're saying it would reflect, you know, essentially, the past, or is it -- are

you saying that it's forward looking?

Q Well, and maybe I used past terminology. I meant going forward.

A (Witness Barnes) Okay. I'll ask you to repeat the question again because now I've kind of turned myself around.

Q Okay. The difference in what the company planned for to collect and then what the company will collect is the revenue erosion that the company is asking the Commission to make the adjustment for; right?

A (Witness Barnes) That's right. And as I discussed in my testimony, the potential for that revenue erosion is already well addressed by the earnings sharing mechanism with the earnings band, and, therefore, there's no need to go out and pick and choose individual elements that might cause revenue attrition or revenue expansion and move them outside of that process.

Q Okay. There are revenue deficiencies that occur because customers use less electricity than anticipated; right?

A (Witness Barnes) Yeah, that's one possible cause of a lower amount of revenue than was expected.

Q Right.

And there is revenue deficiency because forecasts and projections can't be entirely accurate; right?

A (Witness Barnes) Sure. There's a hundred different reasons.

Q All right. And those revenue deficiencies, though, were not result of a Commission-imposed program instituted after the revenue requirement was set, was it?

A (Witness Barnes) Well, I mean, kind of everything is Commission-imposed, is it not? I mean, the commissions set the rates --

Q Well --

A (Witness Barnes) -- therefore --

Q I'm sorry. Go ahead.

A (Witness Barnes) The commissions set the rights, the commissions set the revenue requirement; therefore, I think kind of everything is imposed on the company, in theory, by the commission.

Q Well, yeah, but that wasn't -- the Commission in position of the net metering pilot isn't the same, I guess is my point, as customers just using less electricity or the forecast being off.

A (Witness Barnes) I mean, I don't think it's really distinctly different. It's one of many different factors that could play a role.

Q Okay. And one of your critiques of the company's position is that the revenue erosion analysis does not consider the long-term costs and benefits of monthly

netting, with those benefits being the avoidance of future costs on the system; right?

A (Witness Barnes) Yes, that's my testimony.

Q And to the extent those benefits may materialize over time, they are not present in the three-year window that we are addressing in this rate case; do you agree with that?

A (Witness Barnes) Some of the benefits that accrue, say, within an individual class are something that would, you know, kind of, in theory, accrue immediately if you properly conducted your cost of service study in order to reflect, you know, differences in the coincident peak allocators to a given class. So there are benefits that would accrue to, kind of, individual customers within a class.

Would that necessarily in the next two years, you know, kind of reduce the overall net cost of the company's system? Not necessarily. I mean, we'd be focused on long-term marginal costs, not short-term marginal costs, in making that kind of judgment.

Q I want to talk about your recommendations on the ECCR.

You recommend that it be collected on a volumetric basis rather than a percentage of the base plan; right?

A (Witness Barnes) That's correct.

Q And that would be based solely on usage, then; right? That's what you mean by volumetric?

A (Witness Barnes) Yeah, a uniform volumetric charge.

Q Okay. And, currently, the ECCR is collected on a percentage of each customer's base bill, which does include demand charges; right?

A (Witness Barnes) Right. It includes -- you know, effectively kind of makes a split with, you know, a portion of the costs, basically, classified as energy related, a portion classified as demand related, a portion classified as customer related, just because those are the revenue sources that comprise a customer's bill.

Q So if your recommendation was accepted, does that mean that for customers on rates with demand charges, ECCR would no longer be calculated on that demand charge, but would be entirely volumetric?

A (Witness Barnes) Yes, uniform volumetric. That's what it means.

Q ECCR costs recover more than just CCR ARO costs; right?

A (Witness Barnes) They do. They certainly recover other environmental costs. But I think the fact of the matter is that those other costs are declining, at least

according to the numbers that I've seen from the company relative to the costs associated with CCR AROs. There is a portion of those costs which the current model would at least kind of imply are energy related.

So going forward, what we have is a cost, like, CCR ARO, which is a hundred percent energy related, being mixed into a group of costs that are kind of a mixture of -- you know, you could say the plant investments that are intended to keep a plant operating, you know, to meet environmental requirements, you know, are both energy and demand related, because that plant is providing energy, it's meeting demand.

What we have going forward is a system -- is a set of ECCR costs which are far more weighted towards energy-related costs; therefore, kind of the simplest way to resolve that problem with the current regime would be to translate it to a uniform volumetric charge. You could potentially get more granular with respect to how you classify costs, but that's not how the company has historically done it.

Q But if you -- or the Commission accepted your recommendation, necessarily, it would be collecting some demand-related pollution control costs through a volumetric rate; right?

A (Witness Barnes) I guess it would depend on,

you know, what portion you actually define as demand related. I mean, it could be de minimis to the point where it doesn't matter. But I'll say yes, that could be the case. The fact of the matter is that the company is now currently collecting a lot of energy-related costs, you know, effectively through demand charges. So, you know, we're -- it's -- we're not creating a different situation. We're just kind of making it fairer overall.

Q With respect to the CCR ARO costs included in this rate case, those costs will have already been spent when the company starts collecting them in rates next year; right?

A (Witness Barnes) Yes, they would.

Q And those costs have nothing to do with and they don't vary with the amount of electricity that Georgia Power will sell in 2023 through 2025; is that right?

A (Witness Barnes) That's right, but they vary with the amount of electricity that the company sold in 2022 and 2021 and 2020. You know, there is a time that -- there is a time shift. I'll grant you that. But they are still energy related. It's pretty axiomatic actually.

Q Right.

And you say in your testimony that there is an intergenerational cost shift, as you put it, and you say that that's okay because some portion of the customer base

benefited from the prior generation; right?

A (Witness Barnes) Well, I say it's irreconcilable. I mean, there is going to be an intergenerational cost shift no matter what recovery mechanism you choose, and there's no rate design mechanism or allocation mechanism that is inherently, you know, better or fairer for addressing the fact that, yes, some customers are going to pay for costs that were caused, you know, prior to them taking service.

Q But costs that lead to intergenerational cost shifts are not typically energy related, are they?

A (Witness Barnes) I don't know that that's necessarily true.

Q Can you identify any intergenerational cost shifts that are energy related?

A (Witness Barnes) Well, I think the situation we're confronting here is that we did have energy-related costs that were not -- it was not appreciated that there would be these costs in the past when something could have been done about that to, you know, apply that to rates back then. In other words, we can't put the toothpaste back in the tube; right?

But, you know, we would have been better off had we known that there would have been those costs, and then we could have charged customers accordingly. We're not

in a situation where we have that luxury now. And so I think any cost that was not fully appreciated in the past, which could be other environmental costs, it could be any number of other types of costs that, you know, become an intergenerational challenge, you know. I don't know that there's anything that confines those two energy or demand or customer related.

Q Well, I understand that we're dealing with a unique situation here, and you're trying to make the best of it in your mind, but is there any other category of cost that is allocated on an energy basis, the collection of which leads to an intergenerational cost shift?

A (Witness Barnes) I mean -- okay. There are many utilities that allocate a portion of the costs associated with production -- you know, coal plants, gas plants, whatever, on methods that utilize an energy allocator in combination with a demand allocator. Those are pretty -- those are fairly universally accepted.

I wouldn't say they're not -- they're not adopted in all cases, but they are accepted methodologies if you consult resources like, you know, the NARUC cost allocation manual. An average in excess referring to a portion is energy, a portion is demand thrown into production cost; therefore, there are many circumstances under which energy-related costs can become, you know,

essentially kind of like stranded from the standpoint of not being collected from customers at the time, say, the unit was in service, like if the plant retires early or something like that.

Q And would you agree with me that in the highly unlikely event that Georgia Power doesn't sell a single kilowatt hour of energy or electricity in 2023, the CCR ARO costs that have already been spent would still be there and need to be collected; right?

A (Witness Barnes) Well, those existing costs, yes, they would still be there. Clearly the company would still be generating CCRs because those coal plants have not entirely shut down, and those will have to be dealt with in the future, you know.

Ideally, that is something that could be added to current rates, but if we're confining it to asset retirement obligations and collecting some of those costs then, you know, we're kind of -- we're always pushing it forward into the future, rather than charging customers, kind of, pay as you go.

Q All right. I want to ask you a few questions about TOU-RD. Obviously, you're not a fan, but I don't read your testimony as suggesting that TOU-RD should be eliminated, just that it should not be used as the default rate.

Is that a fair characterization of your testimony?

A (Witness Barnes) Yes, that's right. I don't recommend that it be eliminated.

Q And would you admit that even under your analysis -- and I think you answered a question on this before from one the Commissioners, but TOU-RD may be a good fit for some customers; right?

A (Witness Barnes) Yeah, I think a relatively small percentage of customers, residential customers, but, yes, some customers will benefit from being on that rate.

Q Okay. And in terms of fixed cost recovery, would you agree that a rate with a demand charge is more palatable to customers than an increased fixed customer charge?

A (Witness Barnes) In theory, a demand rate has some level of controllability. I mean, in reality, customers -- residential customers are not very well able to control their demand.

Q But customers would rather have the chance to control the demand than not?

A (Witness Barnes) I mean, you're talking about the difference between a miniscule ability to control and no control, so I would say that the difference between the two, a fixed charge and a demand charge for residential

customers, is minimal.

Q As you said in your testimony, "The trend in rate designs is towards greater availability of different rate options with an emphasis on time varying rates."

Do you recall that testimony?

A (Witness Barnes) That's right.

Q And if you need to look, it's on page 32, but you've already told me you remember it, so...

And those different rate options often include rates with demand charges often paired with time-of-use rate; right?

A (Witness Barnes) Yes, a lot of the newer residential rate designs that have been established, you know, they have been a mix of rates that feature a demand component and then a mix of volumetric TOU that are exclusively volumetric TOU.

Q Right.

And that's what TOU-RD is, just so we're on the same page, right, it's a time-of-use rate with a demand component?

A (Witness Barnes) Right. It's -- I guess the distinction I was trying to make is that, you know, the demand component is not time differentiated. It's kind of a -- a hybrid of volumetric TOU and noncoincident demand charge.

Q Okay. I get you.

Do you agree with me that the marginal cost to generate and distribute electricity varies significantly hour to hour?

A (Witness Barnes) Yeah, I do agree with that.

Q Okay. And a time varying rate is meant to capture some of those marginal costs; right?

A (Witness Barnes) I mean, typically, at least in Georgia Power's case, kind of applied to embedded costs, if you kind of get the distinction, but the idea being that, you know, yesterday's or today's marginal costs are the day after tomorrow's embedded costs.

Q Okay. Do you agree that Georgia Power's current R rate is a volumetric rate design does not capture the hour-to-hour differences?

A (Witness Barnes) It doesn't directly capture the hour-to-hour differences, but, you know, as I illustrated in my testimony, it does capture kind of the shape of those differences insofar as, you know, it's charging customers higher rates during the summer months, whereas TOU-RD actually does the opposite of that.

Q Do you agree that the R rate sends little, if any, price signal to customers?

A (Witness Barnes) I think it sends -- well, the obvious price signal it sends is use less electricity during

the summer; use more during the winter.

Q Other than that price signal, does it send an actual price signal -- actionable price signal to customers on a day-to-day basis?

A (Witness Barnes) I mean, yeah, I think that's actionable on a day-to-day basis. You can choose whether or not to use this appliance or that appliance, and if you don't use that appliance, you save money. I think it is actionable. It's not directly time differentiated.

But to the extent that a residential customer's summer electricity use is going to be higher during kind of those on-peak periods, you know, discouraging that use with a tiered rate is not necessarily an unreasonable proxy. I mean, it's not as good as time of use.

Q Thank you.

On page 30 of your testimony you quote a regulatory assisted project paper.

To be fair, the premise of the paper is that time varying energy rates are better than demand charges; right?

A (Witness Barnes) At reflecting cost causation, yeah. In particular, when paired with critical peak pricing.

Q And that paper does not advocate for the use of purely volumetric rates with no time-of-use component, does

it?

A (Witness Barnes) No. It's strictly focused around the time varying element.

Q Okay. Thank you.

Moving onto your bill calculator on page 53, you recommend that the Commission direct the company to develop a bill calculator. It seems that you propose this tool be developed for use by residential customers; is that right?

A (Witness Barnes) Right.

Q Have you researched what the cost would be of developing such a tool and maintaining it?

A (Witness Barnes) No, I have not done that.

Q Would you suggest that such cost be paid for by all customers or just residential customers?

A (Witness Barnes) Well, if I remember correctly, the company does have a large power and light bill calculator tool, and I don't know how that's paid for. You know, to the extent that that tool is paid for by all customers, I think I would probably recommend that this particular tool be paid for by all customers.

If it is confined to the LPL class, I think it would probably be reasonable to also confine the cost of the tool to the residential class. I mean, I do not anticipate that it would be super expensive.

Q If such a tool is developed, and large numbers of customers switch to rates on which they pay less, would you agree that that could lead to amounts of revenue erosion for the company?

A (Witness Barnes) It could lead to less revenue, you know. Does it necessarily lead to less revenue than that which the company is entitled to earn a reasonable return, no.

Q But if the revenue requirements are set by the Commission in a rate case, and throughout the duration of that, say, it's a three-year ARP, the revenue erosion causes them to earn or to recover less than the revenue requirements, that would be -- that would be a significant amount of revenue erosion, wouldn't you agree?

A (Witness Barnes) I don't know that it would be significant. If it was less revenue, it would be a revenue erosion, you know. You could conceivably have a scenario where customers use less or, you know, weather normalized -- or, sorry, weather normalized usage was less, which would indicate that, you know, the company would earn less money, but you get more customers -- new customers than you expected. There are other variables that might kind of offset any revenue erosion that exists.

Q Okay. So, therefore, your testimony is if the company has a good revenue collection year, then you

wouldn't see it as revenue erosion, and the company shouldn't be able to recover?

A (Witness Barnes) I don't think the company is entitled to recover anything more than the bottom of that ROE band. At least, it's -- you know, if the company earns below that ROE band, it can come in for a rate increase, as I understand it, you know. To the extent that it is earning at or above that, I don't think it's entitled to any more than what it gets.

MR. HEWITSON: Thank you, Mr. Barnes. That's all the questions I have for you.

MADAM CHAIR PRIDEMORE: Ms. Whitfield -- oh, Ms. Kysor, redirect?

MS. KYSOR: Surprise from the end of the table there. Thank you.

REDIRECT EXAMINATION

BY MS. KYSOR:

Q Mr. Barnes, Mr. Hewitson asked you about the price signal that the basic volumetric R tariff might send.

Do you think that the R tariff would be easy for customers to understand if they use less, then they would pay less on their bills?

A (Witness Barnes) Yes. That's about the simplest price signal you can give.

Q And then Mr. Hewitson was also asking you about

the coal ash cost recovery and the ECCR tariff and your recommendation that it be classified as energy related.

Do you recall that?

A (Witness Barnes) I do.

Q And he talked about some of the complications with coal ash costs that have already been incurred in that time shift.

Do you recall that?

A (Witness Barnes) Yes, I do.

Q Are you aware of any other jurisdictions, any other commissions that had decided it's appropriate to classify those costs as energy related?

A (Witness Barnes) Yes. The Commissions in North Carolina and in Virginia, over utility objections -- or in the case of North Carolina, over utility objections, and in Virginia, it was part of the utility proposal -- have both determined that coal ash mitigation recovery costs should be classified as energy related.

MS. KYSOR: Thank you. That's all I have. We would just ask that the exhibits be moved into evidence.

MADAM CHAIR PRIDEMORE: So moved.

(The documents referred to were admitted into evidence as GIPL's Exhibits 6 through 10.)

MS. KYSOR: And that the panel be dismissed.

**MADAM CHAIR PRIDEMORE: Panel is excused.**

**Okay. We have completed 14. We have eight to go. We back here tomorrow morning at 7:30 a.m. We're going to stop at 9:30, do committees, then do public witnesses, and then resume.**

**(Hearing adjourned at 8:48 p.m.)**

C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.

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Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664

Brenda P. Elwell, RPR, CRR, B-2023

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**STATE OF GEORGIA**

**In Re:**

**Georgia Power Company's 2022 Rate Case ) Docket No. 44280**

**Hearing Room 110**

**Georgia Public Service Commission**

**244 Washington Street**
**Atlanta, Georgia**

**Thursday, November 10, 2022**

**The above-entitled matter came on for hearing Pursuant to Notice at 7:30 a.m.**

**PRESENT WERE:**

**TRICIA PRIDEMORE, Madam Chair**
**TIM ECHOLS, Vice-Chairman**
**FITZ JOHSON, Commissioner**
**LAUREN "BUBBA" MCDONALD, Commissioner**
**JASON SHAW, Commissioner**

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**I N D E X**


| WITNESSES: | DIRECT | CROSS | REDIRECT | RECROSS |
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| By Mr. Thomas | | 3177 | | |
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| KEVIN HURLEY | | | | |
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| By Ms. Ariza | | 3364 | | |
| LARRY BLANK | | | | |
| By Ms. Medlyn | 3397 | | | |
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| By Mr. Marzon | | 3493 | | |
| MICHAEL GORMAN<br>KEVIN O'DONNELL | | | | |
| By Mr. Walsh | 3510 | | 3685 | |
| By Ms. Brown | | 3641 | | |
| By Ms. Coyle | | 3643 | | |
| By Mr. Marzo | | 3651 | | |
| RONALD L. LEHR | | | | |
| (Not present but testimony admitted) | | | | |

N D E X


| WITNESSES: | DIRECT | CROSS | REDIRECT | RECROSS |
|---|---|---|---|---|
| **LEE EVANS** | | | | |
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| **By Mr. Hewitson** | **3715** | | | |
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| **DAVID GATTIE** | | | | |
| **By Mr. Hewitson** | **3819** | | | |
| **By Mr. Thomas** | | **3859** | | |
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| **By Mr. Thomasson** | | **3877** | | |
| **By Mr. Moreland** | | **3889** | | |

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**MADAM CHAIR PRIDEMORE: All right. We are going to get back at it. Call to order Docket No. 44280: Georgia Power Company's 2022 rate case.**

**I want to talk about the order of today and then we'll go through -- we'll go through appearances.**

**First and foremost, we are getting started at 7:30 so that we've got time to try to meet the schedule today. Tomorrow is a state holiday and so it is important now more than ever to pick it up. Get your handouts out. Just I'd like a little gas in your tank today, please.**

**Next, we're going to start at the panels starting with GASEIA and we're going to go through those panels until we get to United States Department of Defense and all other Federal Executive Agencies. At that point we're going to stop and we're going to put in the staff panel of -- that's Mr. Gorman. We are going to put him in then.**

**Then we'll go back and pick up the two Georgia Power Company panels after that.**

**Does that make sense to everybody?**

**(No response.)**

**MADAM CHAIR PRIDEMORE: All right. We also have to stop promptly at 9:30 to run committees.**

We're going to run committees from the bench today. I've got to allow at least a three-minute turnaround to switch out the live feed, so just please be patient.

You will also have people that have business in committees that need to come in and have a seat. So if you don't have committee business, it might be a good opportunity for you to go get a cup of coffee.

And then immediately at the conclusion of committees, we'll do public witness testimony on Docket No. 44280.

All right. Let's call for appearances. Georgia Public Service Commission.

MR. WALSH: On behalf of the Public Interest Advocacy staff, Daniel Walsh and Preston Thomas.

MR. HEWITSON: Steve Hewitson, Brandon Marzo, Allison Pryor on behalf of Georgia Power Company.

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy.

MR. GALLOWAY: Good morning, Madam Chair. Newton Galloway, Terri Lyndall on behalf of AACE. Thank you.

MADAM CHAIR PRIDEMORE: ChargePoint.

(No response.)

MADAM CHAIR PRIDEMORE: ChargePoint.

(No response.)

MADAM CHAIR PRIDEMORE: Commercial Group.

MR. JENKINS: Good morning. Alan Jenkins.

MADAM CHAIR PRIDEMORE: EVgo Services.

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Association of Manufacturers is not going to be present today. They already let me know.

Georgia Coalition of Local Governments.

(No response.)

MADAM CHAIR PRIDEMORE: I don't see them here.

Georgia Conservation Voters.

(No response.)

MADAM CHAIR PRIDEMORE: I don't see them either.

Georgia Interfaith Power & Light.

MS. KYSOR: Good morning, Commissioners. Jill Kysor and Jen Whitfield.

MADAM CHAIR PRIDEMORE: Okay. GASEIA.

MR. THOMASSON: Scott Thomasson for GASEIA.

MADAM CHAIR PRIDEMORE: GA Solar.

MR. MORELAND: Hi. Good morning. Don Moreland for Georgia Solar.

MADAM CHAIR PRIDEMORE: Georgia Watch.

MS. COYLE: Good morning. Liz Coyle for

Georgia Watch.

MADAM CHAIR PRIDEMORE: Interstate Gas Supply.

(No response.)

MADAM CHAIR PRIDEMORE: I don't see them here.

Okay. Kroger is out today.

MARTA.

MS. STURM: Kasey Sturm on behalf of MARTA.

MADAM CHAIR PRIDEMORE: Hi, Ms. Sturm.

Resource Supply Management.

MR. CLARKSON: Jim Clarkson for Resource Supply. Thank you.

MADAM CHAIR PRIDEMORE: Good morning, Mr. Clarkson.

Sierra Club.

MS. ARIZA: Good morning. Isabella Ariza on behalf of the Sierra Club.

MADAM CHAIR PRIDEMORE: Good morning, Ms. Ariza.

SACE.

MR. DOWDY: Good morning, Madam Chairman, Commissioners. Craig Dowdy and Steven Jones on behalf of Southface and SACE.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association.

(No response.)

MADAM CHAIR PRIDEMORE: I don't see them here. Okay.

United States Department of Defense and All other Federal Agencies.

MS. MEDLYN: Good morning, Commissioners. Emily Medlyn on behalf of the United States Department of Defense and All other Federal Executive Agencies.

MADAM CHAIR PRIDEMORE: Utility Management Services.

(No response.)

MADAM CHAIR PRIDEMORE: Okay. All right. Now that we've gone through appearances, are there any other housekeeping matters for the parties that are present?

(No response.)

MADAM CHAIR PRIDEMORE: All right. Hearing none, Georgia Solar Energy Industries Association, Solar Energy Industries Association, and Vote Solar.

MR. THOMASSON: Gentlemen, if you will stand, I will swear you in.

Thereupon,

KEVIN LUCAS,
THATCHER YOUNG,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. THOMASSON:

Q All right. Would you both please state your names, employers, and your business address.

A (Witness Young) Yes, good morning. My name is Thatcher Young. I work for Velo Solar. We are at 154 Krog Street, Suite 140, Atlanta, Georgia 30307.

A (Witness Lucas) Good morning. Kevin Lucas with The Solar Energy Industries Association. We're at 1401 K Street, Washington, D.C. 20005.

Q On October 20th of this year, did you cause to be filed 105 pages of prefiled testimony in this proceeding, along with one exhibit?

A (Witness Lucas) Yes.

Q And did you also cause to be filed on November 3rd one page of corrections to that testimony?

A (Witness Lucas) Yes.

Q Do you have any further corrections to that testimony?

A (Witness Lucas) I do have one further correction that I found last night reading through on page 80, line 7. Where it says PM, that should say AM.

Q All right. And if I ask the same questions today as in your prefiled testimony, would your answers be the same?

A (Witness Lucas) Yes.

A (Witness Young) Yes.

Q Did you also cause to be filed on October 20th a trade secret version of your testimony?

A (Witness Lucas) Yes.

Q Have you prepared a summary of your testimony?

A (Witness Lucas) Yes.

A (Witness Young) Yes.

Q Would you please give that now.

A (Witness Young) Sure.

Madam Chairman and Commissioners, thank you for another invitation to address you and the people of Georgia on our rapidly changing clean energy landscape. Wow, what a season of change it has been as Georgia emerges from COVID-19 and observes and experiences the global energy disruptions of Russia's horrific and unsanctioned invasion of Ukraine.

We seek your support in this proceeding in strengthening behind-the-meter solar, monthly netting, and the partnership between solar asset owners and the company. Georgians are seeking control over their energy mix, price and resiliency. Through a strong partnership we can ensure this is available to all.

We believe the company should begin to look at behind-the-meter solar plus storage as DERs. As reported by a number of our members, over 75 percent of new residential

solar installations are paired with battery storage, essentially removing the intermittency and creating a demand side asset for the company.

Once second-generation EVs like the Rivian R1T, the Hummer EV, and the Ford Lightning enter garages across the state, customers will have over 100 kilowatt-hours of mobile battery storage as an ancillary benefit. We recognize this transition will take time, but it has certainly begun. With correct pricing signals, we believe a large number of customers would be interested in partnering with the company to manage these assets and allow the company to control these DER resources as they do with large commercial and industrial customers today.

In our testimony Kevin states that sending a price signal to manage demand during these hours is more actionable than requiring customers to be hypervigilant over every hour of the month. Software like Sense is available today that can manage this interaction via text to a customer's smartphone.

We have seen in other states pivoting in this direction with great results, Florida, South Carolina, Dominion in Arkansas, all have forms of unrestricted net metering combined with TOU rates and are seeing strong, consistently growing residential and commercial behind-the-meter solar markets.

**The Smart Usage rate is a move in the opposite direction. And as staff has indicated, will create confusion for customers as predicting demand and being able to respond in real time simply isn't feasible with GPC's current customer data clarity. The renamed EV rate, as the Commission has noted, is confusing also and we just believe as Mr. Watkins said, they don't know if they're peaking on the weekend.**

**Like other utilities in our state, GPC's rates for solar and EV should be simple for a customer to understand. The electric cooperatives like Cobb EMC have very simple TOU-based rates for both solar and EV charging and we support the growth of these structures. This could help customers help the company meet its decarbonization goals faster through outside investment and flexibility while taking pressure off the grid in peak periods.**

**We recognize that the growth of behind-the-meter solar has an impact on company revenues. However, based on our analysis, this impact is minimal. GPC complains about a $1.4 million in revenue erosion from them systems, but is asking for billions in rate increases while consistently over-collecting revenue from its customers. Mr. Lucas's analysis shows that even if we were -- it were accurate, the NIM cost would be roughly 20 cents per year per customer compared to more than $400 per year in current**

and anticipated rate increases and over-collection.

Furthermore, we have demonstrated consistently that net metering customers use more grid electricity than an average customer, and second generation EV charging at home overnight will see even more significant increases.

How much revenue erosion has the company asked for recovery from the installation of smart thermostats or LED lighting? With regard to interconnection fees, as my pawpaw used to say, if it ain't broke, don't fix it. And so we'd like to see the 5-dollar-a-kilowatt fee for residential customers maintained and for staff's recommendation that commercial customers' fee be set at $200 with no witness test or site visit from company personnel required, which has created significant delays in starting up projects in this post COVID period.

Further, with the technology advancement, almost 100 percent of solar and battery technology being deployed today is both UL and IEEE certified for electrical safety, and most AHJs require electrical interconnection be done by a licensed electrician. The company does not and never has charged an interconnection fee or done a witness test for the installation of a backup generator.

The solar industry wants to partner with the company and the Commission on behind-the-meter solar as it has so successfully on other DG solar deployment to help

maintain the most reliable and cost-effective grid for all Georgians while giving customers more choice and control of their clean energy.

As always, we appreciate your time, your attention, and your leadership as we work together to advance a clean energy future in Georgia. I yield the balance of my time to the gentleman from Maryland.

(Witness Lucas) Thank you, Mr. Young. And thank you, Madam Chair and Commissioners. It's a pleasure to be back in front of you today again.

My name is Kevin Lucas with the Solar Energy Industries Association and I'm very happy to be able to participate in this extremely important case. This is a big case dealing with big issues and big amounts of money. As we've talked about the last several days, the decision that you will ultimately make in this case is going to affect the people who live in Georgia and the people who operate businesses in Georgia for a long time.

So as part of an incredibly important docket such as this, one of the things that I think is very important is that we have as robust of a record as possible for you to make that decision. And one of the challenges that I have faced as I've worked in this proceeding is providing you with the best information I can because of the way that certain aspects of this process work. Specifically

I'm talking about some of the challenges associated with asking discovery and the time that the company has to respond to discovery.

As you know, Commission staff is able to ask the company discovery, but other intervenors are not. And likewise, the company has 30 days to respond to the questions, making it sometimes challenging to ask multiple rounds of questions which may be needed on complex issues. So I would respectfully ask that in order for intervenors such as SEIA and others to provide you guys with the best information possible, that you consider expanding the ability for other parties to ask discovery, and also consider shortening the time that the company has to respond to those.

When I was flying down here yesterday, I was walking through the airport and as I was going through security, a young girl about seven or eight in front me found a quarter on the ground. Because she and her mom and I were the only folks in the area, she turned to me very politely and asked if it was my quarter. And I said, no, it wasn't, and she excitedly put that quarter into her backpack. Had that girl and her family been a Georgia Power customer, that quarter would have been enough to pay for the entire cost shift that the company is claiming for the RNR pilot program. And, in fact, she would have had five cents

left over. Because as Mr. Young said, we calculated that number to be about 20 cents a year for a typical residential customer, compared to over $400 a year in current asks from the company, pending costs, and over-earning above the ROE. And that $400 does not include the nearly $2 billion in fuel cost that we have talked about the last few days.

So as we talk about the RNR revenue erosion, it's important to keep those two things in mind. Twenty cents a year on the one hand and 400-plus dollars on the other hand.

That said, the $1.4 million revenue erosion figure that the company is claiming must be viewed in the context of the revenue earnings -- the revenue band mechanism that the company enjoys. There was some back and forth yesterday about whether this money was justified to be collected, whether there was a cost shift involved. The company has every year since 2011 collected revenues above its ROE. Every single year. I have an exhibit here on Exhibit 3 that shows those broken down by years.

In 2021 the company collected $258 million above its approved ROE. So the question about whether this 1.4 million represents revenue erosion that the company should have collected, it simply does not. There are not shortages of revenue that the company is not collecting because of these RNR customers. It simply means that

instead of, if this were approved, the company would have collected $259 million extra instead of $258 million extra.

So with regard to that band in particular, one of our recommendations is the Commission reconsider the width of the band. There's been some back and forth on that. Our recommendation is that you narrow this to 50 basis points plus or minus.

Now, the 50 basis points would still allow the company, based on 2021 figures, to earn $80 million above their central earning fund. And we also recommend that the company be allowed to keep the 20 percent above the earnings band as a further incentive for them to continue to run an efficient operation. But we feel that narrowing that band to 50 basis points plus or minus would better balance the ability for the company to earn some excess returns and have flexibility in a multiyear plan, but also protect customers from experiencing revenue collections well above the company's authorized central ROE.

Mr. Young mentioned a little bit about the company's interconnection fee proposal. Again, there was some discussion yesterday on that. A very sizable change going from a $5-per-kilowatt fee to a $200 flat fee. Now, the $5-per-kilowatt fee would be about $35 for a typical customer, so a $200 increase for a residential customer would be sizable.

The company offered no support in its testimony for this fee. It simply asserted that, well, because most of these costs are independent of system size, it's appropriate to charge everybody the same amount. Well, staff asked for support and asked for their numbers; the company provided a one-page paper. There was an Excel sheet with all the formulas removed, so just a bunch of hard-coded numbers. I tried to reverse engineer that work paper to understand the assumptions that were embedded in it and I ran into some problems with it. There was a few numbers that looked like they might contain errors. There were some numbers that were treating figures inconsistently.

I wasn't able to ask discovery to get those follow-up, but the company did agree to have a meeting with us. We had an off-the-record meeting to talk to some of their employees, but, unfortunately, that meeting actually raised more questions about this process than it answered. We found during the course of that meeting that the company has to touch an account three separate times in the process to change them over to the RNR tariff.

The folks on the phone couldn't explain exactly what happens in each of those times, but says that, on average, it takes an hour over those three times to simply update their account to be on the RNR tariff.

But more problematically, they actually said

that their billing analysts go in and manually review every single customer to make sure that the billing system is calculating numbers correctly. That they look at the consumption, they look at the export, they double check that the netting is done right, and they make sure the bill accurate. I've never understood or heard of a process where a billing analyst will manually review every single bill for a customer that is being produced through an automated billing system. So that was something that, again, I would have loved to ask more questions about, but those processes call into question whether the process that the company is using is, number one, scalable. And number two, as effective and efficient as it ought to be.

So because the company did not actually demonstrate that its current fee structure is not recovering its costs and it hasn't demonstrated that the cost estimates it provided in its work paper are reasonable and prudent, we would recommend that you reject the company's proposal to change the interconnection fee and maintain it at its current structure.

I also prepared a good amount of testimony on the Smart Usage tariff. I won't repeat that here because we've had a lot of good discussion. I'll basically say I agree with the former panels from staff and the last one up yesterday that the Smart Usage tariff is not well-designed,

doesn't contain actionable price signals, it's confusing to customers, and people who are on this tend to pay more than they would on other tariffs.

I do want to highlight two different things, though, that I think adds to the discussion here. I have on Exhibit 9 an analysis I did that provides some context about just how bad this tariff can be for different customers.

So Exhibit 9 shows a group of customers that chose to be on this rate. These were all customers who were on the Smart Usage tariff as of the beginning of 2021, which was right when it was made the default rate. So it was -- it was a voluntary tariff up to that point that still is a voluntary tariff, but customers were not being defaulted on. And what this chart shows is that for half of the customers on the left side of that vertical purple line who used less than the median amount of energy, 90 percent of those customer groups had a higher bill on the Smart Usage tariff than they would have on the R tariff. 90 percent of those lower-use customers had a higher bill.

The situation is even worse for those customers who were defaulted onto the tariff. When I looked at the individual bills of customers in 2021, 90 percent of all bills for all customers in all of those months were higher on the Smart Usage tariff than they would have been on the R tariff. This tariff is simply not well positioned to be a

default tariff. And for the reasons discussed by staff and others yesterday, our recommendation is to not allow it to be the default tariff.

The second piece of information about this that I'd like to highlight is there was back and forth about whether or not the company should report back to you on the effectiveness of this tariff. You already have asked them to do that. In the 2019 rate case order, you guys put in the requirement that the company was required to -- I'm quoting here from my testimony on page 64 -- the company was required to, quote, report back to the Commission at the time of its next base rate case regarding the adoption of the TOURD and its use as the default rate for newly constructed residential premises. Nowhere in the company's application did I see any discussion about that point that was already required by you guys in the last case. So for these reasons and the reasons that the other folks in prior panels talked about, I would recommend that the Smart Usage tariff be not the default rate and that it be redesigned substantially to be either more reflective of when costs are actually on the system, or that the demand charge be modified to capture substantially less revenue if the company wants to maintain a 24/7 demand charge.

And then finally I would like to touch on a couple of miscellaneous issues that we talked about broadly

in the category of customer-facing issues and data transparency. Similar to staff and others, I would recommend that the nights and weekend tariff and the flat R tariff be maintained for customers as an available option. I would also recommend that you direct the company to rename and modify the marketing materials associated with the plug-in electric vehicle hybrid -- plug-in electric vehicle tariff. Much to my surprise in reviewing the company's web page, you don't actually need to have a plug-in electric vehicle to take service on a plug-in electrical vehicle tariff, despite the fact that every mention on that tariff on their web page is tied to electric vehicles, is tied to charging, it's tied to savings you can get on that rate with an electric vehicle. This is actually a very well-designed rate and I think more customers would benefit knowing that they could qualify for it.

I would also support staff's recommendation that a bill comparison tool be developed by the company that would allow the ability for customers to see how they would fare on these different demand tariffs as well. As I showed in this analysis, number one, these analyses are complicated for individual customers to produce. But number two, the company should already have this data in its system through its AMI, metering, and billing systems. So producing a bill calculator that would allow customers to see whether they're

on the best tariff may be something that the company can do effectively.

But to that point, I would also recommend that the Commission ask some follow-up about how the company is using the AMI data that it has. In one of the data responses to staff, the company actually said that its AMI data is not robust enough to use in its cost of service study. So despite having billing data on an hourly basis from every customer in its territory, it doesn't use that data to construct the load profiles that go into the cost of service. Instead, it uses traditional load studies.

Now, those load studies are statistic analyses and they're used frequently across the industry when you don't have the actual information from the meter. But the company does have the actual information from the meter, and I would -- I would suggest that the company use that information rather than using statistical analyses to make sure that the data is as accurate as possible and that the AMI infrastructure that the company has already put in place and that the customers have paid for is being used effectively.

And finally, I would recommend that the Commission set aside some money for staff to either themselves or to engage an expert to do some transmission planning studies. One of the issues that we found in the

IRP this spring was a challenge about delivering renewable energy from southern Georgia to the northern Georgia load pockets, and there is a process in place that the company and others are investigating.

But Georgia Power confirmed that none of the transmission spend in this case is designed to address that particular south-to-north transmission issue. So what we would recommend is that while the planning is going on to identify solutions to this, that staff be able to engage an independent evaluator that can do its own transmission analysis to make sure that the money that would be spent on this is going to be as effectively cost-effective and help solve this problem.

Thank you for your time and that concludes my summary.

MADAM CHAIR PRIDEMORE: Questions from Commissioners?

Commissioner Shaw.

COMMISSONER SHAW: Thank you, Madam Chair.

MR. LUCAS: Good morning.

MR. YOUNG: Good morning.

COMMISSIONER SHAW: Mr. Young, you talked a little bit about the fact that you think that there shouldn't be any means testing and site visits on these site systems. Can you go into a little more

detail on that? Because that puzzles me a little bit, because currently -- correct me if I'm wrong -- they do means tests any project of any size; is that correct?

MR. YOUNG: That is correct.

COMMISSIONER SHAW: And so you're saying that you don't think these size projects should be -- should have that level of scrutiny or visits and so forth. Tell me why that is that you feel that way.

MR. YOUNG: Sure. So as I indicated in my testimony, I think there has been an evolution in the technology to a point where now it is stable like other electrical appliances that are being installed in homes and businesses across Georgia. That level of scrutiny is really unnecessary and is a cost burden on solar installers primarily, but also gets passed down to customers and creates real scheduling delays.

I mean, we have -- kind of pre-pandemic, it used to take 30 days or less to get a witness test scheduled and completed by the company. That can often be 45 to 60 days or even longer these days. We are seeing more and more metermen just showing up at sites without notification and then we miss them and then we have to go back and reschedule that again,

which is another further delay. So I think it's just an outdated exercise that, you know, the -- if what we're truly concerned with is electrical safety, which I certainly support, I think that is now being done either by the systems themselves or by the licensed professionals who are installing them.

And the example -- I'm sorry, Commissioner, just to put a finer point on it. The example I gave was backup generators, which had been installed across the system for decades, right, and there is no witness testing or other requirements for the installation of those appliances.

COMMISSONER SHAW: Oh, yeah. And looking at the weather today back home, I'm wishing I had a backup generator because my wife will probably be calling at some point today.

MR. YOUNG: Or solar and battery.

COMMISSIONER SHAW: There you go.

That still puzzles me a little bit, I'll be honest, because, you know, we've dealt with some problems from bad actors --

MR. YOUNG: Sure.

COMMISSIONER SHAW: -- as a result of the pilot.

MR. YOUNG: Uh-huh.

**COMMISSIONER SHAW: And I know that you've -- you're basing your comments here as far as your direction and your recommendation on this based on what you've learned from the pilot, correct?**

**MR. YOUNG: It is somewhat based on what we've learned from the pilot, yes, sir.**

**COMMISSIONER SHAW: But from the pilot we have learned that there are some bad actors out there in this industry.**

**MR. YOUNG: Sure.**

**COMMISSONER SHAW: Not you guys. We like y'all.**

**MR. YOUNG: Thank you, sir.**

**COMMISSIONER SHAW: But there are. And we have still failed to address that issue somewhat.**

**MR. YOUNG: Sure.**

**COMMISSIONER SHAW: So it's an ongoing issue. Don't you feel -- I'll just be honest -- like I do, that those bad actors are probably the ones that you're going to need a site visit to see if they're in -- number one, they're being truthful. That would be a point to clarify that with the customer.**

**MR. YOUNG: Uh-huh.**

**COMMISSIONER SHAW: And it would also be an opportunity to make sure that these safety measures**

are in place and that they've chosen a project that's even viable.

MR. YOUNG: Sure. Agree with you absolutely, Commissioner. I mean, those entities are known in the power clerk application process. So I think if there's evidence that a particular company has not been meeting their obligations, not installing systems correctly, then absolutely the company should send a meter man to check that system.

However, if there are other companies that have a long and storied history of installing these systems correctly, having no issues either with their installation or operation, then maybe it's not necessary to send a meter man to that location.

Again, all of those entities would be known prior to the energization of that system if they're following proper protocols and using the power clerk system as required by the company.

MR. YOUNG: So I guess I would say you maybe could concentrate the focus of the oversight to those entities who need it rather than spreading the limited resources of the company across a much larger number of individuals and companies who are doing the right thing.

COMMISSONER SHAW: Okay. Thank you. One

follow-up question, Madam Chair.

I don't have a copy of my motion from the IRP handy, but I pretty well remember what it said. And so my question is: Do you feel like the intent in my motion as far as Georgia Power providing the cost data that's needed to test and challenge this issue, do you think that that has been met, the intent and the direction of my motion with regards to what was asked for so that you guys and others could test and challenge that data? Do you think that direction has been met?

MR. LUCAS: Thank you, Commissioner Shaw. With regard to the company's current analysis in this case, no, I do not believe that. In the second phase of this case we're going to put in more testimony about that issue specifically. But I did talk in this piece of the testimony that the company's analysis is predicated on a revenue erosion analysis. Revenue erosion is different from cost of service. It's different than cost-based data. And what we'll show in the second phase of our testimony is the distinction between those two and the importance of that difference. So in my view, the company has not presented a cost-based analysis to support its RNR revenue adjustment.

**COMMISSIONER SHAW: All right.**

**MR. LUCAS: And I look forward to coming back in a few weeks and talking in more detail about our testimony.**

**COMMISSIONER SHAW: Thank you.**

**MADAM CHAIR PRIDEMORE: Commissioner Echols.**

**VICE-CHAIRMAN ECHOLS: I have a number of questions for you. Thatcher, I'll go to you first. In 2011, when I lived in Winterville, I went on to this night and weekends rate with Georgia Power. And Liz Coyle yesterday talked about, a warning about rates and Georgia Power had a warning back then on the nights and weekends rate that I had to sign knowing that at 2:00, June 1st through September 30th, my cost of electricity would skyrocket. I willingly signed that and I began to work that system and I save 30 percent. And so that -- the warning that they -- that they gave to me was good, gave me a heads-up. It was an initial signal and then I had the clock and I worked it and it was successful. So her admonition to give people signals, including a warning, and I think now with our smart meters, we've got the ability to barrage them with text messages, you know, if they're about to do something that's going to cause their bill to go up.**

So let me ask you this, Thatcher. Would an initial warning and signature for each customer that's going on the TOURD rate, do you think it would be sufficient, like it was with me in '11, to let them be able to, you know, to beat this curve?

MR. YOUNG: Yeah, thank you for the question, Commissioner. So, I mean, I would say yes, for a subset of those customers who, like yourself and me and others, are kind of energy nerds and constantly chase our children around the house unplugging appliances and turning the thermostat down and then putting it on a passcode lock; right? But in several of the distinguished experts, the Ph.D.s of yesterday said, you know, the average customer, probably not; right? They're just simply consumed with the other aspects of their daily life to be able to manage their energy to that level.

So I think, respectfully, as Mr. Lucas said, having that as an option for energy geeks like us who want to manipulate our energy use, it should absolutely be a choice, but it should not be the default; right? The default rate should be a simple volumetric rate that's going to mirror what a customer would have had in any other part of the state; right? If they were to move to Winterville

from Newnan, it ought to be the same. It should not be the default.

MR. LUCAS: And, Commissioner, if I may add just a little bit more context. I think part of the reason that worked for you on that tariff is you were on a volumetric time-of-use tariff, so the clock was your signal.

VICE-CHAIRMAN ECHOLS: Right.

MR. LUCAS: You knew between 2:00 and 7:00, between June and September, that that's the time when you had to manage your energy. On the Smart Usage rate, you have to manage your every -- every hour --

VICE-CHAIRMAN ECHOLS: Right.

MR. LUCAS: -- of the entire year without fail. Because the second you have one hour that your usage spikes, that's going to lock in a sizable portion of your bill for that entire month. So there really are not ways that you could, even with real-time information, if you had that, there's not really actionable ways that you can control a non-coincident peak-based demand charge like the Smart Usage tariff.

So volumetric time-of-use standpoint, yes, technology has been shown in many places to improve the effectiveness of time-of-use volumetric rates. But non-coincident peak demand charge rates are

extraordinarily challenging for individuals to manage.

VICE-CHAIRMAN ECHOLS: So the time-of-use PEV rate has high customer satisfaction. I've talked to hundreds of customers --

MR. LUCAS: Yes.

VICE-CHAIRMAN ECHOLS: -- that -- that are on it.

MR. YOUNG: Yeah. It's a great --

VICE-CHAIRMAN ECHOLS: And in that initial survey -- and I bragged on the company across America on this, singing their praises for this rate. With the -- with a thousand customers that were on that rate that were surveyed. Looking at their data, they were -- they had to have an electric car to get on it. They don't now; right, we're proposing. But they saved $180 on their annual bills and they got free fuel for their car.

So not only did they save money, but -- you know, on their power bill, but now whatever they're driving in their garage, half of their fuel has been covered. So they're saving money on the power bill. They're saving money on their fuel and gas bill. Why not make that the default rate with the warning? Why not do that? Because that's volumetric; right?

MR. LUCAS: Yeah, that -- that's a very good point. I think that's a very good rate. I agree with you that I think that's one of the better rates that Georgia Power has, not only for electric vehicle owners, but for anybody who is able to basically use more energy overnight. That could be somebody with electric heat or heat pumps in the winter where they would be able to take advantage of those lower rates.

That's a well-designed rate. I'm -- I do talk about this a bit in my testimony, though. There are still classic customers who are either not particularly high usage or who don't have a lot of overnight use, where on that particular tariff they would pay more than on the standard nights and weekends tariff.

MR. YOUNG: That's right.

MR. TROKEY: And the reason is because in order to have that overnight rate be lower, the normal off-peak rate has to be a bit higher. And so if you're a customer that doesn't use a ton of overnight energy and uses more of the sort of off-peak energy, they may end up paying a little bit more on that.

So our recommendation is actually if you want to have a volumetric default rate, to use the nights and weekends tariff. But I would agree with you that

the plug-in hybrid -- that the plug-in electric vehicle rate should be renamed, it should be more broadly advertised. It's an excellent designed rate that could benefit a lot of customers and it should get out there and people should be able to get on this rate and know that they can get on this rate and move towards it. But as a default, I'm concerned that there would be too many customers who wouldn't fit that profile, that they would be better served on the nights and weekends as a potential default tariff for time of use.

VICE-CHAIRMAN ECHOLS: And I didn't mention that those customers, those thousand customers were using 11 percent more electricity than they were and still saving money.

MR. LUCAS: Right.

VICE-CHAIRMAN ECHOLS: So it was just a triple win for them and continues to be.

MR. LUCAS: Sure. And that's an excellent preview of the next round of our testimony that shows that when you use energy and avoiding energy use during peak times and shifting that to off-peak times reduces costs on the system at large, which allows the company to design rates to help individuals save on their own bills.

**VICE-CHAIRMAN ECHOLS: Switching now to the solar, Thatcher. I love your example on the quarter, by the way, versus --**

**MR. LUCAS: It was very sweet that she asked me if it was mine. That was really polite.**

**VICE-CHAIRMAN ECHOLS: Yeah. Versus the $400.**

**It does gall me just a wee bit, Thatcher, and you'll remember in '19 we had just done a big solar array on Sapelo Island, donated -- donated it for the Gullah-Geechee community, and it wasn't until I saw their bill and realized, man, they're not getting much for this. We went to all this work, took us a year to put this together. It was that moment -- and you were there -- when I realized, man, this is not -- this -- we spent $35,000 and we're only getting this? And look at the good that we've done for resiliency for these people, you know, and so, you know, we -- I did -- I did an omnibus motion in '19 right -- sitting right here --**

**MR. LUCAS: Yeah.**

**VICE-CHAIRMAN ECHOLS: -- that as a part of the -- as a part of the package -- and this is what galls me a little bit -- of giving Georgia Power a hefty ROE, a great capital structure, a lot of things that benefited probably billions of dollars, and in**

that was this little net metering motion that now we -- I've discovered is costing about a million and a half dollars.

So let me ask you this: What -- Thatcher, or either of you, can you quantify how the value of solar -- and I don't have a problem with a million and a half, because we -- we've subsidized other things. Military solar. The Ray, The Ray Solar is above avoiding cost. We went back and clarified that. So from time to time, commissioners at this bench have decided that it's worth it. That it's worth it. For whatever reason we want up here, but we decided that it's worth it. And I think we -- you know, and, obviously, on July 21st, we didn't feel good with moving forward with that. We almost did, but we didn't feel good moving forward. But can you quantify how customers, all customers might be benefiting from these 5,000 behind-the-meter solar arrays that's costing 20 cents per customer? Is there -- is there value to everyone? The company says no, but is there value in your opinion?

MR. LUCAS: Yes, I think there is. And, as I said, we're going to be getting into more of this in the second phase where we're trying to do some of those actual quantitative analyses based on the

company's data. There's a few ways that that solar can help the grid at large.

We just had the discussion about time of use and the benefit that happens when we shift our usage to times when the system is not under stress. What we find in Georgia and many places that I have done similar analyses is that the solar is producing during the hours when the system tends to be at stress.

Georgia Power's a summer-peaking utility. Its system peaks in the middle of the afternoon during summer. Because of daylight savings time, that's a time when solar on those roofs is producing a substantial amount of energy. So it helps to reduce the peak that the company would otherwise see. It also helps to avoid the need to spin up the more expensive units to meet that top load. It is basically reducing the marginal cost, which we've discussed a lot about. And as we heard yesterday, that marginal cost can be quite a bit higher than the baseload cost. Solar helps reduce that as well.

In the long run, when you have more of the solar on the grid that is producing at times when the system is under load, it means that the company has to build and plan its infrastructure differently.

Instead of having to build to a level up here, it has to build to a level that's slightly lower. And that's able to -- that savings of, you know, resources that it doesn't have to plan, facilities it doesn't have to build, you know, upgrades that it doesn't have to make, has a monetary value associated with that.

Now, that's the kind of cost data that we were hoping the company was going to provide in this case that they have not. They have done the other side of the analysis where they've just looked at the revenue erosion and they have not provided the cost data and have not done their own analysis on the cost data as Commissioner Shaw requested.

So we're looking into this for the second phase of the testimony and trying to see if we can get some more quantitative information on this. I don't have those figures at the moment because, again, the data has not yet been provided and the company has not performed the analysis on their own.

MR. YOUNG: And if I may just add to that, Commissioner. Just as you illustrated in your example of when you chose to go on the night and weekend rate, I think this is a -- a class of customers who have obviously opted in and are

interested in experimenting with the value of these systems both to their own homes and businesses and to the grid. And so we would encourage the company to partner with them to look at the other resiliency aspects. To poll those 5,000 customers, understand what percentage of them have battery storage in addition to the PEV that is installed in their systems, and then begin to send them some pricing signals to see how they might interact in different ways that strengthen the grid.

VICE-CHAIRMAN ECHOLS: California and others are pulling back on net metering. You know, I read this and I --

MR. YOUNG: Sure.

VICE-CHAIRMAN ECHOLS: -- you know, and I've talked to plenty of folks in Arizona and California, you know, about this. But if we wanted to expand net metering -- and I -- my motion was for 75,000. And I'm not for unlimited. And I would have compromised on that, to 75, to 30, to 25. Do I hear 10? You know, yeah, I mean, my auction roofs and my auction family, I mean, I don't mind compromising and negotiating.

MR. YOUNG: Sure.

VICE-CHAIRMAN ECHOLS: So if we wanted to

expand it, how do we avoid the mistakes that California and others made? We don't want to follow them and then have to claw this stuff back in the future.

MR. LUCAS: Yeah, that's a fair question. One thing I would note about California, as we've discussed, and I know the Commissioners share, it's very different from Georgia. There's a lot of things that have been sort of historically done in California that are unique to that state. One of the things that has happened with respect to the net metering discussion is the way their rates were designed, the top tier, once you got to a certain usage, was like 45 or 50 cents a kilowatt-hour. So when you're able to net that off of your system, it has a much bigger impact than what we have here where maybe the top rate is 12, 13 cents.

VICE-CHAIRMAN ECHOLS: So they were paying too much?

MR. LUCAS: They were -- that's right.

VICE-CHAIRMAN ECHOLS: Yeah.

MR. LUCAS: The source of the large amount is -- is from their rate structure and they were paying too much. So the reform that's happening in California is to move away from this sort of, you

know, flat retail-based structure to something that is more of an export-based compensation for the power that's put on the grid, and then requiring new rates to be followed for people who have PEV.

So those are -- those are the types of things, you know, that California is doing. Georgia does not currently have traditional net metering, which is where the kilowatt-hours would carry forward, where you get them rolling from one month to the next and offset your next bill. It has a net billing construct where the extra energy that is put on the system beyond your monthly usage, even in the monthly pilot, that is paid out of the avoided cost. But the instantaneous, the RNR instantaneous which is right now the only available program for people who want to install solar, unless the pilot is expanded, it is actually fairly conservative on the spectrum of net metering options.

You know, from a traditional, full-blown kilowatt-hour-based net metering to a buy all, sell all, where you don't do anything and simply have those completely separate, the current RNR instantaneous is much closer to the one end than the other. You have instantaneous netting, you have avoided cost at just the energy basis, and you have

no ability to -- to balance this over the course of the month. So that is already many, many steps away from traditional net metering that a bunch of states currently have.

And so, yes, there is some talk about how states are sort of evolving their tariffs and maybe going to a net metering 2.0. Georgia has already done that with its RNR instantaneous. That is already well beyond what a traditional net metering construct in many states have.

VICE-CHAIRMAN ECHOLS: Not only is the company concerned about this, but I've heard from the EMCs, they are very concerned about anything that we might do that might bleed over and impact their policy. So after July 21st, as I look forward, I thought, well, maybe -- maybe just an another baby step. Maybe just something small where we can continue -- because the company's already stood up the whole department over there; right? So they've gotten pretty good at being able to process these. All the rust is, I think, mostly off of that from the pandemic.

So maybe we just do something that's small. Maybe we just add a tiny amount. I mean, if -- if my -- you know, if my fellow commissioners felt like that was prudent to do, and I don't know that they

do, then maybe we -- maybe we take another baby step.

Let me just ask just one more question.

MR. YOUNG: Commissioner, can I just make one comment to that?

VICE-CHAIRMAN ECHOLS: Yes.

MR. YOUNG: So three of the largest EMCs in the state, Cobb, Jackson and Walton, all offer monthly netting for residential customers as a standard offer today. So I would argue that they're actually taking a leadership role and are clearly comfortable with these policies and they're seeing phenomenal response from their members while their community solar programs stay fully subscribed, or close to full subscription, which is not the case in Georgia Power's community solar offering.

VICE-CHAIRMAN ECHOLS: It's a little bit baffling to me that they've had that success, you know, with their more limited resources, but it does seem to be a different -- a different perspective and attitude towards net metering.

MR. YOUNG: Well, and they also price it correctly; right? A kilowatt-hour block at Walton EMC or Cobb is $5, not $20. So it's kind of a better deal.

VICE-CHAIRMAN ECHOLS: Either of you, is -- I

am told by some solar developers that net metering is going to be a thing of the past, that it's going to be moot in the age of home battery installations. That there are ways that customers can beat the system using their batteries and, you know, with a time of use rate and that they really don't need net metering anymore. And that's coming from some in the solar community. Do you agree with that?

MR. YOUNG: I mean, I think that, yes, that will be true in the future when Starbucks no longer exists because the food replicator will give us a really hot, piping cup of coffee from a hole in the wall every 5 feet from us. But I think we're a bit of a distance from that future state.

MR. LUCAS: Yeah, and I would agree with that. There still are a good number of people who are installing solar who currently have solar. Batteries are helpful and batteries can add value to that. And as Thatcher mentioned, you know, there are programs that you can put in place that makes sure that that battery is used to not only benefit the customer, but also to benefit the grid as a whole, and then produce those system savings to justify it.

VICE-CHAIRMAN ECHOLS: Great. Live long and prosper.

MR. YOUNG: Thank you, Commissioner.

MADAM CHAIR PRIDEMORE: Okay. Start the list. Georgia Public Service Commission.

MR. THOMAS: Thank you.

CROSS-EXAMINATION

BY MR. THOMAS:

Q Good morning. Preston Thomas on behalf of Public Interest Advocacy Staff. I just had a couple of questions regarding your recommendations around tools on the company's website.

First, you recommend the company should construct a bill comparison tool for its residential time-of-use rates. Is this a resource you're seeing commonly at other utilities? And if so, can you give us some examples?

A (Witness Lucas) I would -- I know it exists at other utilities. I don't have a list off the top of my head. But I am aware that this is something where you can go in, you can -- you know, companies that have installed AMI typically store 12 months of data for each customer. And creating a customer-facing calculator that lets you compare how you would do it on different tariffs I believe is a fairly common thing. I don't have a list of utilities that have done that, but I can maybe try to find some.

A (Witness Young) So I did some AMI work with

Commonwealth Edison in Illinois and helped them build a bill calculator that's similar to what we're proposing.

Q And in your testimony you analyzed the company's solar advisor tool and you conclude that it's detrimental and should be scrapped. Can you give us a little more explanation around that.

A (Witness Lucas) Yeah. I went through that tool and found that it is not designed to really support a customer in trying to get to yes on solar. The first four or five questions that you're presented are questions that are basically designed to say, well, think hard about this. Are you sure you really want to do this? You know, there's other ways that you can do this.

All of those questions were not designed to help a customer understand how solar would work for their house, and none of those questions impacted the results of the tool. The tool produced the same result no matter what you answered on those initial questions. So the only reason those questions were there, since they didn't actually affect the result of the tool, was to introduce some doubt in the mind of the customer.

It questioned whether your roof was more than five years old, suggesting that maybe if you have a roof that's five years old, it's not suitable for solar.

It asked whether you had, you know, enough

uninterrupted space on your roof, you know, again, suggesting that if you have a type that comes up from your roof, that maybe it's not suitable for solar.

And at the end of the process, no matter what you put in, whether you have shade or didn't have shade, it came up with the same answer. So my conclusion on that is the tool was not designed to get customers to say yes about solar; it was designed to introduce confusion to those. And even when you get through the end of the process, it doesn't say, you know, here's a bunch of potential people who can do it. It's a referral to Georgia Power's website, which talks about alternatives to rooftop solar.

So, again, I just didn't find that that tool was particularly useful for customers trying to understand whether solar would work well on the roof. And found that all else equal it would be probably better if it didn't exist.

Q But if this Commission sees value in a tool that helps advise customers on whether solar would work for them, do you think it could be redesigned to be more useful?

A (Witness Lucas) It could potentially be redesigned. Again, if the questions asked were germane to the output, if the data that the company's calculator actually used was transparent on the assumptions, I -- there was no indication of what assumptions were behind the scene

on this. Whether the cost information was current. Whether the rate designs were accurate. Whether the size of the customer and the size of the system corresponded. So there might be ways to improve this. Whether, you know, the Commission should host that or Georgia Power should host that or Georgia SEIA should host that, you know, is maybe an open question. But there could theoretically be a way that would provide better information to customers and then direct them to companies that would be able to help continue that conversation.

MR. THOMAS: Thank you. That's all.

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy.

MR. GALLOWAY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Commercial Group.

MR. JENKINS: No questions.

MADAM CHAIR PRIDEMORE: GA Solar.

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch.

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: MARTA.

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management.

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club.

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE.

MR. DOWDY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: United States Department of Defense.

MS. MEDLYN: No questions.

MS. KYSOR: (Inaudible.)

MADAM CHAIR PRIDEMORE: GIPL. GIPL's here. All right. You weren't here for roll call. I'm sorry.

MS. BROWN: Madam Chair, can the Coalition also appear on the appearance list?

MADAM CHAIR PRIDEMORE: Yes. You're here. Good to see you. Do you have questions?

MS. BROWN: Yes, ma'am, I do.

MADAM CHAIR PRIDEMORE: Step right up.

CROSS-EXAMINATION

BY MS. BROWN:

Q Good morning. Alicia Brown on behalf of the Georgia Coalition of Local Governments.

A (Witness Young) Good morning, Alicia.

Q If I could direct you to page 75 of your testimony.

A (Witness Lucas) Yes, we're there.

**Q Okay. In his cross of the coalition yesterday, Mr. Marzo noted that there was a residential satisfaction survey performed by Georgia Power that found that time-of-use RD customers reported higher satisfaction than customers on the R tariff. Recognizing that this is a trade secret document and what you can say is limited, do you find this finding to be representative?**

**A (Witness Lucas) Yeah, I did discuss this survey. And again, much of this is trade secret. It was a little bit unclear to me why the company required redaction on these answers, given it was for residential customers who don't have an alternative provider. But I have a hard time reconciling some of responses from the customers with the actual data that we got from the company and analyzed. One of the challenges with any survey is the answer to the survey is going to be extremely dependent on how the survey is constructed, what customers are chosen and selected for the survey, how the questions are phrased, what is not asked in the questions.**

**And in reviewing the survey, which I go into more detail in the trade secret, I found that there were nuances in the way the questions that were asked that were probably providing results from the survey, as any survey provider would do, that was, you know, what the provider -- in this case, Georgia Power -- was looking for.**

So when I actually looked at the numbers, and we looked through this chart earlier, these are actual numbers from actual customers on the RD tariff. Whether these customers know or don't know if they're on the best tariff for them is an open question. Like we said, there's not a bill comparison tool where they can see that.

But what Georgia Power data show is that these customers are paying substantially more on a Smart Usage tariff than they would on alternate tariffs. I did a similar analysis against the nights and weekends tariff and the PEV and found directionally similar results. So independent of whether a customer is satisfied with the survey or the aggregate numbers were higher than what they had on the residential, they clearly are not saving money in aggregate. Some customers might. And we talked about this yesterday. There are structural customers, the larger customers, who just because of the way they use energy tend to save on the Smart Usage tariff. But I don't think if the people who are given the survey were given this chart and were allowed to compare their bills to the other tariffs that they would come to the same conclusions.

Q You mentioned the way that the questions were framed. Were there also decisions made in who was allowed to take the survey that might have affected the results?

MR. MARZO: Madam Chair, I'm going to object.

I mean, this is obviously friendly cross. She's asked the first question; now we're on a line of this friendly cross for this witness.

MADAM CHAIR PRIDEMORE: Sustained.

BY MS. BROWN:

Q Okay. Moving on. On page 95 through 99 of your testimony, you raise questions about the use of AMI data versus statistical load forecasting. In your experience with other utilities, do any other utilities use statistical load forecasting when that AMI data is available?

A (Witness Lucas) I haven't found that. You know, statistical load data is common in places that don't have universal AMI. Because you need to have different means of -- of getting that hourly data if your traditional meters are not using it. But once you install the AMI and you have access to all the hourly data from all the customers, that is typically directly used in its cost of service studies. So, yes, in other places I have worked where this universal AMI deployment, the numbers from the AMI feed directly into the cost of service studies, they feed directly into the rate-tying processes. There is not statistical sampling done when it's not necessary.

Q And just one other question. Going to page 77.

A (Witness Lucas) Yes, we're there.

Q The company has argued in a previous cross that a rate selection or a comparison tool like you advocate for would be expensive and lead to revenue erosion. Mr. Young, you just said that you have developed such a tool. Does that tool have to be expensive?

A (Witness Young) No. I don't think it has to be overly expensive, no.

Q And will it necessarily lead to revenue erosion and will everyone use it?

A (Witness Young) I don't think it will necessarily lead to -- to revenue erosion. Whether or not everyone will use it or not, I can't say.

MS. BROWN: All right. Thank you.

MR. YOUNG: Thank you.

MADAM CHAIR PRIDEMORE: All right. Did anybody come in late?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. All right. Georgia Power Company.

MR. HEWITSON: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Good morning, gentlemen.

A (Witness Young) Good morning, Mr. Hewitson.

A (Witness Lucas) Good morning.

Q Steve Hewitson on behalf of Georgia Power.

I want to start, Mr. Thomas asked you to explain again your testimony from your written testimony about the solar advisor tool. Just a quick question on that. The purpose of the solar advisor tool was not to encourage people to install solar, was it?

A (Witness Lucas) I don't know what the origin of the tool is. As I recall, the way it's presented, it's asking questions to the customer about whether rooftop solar is good fit for them.

Q Right. And your testimony was that it -- that the first four questions were designed to make people think hard about whether to install solar; right?

A (Witness Lucas) The first four questions have nothing to do with the actual result of -- it's actually the first five questions -- have nothing to do with the actual result of the calculator. And in my view, asks questions that are designed make people think twice about putting it on the roof.

Q Is it a bad thing to make people think twice about doing something that they're going to spend tens of thousands of dollars on?

A (Witness Lucas) When those questions are designed in a way that I think actively discourages them without providing them context for those characterizations,

yes, I do.

Q But your testimony was that it makes them think hard about it. My question was: Do you think it's a bad thing to make them think hard about it? It's a big decision; right?

A (Witness Lucas) It is a big decision. I think it's reasonable for customers to be informed about whether or not solar is good for their roof. I do not think that the questions asked in this tool are designed to get honest reactions and honest answers to that. The questions in here about whether you own your home or not. The questions about whether you have enough uninterrupted roof space. About whether or not you have a roof that's less than five years old. Those are not necessarily relevant to whether solar is going to be a good fit or not. So just prompting those questions is going to create some confusion or doubt from that customer in a way that may not be actually merited based on the way that the solar systems are installed and priced and managed.

Q Do all solar installers in the state of Georgia ask questions of customers to make sure that they're thinking long and hard before they make investments in their solar arrays worth tens of thousands of dollars?

A (Witness Young) They should.

Q Do they?

A (Witness Young) I don't know.

Q On the interconnection fee. You recommend that the company's proposed interconnection fee be rejected and instead that it remains the per-kilowatt fee; right?

A (Witness Young) Yes, sir.

Q Okay.

A (Witness Young) For residential customers.

Q For residential customers.

A (Witness Young) Yes.

Q Thank you.

Do you recall how the 5-dollar-per-kilowatt fee was set.

A (Witness Lucas) I don't know the origin of that. I believed it was based on the witness test, but I don't know what the origin of how the number was originally (inaudible).

Q Okay. So you don't recall that it was a -- a settled amount that during the 2017 discussions on applying the RCB framework to behind-the-meter solar?

A (Witness Young) I do recall some of those discussions, yes.

Q Okay. And that was in Docket 40161 and Docket 16573; right?

A (Witness Young) Yes.

Q And you do recall that the company's proposal

was a higher per-kilowatt-hour fee; right? Or per-kilowatt fee.

A (Witness Young) I do recall it was higher, yes.

Q Okay. And you recall that this 5-dollar fee was a settled amount that the company took the position doesn't cover all the costs; right?

A (Witness Young) Yep.

Q All right. And GASEIA was actually a signatory to that agreement, installing the 5-dollar-per-kilowatt fee; right?

A (Witness Young) Absolutely.

Q Okay. Are you aware that the idea to change to a flat fee instead of a per-kilowatt fee was actually suggested by a GASEIA member?

A (Witness Young) I believe it was on a commercial system, but not on a residential system specifically.

Q Okay.

A (Witness Young) So, again, we're not challenging the flat fee on commercial systems, just specifically to residential systems.

Q Would your organization support staff's recommendation of $100 per residential installation?

A (Witness Young) Again, we feel like the $5 fee for an average of a 7-kilowatt system is sufficient and

doesn't warrant change based on the data provided by the company.

Q So you don't support staff's --

A (Witness Young) Not for a residential system --

Q -- recommendation?

A (Witness Young) Not for a residential system; no.

Q Okay. Moving to the net metering revenue adjustment, you recommend against the company's request to adjust the revenue of $1.4 million due to monthly net metering based on two arguments. First, that the company did not account for exported energy in the cost of service study. And second, that the $1.4-million fee is small compared to the company's earnings. And I understand that it's a very simple summary of about 70 pages of your testimony, but do I essentially have it right?

A (Witness Lucas) There's a third reason as well, which is in the context of the ROE earning band, there's actually not a revenue loss associated with that revenue erosion.

Q Okay. Well, and that's what I meant, in the amount compared to the company's earnings.

A (Witness Lucas) No, the amount compared to the earnings is different. That's a question of scale. That's the 20 cents versus the $400. Whether or not that

1.4 million would actually need to be recovered from anybody else is a separate question and directly related to the earnings band.

Q Well, and that 20-cent cost shift that you calculated is based on a pilot with just 5,000 customers; right?

A (Witness Lucas) That's correct.

Q And not all those customers have been operating for even a full year though; right?

A (Witness Lucas) I believe that the company's work papers from which I pulled that number does gross those up to account for the full 5,000 customers being on that tariff.

Q Right. But we have limited data on the full 5,000 being online; right? Would you agree with that?

Limited time with them being online?

A (Witness Lucas) Yes. As I understand that pilot, the 5,000 customers may have come online sometime in the last year or so.

Q Okay. And to keep that cost shift low, to the 20 cents that you say, would you support keeping the pilot at 5,000 customers and not increasing it?

A (Witness Lucas) No. Because, again, we reject the premise that this is caution. So, first of all, as we have a good discussion with the Commissioners, the company

didn't actually provide cost-based data to support this number. It's a revenue erosion number, which is different from cost of service.

Secondly, every year since 2011 the company has earned revenue in excess of its central ROE. In that situation, the presence or not presence of this $1.4 million is not money that has to be collected from someone else. So I reject that this is a cost shift. It represents revenues that need to be collected from other customers.

Q Okay. On page 33, lines 6 through 8, excuse me, you say that Georgia Power did not appropriately account for exported energy in the cost of service study, the COSS in your testimony and, as a result, has over-allocated costs to customer classes with RNR projects; right?

A (Witness Lucas) Correct.

Q What other costs do you believe have been over-allocated to RNR customers?

A (Witness Lucas) Basically, by not accounting for exported energy in its allocators, the company does not include the benefit associated with that energy that's being produced by these customers. So when it looks at the load studies, for example, and does not decrease the amount of energy that those customers are either consuming or putting onto the grid during those key cost of service hours, their demand allocators and energy allocators are marginally

higher.

And a result for customers that have RNR projects, those allocators are slightly higher, which means they're allocated relatively more cost in the cost of service study, which, in turn, increases the overall revenue requirement of those groups.

Q Okay. I want to make sure I understand that going forward. You said it doesn't account for the exported energy and the benefits that the exported energy provides?

A (Witness Lucas) It doesn't account for the exported energy as a decrement to the allocators that are given for that class. So if a residential customer consumes a certain amount of energy during a critical cost of service study and that is reduced by the amount of energy that their system is producing and putting on the grid, that reduction is not calculated in the cost of service.

So if they -- let's say they had been at 5 kilowatts during that time, they actually exported 3 kilowatts during that hour, the calculation of their usage during that hour is not 2 kilowatts. It doesn't reflect the benefit of that exported energy, even though their system produced that energy and reduces the burden that they put on the system. Therefore, the cost allocation in the cost of service doesn't flow that through.

Q But the system -- the total system cost that

the company has to allocate across the cost of service study doesn't change; right?

You're talking about a reduction in a cost to an individual customer, RNR customer; right?

A (Witness Lucas) I'm talking about a reduction to a class of -- a class that has RNR customers, that's correct. It's a question about how the money is allocated across the customers.

Q Okay. And you don't think that -- or you think the RNR customer should be allocated to your cost because of the value of the export energy, or the -- in your view, the less stress they put on the system?

A (Witness Lucas) Correct. Not the monetary value. Again, it's a function of the reduction in demand from their system that's generating. It doesn't matter whether that system generation is consumed on-site or whether it flows to the neighbor.

It affects the system in the same way. The overall system sees less load because that RNR system exists. So the customers and customer groups that have RNR projects should get credit for that reduction in demand for the full generation, which includes both the self-consumption, as well as the exported energy in the cost of service study.

Q Right. But it doesn't reduce the overall costs

that have to be allocated for in the cost of study; right?

A (Witness Lucas) In the short term in this particular cost of service study, that's correct. It's the reallocation among classes.

Q Right. So if you don't allocate it to the RNR class, you'd have to allocate it to someone else; right?

A That's correct.

Q So you're advocating for a cost shift from the RNR customers to other customers?

A (Witness Lucas) There are many, many -- we had a discussion yesterday where the cost of service is one element of the way that these revenue targets are set.

Q And it -- and RNR customers are not necessarily a class by themselves; right?

A (Witness Lucas) That is correct. They are mixed in with other customer classes.

Q All right. Let's turn to your other argument regarding Georgia Power's earnings. In base rate cases, such as we're here today for, Georgia Power comes to this Commission and identifies revenue requirements necessary to recover the cost of producing and delivering electricity to its customers; right?

A (Witness Lucas) Correct.

Q Okay. Those revenue requirements are discussed and debated by the parties of this proceeding like GASEIA;

right?

A (Witness Lucas) Correct.

Q And, ultimately, the Commission makes a final decision on the appropriateness of the revenue requirement set for the company; is that right?

A (Witness Lucas) That's correct.

Q Okay. And the Commission's decision is often informed by a settlement among some of the parties. Is that your understanding?

A (Witness Lucas) My understanding is, yes, settlements have been done in these rate cases in the past.

Q And that's what happened in 2019. There was a settlement between Georgia Power and seven other parties representing some of the company's largest customers and customer groups; right?

A (Witness Lucas) I understand there was a settlement. I don't know the exact number of customers. Or number of parties to that settlement.

Q Okay. Did you look at the stipulation in the 2019 rate case?

A (Witness Lucas) I did.

Q Okay. And you understand that the Georgia Association of Manufacturers, the Georgia Industrial Group, MARTA, City of Atlanta, Commercial Group and Kroger all signed on the stipulation; right?

A (Witness Lucas) I believe that's -- yes. I don't recall those exact names. I'll, subject to check, accept that those are the parties on that.

Q Okay. And based on revenue requirements determined by the Commission in rate cases, rates are established based on the ROE set point and those rates are confirmed by Commission staff through the company's multiple tariffs. Is that your understanding of how it works?

A (Witness Lucas) Yes.

Q Since 1995, Georgia Power's rates have been set using the alternative rate plan or ARP, where rates are set for a three-year period; right?

A (Witness Lucas) That's my understanding.

Q Okay. And the Commission has found ARPs to be beneficial to the customers for multiple reasons; right?

A (Witness Lucas) Yes.

Q Along with the three-year ARP, the Commission sets and earning band -- earnings band; is that correct?

A (Witness Lucas) That's correct.

Q The earnings band establishes the range of authorized earnings for the company; right?

A (Witness Lucas) It establishes a range above and below the central ROE point that the company can operate this thing. If the earnings fall below that level, the company can come in and request a rate case. If it goes

above that level, there has been various iterations of cost-sharing mechanisms that have been in place over the years.

Q Right. And the Commission determines that the range is reasonable for the company to earn anywhere within the band; right?

A (Witness Lucas) The range is establish -- yes. It is established as a band in which the company can operate. And earnings that fall within that band, the company is allowed to keep. Earnings that fall within the band, but are under the central ROE, the company is required to basically eat that revenue loss.

Q And, as you said, the company earns below the band -- if the company earns below the band, it can come to the Commission and seek relief; is that right?

A (Witness Lucas) That's correct. It's not happened in the last 11 years.

Q It hasn't happened in the last 11 years. But if you go back to '12 and '13, it has; right?

2009, 2010, the company both earned below the band; right?

A (Witness Lucas) I didn't analyze those years in particular.

Q Is there a reason why you went back 11 years, but not 12 or 13?

Is that because those are the years that the company earned below the bland?

A (Witness Lucas) No. I actually -- the 2011 was one of the first ASRs that I looked at. I didn't specifically choose that for one reason or another.

I understand that staff went a little bit further back in this process. But in my review of the documentation, I found a source that looked at the 2011 ASR and that's where I started my analysis.

Q In a traditional rate case, in your experience, where rates are set for one year based on the determined revenue requirements and authorized ROE, what happens if the company earns above the authorized ROE?

A (Witness Lucas) If the company earns above the authorized ROE, it's entitled to keep that. My understanding is that there's a process in Georgia where if the Commission deems those earnings above the ROE to be excessive, it can call the company back in.

Q As we discussed earlier, rates are set using the revenue requirements in the ROE set point approved by the Commission; right?

A (Witness Lucas) Yes.

Q Do you contend that Georgia Power's charged rates higher than those approved by this Commission in the 2019 rate case?

A (Witness Lucas) Not that they charge rates higher than what were approved, but that as a result of a number of different factors, that the company's actual earnings from those rates ended up being higher than they would have been -- the earnings were higher than the authorized amount under the central ROE set point.

Q No. But you just said in testimony when I asked you the company can earn anywhere within the ROE band; right?

A (Witness Lucas) Yes. And I'll rephrase. Not authorized ROE, but the central ROE point that was approved by the Commission.

Q But when the Commission determines that the band -- that the company can earn anywhere within the band and that's just and reasonable, the company is not earning something beyond what the Commission has authorized if it earns within the band?

A (Witness Lucas) And I was careful in my testimony not to say the company is doing anything improper or illegal here. I'm not suggesting that the company is not entitled to those.

I'm merely pointing out the fact that this earning mechanism has existed in this time. The company has been able to use that earnings mechanism to increase its earnings, sometimes above the ROE, but below the upper band,

sometimes below the upper band. Never below the central ROE.

Q Okay.

A (Witness Lucas) And in the context of the $1.4 million revenue adjustment when we're talking, that's germane because it impacts whether there is actual revenue to be collected from other customers in the context of this earning band.

Q Okay. So let's just make sure we get the record clear. When you claim the company is overcharging customers, you're not asserting that Georgia Power is charging rates higher than what the Commission authorized; right?

A (Witness Lucas) I don't think I'm claiming that the company is overcharging customers. What I'm saying is that the company is realizing excess revenues.

Q Your press release says: "Georgia Power Company overcharges customers by $1.87 billion," doesn't it?

A (Witness Lucas) I didn't write the press release.

MR. HEWITSON: May I approach?

MADAM CHAIR PRIDEMORE: You may approach.

BY MR. HEWITSON:

Q Mr. Lucas, you represent SEIA here; right?

A (Witness Lucas) Correct.

Q Okay. What you've been handed as Georgia Power's Exhibit 39 is a press release from SEIA, the title of which says: "Georgia Power Company overcharges customers by $1.87 billion."

Do you see that?

A (Witness Lucas) I do.

Q So your organization, based on your testimony, has issued a press release that says the company overcharges customers by $1.87 billion; is that correct?

A (Witness Lucas) That is correct.

Q And you're saying that is not consistent with your testimony here today?

A (Witness Lucas) My testimony is that the company has earned revenues above its central ROE point of the $1.87 billion.

Q Okay. So just to make the record is very clear, you do not support the press release that SEIA issued?

A (Witness Lucas) I'm not saying that. I'm saying there's a nuance between overcharging and earning above the central ROE band.

Q There is a nuance. And the language used, the words used in SEIA's press release, is overcharge; right?

A (Witness Lucas) That is what is in the press release.

Q And you're saying that's not what your testimony says here today; right?

A (Witness Lucas) My testimony speaks about excess earnings. Excess revenue collection.

Q Okay. And your testimony of the $1.87 billion that you call excess is all the earnings that were within the authorized band; right?

A (Witness Lucas) I believe it includes both those within the authorized band, as well as earnings above the authorized band.

Q Help me out. What is the -- never mind. I found it.

Okay. The $1.87 billion is included. I think it's Table 4 on page 43; right?

A (Witness Lucas) That's correct.

Q Okay. And earnings above the band, as you recognize, go back to customers in a large portion; right?

In fact, the majority goes back to customers?

A (Witness Lucas) That is correct.

Q So if you're including within your $1.87 billion calculation of Georgia Power's -- as your organization says, overcharge, that $380 million that you calculated Georgia -- in revenue that was above the band, approximately $297 million of that went back to customers; right?

A (Witness Lucas) Yes. And I do discuss that in my testimony.

Q Okay. And that 78 percent of the earnings above the band are used to the benefit of customers; right?

A (Witness Lucas) Subject to check. That's -- that is collected from the customers in real time. My understanding is that there has been changes in the percentage that's been returned, as well as changes about how that money is returned.

In some instances it was given back as a rebate. In some instances it was used to pay down future costs by reducing regulatory asset balances.

In those latter instances, the customers are not directly in real time receiving the benefits of the money that they paid. They basically paid in now and that funding is used to reduce a future cost, which they may or may not be around to have to pay.

Q You don't think it's misleading to say that that's an overcharge when 300 million of the $380 million gets used to the benefit of customers?

A (Witness Lucas) I'm sorry. Can you repeat the --

Q You don't think it's misleading to call that an overcharge if 300 million of the $380 million goes back to the benefit of customers?

A (Witness Lucas) I don't think I called it an overcharge in my testimony. I talk about --

Q Your organization does, based on your testimony. I think you're going to have to own up to that, don't you think?

A (Witness Lucas) I'm here to talk about the testimony that I put in this docket. In my testimony, I was very clear about referring to this as excess revenue collection. The company collects excess revenue above its central ROE point, based on the information that I provided in this table.

Some portion of that, as you mentioned, above the ROE band is returned for the benefit of customers in different forms. That amount has varied by year. It's varied by form.

Right now my understanding is it's 80 percent for the benefit of customers, 40 percent of which is rebates, 40 percent of which, I believe, is paying down future regulatory assets, and 20 percent of which the company keeps.

Q Okay. And just to be very clear also, the $1.489 billion that you say is above the ROE, but below the upper band, is still within the authorized band that this Commission has found just and reasonable; right?

A (Witness Lucas) That's correct.

Q Okay.

A (Witness Lucas) And one of my recommendations is to narrow that band so that the company is not able to collect in 2021, for example, $243 million above the central ROE, but below that upper level.

COMMISSIONER MCDONALD: But when we go back to Georgia Power's witness, Mr. Cowan, the Commission sets an ROE and it's for the company to manage within that framework of their ROE. And it was designed years ago for if it went above the band that there'd be a sharing of the -- but it encourages the company to be frugal in its operation because the Commission is not to dictate the operations of the company.

But, Mr. Hewitson, when you talk about the Commission author- -- you should say the majority of the Commissioners authorized that. Because all the Commissioners -- every Commissioner did not agree with -- with the ROE and the band itself.

So clarification for the earnings, it's an incentive for the company to manage well. The -- all parties participate in the over-earnings, which that was what it was designed for. But also it wasn't in total agreement that that be what it is today.

MR. LUCAS: Thank you, Commissioner. And to that end, my testimony supports this structure. I

recognize the benefit of having a multiyear structure and having an ROE earnings band to give the company that flexibility.

The recommendation that I have on reducing this band is simply to shift the balance between the benefits that are accrued to the company and the benefits that can accrue to the customer.

So I agree with you that there is value to this structure, but it needs to be done in a way that -- that, I think, balances those two things between the customers and the company's ability to have these above authorized -- above central ROE earnings.

MR. HEWITSON: Thank you, Commissioner McDonald.

Thank you, Mr. Lucas.

BY MR. HEWITSON:

Q Just before I leave Exhibit 39, were you provided any draft to review?

Did you approve the press release before it went out?

A (Witness Lucas) There were multiple versions of the press release. I did see versions as it was created. I don't recall whether there was changes from the last version that I saw to the one that was put out in -- yeah.

Q Did the version you see use the title "The

company overcharges customers"?

A (Witness Lucas) I don't recall whether that title was in place at that time.

Q If it did, would you have corrected it; do you think?

A (Witness Lucas) Yeah. I was very careful, again, in my testimony to make this distinction between excess revenue collection and over-earnings. I did not imply at any point, nor am I implying here, that the company broke Commission rules.

I'm simply saying that this mechanism exists in a way that the company has been able to earn returns above the central ROE point for every year for the last 11 years --

Q And, again, your testimony -- I'm sorry. I didn't mean to cut you off.

Your testimony here today is you do support that mechanism?

A (Witness Lucas) I think the mechanism, when properly designed, as I say in my testimony and it's my written testimony, that there is value in multiyear plans and there's value in having an earnings band.

But I think that that earnings band should be narrowed, as I mentioned, to plus or minus 50 basis points. But that the 20 percent/80 percent share should be

maintained.

Q Earnings are determined in part by revenue; right?

A (Witness Lucas) In part by revenue, correct.

Q Yeah. In other words, the last 11 years, the national economy, and especially the Georgia economy, has experienced enormous growth; wouldn't you agree?

A (Witness Lucas) Yes.

Q Okay. In fact, Georgia was just named the best state in which to do business for the ninth year in a row; right?

A (Witness Lucas) I can't confirm or deny that.

Q Okay. You've heard that said a number of times in this hearing, though, haven't you?

A (Witness Young) Yes.

A (Witness Lucas) There has -- there definitely has been reference to Georgia being an excellent place for people to work.

Q Mr. Young?

A (Witness Young) Yes, sir.

Q You're aware; right?

A (Witness Young) I'm familiar with that statistic, yes, I am.

COMMISSIONER MCDONALD: If you turn the radio on or the TV, you hear it. If you don't believe it,

ask the Governor.

MR. YOUNG: That's right.

MADAM CHAIR PRIDEMORE: Water is wet, gentlemen.

MR. YOUNG: That's right. That's right.

COMMISSIONER MCDONALD: Or J.D. Power, either one of them.

MR. YOUNG: That's right.

BY MR. HEWITSON:

Q A booming economy can create additional demand for electricity and demand -- and drive up sales; right?

A (Witness Lucas) It can.

Q Okay. And are you aware that rates are set on a weather-normal basis?

A (Witness Lucas) Yes.

Q So if the weather is hotter, like it's been at various times over the last 11 years, that can also create additional demand for electricity and drive sales up; right?

A (Witness Lucas) Correct.

Q And revenue is just one part of the calculation; don't you agree?

A (Witness Lucas) Yes.

Q If Georgia Power can manage costs to operate more efficiently, like Commissioner McDonald said, it can achieve higher earnings; right?

A (Witness Lucas) Correct.

Q Okay. And when the company operates efficiently and drives down cost, do you agree that those savings can be passed on to customers in future rate cases by virtue of lower costs to be recovered through revenue requirements?

A (Witness Young) I would say potentially, yes.

A (Witness Lucas) Yeah. I'm just trying -- I'm trying, again, to be careful in the way I phrase this. Potentially.

As we've discussed, there's been a lot of discussion in this case about how the company should devise its rates, how the cost of service should work.

There are more things that go into the cost of service than just expenses. That is one element. And certainly if the company has lower expenses and continues to predict lower expenses, that could have downward pressure on revenue requirements.

But there are many other factors, including the discussions we've had about return on equity, capital structure, you know, potential changes in law, forecast adjustments. All those things factor in to whether or not future revenues would be higher or lower. It's not just based on the operating expenses.

Q Okay. I want to ask you a couple of questions

about TOURD, but I think you answered a few of the first few ones, but let me just confirm. You agree that TOURD may be a good fit for some customers and should be retained as an option?

A (Witness Lucas) Yeah. We're not recommending that the tariff be disbanded. What we are specifically recommending is it be redesigned. My position on that in testimony is that the non-coincident peak demand structure is severely flawed.

And so in my testimony I have two specific recommendations on changes. One is to change that to not only a time-of-use energy rate, but a time-of-use demand charge where the demand is only counted during certain hours. You know, summer afternoons, for example.

And then the second recommendation would be if the company wants to maintain a 24/7 demand, that the costs collected in that demand charge be substantially reduced to only include those assets that are very close to the customer, such as line transformers.

Q Your recommendation is that TOUREO be used as a default residential rate; is that right?

A (Witness Lucas) That's correct.

Q Is that because you recognize that time-varying rates better capture the marginal cost to generate and deliver electricity?

A (Witness Lucas) I don't know if I would draw it exactly to that line. I think the time-bearing rates are good rate designs. I think the nights and weekend is a simple tariff that customers understand.

As the discussion with Commissioner Echols earlier says, you know, if there's a clock, you can -- you can set your thermostat based on that. You can change your behavior based on that clock. It's an easy-to-understand signal.

You know, the mechanics of how the rate is structured is just one element of what goes into designing rates and whether a rate is good for customers or not.

Q Do you agree that there is merit to moving customers away from a fully volumetric R rate to something that's more time-varying?

A (Witness Lucas) With the distinction that fully volumetric -- I don't think you need to move away from fully volumetric, in the terms of a kilowatt-hour-based tariff. I already said I disagree that demand-based tariff for residential customers can be very challenging.

I think that there are benefits of moving towards more time-varying rates and variable rates. So still in the kilowatt-hour domain, but having a time-of-use-based rate, yes, I agree that there's benefits of moving in that direction.

Q Okay. On the rate comparison tool, on page 88, lines 2 to 4, you recommend that the Commission require the company to develop a rate comparison tool. And I do believe Mr. Thomas also asked you questions about it.

This tool would be available for residential customers; is that your intent?

A (Witness Lucas) I don't know if we specifically limited to residential customers. We talked in the context of residential customers. My understanding -- I haven't closely reviewed the commercial tariffs.

But my understanding is that there is more restrictions in terms of, you know, different demand levels that might place you into one tariff or another. That there may not be as much optionality among those -- those commercial tariffs.

So this was sort of in the context of the residential tariff discussion. But I don't think I would be opposed to developing a tool like this that is more broadly available.

Q Okay.

A (Witness Young) And I think the PLML, the PLM large tool is useful for commercial industrial customers. I have some familiarity with that tool. I think it could be adapted for other rate structures for sure.

Q Okay. Mr. Young, do you recall how much the

Comed tool cost that you helped design?

A (Witness Smith) I do not. I was just marketing it.

Q Oh, so you didn't help design it?

A (Witness Smith) I mean, I did help review the UI of the tool, but not the mechanics or the cost, no.

Q Okay. Would you suggest that -- if it were limited to residential customers, would you anticipate or expect that the cost of such tool be spread among residential customers and then if it's used more broadly, it's -- let me ask it this way.

Would you suggest that the cost of the tool be spread among the customer classes for which it's intended to be used?

A (Witness Young) I mean, I guess I would recommend that the company treat it like any other tool and cost allocations should be according -- treated accordingly. So I'm not familiar how you recover cost of those types of tools.

Q Okay. A couple of questions on the 4CP allocator for production costs. You recommend that the Commission adopt the 4CP methodology for allocation of production costs; right?

A (Witness Young) Correct.

Q And, admittedly, part of your motivation is to

make solar appear more valuable than it does under the 12CP allocators; right?

A (Witness Lucas) No, I wouldn't agree with that characterization. What I'm saying in that instance is that in order for solar to be properly valued, it has to be able to reflect how costs are allocated within the system.

So I believe my testimony is that the company peaks during summer months. That's when its system is built and designed to. It's how the rates are designed in order to shift usage.

Recognizing that in the cost allocation process and the cost of service study, I think it's more appropriate based on the company's load patterns. And under that circumstance, it is true that solar tends to produce more during those 4CP hours than it does during all of the 12CP hours.

But as I also explained, the 12CP hours include peaks in March and April and September when the system is not under stress. So allocating production costs based on time when the system is not under stress is inconsistent with some of the other states and territories that I have seen cost allocation done.

Q On page 102, lines 16 to 18, you say: If production costs are not allocated to customers based on these summer months, then solar generation will appear less

valuable than it actually is.

Did I read that correctly?

A (Witness Lucas) That's correct. And I think that's what I just described. Solar produces well during the 4CP months. If the cost allocation process doesn't reflect the actual demand during those 4CP is how the system is built and managed, then there's a mismatch between the benefits that solar produces and the recognition within the cost of service study.

Q Right. So you want the 4CP allocator to be used because then it will make solar appear more valuable?

A (Witness Lucas) No. That's -- that's -- the third time. I said this the third time.

What I'm saying --

Q But that's the converse of your testimony?

A (Witness Lucas) No. But that's not my testimony. My testimony is I think the 4CP allocator is technically more accurate because it reflects the way the system loads occur.

Q Okay. You're aware --

A (Witness Lucas) It is true that under that circumstance solar produces more in the 4CP. But I'm not accepting the converse that that's why I chose it.

Q Okay. It's just a result of your recommendation; right?

**A (Witness Lucas) The result of my recommendation is that the company would allocate costs that are more appropriate for the way its system is built and managed.**

**Q You're aware the company's reliability risks have changed over the last several years and much more consideration must be given to the growing winter need in making planning decisions; right?**

**A (Witness Lucas) Yes.**

**Q And PIA staff acknowledged this issue in the Barber, Deitchman, Watkins testimony; right?**

**A (Witness Lucas) Yes. I think that staff did recognize that. And I do have some discussion and show some data on how the system in recent years still is summer-peaking.**

**I understand, again, from the IRP testimony that there is increasing consideration of those winter loads. But, again, I talk in my testimony that even if winter loads are a factor, there's really only two months that are consistently of high use. And that, I believe, is December and January. Perhaps January and February.**

**But that the 12CP allocator picks up a bunch of other months that do not have high loads. So, yes, I recognize that winter planning is becoming more important. 12CP is not winter planning. Those are two different things.**

Q Right. But you understand that Georgia Power is required to serve load in all 12 months; right?

A (Witness Lucas) Yes.

Q Okay. And using the 4CP method would focus only on the four summer months, as we have been talking; right?

A (Witness Lucas) It would -- it would on when the system is built. If you built your system to handle your summer months, you're going to be able to handle spring and fall loads. Because those loads are consistently lower in the spring and fall and lower in the winter than they are in the summer.

In fact, I think it's the exact justification the company gives for using the 4CP allocator for its transmission. The company says: If you build the system to handle the summer loads, it can handle the loads at the rest of the time of the year. The same thing is true for the generation.

Q But focusing only on the 4CP, only on the four summer months, would ignore the increased reliability risk in the winter months, wouldn't it?

A (Witness Lucas) I think those are two different things. Again, we're talking about reliability planning, which is in the context of what we're talking about, winter risk, the resource adequacy argument, the reserve margin

that the company puts in place, whether it focuses on summer, winter, or so on. That's more the planning side, the IRP side.

What we're talking about here is cost allocation and how customers use that system. So I think those are two slightly different domains. And I don't think it's completely accurate to say that using a 4CP allocator and a cost of service study completely ignores winter reliability risks which are handled under a different planning process.

Q Right. But you would agree that the company is planning and operating the system with an eye toward the increased winter reliability risk; right?

A (Witness Lucas) I think that's accurate. And staff asked the company whether it would consider introducing a winter change of its rate design to reflect the fact that it's doing this planning and the company said no. They basically said: We don't think that that's something that needs to be addressed in rate design right now. That the focus on the summer peak times is appropriate.

MR. HEWITSON: Gentlemen, thank you very much for your time. That's all the questions I have for you.

MR. LUCAS: Thank you.

**MR. YOUNG: Thank you, sir.**

**MADAM CHAIR PRIDEMORE: Mr. Hewitson, you passed out a demonstrative. Do you want to add that to the record?**

**MR. HEWITSON: Yes, please. Georgia Power Exhibit No. 39.**

**MADAM CHAIR PRIDEMORE: So marked. So moved.**

**(The document referred to was marked for identification and admitted into evidence as Georgia Power Company Exhibit 39.)**

**MADAM CHAIR PRIDEMORE: Redirect.**

**MR. THOMASSON: Madam Chair, I don't have redirect, but I do have just some housekeeping cleanup.**

**So I would move the witnesses' testimony be read into evidence as if read from the stand. And move that exhibits to the testimony, the corrections filed to that testimony, the trade secret attachment, and demonstratives be moved into evidence as GASEIA Exhibits 2 through 11.**

**MADAM CHAIR PRIDEMORE: So moved. So marked.**

**(Whereupon, the prefiled direct testimony and errata of Kevin Lucas and Thatcher Young follows:)**

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**BEFORE THE PUBLIC SERVICE COMMISSION**

**STATE OF GEORGIA**

| | | |
|---|---|---|
| **In Re: Georgia Power Company's 2022 Rate Case** | ) | **Docket No. 44280** |

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**REDACTED – PUBLIC DISCLOSURE VERSION**

# DIRECT TESTIMONY OF KEVIN LUCAS AND THATCHER YOUNG

Presented as a panel on behalf
of the Georgia Solar Energy Industries Association,
Solar Energy Industries Association, and Vote Solar

October 20, 2022

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## I. INTRODUCTION AND QUALIFICATIONS

**Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A1. [Mr. Lucas] My name is Kevin Lucas. I am the Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

A1. [Mr. Young] My name is Thatcher R. Young. I am Vice-President of Business Development of Velo Solar, LLC ("Velo Solar"). My business address is 154 Krog Street, N.E., Suite 140, Atlanta, Georgia 30307.

**Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.**

A2. [Mr. Lucas] I began my employment at SEIA in April 2017 as the Director of Rate Design. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 30% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+ Decade through research, education, and advocacy.

As Senior Director of Utility Regulation and Policy, I have developed testimony in rate cases on rate design and cost allocation, in integrated resource plans on resource selection and portfolio analysis, worked on net energy metering and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy ("Alliance") from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service

providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

A2. [Mr. Young]: I have been with Velo Solar since 2019. Velo Solar's business is predominately focused on developing BTM DG projects in Georgia and, to a lesser extent, the rest of country. Velo Solar also develops stand-alone DG projects most of which are located in Georgia.

I hold a Bachelor of Arts degree in Philosophy and a Master's Degree in Environmental Public Policy and Natural Resources Management from Georgia State University. From 2016 through January of 2019, I was the Vice President of Business Development with Radiance Solar. Before that, from 2008-2016, I was Vice President of Sustainability and Strategy for Ignition/Havas.

**Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?**

A3. [Mr. Lucas] Yes, I have. I testified in Georgia Power Company's 2022 Integrated Resource Planning and Demand Side Management docket (collectively, the "2022 IRP Proceeding").[1]

A3. [Mr. Young] Yes, I testified in the 2022 and 2019 IRP Proceedings.

**Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?**

A4. [Mr. Lucas] Yes. I have submitted testimony in rate cases, integrated resource plans, utility merger proceedings, and renewable portfolio and energy efficiency resource standards before the Maryland Public Service Commission, Public Utility Commission of Texas, the Public Utility Commission of Nevada, the Arizona Corporation Commission, the North Carolina Utilities Commission, the Public Service Commission of South Carolina, and the Virginia State Corporation Commission. My complete CV is attached to my testimony.[2]

A4. [Mr. Young] No, I have not.

**Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?**

A5. Our testimony is provided on behalf of SEIA, the Georgia Solar Energy Industries Association ("GASEIA"), and Vote Solar, as joint intervenors in this proceeding (collectively "Joint Intervenors").

**Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A6. The purpose of our testimony is to review and comment on the Georgia Power Company's ("GPC" or "the Company") application in this rate case. The bulk of the testimony focuses on topics that directly and indirectly impact the solar industry, including the proposed interconnection fee modification, the Company's request to recover $1.4 million in revenue deficiency due to RNR customers, and its decision to close several tariffs while directing customers onto the "Smart Usage" tariff. We also discuss several other issues related to transparency and fairness in this case and make recommendations on how the Commission can ensure that the Company is not abusing its monopoly position.

[1] *In Re: Georgia Power Company's 2022 Integrated Resource Plan*, Docket No. 44160; *In Re: Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan*, Docket No. 44161.
[2] Exhibit KL-1, Kevin M Lucas CV.

**Q7. WHAT IS YOUR ANALYSIS OF THIS CASE?**

A7. This is a critical juncture for the Company and its customers. GPC, along with the rest of the electric industry, is in the middle of a massive transformation towards cleaner resources. To their credit, GPC and the Commission have shown leadership to advance this transition through renewable energy procurements. But the Company cannot request – and the Commission cannot approve – a blank check to fund its transition without first proving that its investments and expenses are reasonable and prudent.

GPC comes to the Commission requesting permission to increase its rates by nearly $3 billion over the next three years. It supports this massive request with sparse testimony and limited supporting evidence while being protected by a regulatory process that denies non-Staff intervenors discovery rights to push back on the Company's claims. If the Company's proposals are granted, customers will be subjected to massive rate hikes that have not been robustly supported or even well documented by the Company.

Unfortunately, the Company's case is full of questionable investments and tactics that do little to contain costs in the transition. For example, the Company proposes to spend nearly $100 million on a distributed energy resource management system ("DERMS") despite having a tiny fraction of distributed energy resources of more advanced states that manage without a DERMS. At the same time, the Company maintains a "tool" that purports to inform customers about onsite solar generation, but is instead designed to discourage customers who are seeking to actively manage their (soon-to-be-increasing) bills through solar.

Absent robust oversight by the Commission, the Company will continue its decade-long tradition of increasing profits well above its approved ROE. Since the Annual Surveillance Report ("ASR") process was implemented in 2011 alongside the multi-year Alternative Rate Plan ("ARP") structure, GPC has collected than $1.87 billion in revenue above its approved ROE. Further, because of the overly generous ROE dead band approved

by the Commission, the Company has been able to keep more than $1.57 billion of this amount, with more than $460 million coming during the COVID years of 2020 and 2021.

Actions proposed by the Company in this case could enable this trend to continue. The Company requests permission to close several residential tariffs to new premises while shifting more customers to its demand-based default rate and actively obfuscating eligibility requirements on the remaining time of use tariff. If approved, this would drive more and more customers onto a poorly designed demand-based tariff that will charge them much more than the costs they incur on the system. Exacerbating this issue, the Company completely ignores core functionality of its multi-million-dollar advanced metering infrastructure ("AMI") deployment to provide data for its rate design and cost of service study ("COSS"). Instead, it relies on statistical load studies that appear to result in a massive over-collection of revenue from residential customers.

From top to bottom, the Company's application advances its profits at the (literal) expense of its customers. Yes, more investment will be needed to transition to clean energy resources, but GPC should not be allowed to exercise outsized market power. The magnitude of the potential cost increases in this and future cases will have material impacts on residential and business customers in the state. The Commission must remain steadfast and carefully scrutinize the Company's proposals, paring back those that are unnecessary or unsupported while providing sufficient but not excessive financial security to the Company.

**Q8. WHAT ARE YOUR RECOMMENDATIONS ON THE COMPANY'S PROPOSALS?**

A8. Our recommendations on the specific points of the Company's proposal that we discuss follow:

- The Company's proposed $200 interconnection fee should be rejected and its current $5/kW fee for systems under 250 kW maintained. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW.
- The Commission should deny the Company's request to adjust revenue by $1.4 million. The Company did not appropriately account for exported energy in its COSS, and as a

result, has overallocated costs to customer classes with RNR projects that is not considered in this figure.

- The Commission should strongly reconsider the width and asymmetry of the currently-approved ROE dead band. Ideally, it would be reduced to +/- 50 basis points, but at a minimum should be returned to the +/- 100 basis points in place prior to 2020.
- The Smart Usage tariff should not be the default rate and should be substantially redesigned with either a peak TOU demand charge collecting a fraction of production and transmission costs or a non-coincident peak charge collecting only low-voltage distribution assets. The Commission should require the Company to validate that the Smart Usage tariff is revenue neutral with respect to the traditional Residential tariff.
- The Commission should require the Company to continue offering the Residential and Nights and Weekends tariffs to new premises. The default rate should be changed to the Nights and Weekends tariff.
- The Commission should require the Company to develop a rate comparison tool that would automatically calculate a residential customer's bill based on historic usage on the various tariff options. It should also be required to collect billing demand data for each customer.
- The Solar Advisor Tool should be scrapped as it is actively biased against onsite solar.
- The Company should explain why its AMI data is insufficiently precise to use in its rate design and COSS. Absent statistically valid reasons, the Commission should direct the Company to use AMI data to its maximum extent in its COSS and rate design going forward while eliminate as many load research costs as possible.
- The Commission should adopt the 4CP allocator for production costs. The Company's historical data and discovery responses show that it has and will continue to be a summer peaking utility, and in my experience, this is the dominant production cost allocator for summer peaking utilities.
- The Commission should direct the Company to provide funding for Staff and/or independent consultants to perform additional transmission studies related to North Georgia Reliability and Resilience Action Plan and transmission planning generally.

## II. THE COMMISSION AND THE PUBLIC ARE HARMED BY THE INABILITY OF INTERVENORS TO PROPOUND DISCOVERY ON THE COMPANY

**Q9. WHAT ARE THE TOP LINE REQUESTS AND RECOMMENDATIONS FROM GPC IN THIS RATE CASE?**

A9. At a high level, GPC is asking the Commission to approve the recovery of billions of dollars of existing and planned assets, increase its return on equity ("ROE") to 11%, and authorize a proposed rate adjustment that will collect roughly $2.8 billion in additional revenues between 2023 and 2025.[3] If these revenues are approved, rates will collect $1 billion more annually in 2025 than in 2022, leading to an increase of roughly $16.29 to a residential customer using 1,000 kWh per month.[4]

The Company proposes to change its interconnection fee structure for systems connecting to the distribution grid, implementing a flat $200 for all projects regardless of size. It also makes an upward revenue adjustment of $1.4 million to collect what it claims is a cost shift associated with the implementation of the RNR Monthly pilot program.

The Company also proposes to close two residential tariffs, including the traditional flat rate tariff ("R tariff") and the Nights and Weekends TOU tariff ("TOU-REO tariff"), to new premises. With the three-part Smart Usage ("TOU-RD"), which includes a sizable non-coincident demand component, now acting as the default tariff, and the Company's refusal to eliminate confusion regarding its inappropriately-named Plug-in EV rate ("TOU-PEV tariff"), new customers are increasingly put on a rate that is poorly suited for their usage patterns.

**Q10. WHAT IS YOUR OVERALL IMPRESSION OF GPC'S RATE CASE FILING?**

A10. On balance, we found the GPC written testimony quite minimal given the magnitude of the financial and policy changes that the Company is requesting. The Company presented

[3] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson On Behalf of Georgia Power Company at 7, 9 ("Panel Direct").
[4] Panel Direct at 11.

testimony from three individual GPC witnesses, one panel of GPC witnesses, and two consultants, discussing the following topics:

- GPC Company or Affiliate Witnesses
  - Christopher C. Womack: overview of rate case filing[5]
  - Larry T. Legg: rate design[6]
  - Lee Evans: cost of service study[7]
  - Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson panel: revenue requirement[8]
- Consultants
  - James M. Coyne: ROE and capital structure calculation[9]
  - Steven M. Fetter: role of credit ratings and utility regulation on utility financials[10]

Discounting the introductory section of the testimony, all three of the individual Company witnesses' testimonies providing the overview of the case, the discussion of rate design, and the cost of service model were roughly 20 pages each. The panel supporting the revenue requirement produced roughly 50 pages of testimony. The two consultants, who supported the ROE and capital structure recommendations, produced testimony of 45 and 20 pages. GPC is requesting to increase customer rates by billions of dollars while making impactful policy changes, all supported with fewer than 200 pages of written testimony.

**Q11. HOW DOES THIS COMPARE TO SOME OF THE OTHER CASES IN WHICH YOU HAVE PARTICIPATED?**

A11. [Mr. Lucas] It is notable in its brevity. For example, in Consumers Energy's 2022 rate case, the primary utility witness sponsored over 250 pages of written testimony himself in a filing that contained more than 1,800 pages of written testimony from 35 witnesses.[11] This does not include additional thousands of pages of witness exhibits. While I am not suggesting that

[5] Direct Testimony of Christopher C. Womack On Behalf of Georgia Power Company. ("Womack Direct").
[6] Direct Testimony of Larry T. Legg On Behalf of Georgia Power Company ("Legg Direct").
[7] Direct Testimony of Lee Evans On Behalf of Georgia Power Company ("Evans Direct").
[8] Panel Direct.
[9] Direct Testimony of James M. Coyne On behalf of Georgia Power Company ("Coyne Direct").
[10] Direct Testimony of Steven M. Fetter On behalf of Georgia Power Company ("Fetter Direct").
[11] *In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission Case No. U-21224.

maximizing page count should be the goal of a utility filing, there are some topics that simply require more attention than can be afforded in a sub-20 page document.

**Q12. CAN YOU PROVIDE SOME EXAMPLES OF THIS IN GPC'S FILING?**

A12. [Mr. Lucas] Yes. GPC mentions that the Commission authorized $1.3 billion in spending from 2020 through 2022 on its Grid Investment Plan project in the 2019 rate case.[12] However, the Company spent $1.5 billion over this time,[13] and requests to spend an additional $2.2 billion in the next three-year phase.[14] There is no specific mention in testimony of the roughly $200 million of incremental spending beyond the original approved cost; in fact, the figure needed to be calculated from two different pieces of testimony.

Further, the Company declined to discuss the preliminary results from the 2020-2022 investment round at all, claiming that revisiting the benefit estimates was "not warranted at this time" as too few projects had been in service through a full year.[15] While a full reckoning of the benefits may be premature, some discussion of the preliminary results is certainly appropriate given the Company's request for an additional $2.2 billion in spending on this program.

Another example is the proposed flat $200 interconnection fee for customer-generators seeking to interconnect to the Company's system. This new fee is a notable change from the current process and would apply equally to all systems regardless of their size and complexity of the interconnection process, a departure from both current practices and industry standards. Despite the many questions that this new fee raises, the totality of the Company's justification is one sentence long: "This fee is designed to recover costs associated with supporting the safe and reliable interconnection of a customer-generator to the system and helps ensure that such costs are not borne by all other customers."[16]

[12] Panel Direct at 49.
[13] Direct Testimony of Christopher C. Womack On Behalf of Georgia Power Company at 6 ("Womack Direct").
[14] Panel Direct at 49.
[15] Panel Direct at 50.
[16] Legg Direct at 14.

One other example comes from a seemingly innocuous mention: "The Company is modifying its payment and service policies in section F to help make those policies more transparent to customers. These additions are meant to help protect all customers from higher costs that could result from legal claims against the Company."[17] There is no mention in testimony of what section F is, much less what the changes are. One has to seek out section F in the Company's exhibits, where one would find a rather startling change of policy:

> 9. Without restricting the limitations of liability provided elsewhere within these rules, to the extent a cognizable claim arises, the customer waives any right to consequential, special, indirect, treble, exemplary, incidental, punitive, loss of business reputation, interruption of electric service or loss of use (including loss of revenue, profits, or capital costs) damages in connection with any outage, surge, voltage fluctuation, disturbance or other variation or failure of electric service, or the Company's equipment, even where such variation, interruption, or failure of electric service was reasonably foreseeable, contemplated, or avoidable. To the extent the Company is liable under an agreement, and to the extent allowed by applicable law, the Company's liability is expressly limited to proven direct damages. The Company's liability for damage to personal property will be limited to the depreciated value of such personal property.[18]

This entirely new section 9 would dramatically limit the ability for customers to seek damages from the Company arising from issues with the customer's electricity service, including issues that are "reasonably foreseeable, contemplated, or avoidable" by GPC. While I will leave it to other parties to argue about the policy merits of this proposal, it is a striking change to have been buried in written testimony as it was.

**Q13. BUT SURELY THESE OBFUSCATION TACTICS ARE NOT UNIQUE TO GPC?**

A13. [Mr. Lucas] No, they are not. In my experience participating in cases in various jurisdictions, the utility rarely discloses more than is necessary to make its case. Excel workbooks are stripped of all formulas, or sometimes presented only as PDFs. Even when available as interactive files, key figures are often hardcoded and summary data presented without supporting backup data. Declarative statements in written testimony often lack references, making it challenging to trace their origin and validate their claims. While GPC's tactics in

[17] Legg Direct at 13.
[18] 1.60_R&R Sec F - Contract and Enforcement Regulations Tracked.doc

this case are at times frustrating, they are not unique. But at the same time, the burden is on the Company to demonstrate that its request is just and reasonable, and the Commission should scrutinize how robustly such a thin application makes this case.

**Q14. WHAT IS THE TYPICAL WAY THAT INTERVENORS PUSH BACK ON THESE TACTICS?**

A14. [Mr. Lucas] The typical approach is for intervenors to ask discovery. This vital process allows participants in the case to fill in the many missing gaps. Working Excel models are requested, supporting documentation must be furnished, original sources can be vetted. The less that is provided by a utility in its original filing, the more that needs to be uncovered through discovery.

**Q15. DOES THIS CRITICAL PROCESS EXIST IN GEORGIA?**

A15. For intervenors other than Staff, no, it does not. Intervenors are not authorized to ask discovery in proceedings such as this rate case.[19] We are grateful that Staff is robustly exercising its discovery rights in this proceeding, and we have cited to its discovery in our testimony. However, there are certain analyses that we were unable to perform due to the inability to ask our own questions.

**Q16. WHAT ARE SOME OF THESE ANALYSES?**

A16. One relates to the aforementioned interconnection fee. After the Company initially provided zero analytical support for its proposal, Staff requested and received additional data on the calculation – in an Excel file with only hardcoded numbers and no formulas.[20] However, the responses provided by the Company simply invite more questions. For example:

- Why do the number of feasibility studies or standard impact studies not match the number of projects?
- What triggers a Network Underground or Reliability Study?
- Why does the Company use a different inflation assumption in this worksheet than in the rest of its case?
- Why is it appropriate to spread costs for impact and feasibility studies that appear to only apply to larger projects to all projects regardless of size?

[19] See O.C.G.A. § 46-2-57; Procedural and Scheduling Order issued April 7, 2022 in Docket No. 44280 ("The Commission authorizes PIA Staff to issue discovery pursuant to O.C.G.A. § 46-2-57(a). PIA Staff may conduct depositions and use any other methods of formal and informal discovery in this docket.")

[20] STF-TAI-1-40 and STF-TAI-1-40 Attachment.

- What is actually done in the "Project Review and Generate Agreement" step, and why does it cost $105 for a small system and $2,096 for a large system? Given this disparity, why does the Company charge every project a $59 fee for this step regardless of the project size or whether that project required that step?
- Why does the number of sub-10 kW projects that undergo the "Project Review and Generate Agreement" and "Witness Test and Meter Re-Programming" steps fall over time?
- What specific steps are needed for the "Project Billing and Tariff Rider Added" step and why does it cost $88 to perform these tasks? Why does this step only apply to 3,555 projects, which does not match any of the other project numbers?

To perform a robust analysis of the Company's interconnection proposal, these questions need answers. Some may have straight forward answers, some may uncover errors in GPC's analysis, while other may reveal arbitrary decision making. In response to our request for clarification of these questions above, the Company arranged a meeting with members of the Company's renewables team to answer our specific questions about the interconnection workpaper. That meeting was useful in answering many of our questions. However, because we were unable to ask the required follow ups through formal discovery, and the Company's witness sponsoring this testimony was unable to provide the needed details, these issues very well could have remained unresolved when this testimony was due.

**Q17. DOES GEORGIA'S MULTI-PHASE HEARING PROCESS OFFER INTERVENORS AN OPPORTUNITY TO ADDRESS THESE TYPES OF ISSUES?**

A17. In theory, it does. However, live cross-examination is necessarily less robust than a deliberate written discovery process. For instance, Joint Intervenors' counsel sought answers to questions such as those above from Company witnesses during the first round of hearings. Unfortunately, the Company witness who discussed the interconnection agreements during the hearings in some answers directly contradicted the documents that the Company provided in discovery while in other answered claimed to be unable to answer as his group did not prepare the studies, as discussed in Section III below. With no ability to ask follow-up discovery questions, and Company witnesses failing to have knowledge of the topics they sponsored in testimony, the record on the matter is muddied to the detriment of the Commission and the public.

**Q18. WERE YOU ABLE TO PARTIALLY RESOLVE YOUR QUESTIONS ON THIS ONE PARTICULAR ISSUE?**

A18. We were. At the request of our counsel, the Company arranged a meeting after its initial testimony to discuss our questions regarding the interconnection fee. We are very appreciative that the Company made their staff available for our questions, and while they were able to answer some of those questions, several of their responses simply identified more issues that would have benefitted from additional follow up.

Further, the interconnection fee analysis was only one of many lines of questioning that we had on the Company's testimony and responses to Staff's discovery questions. We had many other questions on many other topics that would have required multiple meetings with multiple business groups. Obtaining answers to all these questions through an informal, off-the-record process does not feel like a long-term sustainable process.

The function of a formal discovery process is to ensure that questions are clearly asked, clearly answered, and available to enter into the record on which the Commission makes its decision. We are pleased that we are able to submit this testimony without having to guess about the Company's interconnection fee workpaper, but we had to make educated guesses and assumptions about several other topics discussed here.

**Q19. WHAT IS THE IMPACT OF INTERVENORS NOT BEING ABLE TO ASK DISCOVERY?**

A19. On the whole, it does a disservice for both the Commission and the public as a whole. The Commission is being asked to make very hard decisions in this and other proceedings that directly impact the livelihood of Georgia residents and businesses. In this case, among other things, the Company is asking permission to raise residential bills by hundreds of dollars per year, and some business bills by thousands of dollars per year. To do so without the most robust record possible means that some important information may be missed.

**Q20. DOES THIS HAVE A PARTICULARLY PROBLEMATIC IMPACT FOR THE SECOND PHASE OF THIS DOCKET?**

A20. Yes. The second phase of this docket will address cost of service issues associated with RNR customers. The Company will file its testimony on October 20th. Responses from other intervenors are due 21 business days later on November 18th. However, the Company has 15 business days to respond to discovery.[21] This means that even if Staff reads the Company's testimony and submits discovery the next day, and they will have less than a week to analyze and incorporate the response in its own testimony. It also means that there is no opportunity to ask a second round of discovery on the first set of answers, something that Staff frequently did in the initial phase of the hearing. This timeline is simply not compatible with producing a robust record on what will certainly be a complex issue.

**Q21. WHAT DO YOU RECOMMEND WITH REGARD TO THIS ISSUE?**

A21. [Mr. Lucas] Ideally, all intervenors would be able to ask discovery. In the various jurisdictions I have worked, only one commission put a restriction on discovery, and that was only to limit the number of questions that could be asked in one day.[22] All other jurisdictions allowed unlimited intervenor discovery by parties to other parties in formal proceedings, while the respective utilities and intervenors maintained the right to object to questions asked.

If the Commission feels that unlimited discovery is too large of an initial step to take, it could offer non-Staff parties limited discovery rights. These could include a cap on the number of questions asked per day or in total. That said, if the Commission were to expand discovery rights, I would caution against strong restrictions given the purpose of discovery is to produce a more robust record on which the Commission can base its decisions.

The burden to prove that its requests in this case are just and reasonable is on the Company. It must do so under scrutiny of the Commission, Staff, and other intervenors. Discovery is a critical element of this examination and preventing all non-Staff intervenors discovery rights necessarily results in a weaker record on which the Commission must make its decisions.

[21] Second Amended Procedural And Scheduling Order issued August 5, 2022 in Docket No. 44280.
[22] The Public Utility Commission of Texas limited intervenors to 50 questions and/or subparts per day, but there was no limit on the total number of interrogatories.

## III. GEORGIA POWER'S PROPOSED $200 FLAT INTERCONNECTION FEE SHOULD BE REJECTED

**Q22. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A22. We discuss the Company's proposal to institute a flat $200 interconnection fee for projects seeking to connect to the Company's system. This approach replaces the current protocol of $5/kWAC for systems under 250 kWAC in the RNR or Energy Offset Only program, and $3,900 (weekdays) or $4,400 (weekends) for systems over 250 kWAC in the Energy Offset Only or Qualifying Facility program.[23]

**Q23. PLEASE SUMMARIZE YOUR FINDINGS.**

A23. The Company's proposal is vague, lacks support, and should be rejected. It provides no evidence for its claim that the current fee structure causes non-participants to pay for the interconnection studies needed to install distributed generation ("DG") systems on its grid. The one piece of analysis that the Company provided raises more questions than it answers. GPC has not demonstrated that this change is reasonable and prudent, and as such, the existing structure should be left in place.

**Q24. WHAT IS YOUR RECOMMENDATION ON THE COMPANY'S INTERCONNECTION FEE PROPOSAL?**

A24. We recommend the Commission reject the proposal and maintain its current fees of $5/kW for systems under 250 kW. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW. The interconnection fees of neighboring utilities discussed below provide the Commission with a range of reasonable options.

[23] Georgia Power "Behind the meter solar workshop Q&A", question 23. ("BTM Solar FAQ"). Available at https://www.georgiapower.com/content/dam/georgia-power/pdfs/residential-pdfs/residential-rate-plans/georgia-power-btm-solar-faq-document-august-2021.pdf

*The Company's Proposal is Overly Vague*

**Q25. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE INTERCONNECTION PROCESS AND FEE?**

A25. The Company proposes to change its testing requirements and shift from a per kW fee for smaller systems and a high flat fee for larger systems to one that has a $200 flat fee for all customers.[24] The entirety of GPC's discussion of this change follows:

> Q. PLEASE EXPLAIN THE CHANGES TO THE CUSTOMER GENERATION SECTION OF THE RULES AND REGULATIONS.
>
> A. The Company has proposed new language to clarify when a customer-owned generator is required to undergo witness testing and would be responsible for the appropriate fees associated with this testing. The anticipated impact of this change is to reduce the number of instances that require witness testing going forward. The Company is also proposing to introduce a one-time $200 interconnection fee that will be required for all customers proposing to interconnect a customer generating facility to the Georgia Power system. This fee is designed to recover costs associated with supporting the safe and reliable interconnection of a customer-generator to the system and helps ensure that such costs are not borne by all other customers.[25]

**Q26. DO THE CHANGES IN THE CUSTOMER GENERATOR SECTION OF THE RULES AND REGULATIONS CLARIFY WHEN A CUSTOMER-GENERATOR IS REQUIRED TO UNDERGO WITNESS TESTING?**

A26. No, it does not. Currently, the Company performs "witness testing" for all systems – regardless of size – connecting to its distribution system that is intended to validate the protection protocols of systems; in essence, GPC employees make sure that the system trips offline when it is supposed to do so. The Company does not propose witness test modifications for systems over 250 kW but adds the sentence "Customer-owned generators less than 250 kilowatts may also be required to undergo witness testing if the Company deems that the generator poses a safety or reliability risk."[26]

**Q27. DOES THE COMPANY PROVIDE ANY EXPLANATION FOR HOW IT WOULD DEEM THAT A GENERATOR POSES A SAFETY OR RELIABILITY RISK?**

[24] Legg Direct at 14.
[25] Legg Direct at 14.
[26] 1.70_R&R Sec G - Customer Generation Tracked.doc

A27. No. There is no further explanation in the Rules and Regulations for how the Company would determine this. Although the Company claims this will reduce witness testing in the future, it provides no support in its documentation for this assertion as it does not explain what would trigger a "safety or reliability risk" that would still necessitate a witness test.

*The Company's Interconnection Fee Analysis Contains Inconsistent, Unsupported, and Erroneous Data*

**Q28. DID THE COMPANY PROVIDE ANY ADDITIONAL INFORMATION ABOUT THIS PROPOSAL?**

A28. Yes. In response to a discovery request from Staff, the Company provided additional details on its proposal and a single page, hardcoded Excel file with some analytical support for the costs underlying its $200 fee. According to GPC, this fee "collects the known costs directly attributed to process project applications for interconnection."[27]

**Q29. HOW MUCH REVENUE DOES THE COMPANY PROJECT TO COLLECT THROUGH THIS NEW FEE?**

A29. It projects collections of $3.05 million between January 2023 and December 2025, or roughly $1.0 million per year.[28]

**Q30. DOES THE COMPANY OFFER ANY TESTIMONY OR EVIDENCE THAT THE CURRENT INTERCONNECTION FEE UNDER-COLLECTS REVENUE ASSOCIATED WITH INTERCONNECTION APPLICATIONS?**

A30. No, it does not. We were not able to locate any information in the Company's testimony or exhibits that details interconnection application fee revenues under the current process, nor any discussion supporting the claim that these are insufficient compared to costs.

**Q31. PLEASE DISCUSS THE WORKPAPER THAT THE COMPANY PROVIDED IN RESPONSE TO STAFF'S DISCOVERY REQUEST.**

A31. The Company provided a one-page Excel file breaking down the interconnection cost schedule for 2023, 2024, and 2025. All formulas were removed, leaving only hardcoded values. There is no reason for the Company to do this; it protects no information and just

[27] STF-TAI-1-40.
[28] Id.

makes subsequent analysis by intervenors more complex. While this particular analysis was relatively easy to reverse-engineer, GPC's practice of removing formulas in Excel files is an unnecessary obstruction tactic and should be strongly discouraged.

The file broke down the fee into five components, listed below in Table 1 along with the average cost for each category for each year.[29] The overall average cost is $190, to which the Company adds $10 per application for "costs not easily quantifiable or attributable on an average per project basis."[30] The figures assume a 3% annual inflation rate and a 15% year-over-year increase in the number of interconnections and breaks down projects into three size categories: less than 10 kW, 10-250 kW, and greater than 250 kW.[31]

| Average Cost Per Application | 2023 | 2024 | 2025 | Average |
|---|---|---|---|---|
| **Impact & Feasibility Study** | $9 | $9 | $10 | $9 |
| **PowerClerk Costs** | $34 | $34 | $34 | $34 |
| **Project Review and Generate Agreement** | $59 | $35 | $36 | $43 |
| **Project Billing and Tariff Rider Added** | $67 | $60 | $53 | $60 |
| **Witness Test and Meter Re-Programming** | $63 | $33 | $34 | $44 |
| **Total** | **$231** | **$171** | **$167** | **$190** |

*Table 1 - GPC Interconnection Costs*

**Q32. CAN YOU EXPLAIN WHY THE COST OF SEVERAL LINE ITEMS DECREASE OVER TIME?**

A32. Three of the five items fall in cost over time. Of these, the Project Review and Generate Agreement and the Witness Test and Meter Re-Programming steps fall because the Company assumed the number of sub-10 kW projects going through these steps falls from 50% in 2023 to 25% in 2024 and 2025. The Project Billing and Tariff Rider Added cost falls because the Company assumed this step applies to constant 3,555 projects each year, a figure which does not match the number of projects used elsewhere on the schedule and does not increase over time.

[29] STF-TAI-1-40 Attachment. Customer counts, study costs, and other costs referenced in this section are sourced from this attachment.
[30] STF-TAI-1-40.
[31] All system capacity sizes are in $kW_{AC}$ unless otherwise denoted.

**Q33. WHY DID THE COMPANY ASSUME THAT SMALL PROJECTS WOULD MOVE FROM 50% TO 25% IN SOME OF THE STEPS?**

A33. As the Company did not provide any information about its assumptions, it was unclear to what the 50% and 25% applies. Does this mean that only 25% of projects are reviewed, have contracts generated, undergo witness testing, or have the meter reprogrammed? Are project review and generate agreement different steps? Do all projects that undergo witness testing also have their meter reprogrammed, or do some projects require meter reprogramming but not witness testing? None of this is clear in the Company's analysis.

While we were unable to ask discovery to find out these answers, we were able to ask these questions during an informal Q&A session with the Company. The Company clarified it is able to increasingly automate simple "cookie-cutter" projects under 10 kW, avoiding the need of a manual review of basic project information (e.g., the account number matching the address, system components are UL listed, etc.) and witness testing, and are able to have semi-automated interconnection agreements created. The Company also clarified that all meters undergo field reprogramming, and all projects must have a contract generated, despite only listing that 50% to 25% of systems under 10 kW incur these costs.

**Q34. WHY DID THE COMPANY ASSUME THAT A CONSTANT 3,555 PROJECTS UNDERGO THE PROJECT BILLING AND TARIFF RIDER ADDED STEP?**

A34. This was confirmed during our conversation to be an error. The 3,555 projects represented the total number of systems that were brought online in 2021, the baseline year for the analysis. This value was inadvertently applied to 2023-2025 installations rather than using the projected number of projects for those years.

**Q35. WHY DID THE COMPANY FAIL TO INCLUDE A WITNESS TESTING COST PER APP FOR SYSTEMS OVER 250 KW?**

A35. [Mr. Lucas] I initially assumed this to be an error, as it is directly contradicted by the Company's proposed changes to the Rules and Regulations, which clearly states: "3. All customer generation sized 250 kilowatts and above, whether installed behind-the-meter or

stand alone, must undergo a system impact study and **the witness testing process** as required by the Company and will be responsible for all associated fees."[32]

However, the Company confirmed during our conversation that not only do all systems over 250 kW undergo witness testing, but also that this witness testing was sufficiently complex and expensive that the Company decided to exclude these costs from the common interconnection fee calculation.

Q36. **IS THIS DECISION IN ANYWAY CONSISTENT WITH ITS APPROACH FOR THE REST OF THE COSTS?**

A36. No, it is not, and it shows the arbitrary nature of the Company's proposal. The Company is perfectly content to require systems under 10 kW to subsidize $2,000-$2,500 studies and $2,100 project reviews for systems over 250 kW, but it drew a line at the witness testing fee and required large projects to directly pay this fee. Why is it ok to exclude an expensive witness test from common cost recovery, but ok to include expensive study and project review costs in common cost recovery? Further, this confirmation directly undermines its statement that the $200 fee "collects the known costs directly attributed to process project applications for interconnection" as the mandatory witness testing fee for systems over 250 kW is specifically excluded from the calculation.

**Q37. ARE THERE OTHER UNEXPLAINED VARIATIONS IN THE WORKPAPER?**

A37. [Mr. Lucas] Yes. The number of projects that go through the various study process is inconsistent with the number of projects listed. Table 2 below shows the total count of projects by size, along with the number of studies conducted.

[32] 1.70_R&R Sec G - Customer Generation Tracked.doc (emphasis added)

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Less Than 10 kW-AC | 4,610 | 5,302 | 6,097 |
| 10-250 kW-AC | 85 | 97 | 112 |
| Greater Than 250 kW-AC | 12 | 13 | 15 |
| **Total Projects** | **4,706** | **5,412** | **6,224** |
| Feasibility Study | 92 | 106 | 122 |
| Standard Impact Study | 12 | 14 | 17 |
| Network Underground | 5 | 6 | 7 |
| Reliability Study | 4 | 5 | 6 |

*Table 2 - Interconnection and Study Counts*

It appears from these figures that most but not all projects over 10 kW are required to have a Feasibility Study, but there is no explanation for why 5, 4, and 5 of the projects over 10 kW in 2023, 2024, and 2025, respectively would not require a Feasibility Study. Likewise, it seems that the Standard Impact Study applies to projects over 250 kW but appears that some projects between 10 and 250 kW also require this study. Only a handful of projects require a Network Underground or Reliability Study; again, no context was provided for these assumptions.

I was able to get some answers regarding this step during my conversation with the Company. GPC explained that all projects, including projects under 10 kW, undergo a basic screening process that checks to make sure the account information is correct, and that the system size does not exceed the local transformer size. Projects that pass this initial screen – which includes an increasing number of small projects – do not need further studies. At the same time, the Company performs a Feasibility Study on 100% of the projects over 10 kW and a handful of projects under 10 kW that fail the initial screen. Likewise, the Impact Study is mandatory for 100% of systems over 250 kW and the few projects that do not pass the initial Feasibility Study process.

The Network Underground is only done on systems that intend to connect to an urban mesh grid and require additional operational analysis, such as ensuring the system does not export to the grid. The Reliability Study is triggered for the few projects that use new

equipment that has not been encountered by the Company before, even if the equipment is UL listed and conforms with IEEE standards. According to the Company, this is primarily solar plus storage projects.

*The Company's Hearing Witness Directly Contradicted GPC's Testimony and Discovery Answers and Was Unable to Provide Additional Details*

**Q38. WHICH COMPANY WITNESS SPONSORED THE $200 INTERCONNECTION FEE TESTIMONY AND SUPPORTED IT DURING THE HEARING?**

A38. Witness Legg sponsored the Company's testimony on the $200 interconnection fee and answered questions under cross examination during the hearing.

**Q39. DID MR. LEGG CONTRADICT PORTIONS OF THE COMPANY'S TESTIMONY AND DISCOVERY RESPONSES DURING HIS HEARING CROSS EXAMINATION?**

A39. Yes, he did in several instances. Mr. Legg stated: "And again, repeating a little bit of what I said yesterday, I don't run the renewables department, but I'm familiar with generally the cost being outlined here. From the standpoint of witness testing, that is something that for under 250 kW customers, my understanding is that they may not all be witness tested in the future. The company will decide if there is a need to witness test those, so it's -- so even though the fee was being paid by everyone, every single commercial [project] may not be witness tested."[33]

**Q40. WHAT DO THE COMPANY'S PROPOSED CHANGES TO THE CUSTOMER GENERATION SECTION OF THE RULES AND REGULATIONS SAY REGARDING WITNESS TESTING?**

A40. [Mr. Lucas] The Company's proposed language follows: "3. All customer generation sized 250 kilowatts and above, whether installed behind-the-meter or stand alone, must undergo a system impact study and the witness testing process as required by the Company and will be responsible for all associated fees… Customer-owned generators less than 250 kilowatts

[33] Hearing transcript page 1088 lines 15-24.

may also be required to undergo witness testing if the Company deems that the generator poses a safety or reliability risk."[34]

In its workpaper, the Company assumed that 100% of projects between 10 and 250 kW would undergo the Witness Testing and Meter Re-Programming. While it is accurate that a declining fraction of systems under 10 kW will undergo the Witness Testing and Meter Re-Programming step, these are dominated by residential systems. By contrast, 100% of projects over 10 kW, which will encompass nearly all if not all commercial projects, will in fact require witness testing. It was my understanding from the meeting with the Company that functionally all of the commercial projects do require witness testing, along with a declining share of residential projects as more evolve into the "cookie cutter" category.

**Q41. IS THERE ANOTHER EXAMPLE WHERE MR. LEGG CONTRADICTS THE COMPANY'S DISCOVERY RESPONSES?**

A41. Yes. When asked about the discovery workpaper, Mr. Legg stated:

> If you think about what those -- what those things all -- those costs entail, they're not based on the size of the customer. So setting up, in your example, a 7 kW customer versus a 200 kW customer in the billing system, or taking their application, or looking at a feasibility study, doing project review, all of those types of things are just based on the fact that they are interconnecting with the system. They're not necessarily driven by the size of the customer. So that's where we're proposing -- that's why we're proposing to spread those costs evenly across everyone who applies.[35]

**Q42. WHAT DOES THE WORKPAPER BEING DISCUSSED SAY ABOUT THESE STEPS?**

A42. [Mr. Lucas] While the workpapers were ambiguous on this matter, I confirmed through my conversation that all systems over 10 kW require a Feasibility Study and all projects over 250 kW require a full Impact Study. Systems under 10 kW do not require a Feasibility Study unless they fail the initial screening process, which based on the figures in the workpaper almost never happens. Further, only a few systems under 250 kW were required to undergo a full Impact Study.

[34] 1.70_R&R Sec G - Customer Generation Tracked.doc
[35] Hearing transcript p 1090 lines 5-12

Further, the Project Review and Generation Agreement cost is strongly differentiated by system size; projects under 10 kW cost $105, while projects over 250 kW cost $2,096. Despite Mr. Legg's testimony, there are clear instances that these costs are not only differentiated by project size, but that small projects are subsidizing large projects.

**Q43. WERE THERE INSTANCES IN WHICH MR. LEGG WAS UNABLE TO ANSWER QUESTIONS BECAUSE OF HIS LACK OF KNOWLEDGE OF THE SUBJECT MATTER?**

A43. Yes, there were several instances. When asked about whether larger systems are going to require more witness testing than smaller systems, Mr. Legg responded "I don't know that larger or smaller systems would require more or less witness testing. I'm not familiar with the procedures for who needs a witness test or not. That's really determined by our renewables department."[36]

When asked whether other utilities, including neighboring utilities in the South, waive similar fees for smaller systems, Mr. Legg responded "I'm not aware."[37]

When asked whether larger systems may require more studies and costs associated with interconnection than smaller systems, Mr. Legg again responded "That's possible, but I just -- I don't know because my group does not prepare those studies."[38]

When asked whether smaller systems would be subsidizing larger systems under the Company's proposal, Mr. Legg responded, "Well, as I look down through the data request -- and again, I'm limited in knowledge, that my department, like I said, doesn't run these different types of tests or take the applications."[39]

When asked about what is involved in the various steps such as Project Review and Generate Agreement and Project Billing and Tariff Rider Added, Mr. Legg again struggled to provide clarity to the Company's data:

> Yeah, we're reaching -- again, we're reaching the limits of my understanding of this, but, you know, reviewing projects and generating an agreement for the customer to

[36] Hearing transcript page 1090 lines 19-23
[37] Hearing transcript page 1091 line 5
[38] Hearing transcript page 1092 line 4-6
[39] Hearing transcript page 1092 line 24 to page 1093 line 2

sign. I would assume project billing and tariff rider, these have to be set up in our billing system and billed through -- through -- you know, it's more complex billing than standard residential billing because you have the pushback aspect. You have the netting aspect. So there's more handling in the billing setup for these customers as well.[40]

**Q44. WERE YOU ABLE TO GET MORE INFORMATION ABOUT THE BILLING MODIFICATION PROCESS IN YOUR INFORMAL CONVERSATION?**

A44. [Mr. Lucas] Yes, I was, and the answers were very surprising. Based on my understanding of the conversation, the steps need to process billing system changes is extremely inefficient, requiring multiple "touches" of the customer's account throughout the interconnection process. As I recall, the Company said that billing personnel had to make account adjustments to the billing system three different times in the process. This is followed by manual review of every single RNR account to ensure that the billing system, meter reads, and netting calculations are performed correctly.

**Q45. DOES GPC PROVIDE ANY SUPPORT FOR THE COST OF EACH STUDY OR STEP IN THE INTERCONNECTION REVIEW PROCESS?**

A45. [Mr. Lucas] No, it did not. The studies range from $53 for the Feasibility Study to $2,472 for the Network Underground study. Similarly, the Project Review and Generate Agreement costs vary substantially; $105 for systems under 10 kW, $157 for systems between 10 and 250 kW, and $2,096 for systems over 250 kW. No data, such as the number of labor hours required to perform the study, is provided to support these figures.

The Company assumes a cost of $105 for systems under 10 kW to complete the project review and generate the interconnection agreement. Given the Company's use of PowerClerk, which standardizes the intake of project information, it should be trivial to automatically generate a standard form interconnection agreement. However, I learned during my meeting that PowerClerk cannot directly create the interconnection agreement despite having all the relevant information. Instead, a GPC employee must enter the

[40] Hearing transcript page 1094 lines 5-14

information into another form, which can then be used to generate an interconnection agreement. It is unclear why this functionality is not fully automated.

The Company also assumes a total cost of $88 for the Project Billing and Tariff Rider Added step. Given that GPC has not indicated anywhere in its testimony that it manually bills these customers, I expected RNR bills to be generated automatically by the billing system software and that enabling an RNR tariff would involve little more than updating a few account flags in the Company's billing system. But after my conversation with the Company, it appears that these steps are much less efficient than they should be.

**Q46. PLEASE EXPAND ON THIS POINT.**

A46. [Mr. Lucas] I am particularly concerned about the revelation that billing analysts have to manually verify every account to ensure the billing system is working properly. The details were a bit unclear, but it was suggested that this step was needed to validate that the tariff was eligible for the RNR program, that meter reads were properly pulled into the system, that solar generation was properly read, that the netting calculation was done correctly.

It is concerning how a billing system that surely cost millions of dollars and an AMI infrastructure that cost tens or hundreds of millions of dollars needs to be manually checked for such basic billing functionality. Before I switched to clean energy policy, I worked for Accenture for six years implementing enterprise resource software at Fortune 500 companies. When I worked on these systems 20 years ago, I would never have designed a process that needed this level of manual intervention, nor would any client ever accept such a solution as it would be notoriously inefficient and fail to achieve adequate cost savings.

*Under the Company's Proposal, Customers with Small Systems Would Subsidize Customers with Larger Systems*

**Q47. DOES THE COMPANY PROPOSE TO CHARGE INDIVIDUAL PROJECTS BASED ON THE STUDIES AND PROCESS STEPS THEY ARE REQUIRED TO PERFORM?**

A47. No, it does not. Rather, it proposes to charge every project a pro rata share of the total cost of all the studies for all projects. For example, the Feasibility Study (at a cost of $53 per study in 2023) is generally constrained to projects over 10 kW, and the Standard Impact ($1,988), Network Underground ($2,472), and Reliability ($227) studies are applicable to just a handful of projects over 250 kWAC. Rather than charge these costs to the size category, the Company proposes to have every system pay $9 in 2023 for these studies.

Similarly, the Company assumes that 50% of projects under 10 kW will undergo the Project Review and Generate Agreement step (at $105 per application in 2023), while all projects between 10 and 250 kW ($157 per application) and over 250 kW ($2,096) will require this step. As with the interconnection study, rather than charge the costs on a per-size basis, the Company lumps all costs into one average $59 fee for this step. This means that a large project saves more than $2,000 by having smaller projects subsidize its project review.

**Q48. WHAT WAS THE COMPANY'S JUSTIFICATION FOR THIS APPROACH?**

A48. Mr. Legg discussed the Company's approach during cross-examination "So I think the thought was, yeah, it's the -- these costs are spread across all of these different customers. There may be some that vary by size of customer, but generally these are costs that are being caused across, regardless of size, across this group of customers and they should be responsible for paying those costs."

**Q49. IS THIS STATEMENT SUPPORTED BY THE EVIDENCE PRESENTED IN THE DISCOVERY RESPONSE?**

A49. [Mr. Lucas] No, it is not. I was able to produce an analysis that broke out the various costs from the Company's workpaper on a per application basis. This required making assumptions about the cost of the excluded witness test fee for systems over 250 kW and to correct the error related to the 3,555 projects in the Project Billing and Tariff Rider Added step. I assumed the Witness Test for systems over 250 kW cost $2,500 in 2023 as this was just slightly higher than the highest cost that the Company deemed appropriate to socialize among all projects.

**Q50. WHAT IS THE RESULT OF THIS ANALYSIS?**

A50. [Mr. Lucas] The results are shown below in Table 3 below using the Company's assumed costs. As discussed above, the Company did not provide support for its Project Review and Generate Agreement and Project Billing and Tariff Rider Added steps. Even given the incredible inefficiencies in these steps uncovered during my conversation with the Company, these costs may be overstated, and I was not able to obtain the details needed about the labor rate and hours required to perform each step. The Company also provided no support for the specific fraction of sub-10 kW systems that it deemed to not be "cookie cutter" that would be able to bypass several of the manual steps.

Despite this, it is clear as day that there is a substantial variation in interconnection costs. Systems under 10 kW – using the Company's unverified cost figures for its billing steps – average $203 over the three years. Systems between 10 and 250 kW average $469. By contrast, systems over 250 kW incur an average cost of $8,294, which may be understated given the additional complexity of the mandatory witness test for large systems.

| | 2023 | 2024 | 2025 | Avg |
|---|---|---|---|---|
| **Less Than 10 kW-AC** | **$236** | **$184** | **$188** | **$203** |
| Impact & Feasibility Study | $0 | $0 | $0 | $0 |
| PowerClerk Costs | $34 | $34 | $34 | $34 |
| Project Review and Generate Agreement | $52 | $27 | $28 | $36 |
| Project Billing and Tariff Rider Added | $88 | $91 | $93 | $91 |
| Witness Test and Meter Re-Programming | $62 | $32 | $33 | $42 |
| **10-250 kW-AC** | **$456** | **$469** | **$482** | **$469** |
| Impact & Feasibility Study | $53 | $55 | $57 | $55 |
| PowerClerk Costs | $34 | $34 | $34 | $34 |
| Project Review and Generate Agreement | $157 | $162 | $167 | $162 |
| Project Billing and Tariff Rider Added | $88 | $91 | $93 | $91 |
| Witness Test and Meter Re-Programming | $124 | $127 | $131 | $127 |
| **Greater Than 250 kW-AC** | **$7,947** | **$8,271** | **$8,665** | **$8,294** |
| Impact & Feasibility Study | $3,228 | $3,412 | $3,662 | $3,434 |
| PowerClerk Costs | $34 | $34 | $34 | $34 |
| Project Review and Generate Agreement | $2,096 | $2,159 | $2,224 | $2,160 |
| Project Billing and Tariff Rider Added | $88 | $91 | $93 | $91 |
| Witness Test and Meter Re-Programming | $2,500 | $2,575 | $2,652 | $2,576 |

*Table 3 - Interconnection Fees by Project Size*

**Q51. IN YOUR VIEW, IS IT APPROPRIATE FOR SMALL CUSTOMERS TO SUBSIDIZE LARGE CUSTOMERS IN THIS WAY?**

A51. No, and given the rhetoric the Company uses in other contexts about not charging customers for costs they don't create, it is surprising to see the opposite proposed here.

*There is Precedent for Tiered Fees and Reducing or Eliminating Interconnection Fees for Small Customers*

**Q52. DID THE COMPANY PROVIDE ANY EVIDENCE REGARDING THE PREVALENCE OF FLAT INTERCONNECTION FEES REGARDLESS OF SYSTEM SIZE?**

A52. No, it did not. Further, when asked whether utilities, including neighboring utilities in the south, waive interconnection fees for smaller systems, Mr. Legg responded "I'm not aware."[41]

**Q53. DID YOU REVIEW THE INTERCONNECTION FEES FOR UTILITIES IN NEARBY STATES?**

A53. Yes. Two themes appeared from this review, neither of which are found in the Company's proposal. First, utilities charged differential fees based on system size. Second, small systems often pay no interconnection fees.

The state of Florida issued regulations guiding the interconnection process.[42] These rules establish three tiers: under 10 kW, between 10 and 100 kW and between 100 kW and 2 MW. For the smallest tier, utilities are prohibited from charging any interconnection fees, and for the two larger tiers, the utility can petition the Florida commission to implement cost-based fees. Florida Power and Light charges a flat $400 fee for projects between 10 and 100 kW.[43] For projects between 100 kW and 2 MW, FPL charges an application fee of $1,000 and, if necessary, and interconnection study fee of $2,000.[44]

[41] Hearing transcript page 1091 line 5
[42] https://www.flrules.org/gateway/readFile.asp?sid=0&tid=5455200&type=1&File=25-6.065.doc
[43] https://www.fpl.com/content/dam/fplgp/us/en/clean-energy/net-metering/pdfs/net-metering-tier2.pdf
[44] https://www.fpl.com/content/dam/fplgp/us/en/clean-energy/net-metering/pdfs/net-metering-tier3.pdf

Dominion Energy in Virginia does not charge a fee for systems under 10 kW, but does charge a witness test fee of $50 for systems between 10 and 25 kW.[45] Systems up to 500 kW pay a $100 processing fee, and systems over 500 kW pay a $1,000 processing fee.[46] In South Carolina, Dominion charges $100 for systems up to 20 kW, $250 for systems between 20 and 100 kW, and $500 for systems between 100 kW and 2 MW.[47]

Duke Energy has a similar structure as the other utilities. In North Carolina, it charges a $100 application fee for residential systems up to 20 kW, $750 for non-residential projects between 20 and 100 kW, and $1,000 for projects between 100 kW and 2 MW.[48,49]

**Q54. WHERE DOES THIS LEAVE THE RECORD ON THE COMPANY'S INTERCONNECTION FEE PROPOSAL?**

A54. [Mr. Lucas] The Company has offered no evidence in its testimony or exhibits that the current fees fail to collect the costs for reviewing interconnection applications. The Company's witness at the hearing was unable to explain what each step consisted of, much less whether the values in the Company's workpaper were supportable. He also contradicted key elements of the Company's own documentation, which clearly shows that interconnection fees are highly dependent on system size. And despite this, GPC proposes to dramatically increase fees for small systems. Under the current regime, a customer with a 7-kW system would pay $35. This would increase to $200 under its proposal.

The Company's only support for its proposal contained seemingly inconsistent data, unsupported assumptions, and at least one calculation error. The number of projects is inconsistently handled within the workpaper, and no justification for these discrepancies was provided. Some of the steps are performed less frequently in future years, reducing costs, but

[45] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/terms-and-conditions/vatc25ra.pdf?la=en&rev=23280dd2f29e4b5c91ca2f163976a50e
[46] https://law.lis.virginia.gov/admincode/title20/agency5/chapter314/section170/
[47] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/south-carolina/renewable-energy-developers/sc-generator-interconnection-procedures.pdf?la=en&rev=c0dc6f7905574d5d80fce185c8352ad4
[48] https://www.duke-energy.com/home/products/renewable-energy/generate-your-own/interconnection-up-to-20kw#:~:text=A%20nonrefundable%20%24300%20fee%20is,the%20Interconnection%20Request%20Online%20Application.
[49] https://www.duke-energy.com/business/products/renewables/generate-your-own/interconnection-more-than-20kw

no explanation was offered for why these values fall over time. The cost for steps such as making billing system modifications are not supported by any data in the record or in discovery responses. Steps that appear to be quite basic – such as flagging an account as a RNR customer in the billing system – have costs that imply unreasonably high levels of effort. Although I was able to clarify some of these issues – including the surprisingly inefficient billing process – during my meeting with the Company, it has offered no evidence into the record on these points that support its cost structure.

Even if the Company was able to demonstrate that it is under-collecting interconnection review costs, its proposal is unfair to small customers. Customers installing larger systems require impact and feasibility studies that are simply not performed for small systems. In total, the cost of the interconnection review for a project over 250 kW is more than 40 times more expensive than for a project under 10 kW, and yet the Company proposes charging every customer the same fee.

Further, the Company arbitrarily decided to socialize high study costs for large systems while selectively choosing to exclude witness testing fees for those same projects. This approach is completely inconsistent with its stated claim that all projects should bear interconnection costs proportionately.

**Q55. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?**

A55. We recommend the Commission reject the proposal and maintain its current fees of $5/kW for systems under 250 kW. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW. The interconnection fees of neighboring utilities discussed above provide the Commission with a range of reasonable options.

## IV. GEORGIA POWER'S NET METERING REVENUE ADJUSTMENT IS FLAWED AND LACKS CONTEXT

**Q56. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A56. We discuss the Company's proposed $1.4 million revenue adjustment related to "base revenue erosion associated with the monthly netting cost shift."[50] Given the Company plans to provide RNR-related testimony in the second phase of this proceeding, we limit our discussion to the specific $1.4 million figure and its incorporation into the Company's cost of service study. We anticipate the Company will produce more than the one paragraph of testimony it submitted in this round – half of which was directly copied from its IRP filing – in the second phase of this case, and we will discuss its broader RNR testimony at the appropriate time.

**Q57. PLEASE SUMMARIZE YOUR FINDINGS.**

A57. The $1.4 million adjustment is based solely on lost revenue and not supported by any cost of service analysis. The Company did not incorporate any demand or energy reductions from exported energy from RNR customers in its cost of service study ("COSS") model. This results in the Company using billing determinants that are too high for classes with either RNR Monthly or RNR Instantaneous customers, which in turn results in too many costs being allocated to these classes. These steps are necessary to determine whether the $1.4 million in revenue erosion is offset in full or in part by cost reductions from exported energy.

Even if one were to take the $1.4 million base revenue erosion figure at face value, it pales in comparison to the astounding amount of excess revenue that the Company has collected from its customers over the past decade. While the Company touts that the "embedded sharing mechanism" associated with the Alternate Rate Plan structure "has enabled the Company to provide approximately $297 million in benefits back to its customers since 2013", this is a spectacularly misleading statement. In reality, the Company

[50] Legg Direct at 11.

has collected more than $1.8 billion above its approved ROE from customers in the past eleven years, with only a small fraction of that returned to customers through the sharing mechanism.

**Q58. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE PURPORTED COST SHIFT?**

A58. We recommend the Commission deny the Company's request to adjust revenue by $1.4 million. The Company did not appropriately account for exported energy in its COSS, and as a result, has overallocated costs to customer classes with RNR projects that is not considered in this figure. This hits the residential class most directly given its higher proportion of exported energy.

We also recommend the Commission strongly reconsider the width and asymmetry of the currently-approved ROE dead band. The Company has consistently managed its operations to increase its profits well beyond the central approved ROE value. Expanding the delta between the ROE and the upper end of the dead band has resulted in the Company collecting $114 million in 2020 and 2021 that would have otherwise been returned to customers.

*The Company Does Not Incorporate Demand or Energy Reductions from Exported RNR Generation in its COSS Model*

**Q59. HOW DOES THE COMPANY CALCULATE THE $1.4 MILLION COST SHIFT FIGURE?**

A59. The Company's original filing did not contain details on the calculation, so Staff asked for the workpapers in discovery.[51] In response, the Company provided a nearly-identical analysis that it presented in its 2022 Integrated Resource Plan proceeding.[52] This analysis takes the following steps to calculate the figure:

[51] STF-TAI-1-27.
[52] STF-TAI-1-27 Attachment A.

1. Calculate the bill a customer would have had on the RNR Instantaneous rate, specific to the customer's tariff and inclusive of all rider revenues.
2. Calculate the bill a customer received on the RNR Monthly rate, which first nets inflow from the Company and exported energy on a monthly basis.
3. Add up the difference between these two values for all months for all customers on a given tariff.
4. Scale each tariffs' results to 5,000 customers based on the composition of the RNR active, pending, and wait list customers.

**Q60. IS THIS ARGUMENT BASED ON COST OF SERVICE OR BASED ON REVENUE DEFICIENCY?**

A60. This analysis is based entirely on revenue deficiency and does not factor cost of service at all. The Company simply calculated the difference in customer bills on the two netting schemes (instantaneous vs. monthly) and added up the total difference. There is no consideration of how the exported energy impacts the Company's cost of service.

**Q61. DID YOU IDENTIFY AN ISSUE WITH THE AVOIDED SOLAR COST RATE THE COMPANY USED IN ITS ANALYSIS?**

A61. Yes. In its workpapers, GPC uses the incorrect solar avoided cost rate. It is using the 2022 value of $0.02676/kWh from the 2021 Avoided Cost and Solar Avoided Cost Projection filing in Docket 16573.[53] Nine of the twelve months of data in the Company's analysis was from 2021, not 2022. GPC should have used the appropriate rate for the appropriate month, or if simplifying the analysis, used an avoided cost figure more weighted towards the 2021 value ($0.02884/kWh) than then 2022 value ($0.02676/kWh). Using a lower value for the avoided cost credit rate increases the apparent difference between the monthly and instantaneous RNR netting, making the total "cost shift" appear larger than it would otherwise. While this does not directly impact the base rate calculation as the RNR credit is accounted for separately, it does make the program seem more expensive in total than it should.

We also find it problematic that the Company assumed the solar avoided cost rate will remain constant through the three years of the ARP. This calculation is a function of the Company's avoided cost of generation, which is itself heavily influenced by the price of

[53] 2021 Avoided Cost and Solar Avoided Cost Projections, Docket 16573, July 30, 2021. https://psc.ga.gov/search/facts-document/?documentId=186573

natural gas. In fact, when the Company updated its filing this summer, the 2022 BTM solar avoided cost rate increased from $0.02676/kWh to $0.03400/kWh, a 27% jump.[54] Natural gas prices have remained high through all of 2022 and are projected to remain elevated through 2023 as well.[55] This suggests that the solar avoided cost rate will remain higher in the future than in the past, further inflating the Company's estimate of the "cost shift" associated with this program.

**Q62. HOW DOES THE COMPANY TREAT CUSTOMER-GENERATOR ENERGY THAT IS DELIVERED TO ITS GRID FROM BEHIND-THE-METER ("BTM") SYSTEMS IN ITS COSS AND ASSOCIATED WORKPAPERS?**

A62. GPC ignores it. The billing determinants that are used in the COSS are not adjusted for excess generation that is exported to the Company's system.

**Q63. HOW DID YOU DETERMINE THIS?**

A63. [Mr. Lucas] It was through a combination of discovery responses and an analysis of the Company's workpapers. GPC provided two data sets in response to Staff discovery requests; one that contained hourly loads during 2021 for the entire Georgia Power system,[56] and one that contained hourly loads during 2021 for each rate schedule.[57] Staff asked subsequent discovery on whether the data file with hourly loads for each rate schedule included exported energy from the RNR tariffs.[58] The Company responded that the original data "does not include customer generated energy (delivered to the Georgia Power Grid) under Rate RNR-10."[59]

I was able to reconcile the data between the schedule-specific hourly load file (which was confirmed to exclude exported energy), the total Georgia Power hourly load file, and the

[54] 2022 Avoided Cost and Solar Avoided Cost Projections, Docket 16573, July 29, 2022. https://psc.ga.gov/search/facts-document/?documentId=191003
[55] https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html
[56] STF-TAI-1-10.
[57] STF-TAI-1-12.
[58] STF-TAI-4-2.
[59] Id.

Company's COSS model using the historic 2021 test year.[60] In particular, I was able to confirm that the tariff-specific and total jurisdictional demand figures matched between the files, meaning they were developed from the same original data source. Given the tariff-level hourly load file did not contain any excess energy, it follows that the COSS does not either.

**Q64. WHY DOES THIS MATTER?**

A64. Exported energy from a customer's BTM system flows to meet the nearest demand. In almost every case for small RNR systems, this will mean the excess energy flows out through the customer-generators meter to the nearest transformer, and from there flows to the nearest neighbor's load. The energy flows through the neighbor's meter, causing the neighbor to be billed the full retail rate for this energy, including embedded costs for the Company's entire generation, transmission, and distribution system, as well as rider charges related to fuel expense, nuclear prepayments, and coal ash pond mitigation costs. This is despite the fact that the Company did not generate the energy, does not own the BTM asset, and only a tiny fraction of its distribution system was used to facilitate the energy delivery.

From a COSS perspective, failing to decrement the class's energy and demand allocators for exported energy means that the Company is overstating the allocators for classes with RNR systems. While the residential class only consumes 36% of electricity purchased from the Company by customers on an RNR tariff, it accounts for nearly 60% of exported energy.[61] These customers invested capital in generators that provide benefits to the Company's system through peak demand reduction and avoided fuel costs, among other benefits. Further, because residential customers export a relatively higher proportion of generation compared to non-residential customers, they are disproportionately harmed by the Company's omission of exported generation in the COSS. The Commission should require GPC to incorporate exported energy through the COSS model and flow the resulting class allocator reductions to the appropriate customer class.

[60] STF-TAI-1-1.
[61] STF-TAI-4-1.

*The $1.4 million NEM Adjustment Pales in Comparison to the Company's Pending Revenue Requests and Billions of Dollars of Excess Revenue Collection*

**Q65. HOW DOES THE $1.4 MILLION NEM ADJUSTMENT COMPARE TO SOME OTHER FIGURES FROM THIS CASE?**

A65. It is literally a rounding error. The $1.4 million NEM adjustment, if approved, would amount to less than twenty cents a year.[62] By contrast, the Company is requesting a total rate increase of roughly $2.8 billion in additional revenues between 2023 and 2025.[63] If these revenues are approved, rates will collect $1 billion more annually in 2025 than in 2022, leading to an annual increase of roughly $195.48 to a residential customer using 1,000 kWh per month.[64] In other words, the rate increase requested by the Company is about 1,000 times larger than the NEM adjustment.

On top of this, the Company is not seeking to add all its investments in Plant Vogtle to the rate base in this rate case, resulting in an anticipated $8.2 billion exclusion in rate base in 2024.[65] When asked how an on time delivery of Plant Vogtle will impact rates, the Company answered that it will increase rates by another 10.1% in 2024, on top of the request being made in this docket, and excluding costs over the already-approved $7.3 billion level.[66] Based on current rates, this adjustment may create an additional increase of $166 per year for a typical residential customer using 1,000 kWh per year, not including any future approved costs over $7.3 billion.[67]

Between the Company's rate case request in this docket and the potential approval of partial costs of Plant Vogtle, residential customers may see an increase in base rates of more

[62] $1,383,445 / 84,459,603 MWh = $0.0164/MWh. $0.0164/MWh * 12 MWh/year = $0.197/year. STF-TAI-1-27 Attachment A, Evans Exhibit LPE-1 and LPE-2.
[63] Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson On Behalf of Georgia Power Company at 7, 9 ("Panel Direct").
[64] Panel Direct at 11.
[65] APA-SPA-ADH-MBR-6, Schedule 3.
[66] STF-NEC-1-14.
[67] 10.1% / 11.9% * $16.29 *12 = $165.91

than $350 per year in a few years. Compared to this, the two dimes per year for the NEM adjustment is literal pocket change.

**Q66. IS THERE ANOTHER MECHANISM IN THE RATE CASE THAT ALSO EXPOSES CUSTOMERS TO SIGNIFICANT COST INCREASES?**

A66. Yes. Each rate case, the Commission approves a specific ROE and capital structure. Currently, the Company enjoys a 10.5% ROE and a ~~54%~~ 56% equity / ~~46%~~ 44% debt capital structure.[68] These values feed into the COSS to calculate the total revenue requirement based on forecasted net plant in service, operating expenses, and taxes. From this revenue requirement, rates are designed based on forecasted usage to exactly collect the revenue requirement. Of course, the assumptions embedded in the COSS, load forecast, and cost projections will have errors, and the actual revenues collected and costs incurred will not exactly match those in the COSS models. The result is an ROE that differs from the Commission-approved 10.5%.

This is addressed in Georgia through the use of an ROE earning band mechanism. While rates are calculated based on assumptions to produce an ROE of 10.5%, if the Company collects revenue or manages costs to produce an ROE above or below this figure within a certain range (the "dead band"), no additional action is required. Currently, the Company's Commission-approved ROE is 10.5%, but the Company's multi-year rate plan is authorized to operate within an ROE dead band of 9.5% to 12%.[69]

**Q67. WHAT WAS THE ORIGIN OF THE ROE DEAD BAND MECHANISM?**

A67. The ROE dead band concept has been in place since at least the 2010 rate case settlement. In that case, the ROE dead band of 10.25% to 12.25% was established, with a central approved ROE of 11.15%.[70] In the 2013 rate case settlement, which remained in force from 2013 through 2018, the Commission approved an ROE dead band of 10% to 12% while dropping

[68] Order Adopting Settlement Agreement at 6, December 17, 2019, Docket 45216. ("2019 Rate Case Order")
[69] 2019 Rate Case Order at 9.
[70] Final Order at 10, December 29, 2010, Docket No. 31958.

the ROE to 10.95%.[71] Two-thirds of earnings in excess of 12% were returned to customers, and the Company could petition for an interim cost recovery mechanism should the ROE drop below 10%.[72] In the 2019 rate case settlement, the ROE was reduced to 10.5% and the ROE dead was adjusted to its current 9.5% to 12.0% with 80% of excess earnings being returned to customers.[73] GPC agreed to a one-time foregoing of its share of the earnings above the dead band in 2019 as part of a settlement agreement.[74]

Under this structure, if the ROE obtained from actual adjusted revenues and costs in a year is between 9.5% and the authorized ROE of 10.5%, the Company would be required to absorb the lower revenues. Conversely, if actual adjusted revenues and costs produce an ROE between 10.5% and 12%, the Company is entitled to keep all of the excess revenue. If the effective ROE falls below the lower end of the dead band (currently 9.5%), the Company may petition the Commission for an increase in base rates. If the effective ROE rises above the top of the dead ban (currently 12%), the Company must return to customers 80% of earnings above the top ROE threshold.

**Q68. ARE APPROVED ROE DEAD BANDS A REASONABLE CONCEPT IN THEORY?**

A68. Yes. When implemented properly within a multi-year rate plan construct, an ROE dead band can provide useful flexibility to a utility. Locking in rates for several years increases rate certainty for both the utility and customers and reduces the time and expenses involved in rate cases. Pairing this with an earnings dead band provides flexibility when actual results invariably diverge from forecasts.

However, there must be correspondingly robust controls over the ROE dead band and earnings mechanisms that mitigates extreme outcomes. For example, if rates were calculated based on certain assumptions that were reasonable at the time but turned out to be meaningfully short of what a utility needed to cover its costs and earn a reasonable rate of

[71] Order Adoption Settlement Agreement, December 23, 2013, Docket 36989.
[72] Id.
[73] 2019 Rate Case Order at 5-6.
[74] Id at 11.

return, there would be policy benefits to allowing the Company to request a rate increase prior to the end of the multi-year plan to help maintain its financial security. On the flip side, if the embedded assumptions in costs and rates result in the Company earning an outsized profit, mechanisms should kick in to protect consumers.

As with all things in utility regulation, there is debate over the "right" answer. This was an issue in the prior rate case, with Staff recommending an earnings band of 9.2% to 10.5% against an ROE of 9.2%, and DOD/FEA recommending narrowing the dead band to +/- 0.5% around the authorized ROE of 9.1%.[75] Instead, the Commission found reasonable and approved the Company-proposed 9.5% to 12.0% ROE band.[76] This resulted in an ROE dead band of -1% / +1.5% around the approved ROE, which was an expansion from the prior -0.95% / +1.05% band that had been in place from 2014 to 2019. As discussed shortly, this decision had material consequences for customers.

**Q69. HOW HAS THE COMPANY PERFORMED RELATIVE TO ITS AUTHORIZED ROE?**

A69. GPC has consistently over-performed relative to its authorized ROE, although the exact amount was not produced because the Company dodged answering a discovery question on this issue. When asked by Staff to "identify the incremental profit (in dollars) retained by Georgia Power above *the ROE* set by the Commission for each year from 2013 through 2021", the Company responded with a workpaper that identified earnings over the *ROE dead band* approved by the Commission.[77] This subtle deflection obscures a critical data point that Staff appeared to be seeking by asking for the incremental revenue and profit above "the ROE" (singular, implying the central, approved ROE) set by the Commission, not the "REO band" as answered by the Company.

Despite its attempt to obscure the question asked, GPC's response is revealing. In the nine years between 2013 and 2022, the Company collected excess revenue in six years totally

[75] 2019 Rate Case Order at 5-6.
[76] Id.
[77] STF-PIA-3-2 (emphasis added).

$380 million *above* the top of the ROE dead band.[78] This response does not include excess revenue above the approved, central ROE value and below the top of the ROE band. Given the Company has not requested a special rate case in these years to address earnings below the bottom of the ROE threshold, it stands to reason that it has not under-earned below the ROE band.

**Q70. HOW DID THE COMPANY DISCUSS THESE RESULTS?**

A70. In testimony, the Company touted the results as a "benefit" of the multi-year plan: "Not only have the three-year rate plans helped to keep rates stable and predictable, but the embedded sharing mechanism has also enabled the Company to provide approximately $297 million in benefits back to customers since 2013."[79]

This characterization is staggering in its bravado. To frame as a "benefit" to customers the return of a portion of the nearly $400 million collected above and beyond a generous ROE earnings dead band is Orwellian doublespeak. To accept this framing is to accept the notion that the Company is entitled to unlimited upside profits from its operations and that any limits on its earnings is a "benefit" for customers. This is simply not how a monopoly's earnings should work under the regulatory compact.

**Q71. HOW MUCH HAS THE COMPANY COLLECTED ABOVE ITS CENTRAL APPROVED ROE BUT BELOW THE TOP OF THE ROE EARNINGS BAND?**

A71. [Mr. Lucas] This is an excellent question, and in fact was directly asked by Staff in discovery. However, as mentioned above, the Company did not answer the question posed. As I am unable to ask discovery, I was not able to ask a follow up question requesting this information directly from the Company.

That said, I was able to produce a reasonable estimate based on the Annual Retail Surveillance reports ("ARS") that have been filed since 2011. Based on my analysis, between 2011 and 2021 the Company has collected a total of $1.49 billion in revenue above

[78] STF-PIA-3-2 Attachment.
[79] Womack Direct at 4.

its approved ROE but below the upper limit of the ROE dead band. This revenue is not impacted by the sharing mechanism, and the Company is authorized to keep every dollar. Further, the Company has retained an additional $83 million from earnings above the top of the ROE dead band, pushing its total excess collection to $1.57 billion.

**Q72. HOW DID YOU CALCULATE THIS FIGURE?**

A72. [Mr. Lucas] I used the workpapers that were filed with each of the Company's ASRs.[80] These workpapers included a summary of the Company's adjusted earnings and adjusted rate base; its cost of equity, debt, and capital structure; and a calculation of its actual ROE based on those values. Workpapers for years in which the Company reported excess earnings above the ROE dead band had a "Sharing" tab that calculated the excess revenue and cost share between customers and the Company.

Using these files, I was able to simply update the ROE to the central approved value and have the model calculate the excess revenue requirement collected. For years in which the Company did not report an ROE above the top of the ROE band, I recreated the "Sharing" tab to perform this calculation. I also reviewed the annual Staff filings and Commission orders on the ASRs, some of which made adjustments to the ROE or reported revenue collections found in the Company's original filing.

**Q73. WHAT ARE THE RESULTS OF THIS ANALYSIS?**

A73. [Mr. Lucas] My results are below in Table 4. Over the past 11 years, the Company has collected a staggering $1.87 billion above its approved ROE. "Only" $380 million of this is above the upper ROE dead band limit and subject to partial refund to customers; this is the source of the $297 million "benefit" that the Company references in testimony.

[80] See e.g. Georgia Power Company 2021 Annual Surveillance Report, Docket 42516, workpaper "2021 DI21.xlsx"

| | Approved ROE | Upper Band | Actual ROE | Above ROE & Below Upper Band | Above Upper Band | Total Excess Revenue Collection |
|---|---|---|---|---|---|---|
| **2011** | 11.15% | 12.25% | 11.72% | $67,795,000 | $0 | $67,795,000 |
| **2012** | 11.15% | 12.25% | 12.14% | $122,525,000 | $0 | $122,525,000 |
| **2013** | 11.15% | 12.25% | 11.56% | $52,200,000 | $0 | $52,200,000 |
| **2014** | 10.95% | 12.00% | 12.14% | $132,184,000 | $16,962,000 | $149,146,000 |
| **2015** | 10.95% | 12.00% | 11.55% | $74,961,000 | $0 | $74,961,000 |
| **2016** | 10.95% | 12.00% | 12.49% | $142,500,000 | $65,325,000 | $207,825,000 |
| **2017** | 10.95% | 12.00% | 12.04% | $153,033,000 | $5,784,000 | $158,817,000 |
| **2018** | 10.95% | 12.00% | 13.18% | $136,196,000 | $154,400,000 | $290,596,000 |
| **2019** | 10.95% | 12.00% | 12.88% | $147,463,000 | $123,480,000 | $270,943,000 |
| **2020** | 10.50% | 12.00% | 11.89% | $216,976,000 | $0 | $216,976,000 |
| **2021** | 10.50% | 12.00% | 12.09% | $243,860,000 | $14,167,000 | $258,027,000 |
| **Total** | | | | $1,489,693,000 | $380,118,000 | $1,869,811,000 |
| **Average** | 10.92% | 12.07% | 12.15% | $135,427,000 | $34,556,000 | $169,983,000 |

*Table 4 - GPC Excess Revenue Collection*

**Q74. WHAT ARE YOUR OBSERVATIONS ON THIS RESULT?**

A74. [Mr. Lucas] I have several. First, despite the revenue sharing mechanism, the Company has been able to retain hundreds of millions of dollars per year of excess revenue above its central, approved ROE value before it has to return a single dollar to customers. While the ROE earnings dead band can be a useful policy construct when paired with multiyear rate plans, it is currently set too wide and too strongly favors the Company over customers. I urge the Commission to revisit the appropriateness of the current band, particularly the recent approval of the upside potential to 1.5% over ROE.

Second, the Commission's approved ROE is not functioning as a practical limit on the Company's earnings. If the Company had experienced years in which it earned less than its ROE and years in which it earned more than its ROE, one could argue that its rates were set correctly. But the persistent one-way prejudice towards overearning strongly suggests that the Company rates are consistently set too high relative to the costs it actually incurs. GPC has collected excess revenue in every single year since 2011, with an average of $135 million collected above the central ROE and below the top of the ROE dead band. The smallest annual increment was an excess ROE of 0.41% worth $52 million; the largest was 2.23% worth $291 million. The Company's actual ROE has averaged 12.15% over the past 12 years, 223 basis points higher than the average approved ROE of 10.92%.

Third, the changes over time in GPC's rate base and capital structure have exacerbated this issue. In 2011, the Company's adjusted net rate base was $14.3 billion and its equity share set to 51.4%.[81] In 2021, its adjusted net rate base had grown 51% to $21.6 billion and its equity share nearly 5% to 56.1%.[82] The combination of a larger rate base on which it earns a return, a higher share of equity in its capital stack, and the approval of a 1.5% upside prior to any refunds to customers has resulted in huge increase in revenue collections above the ROE but below the upper ROE band. The Company had an ROE of 12.14% in 2012 and collected $123 million above its ROE but below the upper ROE dead band. GPC's 2021 ROE was lower at 12.09%, but it collected $244 million above its ROE and below the upper ROE dead band.

**Q75. HOW DO THESE FIGURES TRANSLATE INTO A COST PER TYPICAL RESIDENTIAL CUSTOMER?**

A75. [Mr. Lucas] It is difficult to calculate this figure precisely as customers on different tariffs may be contributing relatively more or less to the over-collection depending on how their rate was designed. However, I reviewed the total revenue collected per class from 2011 to 2021 using Energy Information Administration ("EIA") data and applied the overcollection in proportion to total revenue share.[83] These figures were divided by the number of residential customers in each year to produce an average impact shown below in Table 5.

[81] GPC 2011 Annual Retail Surveillance Report.
[82] GPC 2021 Annual Retail Surveillance Report.
[83] Energy Information Administration Form 861. Available at https://www.eia.gov/electricity/data/eia861/

| | Above ROE & Below Upper Band | Residential Share | Annual Per Customer |
|---|---|---|---|
| **2011** | $67,795,000 | $27,129,274 | $13.24 |
| **2012** | $122,525,000 | $49,700,126 | $24.15 |
| **2013** | $52,200,000 | $20,948,286 | $10.11 |
| **2014** | $132,184,000 | $53,751,705 | $25.69 |
| **2015** | $74,961,000 | $31,429,969 | $14.84 |
| **2016** | $142,500,000 | $60,861,550 | $28.38 |
| **2017** | $153,033,000 | $63,995,058 | $29.44 |
| **2018** | $136,196,000 | $57,899,108 | $26.26 |
| **2019** | $147,463,000 | $62,998,967 | $28.15 |
| **2020** | $216,976,000 | $98,263,733 | $43.15 |
| **2021** | $243,860,000 | $105,947,061 | $45.75 |
| **Total** | $1,489,693,000 | $632,924,839 | $289.16 |
| **Average** | $135,426,636 | $57,538,622 | $26.29 |

*Table 5 - Residential Impact of Revenue Above ROE & Below Upper ROE Band*

Over the past 11 years, the Company's revenue collection above its approved ROE but below the upper ROE band has cost residential customers $633 million in total. The average customer's annual impact is around $26, but due to the factors discussed above, in 2020 and 2021 has jumped to around $45 per year.

**Q76. TURNING FULL CIRCLE, HOW DO THESE FIGURES COMPARE TO THE PURPORTED NEM COST SHIFT?**

A76. They are also orders of magnitude larger. In 2021, the Company claims the total base rate revenue erosion from NEM is $1.4 million, or less than $0.20 per year for a customer using 1,000 kWh a month. In the past two years, the Company has collected more than 200 times as much from residential customers from revenue above its approved ROE and below the upper ROE band.

**Q77. PUTTING EVERYTHING TOGETHER, HOW DO THE VARIOUS REQUESTED AND PENDING COST INCREASES AND EXCESS REVENUE COLLECTION COMPARE TO THE PURPORTED NEM COST SHIFT?**

A77. There simply is no comparison. The NEM revenue erosion, even if taken at face value, amounts to about $0.20 a year for a typical residential customer. Between the requests made in this case, the projections of the currently-authorized Plant Vogtle costs, and the excess

revenue collected above the approved ROE but below the upper ROE dead band under the current structure, the annual bill for a typical residential customer will increase by about $34 per month or more than $400 a year. This is more than 2,000 times as large of an impact and is the very definition of a red herring.

| Cost Impact for Residential Customer | Monthly Amount | Annual Amount |
|---|---|---|
| GPC Requests in This Case | $16.29 | $195.48 |
| GPC Projection of Vogtle Costs | $13.83 | $166.00 |
| 2021 Revenue Above ROE but Below Upper ROE Band | $3.81 | $45.75 |
| **Subtotal** | $33.91 | $407.03 |
| NEM Revenue Erosion | $0.02 | $0.20 |
| **Total** | **$33.93** | **$407.23** |

*Table 6 - Summary of Rate Impacts for Residential Customer*

**Q78. AS A PRACTICAL MATTER, GIVEN THE COMPANY HAS EXCEEDED ITS APPROVED ROE EVERY YEAR SINCE 2011, WHERE WOULD THE $1.4 MILLION IN REVENUE ADJUSTMENT GO?**

A78. It would either go entirely to the Company (if its earnings are above the approved ROE and below the upper ROE band) or be refunded 80% to customers (if its earnings are above the top of the ROE band). For example, if the revenue adjustment had been in place in 2020, then the Company would have collected an additional $1.4 million in revenue below the top of the ROE dead band. This would have been added to the $217 million that it already collected and kept that year. If the adjustment had been in place in 2021, then 80% of the adjustment would have been returned to customers since the Company's ROE exceeded 12%.

The only way that the $1.4 million in revenue erosion could represent a revenue deficit as opposed to just more money collected by the Company is if GPC earned below its approved ROE. And considering this is something that has never happened since the ASR process was implemented, the overwhelming likelihood is all or part of the $1.4 million adjustment would simply be added to the annual revenue overcollection.

**Q79. WHAT DO YOU RECOMMEND WITH REGARD TO THIS ISSUE?**

A79. [Mr. Lucas] I strongly recommend the Commission revisit the ROE dead band that governs the ARP. The decision to lower the central ROE to 10.5% in the last case while leaving the

top of the ROE band at 12% instead of lowering it to 11.5% resulted in GPC collecting and keeping $142 million more in 2020 and 2021 above the ROE but under the 12% upper dead band.[84] If the upper band had instead been set at 11.5%, $114 million (80% of the total) would have been returned to customers to help reduce current and future bills. Instead, GPC kept 100% of the excess.

Given the increase in rate base and equity share, I would recommend the Commission set the ROE band to +/- 50 basis points. The Company has clearly demonstrated that it is able to manage costs to maximize profitability, having never failed to exceed its approved ROE in the past 11 years, while exceeding a 12% ROE in 7 of the last 11. If the Commission were to set the upper ROE band at 11% in 2021, the Company would have still kept $81 million before hitting the upper ROE band and having the shared savings mechanism kick in. Combined with 20% of all revenue beyond 11%, there should be ample incentive for the Company to continue to effectively maximize its profits while providing more protection to customers against higher bills.

[84] 2020 and 2021 ASR Reports.

## V. GEORGIA POWER'S DEMAND-BASED "SMART USAGE" TARIFF IS FLAWED AND SHOULD NOT BE THE DEFAULT RATE FOR NEW PREMISES

**Q80. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A80. In this section, we discuss the Company's "Smart Usage" TOU-RD tariff. This is a three-part tariff consisting of a fixed customer charge, a peak/off peak energy charge, and a demand charge. We discuss the design of this tariff and how its use of a non-coincident peak ("NCP") demand charge to collect a significant portion of a customer's bill is fatally flawed. We also analyze the usage patterns of new customers added to this tariff since it became the default rate choice for new premises.

**Q81. PLEASE SUMMARIZE YOUR FINDINGS.**

A81. The TOU-RD tariff is not reflective of cost-causation and should not be the default residential tariff. Its NCP billing demand is a faulty measure that does not consider the timing of an individual customer's peak demand. Further, it produces higher bills for most customers on the tariff compared to the R, TOU-REO, or TOU-PEV options, particularly for lower-than-average use customers. This exacerbates the problem of having the TOU-RD rate as the default rate for new customers; those added to this tariff in the past two years are disproportionally lower-than-average use customers and are experiencing significantly higher bills than they would have on the R tariff.

**Q82. WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO THE TOU-RD RATE?**

A82. The Commission should require substantial modifications to the TOU-RD tariff. First, it should no longer be the default tariff due to the all the reasons discussed below. Second, it should be redesigned in one of two ways: with a TOU billing demand charge that recovers a smaller portion of the fixed production, transmission, and distribution costs, or as an NCP billing demand charge that only recovers low voltage distribution equipment close to the customer. Third, the Commission should require the Company to update its billing determinants to ensure that the rate is revenue neutral with respect to the R tariff. We discuss each of these recommendations below.

*The Smart Usage Tariff is Improperly Designed and Should be Modified*

**Q83. PLEASE DESCRIBE THE TOU-RD TARIFF.**

A83. The TOU-RD tariff is a three-part tariff, with a fixed customer charge, a volumetric energy charge based on total peak and off-peak kWh consumption, and an NCP demand charge based on the highest 60-minute billing demand in a month. Currently, customers pay about $14 per month for the customer charge, $0.096/kWh and $0.0103/kWh for peak and off-peak energy, respectively, and $8.21 per kW of peak demand for base rates.[85] Peak periods for energy consumption are between 2 and 7 PM weekdays from June to September, with all other hours (and summer holidays) being off-peak; there is no time constraints on the maximum demand.

**Q84. IS THE CONCEPT OF "BILLING DEMAND" EASILY UNDERSTOOD OR EASILY CONTROLLED BY TYPICAL CUSTOMERS?**

A84. No, we do not believe it is. While the Company's literature suggests that customer can simply stagger appliance use (such as the laundry, cooking dinner, or running the air conditioner) at the same time to avoid high charges on the TOU-RD tariff, this concept is not as easily done as it is made out to seem.[86]

Customers generally do not know how much power their appliances consume. Laundry can have substantially different impacts on one's energy use. Old dryers consume substantially more energy than new ones, and gas dryers use much less electricity than electric dryers. Further, the power demand depends on the temperature setting and duration of the cycle. Likewise, cooking loads vary substantially based on equipment and preparation. Modern induction cooktops can pull upwards of 10 kW of power, while oven power consumption varies greatly depending on whether it is on a low bake or high broil setting. Air condition is certainly a major contributor to power usage, but the types of air condition

[85] TOU-RD-6 tariff. Customers separately pay for the various fuel, ECCR, and NCCR riders. Available at https://www.georgiapower.com/content/dam/georgia-power/pdfs/electric-service-tariff-pdfs/TOU-RD-6.pdf

[86] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans/smart-usage.html

units can vary dramatically from small, window units in apartments to multiple 5+ ton units in detached single family homes.

On top of this, many appliances pull different amounts of power at different times in their usage cycle. Even if set to a constant temperature, air conditioners kick on and off depending on the ambient temperature, heating load from the sun, air circulation, insulation level, and many other factors. Similarly, running hot water in the sink for a few minutes may cause the electric water heater to kick in, pulling many kW of power without the customer's knowledge or control. It is simply unrealistic to expect a customer to manually manage all the appliances in her house during every single hour of the month lest a single unfortunate event conspire to set a customer's peak demand for a month.

Even worse, customers with electric vehicle chargers or electric space heaters with high power draws that cannot be avoided indefinitely have no means of reducing their bills under a certain level, even if they never used other appliances at the same time. This effectively converts the demand-based tariff into an unavoidable fixed charge, which is neither cost-reflective nor just and reasonable.

**Q85. DID THE COMPANY PROVIDE WORKPAPERS THAT DETAILED HOW THIS RATE WAS DESIGNED OR WHAT COSTS THE ENERGY AND DEMAND CHARGES WERE DESIGNED TO RECOVER?**

A85. No, it did not. Staff asked in discovery "Please provide executable copies of all workpapers and analyses utilized to develop the proposed rate schedule revenue increases and specific rate designs for all aspects of this case."[87] The workpapers that the Company provided did not detail the composition of the various rate design components, but instead generally scaled up each existing rate component (i.e., the base, energy, and demand rates) to collect the targeted revenue increase. As such, there is no evidence in the record or Staff discovery on how the rate is intended to recovery various costs from the COSS model.

[87] STF-TAI-1-16.

**Q86. WERE YOU ABLE TO DETERMINE HOW MUCH REVENUE IS COLLECTED THROUGH EACH COMPONENT OF THE TARIFF?**

A86. [Mr. Lucas] Yes. GPC provided confidential workpapers that have the specific values used for its rate increase calculations,[88] but also provided a public data set of customer usage from which one can perform a similar calculation.[89] I present both figures below including fuel costs and recovery riders in Table 7 as I believe it is important to provide as much information to the public as possible. The slight differences in the figures are due in part to the use of only customers with 12 months of billing data from the public customer database workpaper. These customers have been on the tariff longer, and as discussed below, are higher-use customers who tend to have more energy use relative to peak demand compared to newly added customers.

| TOU-RD Revenue | Customer | Energy | Demand |
|---|---|---|---|
| GPC Rate Design | [redacted] | [redacted] | [redacted] |
| Customer Database | 11.8% | 40.7% | 47.5% |

*Table 7 - TOU-RD Revenue Split*

Based on the public customer database, 59% of customer's annual bills are either fixed customer charges or based on a single hour of demand in each month. The share is even [redacted] at [redacted]% for the GPC rate design workpaper. In other words, only [redacted]% to 41% of customer's annual bill can be controlled by how much energy they use in a month; the rest is either fully fixed or locked in from load in only 12 hours a year.

**Q87. WERE YOU ABLE TO DETERMINE HOW THE COMPANY'S COSTS BREAK DOWN BETWEEN CUSTOMER, ENERGY, AND DEMAND CLASSIFICATION?**

A87. [Mr. Lucas] I was not able to exactly duplicate the classification structure found in the rate design, but using data from public version of the Company's COSS model, I was able to summarize operating expenses and depreciation and amortization costs by function for the

[88] STF-TAI-1-16 Attachment AJ TRADE SECRET.xlsx
[89] STF-TAI-1-12. ("Customer Database")

residential customer class.[90] These functions map fairly directly to the customer, energy, and demand components of the rate. The results are presented below in Table 8.

| Function | Residential Share |
|---|---|
| **Production - Variable** | 30.3% |
| **Production - Fixed** | 34.8% |
| **Transmission** | 6.2% |
| **Distribution** | 18.7% |
| **Customer** | 10.1% |
| **Total** | **100.0%** |

*Table 8 - GPC Expense Breakdown*

**Q88. WOULD YOU EXPECT THE MAPPING OF COSS EXPENSES TO TRANSLATE DIRECTLY TO THE RATE DESIGN?**

A88. [Mr. Lucas] No, I would not. It is neither necessary nor appropriate to exactly map the COSS results into a rate design. Rate design should be reflective of the COSS results, but other considerations such as gradualism and customer understanding, acceptance, and actionability must also be factored in. For example, it is entirely appropriate to recover demand-based costs through a volumetric energy charge (as all of the residential tariffs except TOU-RD do) despite some of these costs being driven by customer demand.

**Q89. THAT SAID, HOW DO THE COST PROPORTIONS FROM THE COSS COMPARE TO THE TOU-RD RATE REVENUE COLLECTION?**

A89. [Mr. Lucas] They are directionally similar. The Production – Variable cost category contains fuel and variable O&M expenses that are a function of energy generated. The COSS places about 30% of residential expenses into this category, while the rate collects about 40% and [redacted]% of revenue based on the energy usage of the Customer Database and GPC rate design workpapers, respectively.

The Production – Fixed, Transmission, and Distribution costs are typically allocated based on various measures of peak demand (e.g., 4CP, 12CP, Class NCP). These functions

[90] Exhibits LPE-1 and LPE-2

contain about 52% of the COSS expenses, while the rate collects about 48% and [redacted]% of revenue through the demand charge for the Customer Database and GPC rate design workpapers, respectively.

Finally, the Customer costs are independent of energy or demand and pertain to the costs of connecting customers to the system and back-office functions such as billing. The COSS assigns about 10% of residential expenses to this category, while the rates collect about 12% and [redacted]% of revenues through the Customer Database and GPC Rate Design workpapers, respectively.

**Q90. WHAT DOES THIS MEAN?**

A90. [Mr. Lucas] It means that nearly all demand-based costs related to production, transmission, and distribution are collected through the demand charge. While this may appear appropriate given both are demand-based measures, a customer's individual NCP demand level has nothing to do with the coincident peak demand measures that drive costs in the COSS. This is a fatal flaw in the rate design, and the Commission should direct GPC to redesign the rate to correct this shortcoming.

**Q91. PLEASE EXPAND ON THIS POINT.**

A91. [Mr. Lucas] The core premise of the COSS is that customers are assigned costs in proportion to their usage during hours that drive those costs. The system is sized to meet the peak demands of its customer base; as such, costs are allocated based on each customer group's load during peak hours. In the Company's COSS, production capacity costs are generally allocated to customer classes based on a 12CP method, while transmission costs are generally allocated based on a 4CP method. Distribution costs are allocated based on either the 4CP (voltage levels C-E) or Class NCP (voltage levels F-G) demand levels.[91] Precisely zero costs are allocated based on the independent peak demand of individual customers, even though

[91] The Company allocates demand-based production costs and step-up substation costs on a 12CP basis, and high-voltage transmission costs on an 80% 4CP/ 20% 12CP basis. Lower-voltage transmission assets are allocated on a 4CP or NCP basis depending on voltage level. Evans Direct at 17.

there is a commonly used COSS allocator (sum of individual max demand) that captures this value.

A key consideration is rate design is that rates should be reflective of cost-causation; that is, if costs are driven by usage during peak hours, then the rate should reflect this and charge more for usage during peak hours. By designing the TOU-RD rate to capture most of the demand-based costs through an individual NCP demand charge, the Company is breaking the rule of cost-reflective rates.

From a COSS perspective, any customer who sets their individual peak usage during an hour that is not the Class NCP or one of the 12CP hours is necessarily not adding to the peak demand on the system. Put another way, if the individual's peak occurs in the any of the 719 hours a month that are not the 12CP peak hour, or any of the 8,759 hours of the year that are not the Class NCP hour, there is spare capacity on the system.[92] Only in the instance that a customer sets their individual peak demand in the same hour as the Class NCP or one of the 12CP hours could they potentially be adding marginal cost or changing the COSS allocation values.

But even in this case, the theoretical costs that a customer could impose are limited by the physical reality of the system. If a customer's individual maximum demand in April coincides with the 12CP hour for April, even though the COSS allocates some costs based on this hour, there is no incremental cost imposed on the physical system as the total load being served in April is much lower than the total load served during the summer peaks. The stress on all pieces of equipment during the highest load in April is still substantially lower than the stress on all pieces of equipment during peak summer hours. If an asset can handle peak loads in the summer, it necessarily can handle peak loads in April.

**Q92. WHAT DOES THIS MEAN FOR CUSTOMERS ON THE TOU-RD?**

[92] By definition, the peak hour is the one where the aggregate load of a class or tariff is highest, including the demand of the individual customer. All hours other than this hour necessarily have lower total demand, otherwise that hour would become the peak hour.

A92. The combination of these factors means that billing a customer for most of the demand-based production, transmission, and distribution costs based on their individual monthly peak demand does not follow the protocols of cost-reflective rates. The rate is unable to send price signals to reduce system costs because the measure of demand being used – the individual's peak demand – is not a driver of system costs.

Further, the rate is not actionable. A customer is unaware of their billing demand level until after they receive their bill, and even then, they are not provided with any useful information about when or why they set their peak demand. The Company's billing system does not retain the time and date of when the customer's peak demand is set, so not even this basic information can be passed onto a customer's bill.[93] With no knowledge of when they set their peak or what occurred to make this happen, there is no ability for customers to manage their peak demand.

**Q93. DO YOU HAVE AN EXAMPLE OF HOW THESE MISMATCHES CAN RESULT IN CUSTOMERS BEING OVERCHARGED FOR THEIR USAGE?**

A93. A perfect example is a customer with an electric vehicle ("EV") who always charges during overnight hours, and whose EV charger is the largest power draw in their house. Residential EV charges commonly draw 9.6 kW, and some more powerful units can pull 19.2 kW. A customer who routinely charges overnight when there is spare capacity on the distribution, transmission, and generation system is not driving any cost increases as the capacity of system is capable of handling much more load.

However, on the TOU-RD rate, this customer would lock in monthly charges of nearly $80 for the 9.6 kW charger and over $150 for the 19.6 kW charger despite the fact that these loads do not cause any demand-based costs on the system. Worse, because the customer's demand-based bill would be locked in every month from charger her car, there is no incentive for the customer to manager her other loads (e.g., air conditioning, washing

[93] STF-TAI-2-2.

machine, etc.) during the actual high stress hours. This perverse incentive could cause her to increase her peak demand during hot summer afternoons which could contribute to higher costs while avoiding any cost responsibility for her usage.

**Q94. WHAT DO YOU RECOMMEND WITH REGARD TO THIS ISSUE?**

A94. We are not proponents of demand charges for residential customers, particularly those offered without any supporting technology to help customers enable their demand. But given the TOU-RD rate is a voluntary rate and customers are not required to take service on it, there are a few ways the rate design could be improved.

The first would be redesigning the demand charge as a TOU demand charge. In this structure, the demand rate would only be based on peak hours of the day, much like the volumetric rate is higher during peak hours. These peak summer afternoons from 2 to 7 contain the hours in which the grid is under stress and where load reduction from customers is most useful. Sending a price signal to manage demand during these hours is more actionable than requiring customer to be hypervigilant over every hour of the month.

The second would be to maintain the NCP demand charge but use it to only collect low-voltage distribution costs near the customer's premise (i.e., voltage levels G). While these assets are still often shared among multiple customers, they have lower load diversification than higher voltage assets. Using an individual's NCP demand to collect this small set of costs would be more reflective of cost-causation. In this structure, the production, transmission, and higher-level distribution costs would be collected through volumetric TOU rates.

**Q95. DO YOU HAVE THE DATA NEEDED TO DETERMINE WHAT THE RATES WOULD LOOK LIKE UNDER YOUR PROPOSED STRUCTURE?**

A95. No, we do not. If the TOU demand charge was designed to collect most demand-based production, transmission, and distribution costs during the four summer hours, it would likely be set at a very high level (perhaps more than $20/kW). This may not be desirable as it could lead to wide swings in bills based on an inadvertently high hour of usage and very high

summer bills. Instead, we recommend that a sizeable portion of the demand-based costs be recovered through a volumetric TOU rate to produce a demand charge in the $10-12 range. This would still send a robust price signal to reduce demand during summer peak hours but would prevent surges in summer bills.

If the NCP billing demand was kept but the collected costs reduced to low-voltage assets such as line transformers, based on the plant in service ratios from the COSS, we would expect the demand rate to fall to around $1/kW. While this is much lower than the demand charge in the current TOU-RD design, it is all that should reasonably be collected through an NCP-based billing demand given the inherent lack of cost-reflection in this metric.

*Low Use Customers are Substantially Overcharged on the Smart Use Tariff*

**Q96. DID YOU ANALYZE HOW CUSTOMERS WITH DIFFERENT USAGE LEVELS FARED ON THE VARIOUS RESIDENTIAL RATES?**

A96. [Mr. Lucas] Yes, I did. Staff asked for monthly usage data from each residential customer in 2021.[94] Using this data set, I was able to perform several analyses on how customers taking service on the TOU-RD tariff would have fared on the TOU-PEV, TOU-REO, and R rates. I began by trimming the data to only include customers with a full 12 months of recorded data. Given the TOU-RD rate experienced substantial customer growth during 2021 due to the decision to make it the default rate at the beginning of this year, this reduced the data set from about 61,000 customers with partial months of data to about 11,000 customers with 12 months of data. While this does represent a sizable reduction to the data set, these are also customers who self-selected into this tariff prior to it become the default. In other words, they affirmatively chose to be on this tariff.

After trimming the data, I recreated each TOU-RD customer's bill under the other tariffs, including fuel cost and the various adder tariffs. Because the data set did not

[94] STF-TAI-2-2.

specifically break down peak, off-peak, and super off-peak usage for these customers, and I was unable to ask for the data myself, I calculated the tariff average peak, off-peak, and super off-peak values from another data set the Company provided to Staff.[95] Given that an individual's bill may contain relatively more or less peak or super off-peak energy than the tariff average, I also ran sensitivities around these figures.

**Q97. WHAT DID YOUR ANALYSIS SHOW?**

A97. [Mr. Lucas] In theory, since this is a voluntary rate, and all customers who were taking service under it as of January 2021 self-selected into the rate, one might have expected the group of customers to have lower bills compared to other tariffs. However, as is clearly evident, this is not the case. My analysis showed that even for these self-selecting customers, most experienced higher annual bills on the TOU-RD tariff than they would have had on the R (61%), TOU-REO (63%), and TOU-PEV (72%) tariff. Moreover, for customers below the median usage, nearly all customers experienced higher bills on the TOU-RD rate than the R (90%), TOU-REO (89%), or TOU-PEV (94%) tariffs.

Figure 1 is a summary of the results comparing the TOU-RD tariff to the R tariff. In this chart, the blue dots represent the bill increase (above the 0% line) or bill decrease (below the 0% line) shown on the left y axis against the average monthly usage on the x axis. The orange line shows on the right y axis the cumulative percentage of customers up to that usage level that have higher bills on the TOU-RD rate than the R rate shown. The vertical purple line represents the median usage of this customer set, equal to 971 kWh per month.

[95] STF-TAI-1-12.

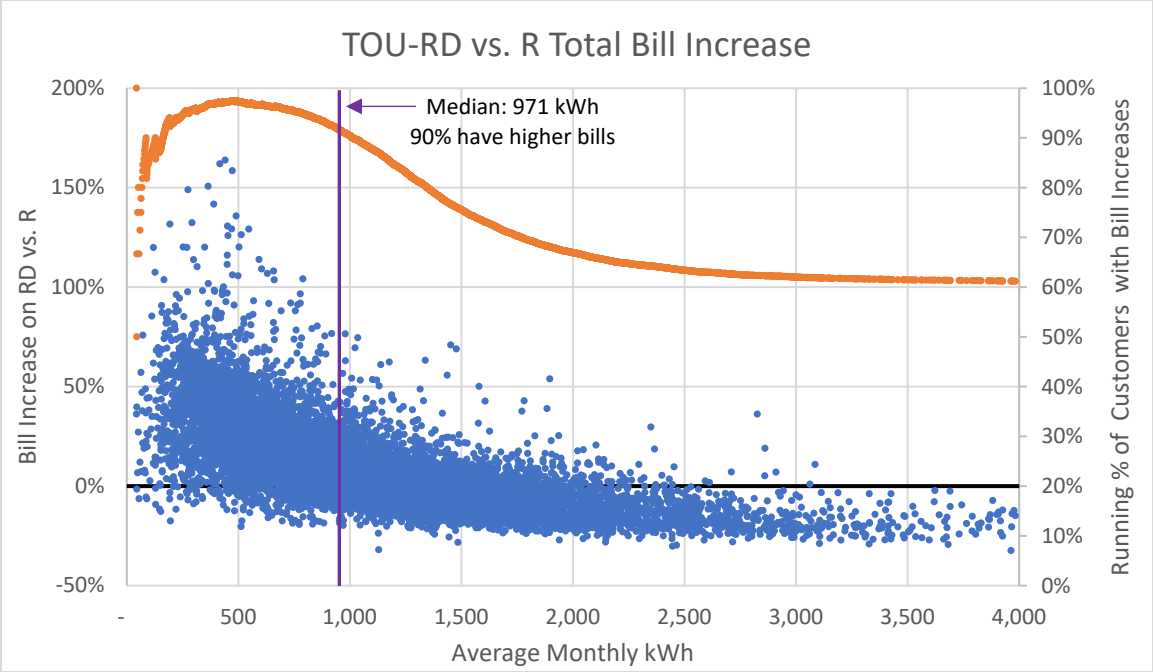


*Figure 1 - TOU-RD vs. R Total Bill Increase*

The chart shows a clear relationship between bills on these two tariffs. Small customers, shown on the left side of the chart, almost exclusively pay more on the TOU-RD tariff. For customers that average less than 500 kWh per month, 97% pay more on the TOU-RD rate than they would have on the R rate. By the time the median usage of 971 kWh is reached, this has fallen slightly to 90%. In other words, 90% of the bottom half of customers by usage level pay more on the TOU-RD rate than on the R rate. In fact, the *average* bill increase of the lower half of customers by usage is a whopping 23.4%. Some unlucky low-use customers see bill increases over 50% or even 100% on this tariff, despite their demand peaks not causing cost increases on the system.

Customers only begin to consistently see savings on this tariff as the usage levels grow. Not until usage has increased to around 1,300 kWh (33% above the median usage) do about half of the customers experience lower bills. By the time usage reaches 2,000 kWh a month (roughly double the median usage) do customers consistently save on the TOU-RD tariff. All told, 61% of all customers in the data set – regardless of usage – had higher bills on the TOU-RD tariff than they would have had on the R tariff.

**Q98. DID YOU ALSO COMPARE BILLS WITH THE OTHER TOU RATES AS WELL?**

A98. [Mr. Lucas] Yes, I did. I preformed the same analysis on the TOU-REO and TOU-PEV rates, and found very similar results. Figure 2 and Figure 3 below show these analyses.

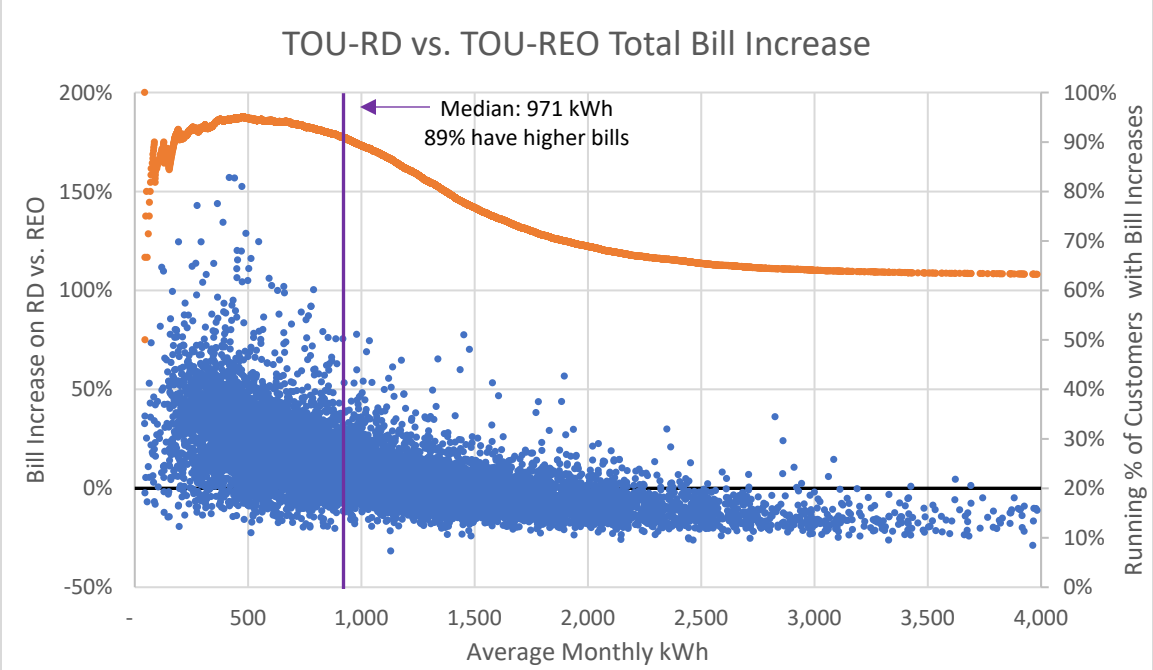


*Figure 2 - TOU-RD vs. TOU-REO Total Bill Increase*

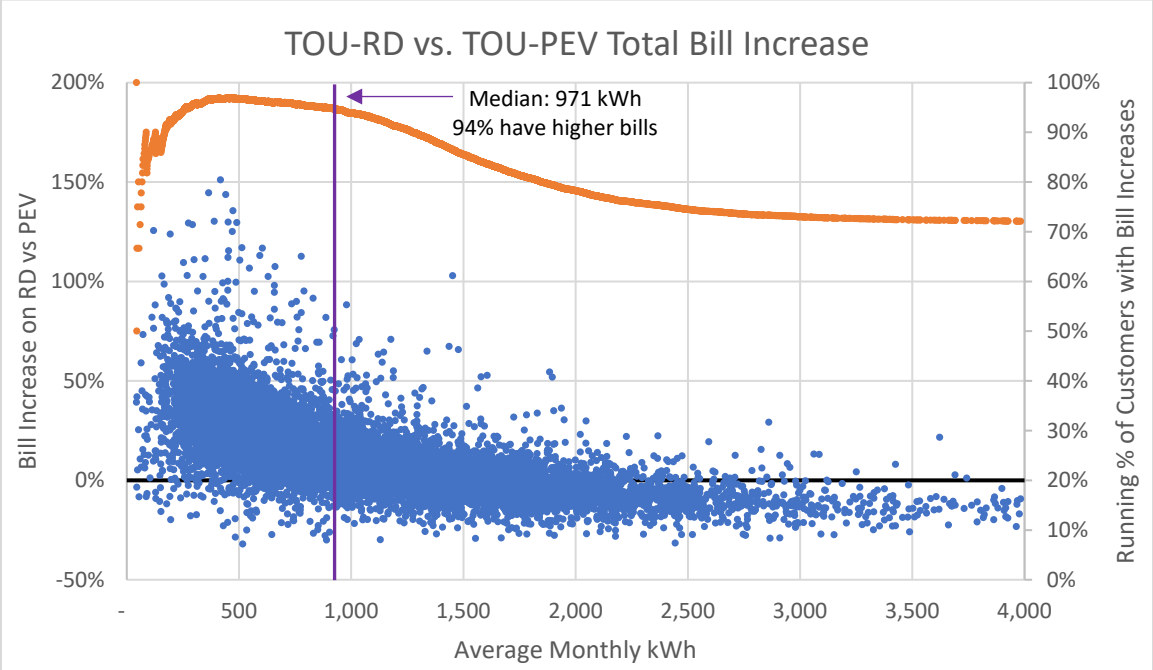


*Figure 3 - TOU-RD vs. TOU-PEV Total Bill Increase*

The shapes are nearly identical, with low-use customers faring equally as poorly on the TOU-REO rate as the R rate and even worse than if they had been on the TOU-PEV rate.

**Q99. WHAT WAS THE IMPACT ON THE RESULTS OF CHANGING THE PEAK USAGE PERCENTAGES?**

A99. [Mr. Lucas] About 20% of the TOU-RD tariff energy usage during summer months was during peak hours. Table 9 below shows the results when I changed the peak usage to 10% and 30% of summer usage, respectively. The changes were minor; the vast majority of sub-median usage customers continued to pay more on the TOU-RD tariff, and the average bill increase for these customers stayed within 7% across the spread of peak usage levels.

| Peak Summer Usage | 10% | 20% (Baseline) | 30% |
|---|---|---|---|
| **% of All Customers with Higher Bills vs:** | | | |
| R | 53% | 61% | 69% |
| REO | 69% | 63% | 56% |
| PEV | 70% | 72% | 72% |
| **% of Sub-Median Use Customers with Higher Bills vs:** | | | |
| R | 83% | 90% | 95% |
| REO | 93% | 89% | 84% |
| PEV | 94% | 94% | 93% |
| **Average Bill Increase for Sub-Median Use Customers vs:** | | | |
| R | 20.0% | 23.4% | 26.8% |
| REO | 24.0% | 20.5% | 17.4% |
| PEV | 24.1% | 24.2% | 24.5% |

*Table 9 - Rate Comparison Peak Usage Sensitivity*

**Q100. DO THESE RESULTS SURPRISE YOU?**

A100. [Mr. Lucas] While the magnitude of the impact on low-use customers is surprising, it is not surprising that low-use customers fare poorly on this tariff. Customers with low monthly usage tend to have lower load factors.[96] And customers with low load factors are penalized by rate designs with NCP demand charges that collect a substantial portion of the overall tariff revenue. I calculated the load factor in the data set, and unsurprisingly, low-use customers had low load factors as seen in Figure 4 below.

[96] A load factor is a fraction that represents the total usage in a period divided by the maximum demand in the period times the number of hours. A load factor of 1.0 represents constant usage at a set level, while a low value such as 0.1 represents occasional high peak demands but low overall usage.

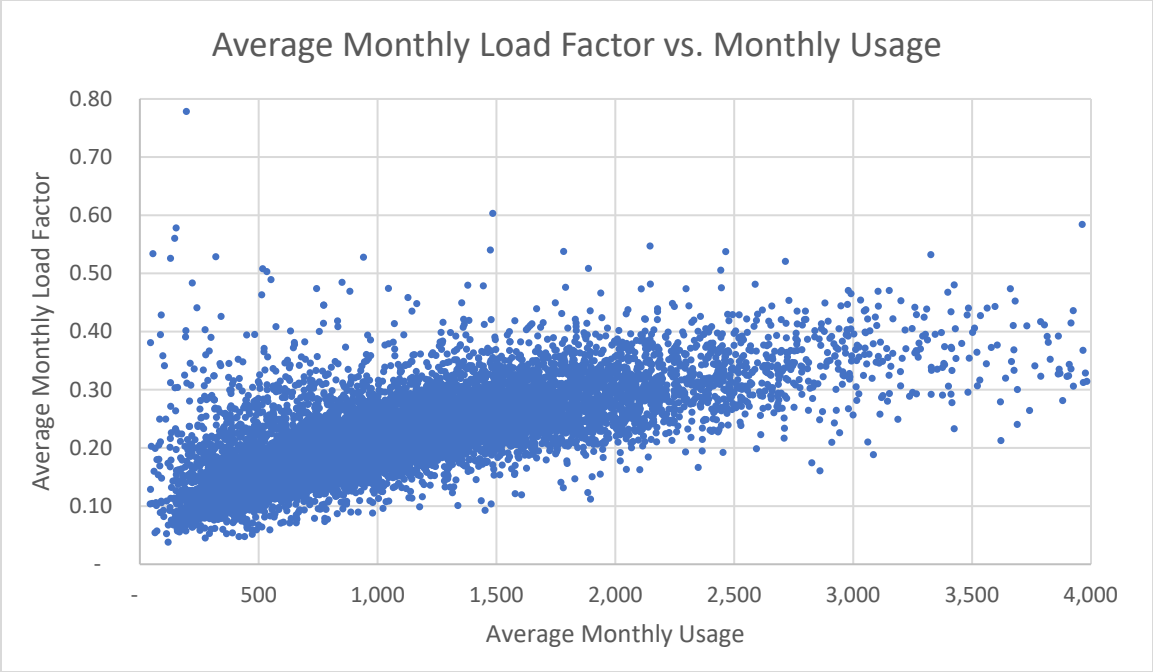


*Figure 4 - TOU-RD Customer Average Monthly Load Factor*

Even worse, customers with low NCP load factors have low coincident factors. This means their individual peak demand is not aligned with system peak hours when high loads actually drive costs. This relationship, dubbed the Bary Curve, has been known for decades and was discussed by the Edison Electric Institute in its 1984 publication "The Art of Rate Design."[97] In summary, high NCP demand from low-use customers is not putting stress on the system because the demand spikes tend to fall outside peak hours.

**Q101. WERE YOU ABLE TO ANALYZE THE GPC CUSTOMER SET TO EXPLICITLY DEMONSTRATE THIS?**

A101. [Mr. Lucas] No, I was not because I was not able to ask for hourly data for a sample of customers. However, in another case in which I was able to ask discovery, I did obtain this information and performed this analysis. DTE Energy in Michigan produced a workpaper that showed the three highest load hours in each month in 2018 and 2020 for 10,000 random residential customers. I analyzed the data to determine how many of those hours corresponding with the 4CP, 12CP, and Class NCP hours.

[97] The Art of Rate Design, Chapter 5, Frank S. Walters, Edison Electric Institute, 1984.

On average, only 1% of the 10,000 customers had their individual peak demand in a month fall during one of the 4CP hours. Even fewer experienced alignment with the 12CP hours. The Class NCP metric was the "highest" of the three, with a mere 1.33% of customers experiencing their monthly peak at the same time as the class peak.

| | Individual Customer Monthly Highest Load | | |
|---|---|---|---|
| **COSS Hour** | 1st Highest | 2nd Highest | 3rd Highest |
| **4CP** | 1.03% | 0.91% | 0.81% |
| **12CP** | 0.78% | 0.59% | 0.51% |
| **Class NCP** | 1.33% | 1.08% | 1.02% |

*Table 10 - DTE Energy Individual Peak Hour Coincidence Analysis*

Further, these customers were not limited to low-use, low-load factor customers, whose overlap between individual peak demand and system peak demand was even lower. I performed the same analysis on customers with rooftop PV who, due to self-consumption, had lower load factors than a non-PV customer. There were only 4 instances over the 1,348 4CP customer-hours – 0.3% – when the customer's highest load hour of the month corresponded to the 4CP hours. Similarly, only 0.5% of peak hours occurred during the 12CP hours. And there was only one single instance where a DPV customer's peak hour fell during the Class NCP peak. These results reinforce the futility of attempting to send a price signal with an NCP billing demand structure; individual customers simply do not peak during the same hours that drive system costs.

**Q102. PLEASE SUMMARIZE YOUR ANALYSIS ON THE TOU-RD TARIFF THUS FAR.**

A102. [Mr. Lucas] I began by analyzing data from a set of 11,000 TOU-RD customers who had been on the tariff for all twelve months of 2021. I found that nearly all low-use customers on this tariff paid substantially more than they would have on the R, TOU-REO, or TOU-PEV rates. I showed that the low-use customers also had low load factors, which strongly contributed to their higher bills on an NCP tariff. I also showed that residential customers from another utility had extremely low levels of correlation between individual peak demand hours and system peak demand hours.

This analysis shows that the TOU-RD rate is poorly designed and is actually harming many of customers that self-selected into the tariff. It also provides quantitative support for my assertion that the NCP billing demand structure does not send meaningful price signals. I now turn to implications of making this rate the default rate for residential customers.

*New Customers are Disproportionately Low Use Customers and are Being Harmed by the Default Rate*

**Q103. WHAT IS A DEFAULT RATE?**

A103. A default rate is the rate that a new customer is placed on at the commencement of their electric service. Customers have the option to choose other rates for which they qualify, but absent an affirmative choice, they are placed on the default rate.

**Q104. WHAT IS THE CURRENT DEFAULT RATE FOR RESIDENTIAL CUSTOMERS?**

A104. The TOU-RD rate was set as the default rate beginning in January 2021 as part of the 2019 Rate Case settlement agreement.[98] The Company was required to "report back to the Commission at the time of its next base rate case regarding the adoption of TOU-RD and its use as the default rate for newly constructed residential premises."

**Q105. WHAT DID THE COMPANY REPORT IN ITS FILING REGARDING THE ADOPTION OF THE TOU-RD AS THE DEFAULT RATE?**

A105. There was only one reference to the word "TOU-RD" in the Company's entire application, and it was in response to its proposal to close the R tariff to new customers:

> Since the beginning of 2020, Georgia Power has proactively promoted its wide variety of residential rate options to help and encourage customers to choose the rate that best meets their needs when establishing service. As a result, customer adoption of alternative residential rate options such as Smart Usage ("TOU-RD"), Plug-in Electric Vehicle ("TOU-PEV"), Pay by Day ("PBD") and FlatBill has increased significantly. Indeed, the number of residential customers who have chosen to participate in a time-of-use rate has increased by more than 250%. Many customers have demonstrated both a demand and preference for these rate plans. By closing the R tariff to new premises, the Company will continue to transition new residential accounts onto other rates within the Domestic Group that better align with the cost to serve customers. Again, the R tariff will remain available to existing residential premises on Georgia Power's system that established service prior to January 2023.

[98] 2019 Rate Case Order at 14.

**Q106. IN YOUR VIEW, DOES THIS MENTION SATISFY THE COMMISSION'S DIRECTIVE TO "REPORT BACK" ABOUT THE TOU-RD RATE AS A DEFAULT OPTION?**

A106. No. The Company has no discussion about the TOU-RD as the default rate and provided no analysis on its adoption. The only mention, cited above, is in passing. Staff needed to ask discovery questions to extract any additional details from the Company.

**Q107. WHAT DID THOSE DISCOVERY RESPONSE SHOW?**

A107. It showed that customers who have been placed on the TOU-RD rate since January 2021 have experienced higher bills than they would have on the R tariff. Further, many customers that were placed on the tariff in 2021 left after a few months. And in contrast with the Company's statement above about the increases in the number of customers on the various TOU rates, the only rate that has been appreciable growth is the TOU-RD rate after becoming the default rate.

**Q108. WHAT DATA DID GPC PROVIDE REGARDING THE RATE CHOICES OF NEW CUSTOMERS?**

A108. In response to a discovery request by Staff, GPC provided the number of new customers who signed up on the various residential rates from January 2021 through May 2022.[99] This data is summarized in Figure 5 below. Between January 2021 and May 2022, about 50,000 and 22,000 customers had been enrolled on the TOU-RD and R tariff, respectively. However, only 17 and 13 new customers had been enrolled on the TOU-REO and TOU-PEV tariffs, respectively. This moribund adoption rate is not distinguishable from zero.

[99] STF-PIA-2.

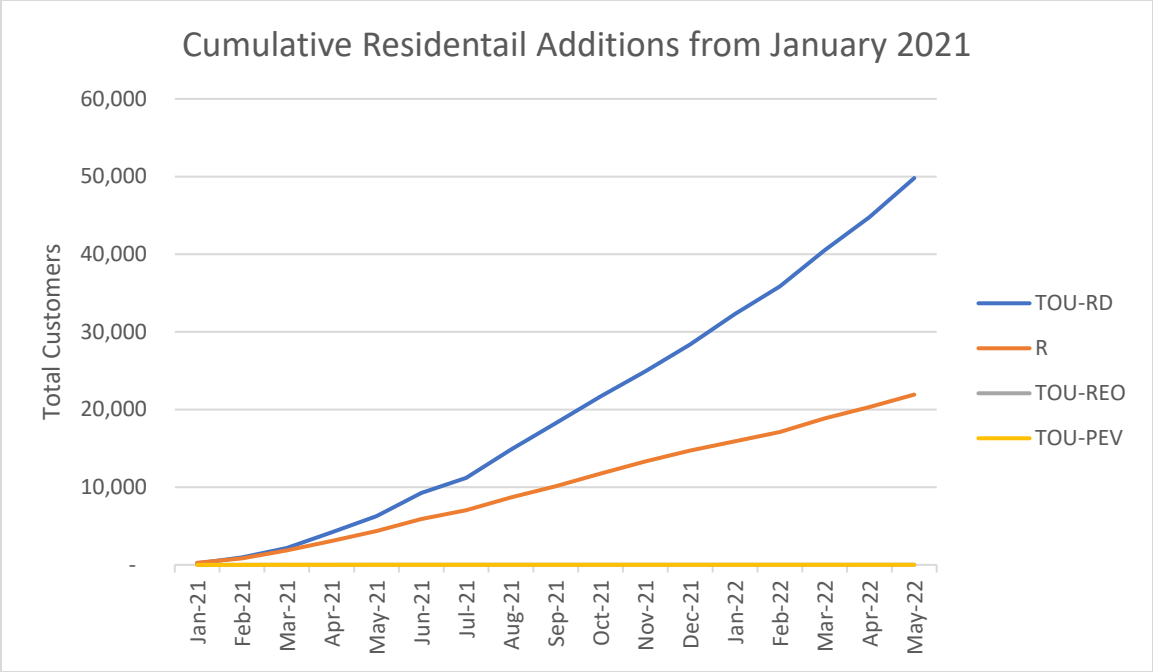


*Figure 5 - Cumulative Residential Customer Additions from January 2021*

**Q109. DO YOU HAVE SIMILAR DATA FOR CUSTOMERS GOING BACK TO 2020, WHEN THE COMPANY SUPPOSEDLY STARTED PROACTIVELY PROMOTING ITS RATES?**

A109. [Mr. Lucas] I have public data for the TOU-REO and TOU-PEV tariffs,[100] but only confidential data for the TOU-RD tariff which I needed to extrapolate from annual customer data. As is seen below in Table 11, the participation increase in the TOU-PEV tariff was relatively small and partially offset by decreases in the number of TOU-REO customers. The only meaningful change occurred in the TOU-RD tariff, as shown above, was driven by the new customers added through the default tariff.

| | TOU-REO | TOU-PEV | TOU-RD (Est) | Total |
|---|---|---|---|---|
| **Jan 2020** | 7,416 | 4,640 | [redacted] | [redacted] |
| **Jan 2021** | 6,935 | 5,208 | [redacted] | [redacted] |
| **Jan 2022** | 6,467 | 6,674 | [redacted] | [redacted] |
| **May 2022** | 6,320 | 7,547 | [redacted] | [redacted] |
| **Delta 1/20-5/22** | **(1,096)** | **2,740** | [redacted] | [redacted] |

*Table 11 - Customer Changes on the TOU Rates*

[100] STF-TAI-1-32

Based on this data, customers are defecting from the TOU-REO rate, slowly signing up for the TOU-PEV rate (which, as discussed below is likely impacted by intentional confusion created by the Company), and being defaulted into the TOU-RD rate. In fact, in the years before the TOU-RD became the default rate, growth was [redacted], with [redacted] between 2017 and 2019 and only [redacted] second half of 2020.[101]

**Q110. DID THE COMPANY PROVIDE DATA ON HOW MANY CUSTOMERS DEFECTED FROM THE TOU-RD RATE?**

A110. [Mr. Lucas] They did, although it strongly conflicts with other data provided by the Company. In response to Staff discovery, the Company stated that only 259 customers unenrolled from the TOU-RD tariff in 2021, 95 of which were from a single properly manager in a single month.[102]

However, data provided in another Staff request tells a very different story. I analyzed 2021 data from the Customer Database discussed above looking for new customers that signed up on the rate (indicated by billing data in a month where none was present before) and then left to go to another rate (indicated by billing activity on a different tariff in a later month). Rather than 259 customers defecting from the rate for the whole year, I found that roughly 1,300 customers who were not on the tariff as of January 2021 left the tariff at some point in 2021, and roughly 1,850 who were on the tariff as of January 2021 left the tariff at some point in 2021. These do not include customers who disconnected their service during the year, as indicated in the data set as a customer whose last bill was prior to December.

**Q111. RETURNING TO THE CUSTOMERS THAT WERE ADDED TO THE TARIFF, HOW DID THEIR USAGE LEVELS COMPARE TO AVERAGE CUSTOMERS?**

A111. [Mr. Lucas] They were lower-use customers. Staff asked for the average monthly peak demand of new TOU-RD customers and the residential class as a whole along. It also

[101] STF-TAI-1-16 Attachment AJ TRADE SECRET
[102] STF-PIA-2-1 Attachment

requested the average usage of the new TOU-RD customers, which I was able to compare to the residential class as a whole from another data set. As seen in below in Figure 6, the new TOU-RD customers have significantly lower usage (solid line) and lower peak demand (dotted line) than existing residential customers. This gap persisted even after some early irregularities in the data set.[103]

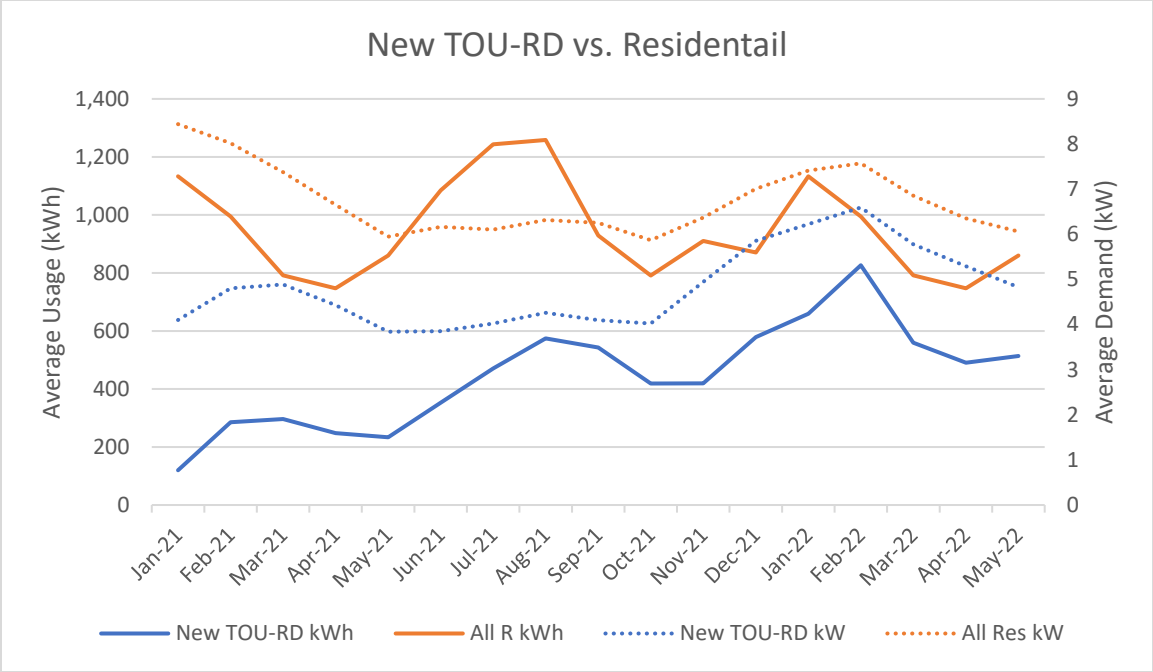


*Figure 6 - New TOU-RD vs. Residential Usage*

**Q112. IS THERE ANOTHER DATA SET THAT SHOWS A SIMILAR IMPACT OVER TIME?**

A112. Yes. The Company provided hourly usage by tariff. As seen in F below, the TOU-RD and R customers usage was nearly identical in the early months of 2021. But as more new customers were added to the tariff as a result of it becoming the default choice, the average usage on the TOU-RD fell. By the end of 2021, the full customer set had usage that was 16% lower than the R tariff. If one were to scale that to the full year, TOU-RD customers would average 815 kWh per month compared to the average R customer of 968 kWh per month.

[103] Early 2021 data for new TOU-RD customers was significantly lower than early 2022 data. One potential explanation is apartment buildings that were hooked up for electric service but not yet occupied.

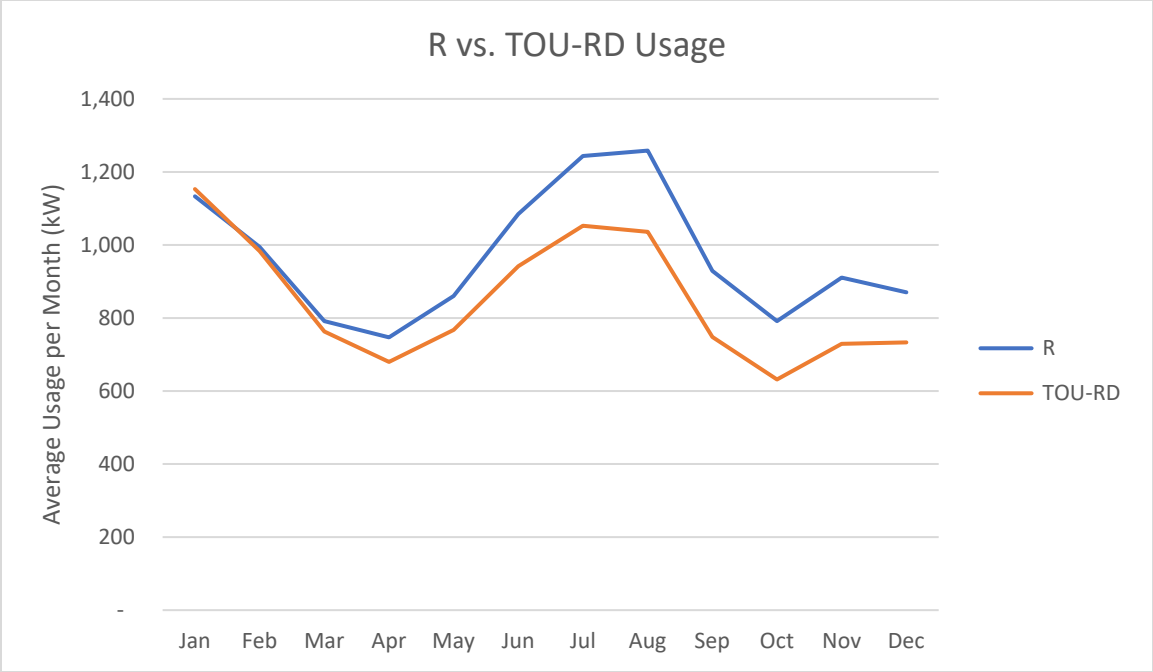


*Table 12 - TOU-RD vs. R 2021 Monthly Average Usage*

This trend also appears in the Customer Database data. Figure 7 below shows a normalized histogram and cumulative distribution function of peak billing demand for customers from January 2021 (blue) and December 2021 (orange). The increase in the number of small customers in December is apparent by the notable "hump" on the left side of the top graph showing many more customers with billing demands under 3 kW and by the higher position of the December line in the bottom chart indicating a larger cumulative percentage of customers at each level of billing demand.

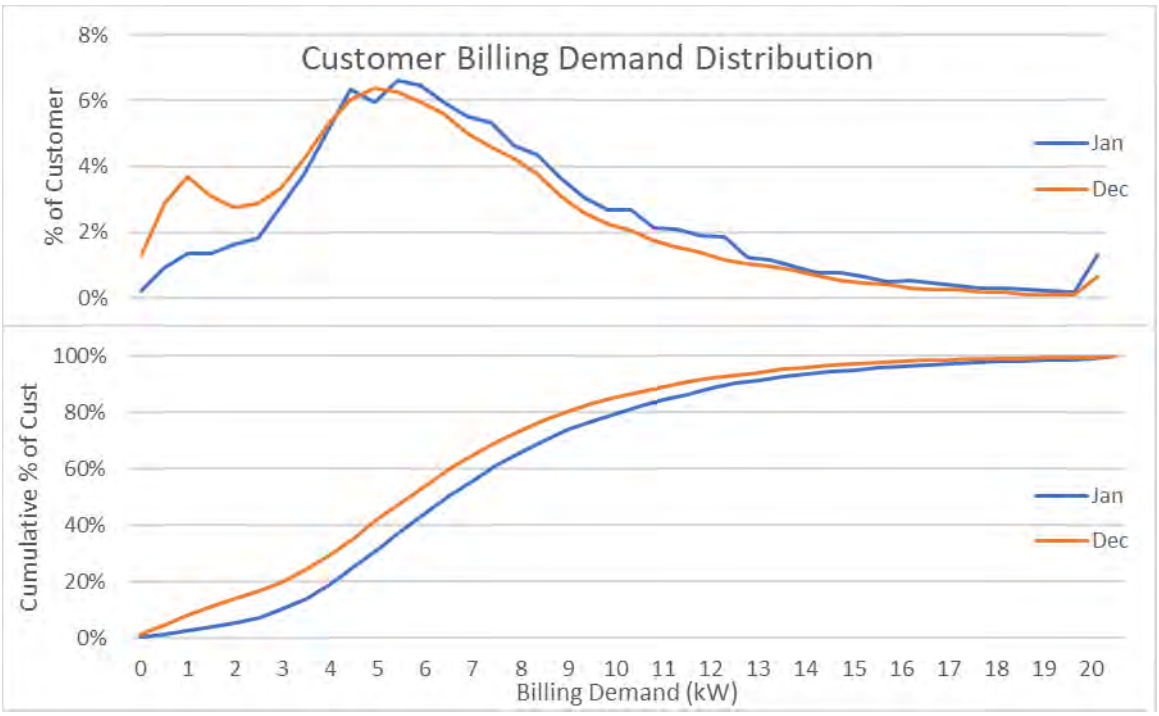


*Figure 7 - January and December Billing Demand Distribution*

**Q113. DID GPC'S DATA SUPPORT YOUR EARLIER ANALYSIS ABOUT LOWER USE CUSTOMERS GETTING HIGHER BILLS ON THE TOU-RD TARIFF?**

A113. [Mr. Lucas] Yes. The Company provided the average bill that new TOU-RD customers received along with what they would have received on the R tariff. As with my analysis, the Company's data shows a substantial premium on the TOU-RD tariff. Over the span of 17 months of data provided by the Company, customers were charged an average total of $1,250 on the TOU-RD tariff, while they would have only been charged $984 on the R tariff. The cost of the "default" choice was a 27% premium on their bills.

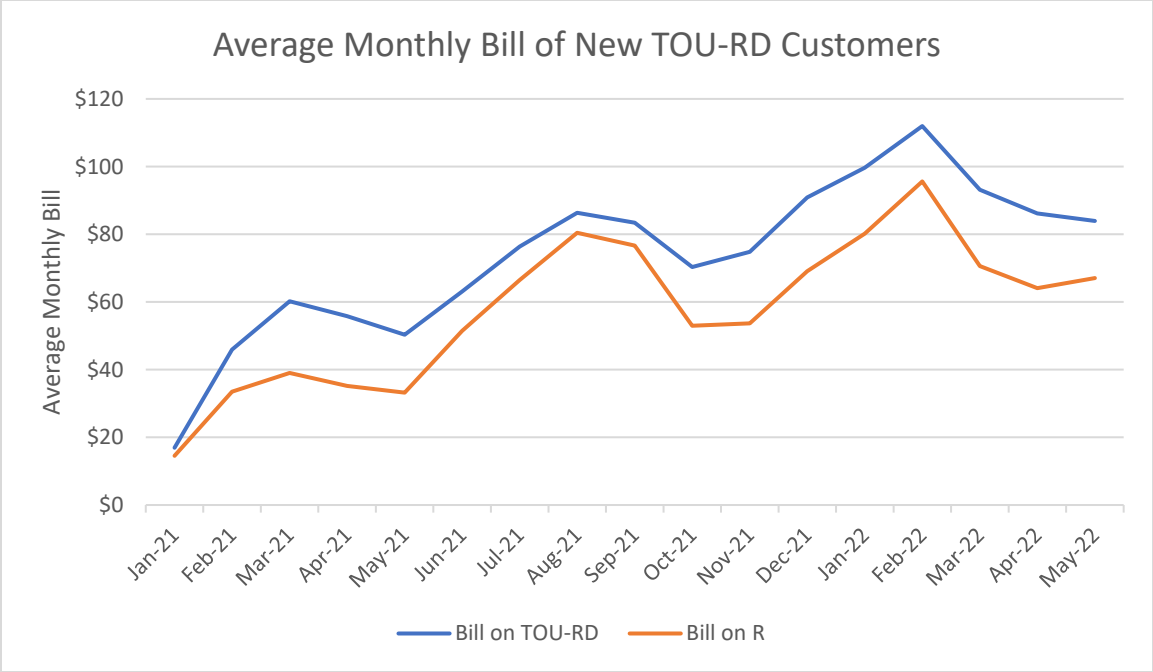


*Figure 8 - Average Monthly Bill of New TOU-RD Customers*

**Q114. DID CUSTOMERS THAT WERE SIGNED UP BY DEFAULT ON THE TOU-RD TARIFF RECEIVE INFORMATION ABOUT OTHER RATES THAT WERE AVAILABLE TO THEM?**

A114. Not directly. When asked by Staff what information customers newly added to the TOU-RD rate receive,[104] the Company responded, "New customers to the Smart Usage rate (TOU-RD) receive a welcome letter that confirms their enrollment and provides helpful information to educate them on how to take advantage of the rate's design." It included a copy of a letter that is mailed to the new customer.[105] Nowhere in this letter is the customer provided with information about other rate options, including those that may save the customer more money than the TOU-RD rate.

**Q115. WHAT IS YOUR CONCLUSION BASED ON THIS AND YOUR PRIOR ANALYSES?**

A115. It is entirely inappropriate for the TOU-RD rate as currently designed to be the default rate. The rate is not cost-aligned given the use of individual customer NCP billing demand to collect shared costs for production, transmission, and distribution. It causes higher bills for

[104] STF-PIA-2-3.
[105] STF-PIA-2-3 Attachment A.

more than 90% of customers that use less than the median amount of energy compared to alternative rates. It appears not to be revenue neutral with respect to the other tariffs.

The TOU-RD rate is the only rate that has seen substantial growth in the past two years, largely due to the decision to make it the default rate in January 2021. But the new customers being added to the tariff are disproportionately low use customers. As a result, they are being penalized through bills that are 27% higher on average than if they had been on the R tariff.

These facts are presumably all known to the Company. It knows that new customers are paying more on the TOU-RD rate than they would on the R rate because it produced data that confirmed this fact. And despite a direct requirement from the Commission in the prior rate case to report on these matters, the Company was conspicuously silent on the issue. The Company now requests to close the R tariff and the TOU-REO tariffs to new premises, which would close all but one conventional post-pay option (TOU-PEV) for new customers. At the same time, it actively sows confusion about the TOU-PEV rate to muddy the waters on eligibility. The net result of these actions is to make customers pay more for their electricity service despite them not causing a corresponding increase in cost.

**Q116. WHAT DO YOU RECOMMEND WITH RESPECT TO THE TOU-RD TARIFF?**

A116. The Commission should require substantial modifications to the TOU-RD tariff. First, it should no longer be the default tariff due to the all the reasons discussed above. Second, it should be redesigned in one of two ways: with a TOU billing demand charge that recovers a smaller portion of the fixed production, transmission, and distribution costs, or as an NCP billing demand charge that only recovers low voltage distribution equipment close to the customer. Third, the Commission should require the Company to update its billing determinants to ensure that the rate is revenue neutral with respect to the R tariff.

## VI. THE COMMISSION SHOULD STRIVE TO INCREASE FAIRNESS AND TRANSPARENCY IN RATE CASES AND OPTIONALITY IN RATE DESIGN

**Q117. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A117. In this section, we discuss various components of the Company's filing regarding availability of certain tariffs, technology tools that can aid or hinder customer education, and technical issues that impact the Company's COSS. While these changes are not as individually impactful as those discussed above, they have an overall effect of reducing transparency and fairness and customer optionality.

**Q118. PLEASE SUMMARIZE YOUR FINDINGS.**

A118. The Company's proposal to close the R and TOU-REO customers to new customers should be denied. There is little policy support for this step, and the Company produced no evidence supporting its claim that customers would be "confused" if the TOU-REO remained active. Worse, the Company is actively sowing confusion among its customers with its public facing materials on the TOU-PEV rate and its "Solar Advisor Tool". Finally, the Company's position on two technical issues related to the COSS are confusing at best, particularly related to the supposed inaccuracy of its AMI data.

**Q119. WHAT ARE YOUR RECOMMENDATIONS FROM THIS SECTION?**

A119. The Commission should require the R and TOU-REO tariffs to remain open to all customers and set the TOU-REO tariff as the default rate for new residential premises. It should direct GPC to rename and rebrand its TOU-PEV tariff to undo the blatantly misleading information regarding the purpose and eligibility requirements of this tariff. The Solar Advisor Tool should be scrapped as it is beyond salvage. Finally, the Commission should direct the Company to use the 4CP allocator for production costs and use actual AMI data instead of statistical load research data for its COSS and rate design workpapers.

*The Residential and Nights and Weekends Tariffs Should Remain Available*

**Q120. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE R AND TOU-REO TARIFFS?**

A120. The Company proposes to close both tariffs to new premises as of January 1, 2023.[106]

**Q121. WHAT IS THE JUSTIFICATION GIVEN FOR CLOSING THE R TARIFF TO NEW PREMISES?**

A121. The Company claims that its proposal "is the logical next step in the Company's ongoing efforts to encourage residential customer to move towards more modern rate structures… Many customers have demonstrated both a demand and preference for these rate plans. By closing the R tariff to new premises, the Company will continue to transition new residential accounts onto other rates within the Domestic Group that better align with the cost to serve customers."[107]

**Q122. DID THE COMPANY PERFORM ANY ANALYSIS ON OTHER UTILITIES THAT ARE PROPOSING TO ELIMINATE OR REDUCING STANDARD VOLUMETRIC RATE OPTIONS FOR RESIDENTIAL CUSTOMERS?**

A122. No. When asked this question, the Company responded, "The Company has not performed a specific analysis of which utilities or jurisdictions are eliminating standard volumetric rate options for residential customers."[108] The Company notes that utilities are increasingly exploring additional rate options that are more reflective of cost of service, but offered no evidence of utilities actively eliminating rates.

**Q123. DID THE COMPANY PROVIDE ANY SUPPORT FOR ITS CLAIM THAT "MANY CUSTOMERS HAVE DEMONSTRATED BOTH A DEMAND AND PREFERENCE FOR THESE RATE PLANS."**

A123. In what should be clearly noticed as a trend in this docket, the Company provided no details in its filing about these preferences. Instead, Staff was required to ask two rounds of discovery to get any documentation to support this statement. In the end, the Company provided a report summarizing its 2022 survey on residential rates. All of the results of the report were redacted as trade secret, despite the fact that there is no competitor to GPC's monopoly control over residential customers.

**Q124. WHAT WAS YOUR IMPRESSION OF THE SURVEY?**

[106] Legg Direct at 15.
[107] Legg Direct at 8.
[108] STF-TIA-1-29.

A124. [Mr. Lucas] We have no ability to dispute what individual customers think of the service that GPC is providing to them. That said, surveys are carefully constructed, between the choice of who to call, when to call, and how to phrase the questions. The survey was crafted with very carefully worded questions such as "[redacted]" and "[redacted]" rather than the more direct "I understand how to use electricity on the rate to save money." These subtle differences are intentional. The only direct comments about saving money or not on a given rate came from free-form comments to the generic "[redacted]" However, absent an actual rate comparison tool (which is discussed in more detail below), customers are not able to tell if they are on the best rate for their usage patterns even if they believe they are saving money on the rate.

Given this, it is telling that many of the free-form comments that the report referenced on the TOU-RD were [redacted]. These comments are quoted below and closely mirror our critiques of the rate design:

[redacted][109]

We also noticed that the selection criteria for the survey excluded many of customers [redacted] rate and did not even [redacted] tariff. In fact, [redacted]% of customers that remember whether or not they [redacted]

[redacted] said [redacted], with only [redacted]% of those saying [redacted].[110] Customers who were added to the rate after it became the default had much higher bills on the TOU-RD tariff than on other rates, but these customers appear to have been largely [redacted].

**Q125. WHAT IS THE JUSTIFICATION FOR THE CHANGE TO THE TOU-REO TARIFF?**

A125. The Company claims that closing this rate, which has been around since 1994, to customers at new premises "will avoid the confusion that could arise from having three competing time of use tariff options."[111]

**Q126. DOES THE COMPANY PROVIDE ANY SUPPORT WHATSOEVER THAT THE "CONFUSION" IT SEEKS TO AVOID EXISTS?**

A126. No, it does not. There is no supporting documents or studies that demonstrate any confusion exists. Further, given this rate has been available to customers for nearly 30 years, it is difficult to see how confusion would suddenly emerge now.

**Q127. ARE THERE DIFFERENCES BETWEEN THE TOU-REO AND TOU-PEV TARIFFS THAT MERIT KEEPING BOTH RATES AVAILABLE?**

A127. Yes. These two tariffs are similar in that they both contain a volumetric TOU rate component, but the off-peak rates are quite different. The TOU-REO tariff contains two TOU periods, while the TOU-PEV adds a super off-peak. The details of the rates are in Table 13 below, showing the current base rate plus fuel rider.

| Characteristic | TOU-REO | TOU-PEV |
|---|---|---|
| **Peak Hours** | 2-7 PM Weekdays June – Sept | |
| **Peak Rate** | $0.240219 | |
| **Super Off Peak Hours** | N/A | 11 PM to 7 AM |
| **Super Off-Peak Rate** | N/A | $0.039512 |
| **Off Peak Rate** | $0.079467 | $0.099043 |

*Table 13 - TOU-REO and TOU-PEV Rate Comparison*

[110] [redacted]% of total respondents indicated they [redacted] said they [redacted], while [redacted]% said they [redacted]

[111] Id.

Both rates share the peak TOU periods and rate. The TOU-PEV adds a low-cost overnight component, which necessarily pushes up the off-peak component. In fact, the off-peak rate on the TOU-PEV tariff is 25% higher than the off-peak rate on the TOU-REO tariff. For customers with higher overnight usage, the TOU-PEV rate might be a good choice. But for customers who do not use much energy overnight, the TOU-PEV rate would be more expensive given the increase in the off-peak rate when most of their consumption occurs.

**Q128. DID THE COMPANY PERFORM AN ANALYSIS THAT SUPPORTS THIS CLAIM?**

A128. Yes. In 2020, the Company performed a rate impact analysis for customers on the TOU-REO and TOU-PEV tariffs.[112] It found that fully 76% of customers on both rates would pay more on the TOU-PEV rate than they would on the TOU-REO rate. As seen below in Figure 9, most of these customers would see bill increases on the TOU-REO tariff of between 2% and 4% ($10-$100 in this data set), with about 20% (those with sufficient overnight usage) saving more than 1% on the TOU-PEV rate.

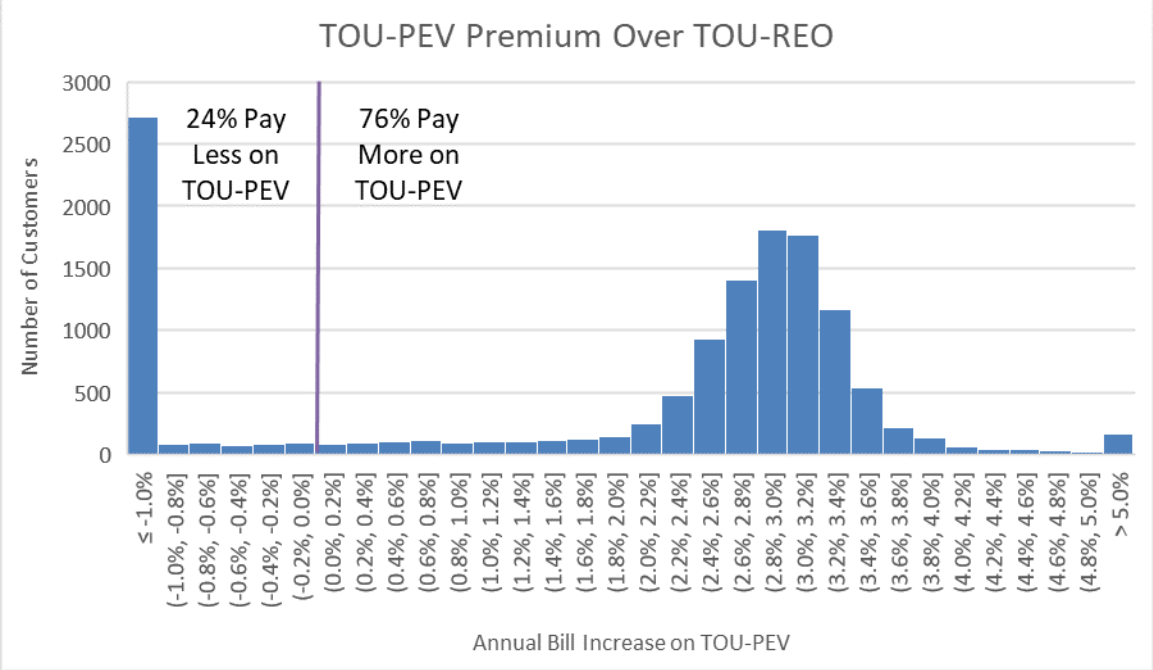


*Figure 9 - TOU-PEV Premium Over TOU-REO*

[112] STF-TAI-1-32 Attachment B.

**Q129. IF THE COMPANY'S PROPOSALS ARE APPROVED, WHAT WOULD HAPPEN TO CUSTOMERS FROM NEW PREMISES SIGNING UP FOR SERVICE?**

A129. New customers are not eligible for the Flat Bill tariff (which is effectively the R tariff with a risk premium adder) as they do not have a year of historical usage on which to base the charge. Thus, they would only have two traditional post-paid options: TOU-RD and TOU-PEV. The TOU-RD rate has serious deficiencies as discussed earlier in my testimony, while the TOU-PEV would result in a bill increases over the R tariff for low-use customers and over the TOU-REO for most new customers.

**Q130. WHAT DO YOU RECOMMEND WITH RESPECT TO THESE RATES?**

A130. We respectfully recommend the Commission require GPC to continue offering both tariffs for new residential premises. While the R tariff does not have a time of use component, the summer inclining block structure appropriately charges low-use customers less based on their lower contribution to summer system peak demands that drives production and transmission costs.[113] Although there is merit in moving more new customers to TOU-based rates, the Company has not provided justification for closing the R tariff or evidence of other utilities taking the same extreme step.

Further, if the TOU-REO tariff was also closed, customers would either need to move onto the TOU-RD rate (which as analyzed earlier charges a substantial premium to low-use customers) or to the TOU-PEV rate (with its much higher off-peak rate that causes bill increases for most customers). The TOU-REO rate continues to serve a purpose for customers without substantial enough overnight usage to save money. It maintains a lower off-peak rate more consistent with the Block 1 rate from the R tariff while still sending a price signal to reduce usage during peak hours that drive system costs.

[113] As discussed in Section V, low use customers tend to have low load factors, and customers with low load factors tend to have low coincidence factors.

**Q131. DOES THE PLUG-IN EV RATE REQUIRE A CUSTOMER TO OWN AN EV TO QUALIFY FOR THE RATE?**

A131. No, it does not.

**Q132. WOULD THE AVERAGE CUSTOMER BE ABLE TO DETERMINE THIS FROM THE COMPANY'S WEBPAGE?**

A132. [Mr. Lucas] No, I do not believe they would. The Company's public-facing content regarding the Plug-In EV rate (discussed here as the TOU-PEV rate) consistently and strongly implies that EV ownership is a necessary prerequisite for qualifying for this tariff. In fact, when I first reviewed the Company's website content on this rate, I was surprised to learn that an EV was not required.

**Q133. DO YOU HAVE ANY EVIDENCE TO SUPPORT THE IDEA THAT MANY IF NOT MOST CUSTOMERS ON THE EV RATE DO IN FACT OWN EVS?**

A133. [Mr. Lucas] Yes. I analyzed hourly data from the TOU-PEV, TOU-REO, and R tariffs provided by the Company.[114] The load profile between 7 AM and 11 PM is very similar across the tariffs, with both of the TOU rates showing a drop in peak usage between 2 PM and 7 PM compared to the R tariff. I created a "Scaled TOU-PEV" load profile by taking the average ratio of the TOU-PEV and R usage in off-peak and peak hours and applying it to the R usage during the super off-peak hours. There was a dramatic increase in usage on the TOU-PEV rate starting at 11 PM that gradually narrowed as the super off-peak period concluded at 7 AM, as evidenced by the difference between the actual and scaled TOU-PEV usage (solid and dashed blue line, respectively, in Figure 10 below).

[114] STF-TAI-1.12 Attachment.

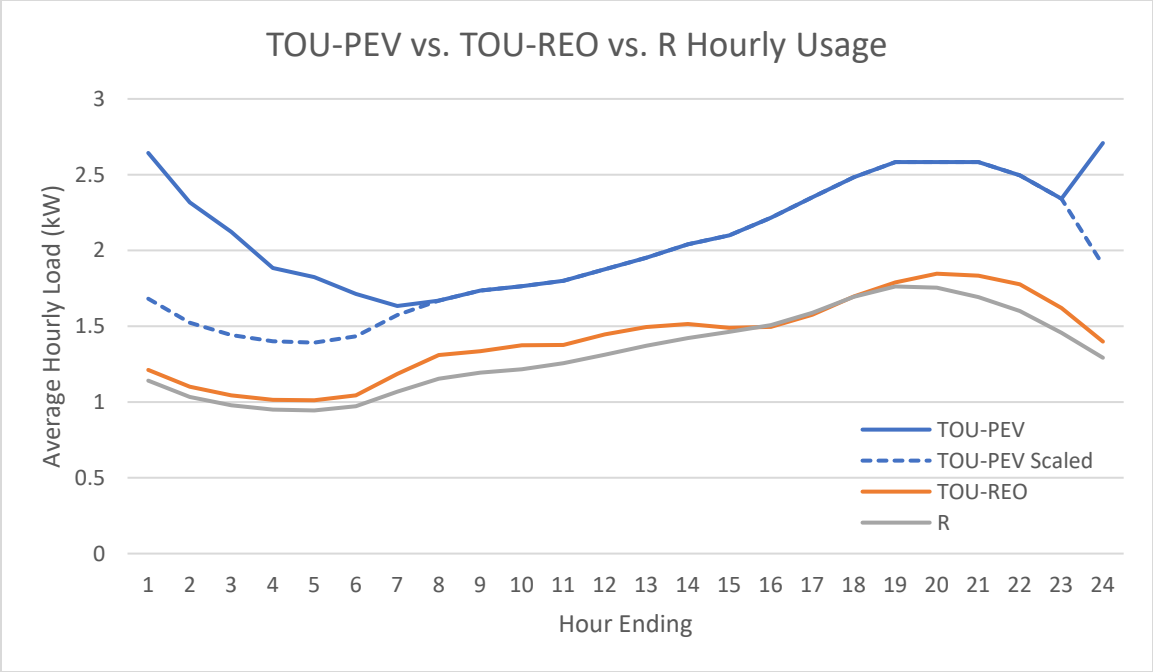


*Figure 10 - TOU-PEV vs. TOU-REO vs. R Hourly Usage*

**Q134. WHAT DOES THIS CHART SHOW?**

A134. [Mr. Lucas] It shows that customers on the TOU-PEV tariff consistently – across all months, seasons, and days of the week – add an average of about 1.5 kW of demand at the strike of 11 PM when the super off-peak rate starts. This increase falls over the next few hours until it largely vanishes by 7 PM. Programmable thermostats cannot explain the data as the leap occurred in winter (electric heating but no cooling or gas heating loads), summer (cooling but no heating loads), and shoulder months (neither much heating nor cooling load).

There are few loads that can consistently add that much demand at the same time or that would show the gradual decay over the super off-peak period as charging an EV. As mentioned, home chargers commonly pull 8-10 kW of power. Not every EV user charges every night, so the fact the step increase is an average of 1.5 kW instead of 8 kW is not surprising. Further, not every EV is charged from a fully depleted state, meaning that all charged cars will charge at the beginning of the super off-peak period, some will charge for half of the super off-peak period, and a few will charge for whole super off-peak period. This perfectly explains the decay shown above.

**Q135. DO YOU HAVE OTHER QUALITATIVE SUPPORT ABOUT THE PREVALENCE OF EVS ON THIS RATE?**

A135. [Mr. Lucas] Yes. In the residential rate survey discussed in the prior section, respondents offered comments on the TOU-PEV rate. Many of these specifically referred to [redacted][115]

**Q136. IS IN FACT NECESSARY FOR CUSTOMERS TO OWN AN EV TO QUALIFY FOR THIS RATE?'**

A136. No, it is not. But one would hardly know that from the Company's webpage. The Company could take any number of simple steps to clarify that this rate is broadly available to all customers, but it has actively decided to perpetuate confusion over the rate.

The Company was directly asked by Staff: "Does the Company have any plans to rename the Time-of-Use Electric Vehicle (TOU-PEV) rate to avoid customer confusion over their eligibility to select this tariff?" The Company responded flatly "There are currently no plans to rename the Time-of Use Plug-in Electric Vehicle rate."[116]

**Q137. WHAT ARE SOME EXAMPLES OF HOW THE COMPANY PERPETUATES THIS CONFUSION?**

A137. It starts with the tariff name. There is no reason to name the tariff the "Time-of Use Plug-in Electric Vehicle" rate. The Company could name it something description like "Overnight Savings" or "Super Off-Peak Savings." The rate provides a reduced rate to all overnight usage, not just for customers charging an EV.

[115] STF-PIA-6-54 Attachment TRADE SECRET at 26.
[116] STF-TAI-1-34.

Every prominent instance of the Company's webpage directly ties the TOU-PEV rate to EVs and EV charging. On the main Residential page,[117] there is an "Explore more" section on "Electric Transportation" that leads to a page on electric vehicles entitled "Discover the Benefits of Electric Vehicles".[118] This page has links to several pages, including the Electric Vehicle Resources page.[119] In the FAQ of this page, there are two Q&As that explicitly and unambiguously imply that the EV rate is offered to EV drivers rather than being generally available.

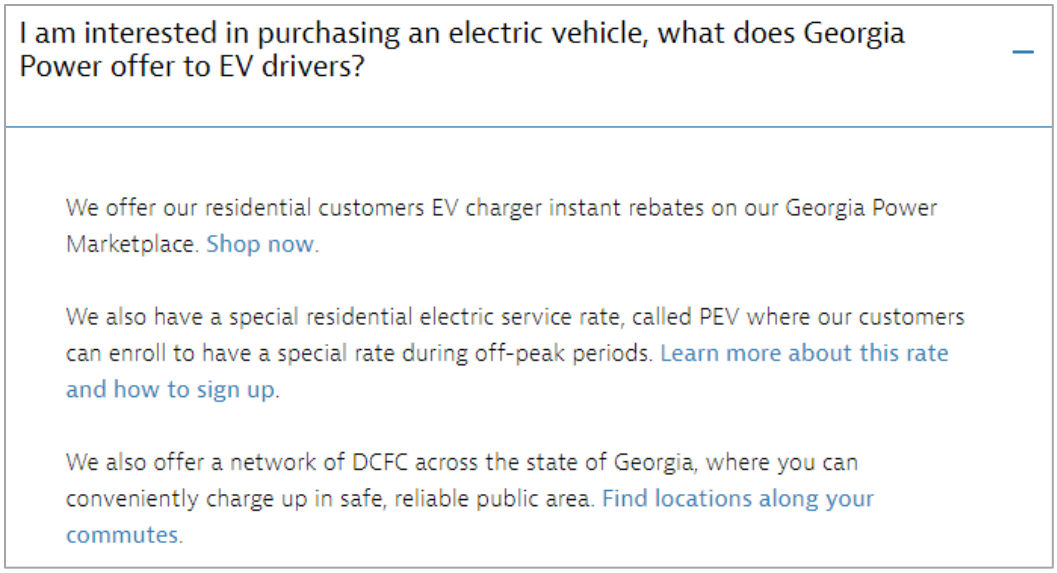


*Figure 11 - GPC EV Resources Webpage*

[117] https://www.georgiapower.com/residential.html
[118] https://www.georgiapower.com/residential/save-money-and-energy/products-programs/electric-vehicles.html
[119] https://www.georgiapower.com/residential/save-money-and-energy/products-programs/electric-vehicles/ev-resources.html

If one clicks on the links in the FAQ, they are directed to the main TOU-PEV tariff page entitled "Plug-In Electric Vehicle"[120] Excerpts from this and other pages discussing the TOU-PEV rate are shown below.[121] There is also a video discussing the different available rate options. The narration for the TOU-PEV rate follows: "Drive an electric vehicle? If so, the Plug in Electric Vehicle rate could be a great option for you. This rate has cheaper prices from 11 PM to 7 AM to encourage nighttime EV charging."

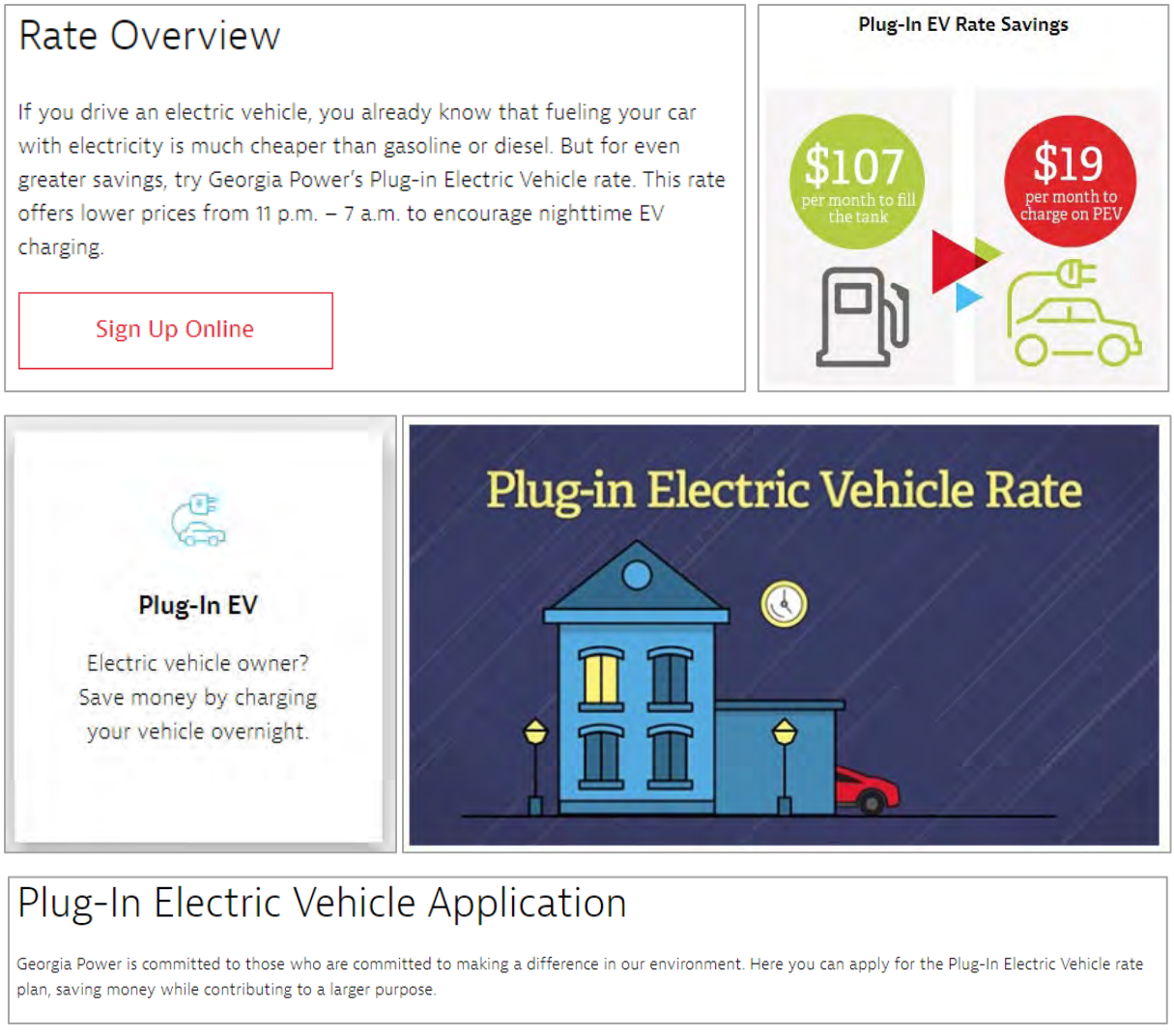


*Figure 12 - GPC TOU-PEV and Related Webpages*

[120] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans/plug-in-ev.html
[121] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans.html

Time and time again on GPC's website, the Company conflates eligibility of the TOU-PEV tariff with driving an EV: "If you drive an electric vehicle", "Electric vehicle owner?", "Drive an electric vehicle?", "$19 to month to charge on PEV". These are not isolated incidents; all these mentions of the rate on its webpage includes a discussion of EVs.

**Q138. DO YOU BELIEVE THE TOU-PEV RATE IS A WELL-DESIGN AND USEFUL RATE?**

A138. [Mr. Lucas] Yes, I do. While I was not able to scrutinize the source data behind the rate design, the TOU-PEV tariff appears to be well-designed. It has a relatively high on-peak energy rate that is constrained to summer weekdays when the system is under stress and sends a robust price signal for customers to reduce or shift usage from this period. It offers a very low overnight super off-peak rate that appears to be intended to only collect fuel and variable O&M costs and not to collect capacity costs which are not driven by usage during this time period.

These are hallmarks of good rate design, but as with any single rate design, the rate is not a perfect match for all customers. Lower use customers with normal overnight usage will not fare well on this tariff. The TOU-PEV off-peak rate – where most of a lower-use customer's consumption will fall – is 13% higher than the Block 1 rate on the R tariff and 25% higher than the TOU-REO off-peak rate. For these customers, other rate options will provide better experiences. On the other hand, customers who use electric space heating or heat pumps may benefit from the lower overnight costs on this tariff compared to the R or TOU-REO rate.

**Q139. IF THIS RATE IS WELL-DESIGNED AND COULD HELP NON-EV OWNERS, WHY WOULD THE COMPANY ALLOW CUSTOMER TO BE CONFUSED ABOUT THEIR ELIGIBILITY ON THIS RATE?**

A139. [Mr. Lucas] It is a good question, and one that I would have liked to ask additional discovery about. Absent that, I can only turn to the numbers. And the numbers confirm that, quite simply, GPC makes more money if customers are on the TOU-RD tariff than if they were on the TOU-PEV tariff. In the Customer Database data set discussed above in Section V, 72% of customers with 12 months of usage experienced higher bills on the TOU-PEV tariff than

on the TOU-TOU-RD tariff, with an average increase in annual bills of 23%. In total, just for this set of 11,000 customers, the Company collected nearly $1 million or 5% more revenue than it would have if they were on the TOU-PEV rate.

If one ramps this up to all new premises, GPC's additional revenue would scale proportionately. In fact, when I reanalyzed the complete Customer Database for all customers on the TOU-RD rate, the figures were even worse. With the complete sample of 61,000 customers with at least one month of service on the TOU-RD rate, 90% of all customers had higher bills in 2021 on the TOU-RD rate than they would have had on the TOU-PEV rate. The Company earned an extra $6.8 million on these customers in 2021, a staggering 19.7% increase over what they would have collected if these customers were on the TOU-PEV tariff.

The large difference between the 12-month customers and the full data set is due to the addition of lower-use customers in 2021 onto a tariff which is particularly poorly suited for them. I would expect if this analysis were repeated next year with more customers with 12 months of usage that the revenue collection difference between the TOU-RD and TOU-PEV rate would increase substantially from the 5% mentioned above.

**Q140. HOW DO THESE FIGURES COMPLEMENT YOUR ANALYSES ON THE INTENTIONAL CONFUSION OF THE TOU-PEV RATE?**

A140. The throughline is evident when looked at holistically. First, the Company petitioned for and received permission to make the TOU-RD rate the default for new residential premises. Then, the Company proposes to close the TOU-REO and R tariffs, which would force new premises onto the TOU-RD or TOU-PEV rate. At the same time, it obscures the eligibility of customers without an EV to take service on the TOU-PEV. This increases the number of new customers who stay on the TOU-RD tariff – most of whom pay more – and decreases new premise additions and existing customer switching to the TOU-PEV rate. The end result is GPC makes more money.

**Q141. WHAT DO YOU RECOMMEND ON THIS ISSUE?**

A141. The Commission should require GPC to rename the TOU-PEV rate, modify its webpage materials, and update its customer service protocols to clarify that all customers can sign up for the rate independent of their ownership or operation of an EV. It should also highlight the potential benefits of customers who use electric space heating, who may receive lower bills relative to other rates from overnight heating use.

*The Default Rate Should be Changed to the Nights and Weekends Tariff*

**Q142. BASED ON THE TOTALITY OF YOUR TESTIMONY IN THIS CASE, WHAT DO YOU BELIEVE IS THE CORRECTION DEFAULT OPTION FOR RESIDENTIAL CUSTOMERS?**

A142. We believe the "Nights and Weekends" TOU-REO rate should be set as the default tariff. Customers should still have the option to opt out of this rate onto any other available rate, including the R rate. The Company has failed to present information required by the Commission in the 2019 Rate Case order to report on the TOU-RD tariff as the default rate. While not a substitute for the Company's obligation, we believe our testimony has provided some useful details. In summary,

- The TOU-RD rate is poorly designed and not reflective of cost-causation principles
- The TOU-RD rate substantially overcharges low-use customers relative to the costs they incur on the system
- New remises added to the TOU-RD rate in 2021 experienced much higher bills than they would have on the R, TOU-REO, or TOU-PEV rate

These are simply not good characteristics for a default rate. By contrast, the TOU-REO rate has been around for nearly 30 years, is simple to understand, and can provide bill savings for customers who are able to shift usage out of the peak 2 PM to 7 PM summer weekday window while reducing systems costs incurred from aggregate demands during those same hours.

*The Commission Should Direct Georgia Power to Create a Robust Bill Comparison Tool*

**Q143. WHAT STEPS WERE INVOLVED IN YOUR BILL IMPACT ANALYSES PERFORMED IN THIS CASE?**

A143. [Mr. Lucas] I had to perform a series of analyses that pulled information from multiple sources, including Company exhibits, discovery questions, GPC's webpage, and multiple tariffs. To calculate the bills of customers on different rates, I created a complex spreadsheet that calculated bills based on on-peak, off-peak, and super off-peak usage; peak demand values; fixed customer charges; and ECCR/NCCR/DSM adders, taking care to align different rates for different TOU periods and months as needed.

**Q144. WOULD YOU EXPECT MOST GPC CUSTOMERS TO BE ABLE TO PERFORM A SIMILAR ANALYSIS ON THEIR OWN USAGE?**

A144. [Mr. Lucas] No. While this is par for the course for a rate design analyst, it is far beyond what could be expected from a typical GPC customer trying to understand their bill. To duplicate these steps, the customer must first set up an account and log in to GPC's webpage. From there, they must download their hourly usage for at least the past twelve months. They would have to look up the tariff information for each rate they want to analyze, while pulling the appropriate fuel cost recovery rate (of which there are three, plus an Interim Fuel Rider), properly calculating the various adder tariffs (of which there are also three), and then correctly factor in the Municipal Franchise Fee and Local Tax Adjustment.[122]

**Q145. IS IT REASONABLE TO EXPECT CUSTOMERS TO DO THIS?**

A145. No, it is simply not reasonable to expect customers to be able to perform this analysis even if they were technically able to do so. GPC's website only has generic information comparing the rates that is not personalized to an individual customers' usage patterns; just because two customers use 1,000 kWh per month does not mean they will have the same bill on the various TOU rates.

[122] https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans.html#tariffs

**Q146. WHAT DO YOU RECOMMEND REGARDING THIS ISSUE?**

A146. We recommend the Commission require the Company to develop a rate comparison tool that would automatically perform the analysis above and present a customer with their bill on each tariff based on their historic usage. The tool could also analyze the customers usage patterns and suggest more targeted recommendations. For example, if the tool notices that the customer uses a lot of energy during peak summer hours, it could recommend ways to save on their bill like using a programmable thermostat to pre-cool their house before 2 PM.

The Company should also begin collecting peak demand information for customers who are not on the TOU-RD rate. Although this is not current practice, given the Company has completed its deployment of AMI and has the ability to store this information, it could be an easy enhancement to implement. By collecting this data, the Company would be able to also inform customers how they would fare on the TOU-RD tariff in the bill comparison tool.

*The Solar Adviser Tool is Biased and Should Be Overhauled*

**Q147. WHAT IS THE SOLAR ADVISER TOOL?**

A147. The Solar Adviser Tool ("SAT") is an online "tool" that is prominently placed on the Company's Solar Programs webpage.[123] The tool's copy states: "Is a Solar Installation Right For You? Use our residential solar adviser tool to explore considerations and estimated costs for a solar panel installation on your home. Get real life figures to help you determine the best solar program for you and your goals."[124]

When one clicks on the SAT, the customer is presented with the following image:

[123] https://www.georgiapower.com/company/energy-industry/energy-sources/solar-energy/solar.html
[124] Id.

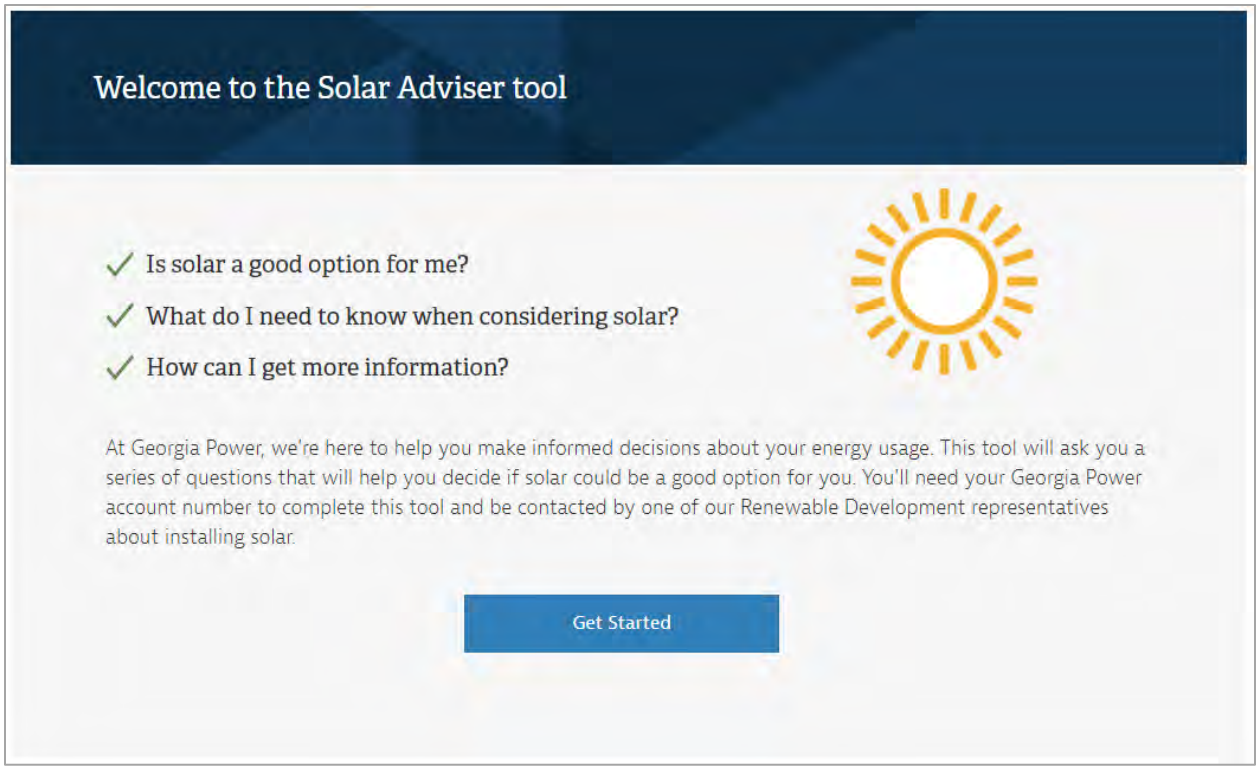


*Figure 13 - Solar Adviser Tool Launch Page*

Clicking on "Get Started" launches the tool into a series of questions. These follow in the order in which they are presented, followed by the text that accompanies the question. The available response options are also shown.

1. Do you own your home?* Solar installation involves drilling to secure solar panels to your roof. For example, if you live in a condominium, you must have ownership of your roof space and it be clearly defined.
    - Yes/No
2. How much sun shines on your roof?* The performance of PV panels may be reduced by the shading effect due to trees, passing of clouds, neighboring buildings and any other means.
    - Full Sun / Shaded / Not Sure
3. Is your roof less than 5 years old?* Consider replacing a damaged or failing roof prior to a solar installation. There are costs involved with un-installing and re-installing a solar installation.
    - Yes / No
4. Does your home have at least 200 sq. ft. of uninterrupted roof space?* Uninterrupted roof space is most efficient for a solar installation (100 square feet of roof space for every 1kW of solar). More complex rooftops can increase the installation cost and time.

- Yes / No / Not Sure

5. Are you planning to live in your home at least 5 more years?* The typical payback period, or breakeven – can exceed 10 or more years. There are costs involved with removing and re-installing a solar installation.
   - Yes / No
6. Select the size of your home. For an estimate of how much you can save by installing solar, pick the home that best matches your own.
   - Small / Below 1,600 sq ft / 4 kW / $10,080
   - Medium / 1,600 – 3,499 sq ft / 6 kW / $15,120
   - Large / 3,500 sq ft & up / 10 kW / $25,200
7. Select the city closest to your home. Solar panel performance varies by your location due to sunlight and weather. Calculations assume a relatively open, southern-facing roof surface.
   - Athens / Atlanta / Augusta / Columbus / Macon / Savannah / Valdosta
8. Select your electric rate. If you are unsure, or on a different rate plan, the standard service figures are used and therefore final results may very [sic] slightly
   - Standard Residential / Nights and Weekends / Not Sure / Other

**Q148. WHAT HAPPENS AFTER ONE ANSWERS ALL OF THE QUESTIONS?**

A148. The SAT produces a "results page" that is based only on the final three questions. A sample of the page is shown below in Figure 14 for a medium-sized system located near Athens on the Standard Residential rate.

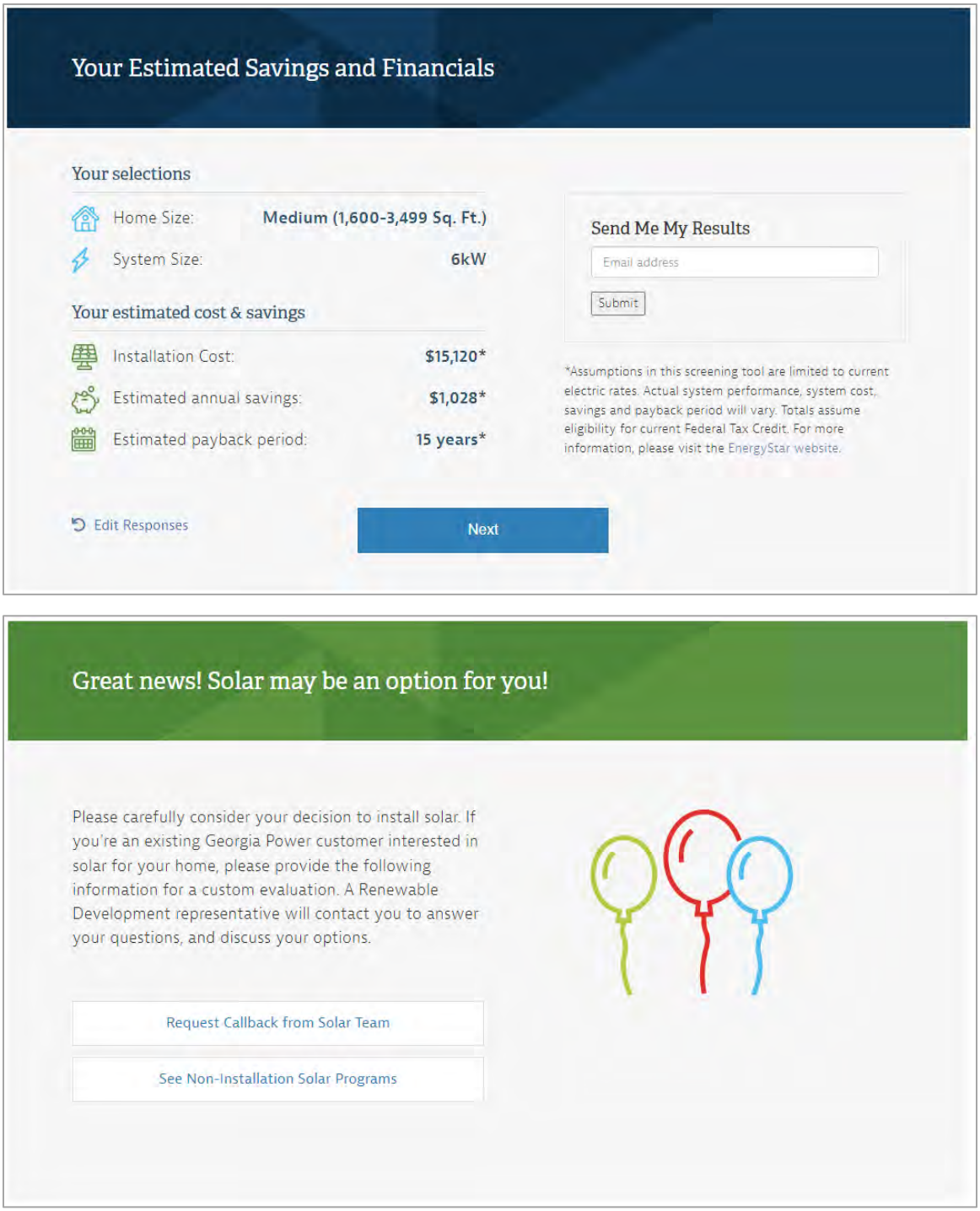


*Figure 14 - SAT Analysis Results*

When one clicks the "Next" button, one is presented with one final page, shown above. If one clicks on the Request Callback button, the user is prompted to enter her name, phone, email, and GPC account number. If one clicks the "See Non-Installation Solar

Programs," the user is taken to one final page with links to the Company's Community Solar and Simple Solar pages, with the following note: "We are dedicated to providing more ways for customers to support the growth of solar energy through our non-installation solar programs. These programs are perfect for residential customers who are unable or do not wish to install their own solar panels."

**Q149. WHAT DO THE ASTERISKS IN THE FIRST 5 QUESTIONS INDICATE?**

A149. These indicate that the question is "for informational purposes only."

**Q150. ARE THESE QUESTIONS REALLY JUST "INFORMATIONAL"?**

A150. No. The only result of asking these is to create FUD – fear, uncertainty, and doubt – in the mind of the customer. The answers do not impact the SAT's results at all. In fact, one can answer anything for the first five questions, including how much sun the roof receives, and not change the results of the analysis.

Many questions and accompanying text are designed to make onsite solar appear less attractive. For example, the third question asks whether your roof is less than 5 years old and suggests "replacing a damaged or failing roof prior to a solar installation." The clear implication is that roofs over 5 years old are suspect and may not be compatible with a new solar installation. This is simply not true.

Likewise, the questions asking whether the roof has at least 200 square feet of uninterrupted roof space or is shaded have no impact on the results. Most customers would be unaware how much uninterrupted roof space they have or how much shade falls on their house, and they should certainly not climb on their roof to take measurements. Not all roof "interruptions" are the same; normal interruptions such as an exhaust pipe has effectively no impact on pricing, but a customer may be confused into thinking that routine roof installs are "more complex rooftops" that can increase the price. And the only choices on shading are Full Sun / Shaded / Not Sure. The year-round level of shading cannot easily be discerned from any single observation, and shade in the morning may have different impacts on the

performance of the system than shade in the afternoon. None of these nuances are captured in the SAT.

Similarly, the question asking whether you plan to live in your house for more than 5 years introduces unneeded doubt and uncertainty. The value of the asset does not vanish if the original owner moves out of the house, but GPC conspicuously notes that payback periods may exceed 10 years and that there are costs of removing and re-installing a solar installation. Modern residential solar systems last for 25 or more years and continue to produce value for all current and future homeowners. In fact, the solar installation adds value to the house and can attract a higher selling price, with a recent report noting "We find clear evidence that solar systems are correlated with higher selling prices if those systems are owned by the homeowner."[125]

**Q151. TURNING TO THE ACTUAL RESULTS OF THE SAT, WHAT DID YOU FIND?**

A151. The results from a system near Athens appear below in Table 14. To make these figures, the Company was required to make assumptions about the usage patterns of customers installing different system sizes, although this is not disclosed anywhere in the tool's workflow.

| Savings ($) / Payback | R Tariff | TOU-REO |
|---|---|---|
| **Annual Savings ($)** | | |
| **Small** | $592 | $594 |
| **Medium** | $1,028 | $961 |
| **Large** | $1,930 | $1,773 |
| **Savings per kW ($)** | | |
| Small | $148 | $148 |
| Medium | $171 | $160 |
| Large | $191 | $177 |
| **Payback (years)** | | |
| **Small** | 17 | 17 |
| **Medium** | 15 | 16 |
| **Large** | 13 | 14 |

*Table 14 - SAT Results by Size and Tariff*

[125] Begley, Jaclene and Hoen, Ben, Solar at High Noon: Solar Home Premiums in a Rapidly Maturing Market (July 2, 2021). Available at SSRN: https://ssrn.com/abstract=3894549

For example, the savings per kW vary depending on the system size and tariff, meaning that the percentage of Block 3 usage (on the R tariff) and Peak usage (on the TEO-REO) tariffs are a function of system size. This would only happen if the Company assumed that customers installing larger systems had higher total usage on the R tariff or a higher on-peak percentage of usage on the TOU-REO tariff. Although it is not unreasonable to assume a customer installing a larger system has higher overall usage, there is nothing that prevents a high-use customer from installing a smaller PV system, particularly given the incentives embedded in the RNR Instantaneous tariff. Further, there is substantial diversity in on-peak usage for customers with similar total load levels; using a generic average assumption could have major impacts on the results of this analysis.

**Q152. WHAT FINANCIAL METRICS ARE ASSUMED IN THE SAT?**

A152. The SAT assumes that all systems cost $3,600/kW assuming a 30% federal ITC eligibility, although it is unclear and undocumented whether the tool reflects the old 22% ITC or new 30% ITC rate.[126] It is also unclear whether the system size and cost is indicative of $kW_{AC}$ or $kW_{DC}$. The former is used in the Company's interconnection process, but the latter is often used in conversations between customers and solar installers. The difference in prices between the two assumptions can be roughly 20%, a non-trivial amount. There is also no sourcing for the $3,600/kW figure in the tool.

**Q153. IS THE "PAYBACK PERIOD" METRIC ALWAYS RELEVANT TO A CUSTOMER?**

A153. No. The payback period is only relevant to systems purchased with cash. In this case, bill savings gradually offsets the initial net purchase price to produce a time when the purchase price has been fully offset and the "payback period" has been met. But if a customer finances a system, she could realize net positive cash flow on day one. For example, if a customer's monthly loan fee was a flat $100, and the bill savings from the PV system was $110, she

[126] Each system cost divided by its capacity divided by 0.7 = $3,600 / kW.

would save $10 immediately. There is no payback period as this metric simply does not apply to financed purchases.

**Q154. WHAT DO YOU RECOMMEND WITH REGARD TO THE SAT?**

A154. We recommend it be scrapped. The SAT is clearly biased against customer-owned, customer-sited solar. It requires customers to answer questions that are irrelevant to its results. The embedded assumptions assume usage patterns and financing methods that are unvetted and non-universal. And even if a customer pushes through all the FUD, the end result is a callback from GPC's own solar team, not a recommendation to use one of the many qualified installers in the state. Georgia Power customers would be better served if this tool did not exist.

*The Company Should Explain Why its AMI Data is "Not Precise Enough" for Universal Use*

**Q155. ACCORDING TO COMPANY FILINGS, HOW MANY SMART METERS DOES THE COMPANY HAVE?**

A155. The Company reported 2.3 million residential and 325,000 non-residential smart meters.[127] This represents 100% of residential and industrial customers and 95% of non-residential meters, although interestingly the Company reports 100% of its energy that year being served through AMI meters.[128] The Company appears to have largely completed its AMI rollout by 2011.[129]

**Q156. GIVEN THE UNIVERSAL AVAILABILITY OF AMI DATA FROM ITS RESIDENTIAL AND INDUSTRIAL CUSTOMERS, AND NEAR UNIVERSAL AVAILABILITY FROM ITS COMMERCIAL CUSTOMERS, DOES GPC USE ONLY AMI DATA IN ITS COSS AND RATE DESIGN?**

A156. [Mr. Lucas] Astonishingly, no. Staff noted this discrepancy and asked how it was possible that the Company could not provide peak demand values for individual customers not already

[127] EIA Form 860, Advanced Meters, 2021 data.
[128] The number of reported residential customers exactly matches the number of residential AMI meters. The Company reported about 15,000 non-AMI meters for commercial customers (out of 331,000 customers) and only 7 non-AMI meters for industrial customers (out of about 10,700). Total sales are reported as 82,944,041 MWh, while total sales from AMI meters are slightly higher at 83,039,174.
[129] EIA Form 860, Advanced Meters, 2011 data.

on the TOU-RD tariff but be able to provide hourly data for all customers on other tariffs.[130] Staff appears to be reasonably expecting that the Company's hourly AMI data was aggregated to produce the hourly load profile data for each tariff. I suspect they were as surprised as I was by the Company's response:

> The rate schedule hourly demands provided in STF-TAI-1-12 are developed from the Company's load research studies as discussed in IRP Technical Appendix Section 9.5 and in accordance with industry standard practices. The Company's standard AMI meter readings, while programed for the accurate determination of billing determinants for rendering bills, are not precise enough to develop individual load profiles that can be summed to represent a rate schedule's load nor total system load...
>
> These studies are designed to deliver representative load profiles at the rate level; they cannot determine load profiles for each individual customer. Therefore, the AMI meters and readings are appropriately used for billing individual customers and the Company's long-standing load research process is appropriately used for developing the hourly demands for rates.[131]

In other words, despite having AMI meters on functionally all of its residential and industrial customers, and on more than 95% of its commercial customers, the Company does not use the AMI data in its COSS or rate design workpapers. Instead, it uses load sampling methods necessary before universal AMI that statistically recreates hourly usage for tariffs and COSS classes from a sample of customers.

**Q157. WHY IS THIS SO SURPRISING?**

A157. [Mr. Lucas] Because the only reason to do load research using a sample of load meters is if access to population-level AMI data was not available. There is no sub-hourly data in COSS; everything is aggregated to a full hour. Residential AMI meters provide hourly readings. Certain commercial rate designs bill based on sub-hourly durations, but these can be easily summed to produce hourly values. Tariff groups that use the roughly 5% or 15,000 non-AMI meters in the commercial class may need to use load research, but that represents a tiny fraction of the Company's total customers and energy usage. If the Company has hourly or

[130] STF-TAI-4-5.
[131] Id.

sub-hourly usage from every customer in a tariff or customer group, it can and should just add those values up.

Load research, no matter how good, can only introduce errors when compared to counting an entire population. The Company states in IRP Technical Appendix Section 9.5 that about 2,000 customers have had load research meters installed on their property, or less than 0.1% of total customers. While this number of meters almost certainly provides a statistically robust sample, it necessarily will have uncertainty with respect to directly counting the population.

**Q158. WHAT IS YOUR RESPONSE TO THE COMPANY'S OBSERVATION THAT AMI METERS ARE ACCURATE ENOUGH FOR BILLING BUT NOT FOR LOAD RESEARCH?**

A158. It is confusing at best. First, the Company did not provide any context for what it means by "not precise enough", but precision is typically related to overall accuracy of the meters. For example, there are multiple ANSI standards on meters. Specifically, ANSI standard C.12-2022 defines various accuracy levels of metering equipment, such as Class 0.5 (+/- 0.5% of actual) and Class 0.2 (+/- 0.2% of actual).[132]

While certain meters are more accurate than others, and it is possible that the Company installed less accurate meters (e.g., Class 0.5 instead of Class 0.2) in its customer base, the measurement errors found in a population should be randomly distributed and non-correlated. This means that even if individual meters have errors up to 0.5% under or over the actual reading, these errors should cancel each other out as more meters are included in the total. The result of adding up all the values from thousands or millions of meters would be a total that is functionally indistinguishable from the real value.[133]

The only way in which this would not hold true is if the errors of the individual meters are not randomly distributed and/or are correlated. For instance, if the meters the Company installed all tended to read higher values than actual, then the results from adding

[132] The previous ANSI standard for meters when GPC was rolling out AMI was C12.20. This has since been merged into a newer standard and updated. https://blog.ansi.org/ansi-c12-1-2022-code-electricity-metering/
[133] Statistically speaking, the more samples in a data set, the lower the margin of error around the actual value.

up all of the meters in the population to produce a total could be skewed. Of course, this also would mean that the Company is systematically over-billing customers, which is its own problem.

**Q159. DO YOU HAVE ANY DATA THAT COMPARES THE BILLING KWH TO THE LOAD RESEARCH KWH?**

A159. [Mr. Lucas] Yes. The Company provided annual billing kWh data in its confidential rate design workpapers.[134] It also included load research kWh in its hourly load by customer file.[135] I compared these for several residential tariffs to see how they differed. The results are below in Table 15.

| Tariff | AMI Billing Data kWh | Load Research kWh | Delta (%) |
|---|---|---|---|
| **R / Flat** | [redacted] | 25,962,520,817 | [redacted] |
| **TOU-REO** | [redacted] | 84,061,880 | [redacted] |
| **TOU-PEV** | [redacted] | 109,255,935 | [redacted] |
| **TOU-RD** | [redacted] | 280,327,637 | [redacted] |
| **Prepay** | [redacted] | 1,076,455,414 | [redacted] |

*Table 15 - AMI vs. Load Research kWh Totals*

**Q160. WHAT DOES THIS DATA SUGGEST?**

A160. [Mr. Lucas] Absent compelling evidence that the AMI meters are systematically biased in one direction (which is contraindicated by the presence of positive and negative variations above), it suggests that the errors in the load research data are small but non-zero.

The result from the R / Flat customer group is particularly problematic. Because there are [redacted] kWh in the Load Research group that were used to set rates, the rates for this class are slightly [redacted] than they would otherwise be in order to collect the desired revenue requirement for this tariff. These [redacted] rates are then applied to [redacted] billing kWh from the AMI meter reads, resulting in [redacted] revenue than should have been collected from the rate.

[134] STF-TAI-1-16 Attachments.
[135] STF-TAI-1-12 Attachment.

Essentially, the tariff collects roughly [redacted] revenue than it should, resulting in [redacted] revenue collection of $[redacted] in 2021.[136]

**Q161. WHAT DO YOU RECOMMEND ON THIS ISSUE?**

A161. [Mr. Lucas] I recommend the Company explain in detail why it is not using its AMI data in its COSS and rate design for customer classes or tariffs that have universal or near-universal AMI deployment. Absent statistically valid reasons, the Commission should direct the Company to use AMI data to its maximum extent in its COSS and rate design going forward while eliminate as many load research costs as possible. Customers paid for AMI and expect to get benefits from that investment such as cost savings from load research. Instead, it appears the Company is installing and maintaining duplicative load research meters while also charging customers for Company resources to analyze the data.

The Commission should also request an investigation as to whether the discrepancies between the load research values and the AMI billing values are resulting in the over-collection or under-collection of revenue from certain tariffs.

*The Commission Should Approve the 4CP Production Cost Allocator*

**Q162. HOW DOES THE COMPANY ALLOCATE COSTS IN ITS COSS?**

A162. In the Company's COSS, production capacity costs are generally allocated to customer classes based on a 12CP method, while transmission costs are generally allocated based on a 4CP method. Distribution costs are allocated based on either the 4CP (voltage levels C-E) or Class NCP (voltage levels F-G) demand levels.[137]

**Q163. IS THIS APPROACH TYPICAL IN YOUR EXPERIENCE?**

A163. [Mr. Lucas] It is somewhat unusual in my experience, particularly for a summer-peaking utility such as the Company. I have usually seen production costs allocated based on a 4CP

[136] STF-TAI-1-16 Attachment A TRADE SECRET. Value represents the excess collections of base, fuel, and adder rider revenue for the R and FlatBill service based on an [redacted] of billed kWh.

[137] The Company allocates demand-based production costs and step-up substation costs on a 12CP basis, and high-voltage transmission costs on an 80% 4CP/ 20% 12CP basis. Lower-voltage transmission assets are allocated on a 4CP or NCP basis depending on voltage level. Evans Direct at 17.

method or a combination 4CP and energy method and transmission costs allocated on a 12CP method. Higher voltage, shared distribution assets are typically allocated based on a Class NCP basis, while lower voltage assets are sometimes allocated based on Class NCP and sometimes on the Sum of Individual Maximum Demand ("SIMD") allocator.[138]

It is clear from the Company's testimony that other parties have noted that production costs are often allocated based on 4CP demand. In fact, the Company produced alternative versions of the COSS that included a 4CP production cost allocator, although it does not recommend their adoption.[139]

**Q164. HOW DO THE COMPANY'S LOADS CHANGE THROUGHOUT THE YEAR?**

A164. [Mr. Lucas] The Company's peak loads are concentrated during the summer months. Figure 15 below shows the average, maximum, and minimum 12CP peak in each month from 2017 through 2021.[140] While there are some years in which the winter months had high peaks, the average and minimum winter peaks remain considerably lower than summer months. In fact, January 2018, the most extreme winter month in the past 5 years, still had lower demand than every summer month in 2018 and would have been no higher than the 3rd highest month peak in any year between 2017 and 2021.

[138] The SIMD is calculated by summing each individual customer's maximum demand regardless of when it occurs. I do not believe that the SIMD is an appropriate allocator for any distribution costs, but when it is used, it is typically used for assets very close to the customer such as line transformers.
[139] Evans Direct at 4.
[140] STF-PIA-8-2 Attachment.

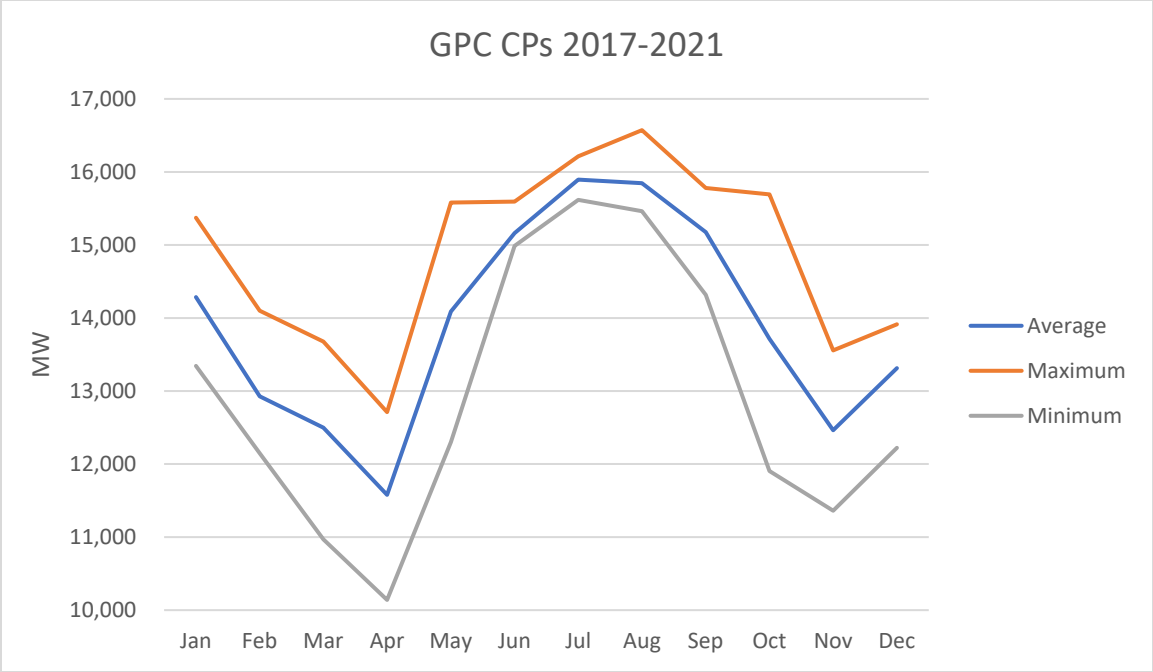


*Figure 15 - GPC CPs 2017-2021*

**Q165. WHY DOES THE COMPANY RECOMMEND CONTINUING THE USE OF THE 12CP ALLOCATOR FOR PRODUCTION COSTS AND NOT RECOMMEND ADOPTING THE 4CP PRODUCTION COST ALLOCATOR?**

A165. [Mr. Lucas] The Company's testimony is a bit confusing on this point. It indicates that the 12CP allocator has been used by the Company since 1989, is often used in FERC filings for wholesale jurisdictional purposes, and has been used by many utilities across the country.[141] While these all may be true, this text applies to the 12CP allocator generically, and not the 12CP allocator as applied to production costs.

The Company does offer some testimony on the value of 12CP to "summer and winter reliability planning", which may refer to production capacity. But even if one were to consider winter and summer peak demands as equally important to reliability (which, based on history, they are not), there is no justification for including the shoulder months in production capacity planning given their substantially lower peak demand levels.

[141] Evans Direct at 14.

**Q166. DOES THE COMPANY TREAT THE IMPORTANCE OF WINTER LOADS CONSISTENTLY ACROSS ITS APPLICATION?**

A166. No. The Company's testimony on the importance of winter load in planning is contradicted by one of its discovery responses. When asked by Staff whether it considered adding a winter TOU rate to its rates to reflect winter peaks on the system, the Company responded "At this time, Georgia Power has not identified a need for a winter peak time of use residential rate. This is due to the fact that the Company continues to forecast its peak loads to occur within the summer months. These summer peaks occur during predictable afternoon hours between the months of June through September, which correspond to existing residential time of use offerings."[142] The Company continued by noting that winter peaks are less predictable, less frequent, and shorter in duration than summer peaks.

**Q167. WHY IS THIS AN IMPORTANT CONSIDERATION FOR SOLAR CUSTOMERS?**

A167. Any discussion of the benefits that solar brings should consider how it performs during peak load hours, and for the Company, peak load hours tend to fall on hot, sunny summer afternoons when solar is generating well. The solar generation is both used onsite to meet load and exported to the grid to meet the neighbor's load. If production costs are not allocated to customers based on these summer months, then solar generation will appear less valuable than it actually is.

**Q168. WHAT DO YOU RECOMMEND WITH REGARD TO THE PRODUCTION COST ALLOCATOR?**

A168. [Mr. Lucas] I recommend the Commission adopt the 4CP allocator for production costs. The Company's historical data and discovery responses show that it has and will continue to be a summer peaking utility, and in my experience, this is the dominant production cost allocator for summer peaking utilities. Further, the 12CP allocator brings in too many low-demand shoulder months that do not contribute to production costs due to spare capacity on the system.

[142] STF-TAI-1-31.

**Q169. ARE ANY OF THE TRANSMISSION PROJECTS REQUESTED BY THE COMPANY IN THIS RATE CASE ASSOCIATED WITH THE NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?**

A169. No. The Company's response to a Staff discovery request noted that none of the projects in this rate case are associated with the North Georgia Reliability and Resilience Action Plan and that Plan is "currently under study and development in conjunction with the Integrated Transmission System Participants."[143]

**Q170. IS THAT A PROBLEM?**

A170. Yes. There is no clear indication in this rate case that the Company has allocated additional costs to pay for the North Georgia Reliability and Resilience Action Plan over the next three years. As Georgia faces retirement limitations in the north, and generation interconnection restrictions in the south, it is extremely important that multiple transmission scenarios be evaluated simultaneously, expeditiously. The proposed rate case does not do an adequate job explaining how the Company intends to plan for the future.

**Q171. DOES STAFF HAVE DEDICATED FUNDING TO CONDUCT TRANSMISSION PLANNING OVERSIGHT?**

A171. It does not appear that the Company has allocated any additional funding for Staff to assist with development, review, or oversight of the North Georgia Reliability and Resilience Action Plan, or transmission planning oversight more broadly.

**Q172. HOW COULD ADDITIONAL FUNDING FOR TRANSMISSION PLANNING FOR THE COMPANY AND/OR STAFF BE HELPFUL?**

A172. Additional funding for the Company could be used to upgrade software programs that evaluate multiple types of economic congestion, as is done in many other regions of the country. It could also be used to allow Staff to issue a request for proposals to hire an

[143] STF-PIA-4-23.

independent transmission consultant firm to run scenario-based analyses, evaluate various benefit metrics, and provide advice and recommendations to the Commission regarding future transmission plans. An independent transmission consultant firm could look beyond the current 10-year transmission planning horizon and could have a broader scope of work developed and led directly by the Commission. This sort of independent analysis is already done to evaluate RFP bids and was used by the Commission Staff in the IRP evaluating generation expansion but has not yet been done with transmission planning.

**Q173. WOULD STAFF'S INDEPENDENT TRANSMISSION CONSULTANT REPORT REPLACE THE COMPANY'S NORTH GEORGIA RELIABILITY AND RESILIENCE ACTION PLAN?**

A173. No. It would provide the Commission alternative recommendations to compare against the Company's recommendations that may even confirm the Company's plan as the preferred plan. Because transmission development can result in assets that last 40 to 60 years, it would be prudent to get a robust second opinion.

## VII. CONCLUSION

**Q174. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.**

**A174.** Our recommendations in this case follow:

- The Company's proposed $200 interconnection fee should be rejected and its current $5/kW fee for systems under 250 kW maintained. If the Company is able to demonstrate that its costs for routine steps such as billing system updates and project review are reasonable, and that the current fees under-collect interconnection review costs, the Commission should direct the Company to establish tiered interconnection fees that seek to minimize costs for systems under 10 kW.
- The Commission should deny the Company's request to adjust revenue by $1.4 million. The Company did not appropriately account for exported energy in its COSS, and as a result, has overallocated costs to customer classes with RNR projects that is not considered in this figure.
- The Commission should strongly reconsider the width and asymmetry of the currently-approved ROE dead band. Ideally, it would be reduced to +/- 50 basis points, but at a minimum should be returned to the +/- 100 basis points in place prior to 2020.
- The Smart Usage tariff should not be the default rate and should be substantially redesigned with either a peak TOU demand charge collecting a fraction of production and transmission costs or a non-coincident peak charge collecting only low-voltage distribution assets. The Commission should require the Company to validate that the Smart Usage tariff is revenue neutral with respect to the traditional Residential tariff.
- The Commission should require the Company to continue offering the Residential and Nights and Weekends tariffs to new premises. The default rate should be changed to the Nights and Weekends tariff.
- The Commission should require the Company to develop a rate comparison tool that would automatically calculate a residential customer's bill based on historic usage on the various tariff options. It should also be required to collect billing demand data for each customer.
- The Solar Advisor Tool should be scrapped as it is actively biased against onsite solar.
- The Company should explain why its AMI data is insufficiently precise to use in its rate design and COSS. Absent statistically valid reasons, the Commission should direct the Company to use AMI data to its maximum extent in its COSS and rate design going forward while eliminate as many load research costs as possible.
- The Commission should adopt the 4CP allocator for production costs. The Company's historical data and discovery responses show that it has and will continue to be a summer peaking utility, and in my experience, this is the dominant production cost allocator for summer peaking utilities.
- The Commission should direct the Company to provide funding for Staff and/or independent consultants to perform additional transmission studies related to North Georgia Reliability and Resilience Action Plan and transmission planning generally.

**Q175. DOES THIS CONCLUDE YOUR TESTIMONY?**

A175. Yes, it does.

(The documents referred to were marked for identification and admitted into evidence as GASEIA Exhibits 2 through 11.)

MR. THOMASSON: And I'd ask the witness be excused.

MADAM CHAIR PRIDEMORE: You may be excused.

MR. LUCAS: Thank you, Commissioners.

MR. YOUNG: Thank you. See you in a few weeks.

(Witnesses excused.)

MADAM CHAIR PRIDEMORE: So we have -- MARTA is up next. Let's see. Where is Ms. Sturm? Hey.

MS. STURM: Hi.

MADAM CHAIR PRIDEMORE: How long? Give me a time estimate because I may have -- I've got to stop you at 9:30.

MS. STURM: I don't think it should be long. I guess it's dependent on cross-examination.

MADAM CHAIR PRIDEMORE: Okay. All right. Good.

Sometimes you guys have an idea of what is coming, so -- all right. Go ahead.

MS. STURM: Good morning. MARTA calls Mr. Kevin Hurley to the stand.

Mr. Hurley, if you could please rise, raise your right hand.

Thereupon,

KEVIN HURLEY,

having been duly sworn, testified as follows:

MR. HURLEY: I do. Yes, ma'am.

MS. STURM: Thank you. You may be seated.

DIRECT EXAMINATION

BY MS. STURM:

Q Please state your full name and business address for the record.

A Yes. My name is Kevin Hurley. And I work for MARTA and our business address is 2424 Piedmont Road, Atlanta, Georgia 30324.

Q Thank you. And are you here today testifying on behalf of MARTA?

A Yes, ma'am. I'm here to testify on behalf of MARTA.

Q Thank you.

On October 20th, 2022, did you file or cause to be filed roughly 15 pages of written direct testimony in this proceeding in question-and-answer format?

A Yes, ma'am.

Q Do you have any corrections to that testimony?

A Yes, ma'am. I do have one correction.

On Page 14, line 299 of that filed testimony, it references MARTA's rider -- MARTA's ridership increase to

pre-pandemic levels will be from '24 to '25. I've gotten new information here in the last week that projects that to be '27 -- 2027 and 2028. So I'd like to adjust that testimony.

Q Okay. Any other corrections that need to be made?

A No, ma'am. That's the only one.

Q Okay. If I was to ask you the same questions today that appear in the prefiled testimony with those changes, would the answers or responses be the same?

A Yes, ma'am.

MS. STURM: Okay. Madam Chair, we would move to have the prefiled testimony of Mr. Hurley with those corrections copied into the record as if read orally today.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimony and errata of Kevin Hurley follows:)

**BEFORE THE**
**GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **In Re:** | **)** | |
| **Georgia Power 2022 Rate Case** | **)** | **Docket No. 44280** |
| | **)** | |

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**DIRECT TESTIMONY OF**

**KEVIN L. HURLEY**
**ON BEHALF OF THE**
**METROPOLITAN ATLANTA RAPID TRANSIT AUTHORITY**

**Q. STATE YOUR NAME, BUSINESS POSITION AND BUSINESS ADDRESS, AND NATURE OF APPEARANCE IN THIS PROCEEDING.**

**A.** My name is Kevin L. Hurley. I am Deputy Chief Financial Officer of the Metropolitan Atlanta Rapid Authority ("MARTA"), 2424 Piedmont Rd. Atlanta, GA 30324. I have the pleasure of appearing today on behalf of MARTA, the public authority responsible for operating bus, paratransit, light rail, and rapid rail service in the City of Atlanta, Fulton County, DeKalb County, and Clayton County, to express MARTA's concern with the cost of electricity for rail propulsion service and to update the Commission on our work to electrify MARTA's fleet and service vehicles as well as provide Electric Vehicle charging infrastructure for our employees and patrons. MARTA stands to be affected by this Commission's decisions concerning Georgia Power's proposed increase to the Electric Transportation Service ("ET") tariff as well as Georgia Power's Electric Vehicle rates and policies.

**Q. BRIFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE**

**A.** I am a 1988 graduate of the University of Georgia with a bachelor's degree in finance, I have a Master of Business Administration from the University of Phoenix, and I am a Certified Retirement Fiduciary. I joined MARTA in 1999 and now have twenty-three (23) years of experience with MARTA, serving in various accounting and financial management positions, with increasing levels of responsibility. I currently serve as the Deputy Chief Financial Officer. Prior thereto, I served as interim Chief Financial Officer for eighteen (18) months. I also recently served as the chair of MARTA's Non-Represented Defined Contribution Pension Committee, and co-chaired MARTA's Represented Defined Benefit Pension Committee. I am also the past Vice President of the Board of Directors for the Georgia Association of Public Pension Trustees.

Prior to joining MARTA, I was senior analyst for The Boeing Company. Prior to Boeing I was a Captain in the United States Air Force where for eight years I was Comptroller, Flight Commander, and Financial Analysis Branch Chief

**Q. WHAT ARE YOUR DUTIES FOR MARTA?**

**A.** As I mentioned, I have served in a range of accounting and financial management positions with MARTA during my twenty-three (23) year tenure. I am familiar with MARTA's financial situation, its operating budget and capital expansion plans. In my current role as Deputy Chief Financial Officer, I support MARTA in the areas of business and financial analysis to ensure maximum yield for investments. I oversee MARTA's debt program,

Accounting and Revenue collections, fare media, cash and investment management, energy hedging, financial modeling, and parking services.

**Q. WHAT HAVE YOU DONE TO PREPARE YOUR TESTIMONY IN THIS MATTER?**

**A.** In addition to relying on my personal experience and knowledge of MARTA's electrical power costs and operations, including its history and benefits to the region, I have reviewed MARTA's electrical power usage and requirements as well as the current rate structure of MARTA's accounts with Georgia Power. I have also consulted colleagues regarding MARTA's history and dealing with Georgia Power and reviewed Georgia Power's filing and the direct testimony of its witnesses in this case. I have discussed these issues with my colleagues and MARTA's attorneys and consultants and arrived at the conclusions and recommendations presented in this testimony.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

**A.** Yes, I testified on behalf of MARTA in the 2021 Rate Case, Docket 43838.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

**A.** The purpose of my testimony is to support MARTA's request that its electric service rate for the Electric Transportation Service ("ET") tariff not be increased but held at current rates. In previous rate proceedings, Georgia Power and this Commission have recognized MARTA's value and importance in helping to make Georgia one of the best states to do business. MARTA continues to be a driver in economic growth in the Metro Atlanta area and State. With the growth that has and continues to occur, there has been and continues to be a strong demand for office and residential properties within a half mile of MARTA's rail stations. For example, MARTA's transit-oriented development projects have resulted

in the development of at least 1,919 multifamily units, 379,300 SF of retail, roughly 2.8 million SF of office, more is in progress and planned over the next decade. MARTA's services and operations continue to be a driver for companies locating and relocating to the area. MARTA's value and importance as a partner in economic development continues to be far greater to Georgia Power, Metro Atlanta, and the State of Georgia than MARTA as a ratepayer. MARTA's ability to execute its capital program is as critical to the future growth of the Metro Atlanta region as the Region's water supply. Reliable, affordable, and efficient public transportation is critical to the continued development and future of the metro area and the state.

## THE MARTA PUBLIC TRANSIT SYSTEM AND ITS OPERATION

**Q. PLEASE DESCRIBE THE GENERAL AUTHORITY OF MARTA**

**A.** MARTA is a public authority established by an Act of the Georgia General Assembly in 1965, and approved by subsequent voter referenda, for the purpose of acquiring, planning, designing, building, maintaining, and operating a public rapid transit system in the City of Atlanta, and in Fulton, DeKalb, and Clayton Counties. In 1972 MARTA acquired the Atlanta Transit System, Inc., and took over the operation of bus service in Fulton and DeKalb Counties and the City of Atlanta. In June 1979 MARTA initiated rapid rail service powered by electricity provided by Georgia Power Company.

**Q. DESCRIBE THE GENERAL FEATURES OF MARTA'S RAPID RAIL SYSTEM**

**A.** MARTA's rapid rail system consists of over one hundred twenty (120) miles of electrified rail in a dedicated right of way, providing, providing forty-eight (48) miles of total rail service via thirty-eight (38) rail stations. The Authority owns a fleet of three hundred

thirty-eight (338) rail cars powered by alternating current (AC) electrical power. All rail cars are equipped with regenerative braking systems, so power produced during braking (when propulsion motors operate as generators) is available for consumption by adjacent trains fed from the third rail system.

**Q. HOW DOES MARTA COMPARE TO OTHER HEAVY RAIL TRANSIT PROVIDERS IN THE UNITED STATES?**

**A.** MARTA serves 2.2 million residents of Metro Atlanta living within our service area and is among the largest transit system in North America (by unlinked passenger trips) providing bus, rail, and mobility services. According to analysis by the National Transit Database, MARTA has one of the lowest costs per-revenue mile for heavy rail service of any public transit system in the United States.

**Q. EXPLAIN THE BENEFITS MARTA PROVIDES TO THE METROPOLITAN ATLANTA REGION AND STATE OF GEORGIA**

**A.** The immediate transportation benefits include providing bus, light rail, mobility, and rapid rail transit service for nearly one-half million passenger boardings each weekday prior to the Covid-19 pandemic and just under 300,000 as we recover from the pandemic, a number that continues to grow. This includes connecting bus and rail service for passengers entering the service area via bus service provided by MARTA's regional partners, CobbLinc, Gwinnett County Transit and Xpress, operated by the Atlanta Region Transit Link Authority. This connection service provides access to employment, services and opportunities for the transit-dependent, mobility for the disabled, convenience for visitors and special events patrons, and a reduction in traffic congestion and pollution for all residents of the region.

MARTA is also a driver of economic development in the metro-area and region. MARTA helps attract new businesses and other development to its service footprint. Many companies wish to locate their businesses and offices near transit, and in particular heavy rail, to reduce their employees carbon emissions, transportation costs, and commuting stress and benefit from the direct connection to the terminal at Hartsfield-Jackson International Airport. Young professionals and younger generations, in general, tend to embrace public transportation, with a larger percentage preferring to live and work in and near communities with reliable, efficient, and affordable public transportation service and quick and easy access to public transportation.

Transit Oriented Development (TOD) on former MARTA surface parking areas has proved hugely successful, both in terms of attracting businesses to the metro-area and increasing residential development in close proximity to services. Residential developments at Avondale, Edgewood/Candler Park, King Memorial, and Chamblee Stations are prime examples of areas with major residential developments on ground leases with MARTA. Transit oriented development is advancing at MARTA's Arts Center, North Avenue, and Bankhead stations as well. By the numbers, MARTA's transit oriented development includes:

- Built TOD to date: MARTA's transit-oriented development projects have resulted in the development of at least 1,919 multifamily units, 379,300 SF of retail, and roughly 2.8 million SF of office.

- TOD in Negotiation/Predevelopment: Currently in negotiation and predevelopment phases are an additional 1,045 multifamily units, 10,000 SF of retail, and 475,000 SF of office space.
- TOD in Procurement includes 1,395 multifamily units and 1.5 million SF of office
- TOD in Planning includes 6,700 multifamily units and 70,000 SF retail space

In total that equates to an additional approximately 9,140 multifamily units, 80,000 SF retail space, and 2 million SF of office space to be brought online over the next fifteen (15) years at an estimated cost of $4.75 billion. The potential is even greater as MARTA has other land holdings that have not yet been fully evaluated, affording additional opportunities for development.

Microsoft, Mercedes-Benz, State Farm, and NCR are just a few of the companies which have deliberately located near MARTA stations to take advantage of public transportation for their employees. When State Farm Insurance moved its headquarters, with over 2 million square feet of office space, from Johns Creek to Dunwoody Station, they also built a platform extension and a new entrance to MARTA to make riding transit convenient for their employees. Atlanta's bid for Amazon's HQ2 advanced through Amazon's site selection process because there were 10 potential office sites near MARTA rail stations. Microsoft's recent decision to develop a 90-acre campus on the Westside of Atlanta was due in part to the proximity of the Bankhead rail station. MARTA is now in the process of expanding the size of the Bankhead station rail platform to be able to accommodate trains up to 6 cars from the current 2 car platform.

Georgia's FY22 state budget includes the first ever line item for MARTA. MARTA will receive $6 million to support the positive economic impacts of the Bankhead station expansion.

MARTA plans to spend more than $3 billion on capital projects over the next ten years. The current ten-year budget includes $715 million in More MARTA spending within the City of Atlanta, including $200 million to transform the Five Points Station. MARTA's largest capital expenses over the next ten years include approximately $680 million to replace aging rail cars with more energy efficient cars and $371 million for station rehabilitation and improvement.

**Q. DESCRIBE IN GENERAL MARTA'S RELIANCE ON GEORGIA POWER COMPANY IN MARTA'S OPERATIONS OF THE RAPID TRANSIT SYSTEM.**

**A.** The light rail (streetcar) and rapid rail systems are powered by electricity provided by Georgia Power Company. During the design and construction of the heavy rail system the Authority contracted with Georgia Power for the construction of electrical distribution facilities to serve the heavy rail system. During the construction of the heavy rail system, MARTA funded the construction of over 100 substations for traction and station power, cabling, and electrical duct banks. This system delivers electrical power from Georgia Power directly to MARTA for use by rail vehicles and for essential station loads such as lighting, faregates, ticketing machines, elevators, escalators, and station audio-visual information systems. MARTA has placed its first six zero-emission electric buses in service in May 2022. MARTA was awarded a $3.85 million Senate earmark and a $19.3 million Federal Transit Administration Low and No Emission Bus grant to

further advance the fleet transition to electric. Further, all future Bus Rapid Transit projects are expected to utilize electric buses.

**Q. HOW DOES GEORGIA POWER COMPANY PARTICIPATE IN THE CONSTRUCTION, MAINTENANCE, AND IMPROVEMENT OF THE ELECTRICAL TRANSMISSION SYSTEM FOR MARTA'S RAPID RAIL SYSTEM?**

A. Georgia Power Company is a contractor to MARTA for work required for the construction, maintenance, and improvement of the electrical transmission system for the rapid rail system. Contracts are negotiated between the Company and MARTA for the performance of specified maintenance or improvements to the electrical transmission system service. Georgia Power is compensated under those contracts through MARTA's operating or capital budgets, as applicable, for each project, in addition to all sums paid to Georgia Power for electrical consumption. Since the inception of the MARTA rail system, MARTA has invested well over $500 million in capital funds for the construction, maintenance, and improvement of the electrical transmission system by which Georgia Power serves MARTA. The financial and operational responsibilities for the maintenance and continued improvement of the electrical transmission system are borne by MARTA. Georgia Power's other ratepayers do not subsidize MARTA. We currently have plans to spend nearly $200 million in modernizing our 40-year- old electrical system. This does not include numerous transit- oriented development (TOD) projects or major expansion projects outlined in the Atlanta More MARTA Plan and Clayton County Plan, which will bring new high capacity transit, new maintenance

depots, new stations and additional vehicles to the Atlanta region and increasing the MARTA'S electrical load.

**Q. PLEASE DISCUSS MARTA' BASIC FINANCIAL STRUCTURE. HOW IS MARTA'S OPERATING BUDGET FUNDED?**

A. As a public authority, the funding sources for operation of the MARTA system consist of: (1) the proceeds of a one percent sales and use tax levied in Fulton County, DeKalb County, Clayton County and 1.5 percent from the City of Atlanta, (2) fare box revenues collected from passenger fares, (3) leases of property, including long term ground leases for TOD, (4) federal formula funds for preventive maintenance, (5) automobile ad valorem taxes from Fulton, DeKalb and Clayton counties and (6) other revenues derived from activities such as advertising on buses, rail cars, rail stations and bus shelters, and short term leases of surplus property.

**Q. HOW IS MARTA'S CAPITAL BUDGET FUNDED?**

A. The funding sources for capital improvements and expansion of the MARTA system consist of: (1) the proceeds of the one percent sales and use tax from Fulton, DeKalb and Clayton counties and the 1.5 percent sales tax from the City of Atlanta, and (2) federal and state grant funds.

**Q. AS A PUBLIC AUTHORITY, DOES MARTA RECEIVE ANY BUDGET BENEFITS FROM ITS PAYMENTS TO GEORGIA POWER?**

A. No. As a public authority, MARTA does not pay taxes and does not return a profit. Therefore, MARTA's payments to Georgia Power for the provision of electrical service are borne completely by the operating budget, without any offset for tax deductions. When electrical power costs increase, a corresponding increase must occur in operating

revenue to provide for payment of electrical costs, or a corresponding decrease in costs must occur to continue offering the same level of service. Since the sales tax is fixed by state law, the only mechanisms for dealing with increased electrical costs are to increase passenger fares or reduce operating expenses.

**Q. PRIOR TO THE COVID-19 PANDEMIC WHAT DID MARTA DO TO REDUCE ITS COSTS AND IMPROVE ITS FINANCES?**

**A.** Prior to the COVID-19 Pandemic, MARTA implemented measures to prepare for the demands of the future while maintaining and improving quality services. MARTA began implementing prudent and aggressive cost-cutting measures, efficiency innovations and new revenue generation opportunities to improve service delivery to its customers and avoid a fare increase. MARTA's pre-pandemic cost reductions were made to improve existing transit services while positioning itself for future investment and expansion. One of MARTA's major strategic priorities was to achieve financial viability and stability. To this end we have engaged in cost reduction measures, including staff reductions, outsourcing, and asking all business partners to assist MARTA by holding down costs. In August, Fitch upgraded MARTA's credit rating to AA based on MARTA's having demonstrated a sustained maintenance of liquidity and financial resilience.

**Q. WHAT ACTION HAS MARTA TAKEN OVER THE YEARS TO REDUCE ITS ELECTRICAL COSTS, OTHER THAN REDUCING SERVICE?**

**A.** After the 2007 Rate Case, a small part of MARTA's electrical power usage began to be purchased under marginal or real-time pricing (RTP) to realize cost savings where possible. At the conclusion of the 2013 rate case MARTA moved 40% of its rail

propulsion load to marginal pricing. However, as the scale of operations changed this needed to be adjusted. For obvious reasons, the rail system must provide service, and therefore has a greater demand for electrical power during the weekday morning and afternoon rush hours when there is the greatest passenger demand for service. Generally, those needs are difficult if not impossible to delay or shift to off-peak times. However, MARTA developed new system operations to reduce electrical use in peak times through sophisticated speed controls and other methods. We have successfully demonstrated this to Georgia Power's satisfaction and had been able to lower the customer base load (CBL) for propulsion service under the ET tariff. Other changes including renovation of MARTA's HVAC system at its headquarters and replacement of station lighting with more energy efficient LED fixtures.

**Q. HAS MARTA DEVELOPED OTHER INITIATIVES FOR ALTERNATIVE ENERGY CONSUMPTION?**

**A.** Yes. MARTA received a federal grant to design, construct and maintain a solar power canopy array at the MARTA Laredo Bus Facility in DeKalb County which is one of four bus facilities operated by MARTA in its service area. The solar project has been operating since the fall of 2011 and generates enough electricity to offset a significant portion of the Laredo Facility's electricity consumption. Also, MARTA has upgraded lighting fixtures at all rail stations, maintenance and office facilities to LED and replaced HVAC and chillers, resulting in 14% energy use reduction since 2012. MARTA is currently evaluating additional solar investments throughout the system.

There are several things we are doing or planning that will assist the Georgia Power system:

- We ordered $680 million of new and more energy efficient rail cars which will begin arriving in November 2024.
- We are replacing natural gas-driven compressors with large electric motors for refueling our natural gas-powered buses. These new motors will operate at night when the buses return to the refueling stations. This increases the utility load factor during off-peak hours making the system more efficient.
- MARTA like other transit systems, is studying the use of "super capacitors" on our rail cars. These devices capture braking energy and use the stored energy to restart rail car motion. This technology not only reduces energy use but helps stabilize the utility system.
- We have increasingly sophisticated centralized controls for our trains and will be able to reduce speeds to reduce power use during critical periods.
- MARTA was awarded a federal grant in 2019 for six (6) electric buses and two fast charging stations to begin the transition from diesel and compressed natural gas-powered buses to all electric buses. The buses are in service between North Avenue and Edgewood/Candler Park. With additional federal funding from a Senate earmark and an additional Federal Transit Administration grant, MARTA has plans to add thirty-one (31) more electric buses by 2024. Future Bus Rapid Transit (BRT) lines including Summerhill, Clayton Southlake and Campbellton will be served by electric buses.
- MARTA has been and continues to work with Georgia Power on deployment of Electric Vehicle (EV) charging facilities at stations and parking facilities. Over 60 chargers have been installed at nine stations as part of Phase One of the EV program. MARTA has EV charging spaces at 9 locations with 11 more in the implementation stage.

## THE IMPACT OF THE COVID-19 PANDEMIC UPON MARTA'S OPERATIONS AND FINANCES SINCE MARCH 2020

**Q. WHAT IMPACT HAS THE COVID-19 PANDEMIC HAD ON MARTA'S CURRENT FINANCIAL OUTLOOK?**

A. The Covid-19 Pandemic has had a dramatic impact on MARTA's ridership and budget. Passenger revenues decreased dramatically after the declaration of the pandemic and implementation of shelter in place orders in March 2020. April 2020 revenues were approximately $2 million, down from $10 million in February 2020. MARTA's actual passenger revenues for 2020 were down $30 million and $79 million in 2021 due to the pandemic. While passenger revenues are starting to recover, they are still 60% of pre-pandemic levels and not projected to return to pre-pandemic levels until 2024 or 2025. MARTA has not included a fare increase in its current budget to provide an additional incentive to its riders to use public transportation again as more people return to work, school, and social events and activities. Additionally, all 110 bus routes were restored to full service by April 24, 2021.

**Q. HAS THE FEDERAL PANDEMIC ASSISTANCE COMPLETELY OFFSET THE SALES TAX AND PASSENGER REVENUE LOSES?**

A. While the Federal financial assistance has been critical to MARTA during these difficult times it has not completely offset or replaced all MARTA's lost revenues from lower sales taxes and passenger revenues. The Federal assistance has filled the short-term revenue gap in FY2020 and FY2021. Furthermore, the Federal assistance buys MARTA the time necessary, due to the uncertainty in timing and levels of fare revenue recovery, to reset MARTA's revenue and expense baselines. MARTA will make budget adjustments over the next few years to maintain balanced budgets into the future without

stimulus fund use. While MARTA anticipates growth in ridership over the next few years, passenger revenues still hover around 60% below pre-pandemic levels, and ar not projected to return to pre-pandemic levels until 2025. Of course, those projections depend on how long the pandemic lingers and how inflation impacts the economy.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

**A.** Yes.

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing TESTIMONY OF KEVIN HURLEY upon the following persons by causing electronic copies of the same to be transmitted to each interested party that has supplied a valid email address, and all other parties to be served via first class mail with adequate postage affixed thereon and deposited in the United States Mail addressed as follows:

| | |
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| Sallie Tanner<br>Executive Secretary<br>Georgia Public Service Commission<br>244 Washington Street, S.W.<br>Atlanta, GA 30334<br>TEL: 404-463-7747<br>FAX: 404-656-2341<br>stanner@psc.ga.gov | **On Behalf of Georgia Watch:**<br>(Intervention filed 07-06-22)<br><br>Liz Coyle<br>Georgia Watch<br>55 Marietta Street, Suite 903<br>Atlanta, GA 30303<br>TEL: 404-525-1085 ext. 402<br>lcoyle@georgiawatch.org |
| **On Behalf of Georgia Public Service Commission:**<br><br>Preston Thomas<br>Staff Attorney<br>Georgia Public Service Commission<br>244 Washington Street, S.W.<br>Atlanta, GA 30334<br>TEL: 656-4554<br>FAX: 404-656-0980<br>E-M: pthomas@psc.state.ga.us | **On Behalf of The United States Departent of Defense and All other Federal Executive Agencies:**<br>(Intervention filed 07-12-22)<br><br>Emily W. Medlyn<br>General Attorney<br>U.S. Army Legal Services Agency<br>ELD Division<br>9275 Gunston Road<br>Fort Belvoir, VA 22060-4446<br>TEL: 703-614-3918<br>FAX: 703-806-0123<br>emily.w.medlyn.civ@army.mil |
| **On Behalf of Georgia Power Company:**<br><br>Brandon Marzo<br>Troutman Pepper<br>Bank of America Plaza, Suite 5200<br>600 Peachtree Street, N.E.<br>Atlanta, GA 30308-2216<br>TEL: 404-885-3146<br>brandon.marzo@troutman.com | **On Behalf of Resource Supply Management:**<br>(Intervention filed 07-15-22)<br><br>Jim Clarkson<br>Resource Supply Management<br>135 Emerald Lake Rd<br>Columbia, SC 29209<br>TEL: 803-312-3500<br>jclarkson@rsmenergy.com |

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| **On Behalf of The Georgia Association of Manufacturers:**<br>(Intervention filed 06-29-22)<br><br>Charles B. Jones, III<br>Lloyd Avram<br>Roy Bowen<br>Georgia Association of Manufacturers<br>The Hurt Building<br>50 Hurt Plaza, Suite 985<br>Atlanta, GA 30303<br>TEL: 404-688-0555<br>FAX: 404-584-0720<br>cjones@gamfg.org<br>lavram@gamfg.org<br>rbowen@gamfg.org<br><br>Jeffry C. Pollock<br>J. Pollock Incorporated<br>12647 Olive Boulevard, Suite 585<br>St. Louis, MO 63141<br>TEL: 314-878-5814<br>FAX: 314-878-7339<br>jcp@pollockinc.com | **On Behalf of The Kroger Co.:**<br>(Intervention filed 07-07-22)<br><br>Kurt J. Boehm, Esq.<br>Jody Kyler Cohn, Esq.<br>Boehm, Kurtz & Lowry<br>36 East Seventh Street, Suite 1510<br>Cincinnati, OH 45202<br>TEL: 513-421-2255<br>FAX: 513-421-2764<br>kboehm@bkllawfirm.com<br>jkylercohn@bkllawfirm.com<br><br>Kevin Higgins<br>Justin Bieber<br>Energy Strategies, LLC<br>215 South State Street, Suite 200<br>Salt Lake City, UT 84111<br>TEL: 801-355-4365<br>FAX: 801-5219142<br>khiggins@energystra.com<br>jbieber@energystrat.com |
| | **On Behalf of Cobb County Chapter Southern Christian Leadership Conference SCLC:**<br>(Intervention filed 07-20-22)<br><br>H. Benjamin Williams<br>Deborah Opie<br>Brionte McCorkle<br>Georgia Conservation Voters Education Fund<br>725 Ponde De Leon Ave FL 2<br>Atlanta, GA 30306<br>TEL: 404-955-7013<br>docben@att.net<br>deborah@gcvoters.org<br>brionte@gcvoters.org |
| | **On Behalf of the Sierra Club:**<br>(Intervention filed 07-25-22)<br><br>Robert Jackson, Esq.<br>Robert B. Jackson, IV, LLC<br>260 Peachtree Street, Suite 2200 |

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| | Atlanta, GA 30303<br>TEL: 404-313-2039<br>rbj4law.@gmail.com<br><br>Isabella Ariza, Esq.<br>Sierra Club<br>50 F Street NW, 8th Floor<br>Washington, D.C. 2001<br>TEL: 857-999-6267<br>Isabella.ariza@sierraclub.org |
| **On Behalf of Concerned Ratepayers of Georgia:**<br>(Intervention filed 07-26-22)<br><br>Ben J. Stockton, PE, MBA<br>Executive Director<br>Concerned Ratepayers of Georgia<br>2230 Allen Road<br>Macon, GA 31216<br>TEL: 404-924-5336<br>encomanager13@gmail.com<br><br>Steven C. Prenovitz, MBA<br>Consultant<br>Concerned Ratepayers of Georgia<br>4295 Amberglade Ct<br>Norcross, GA 30092<br>TEL: 770-448-8978<br>scprenovitz@gmail.com | **On Behalf of Americans for Affordable Clean Energy:**<br>(Intervention filed 07-27-22)<br><br>Newton M. Galloway<br>Terri M. Lyndall<br>Galloway & Lyndall, LLP<br>406 North Hill Street<br>Griffin, GA 30223<br>TEL: 770-233-6230<br>ngalloway@gallyn-law.com<br>tlyndall@gallyn-law.com |
| **On Behalf of Southern Alliance for Clean Energy and the Southface Energy Institute:**<br>(Intervention filed 07-28-22)<br>(Amended filed 08-04-22)<br><br>Bryan Jacob<br>Southern Alliance for Clean Energy<br>1455 Hampton Hill Drive<br>Alpharetta, GA 30022<br>bryan@cleanenergy.org<br><br>Robert B. Baker<br>Robert B. Baker, PC<br>2480 Briarcliff Road, NE, Suite 6<br>Atlanta, GA 30329 | **On Behalf of Utility Management Services:**<br>(Intervention filed 07-29-22)<br><br>Nicole R. Barnett Slaughter<br>Hamlet Law<br>5215 Junction Park Circle, Suite 202<br>Wilmington, NC 28412<br>TEL: 910-777-5995<br>FAX: 910-399-4277<br>nslaughter@hamlet-law.com<br>mhamlet@hamlet-law.com<br>smorin-gage@hamlet-law.com<br>jallen@hamlet-law.com |

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| **On Behalf of Georgia Power & Light (GIPL):**<br>(Intervention filed 08-01-22)<br><br>Jennifer Whitfield<br>Jillian Kysor<br>Southern Environmental Law Center<br>Ten 10th Street, NW, Suite 1050<br>Atlanta, GA 30309<br>TEL: 404-521-9900<br>FAX: 404-521-9909<br>jwhitfield@selcga.org<br>jkysor@selcga.org | **On Behalf of The Commercial Group:**<br>(Intervention filed 08-02-22)<br><br>Alan R. Jenkins<br>Jenkins at Law, LLC<br>2950 Yellowtail Ave.<br>Marathon, FL 33050<br>TEL: 404-729-2037<br>aj@jenkinsatlaw.com |
| **On Behalf of Georgia Solar Energy Association ("GA SOLAR"):**<br>(Intervention filed 08-04-22)<br><br>Donald Moreland<br>Georgia Solar Energy Association<br>1199 Euclid Avenue<br>Atlanta, GA 30307<br>TEL: 770-548-2714<br>FAX: 404-521-9909<br>don@solarcrowdsource.com | **On Behalf of Georgia Coalition of Local Governments:**<br>(Intervention filed 08-04-22)<br>(Amended Intervention filed 08-12-22)<br><br>John R. Seydel<br>City of Atlanta Office of Resilience<br>55 Trinity Avenue<br>Atlanta, GA 30303<br>Jrseydel@atlanta.gov<br>TEL: 470-421-6160<br><br>Alicia Brown<br>City of Savannah<br>Office of Sustainability<br>801 E. Gwinnett Street<br>Savannah, GA 31401 |

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| **On Behalf of ChargePoint, Inc.:**<br>(Intervention filed 08-05-22)<br><br>Scott F. Dunbar<br>Keyes & Fox LLP<br>1580 Lincoln St., Suite 1105<br>Denver, CO 80203<br>TEL: 949-525-6016<br>sdunbar@keysfox.com<br><br>Alicia Zaloga<br>Keyes & Fox LLP<br>1155 Kildaire Farm Road, Ste.202-203<br>Cary, NC 27511<br>TEL: 919-825-1739<br>azaloga@keyesfox.com<br><br>Matthew Deal<br>ChargePoint, Inc.<br>254 E. Hacienda Ave. | **On Behalf of EVgo Services, LLC:**<br>(Intervention filed 08-05-22)<br><br>Nikhil Vijaykar<br>Jason Keys<br>Alicia Zaloga<br>Keyes & Fox LLP<br>580 California St., 12th Floor<br>San Francisco, CA 94104<br>TEL: 408-621-3256<br>nvijaykar@keyesfox.com<br>jkeyes@keyesfox.com<br>azaloga@keyesfox.com |

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| **On Behalf of Cypress Creek renewables, LLC:**<br>(Intervention filed 08-05-22)<br><br>Angie Fiese<br>Cypress Creek Renewables, LLC<br>5310 S. Alston Avenue<br>Building 300<br>Durham, NC 27713<br>TEL: 770-329-4510<br>angie.fiese@ccrenew.com<br><br>Matt Kozey<br>Cypress Creek Renewables, LLC<br>1000 Wisconsin Avenue, Suite 100<br>Washington, DC 20007<br>Matt.kozey@ccrenew.com<br>**On Behalf of Interstate Gas Supply, Inc.:**<br>(Intervention filed 08-05-22)<br><br>J. Brett Newsom<br>Adam Wise<br>Interstate Gas Supply, Inc.<br>3344 Peachtree Road, Suite 2150<br>Atlanta, GA 30326<br>TEL: 404-760-6209<br>brett.newsom@scanaenergy.com<br>adam.wise@scanaenergy.com | **On Behalf of Georgia Solar Energy Industries Association, Solar Energy Industries Association and Vote Solar:**<br>(Intervention filed 08-05-22)<br><br>Scott Thomasson<br>Thomasson Law, LLC<br>1025 Bond Street<br>Macon, GA 31201<br>scott@thomassonlaw.net |

Respectfully submitted this 20th day of October, 2022.

*/s/ Kasey Sturm*

Kimberly (“Kasey”) A. Sturm

BY MS. STURM:

Q Mr. Hurley, do you have a summary that you would like to present?

A Yes, ma'am, I -- I do.

MS. STURM: Okay. Madam Chair, we would ask that he do so now.

MADAM CHAIR PRIDEMORE: Go ahead with your summary, please.

MR. HURLEY: Yes, ma'am.

Good morning, Madam Chair and members of the Commission. I appreciate the opportunity to testify before you today. This is my second time testifying on behalf of MARTA before you.

I'm Kevin Hurley, deputy chief financial officer for MARTA. I have worked for the company for over 23 years. I joined MARTA in 1999 and have held various positions with the authority over those years.

As deputy chief financial officer, I support MARTA in the areas of treasury services, business and financial analysis, accounting, revenue collection, and parking services. I also oversee MARTA's debt program, cash and investment management, energy hedging, and financial modeling.

MARTA has 93 separate electric accounts with

Georgia Power, including the electric transportation service account known as the ET tariff. I'm here today to ask that the Commission help keep public transit affordable and attractive to business by keeping -- by maintaining the ET tariff at current rates and not increase in this rate case.

Again, this request applies just to one of MARTA's 93 separate electric accounts with Georgia Power and pertains to MARTA's critical role in providing public transportation services via light rail and rapid rail systems, services that have continued to fuel growth and economic development in the Metro area, state and region.

MARTA's rapid rail services consist of over 120 miles of electrified rail, providing 48 miles of total rapid rail services via 38 rail stations. MARTA owns a fleet of 338 railcars powered by alternating current. The railcars are equipped with regenerative braking systems so power produced during braking is available for consumption by adjacent trains fed from the third rail system.

MARTA serves over 2.2 million residents in the Metro area and is among the largest transit systems in the country. Depending on which analysis you're looking at, it is anywhere from 8th to 12th largest

transit system.

Current analysis by the National Transit database, MARTA maintains one of the lowest cost-per-revenue mile for heavy rail service of any public transit system in the United States, helping to contribute to MARTA's role and success as an economic driver.

MARTA helps attract new business and development to its service footprint. To that end, we continue to see companies seeking to locate their businesses and offices near transit and, in particular, heavy rail, to reduce their employees' carbon emissions, transportation costs, and commuting stress, and allow them to benefit from the direct connection to the terminal at Hartsfield-Jackson International Airport.

Mercedes-Benz, State Farm, and NCR and Microsoft are just a few of the companies which have deliberately located near MARTA rail stations to take advantage of public transportation for their employees.

When State Farm moved its headquarters, it also built a platform extension and a new entrance to the MARTA Dunwoody rail station to make riding transit convenient for its employees. Atlanta's bid for

**Amazon's HQ2 advanced through Amazon's site selection process because there were ten potential office sites near MARTA rail stations.**

**Microsoft's recent decision to develop a 90-acre campus on the west side of Atlanta was due in part to the proximity of the Bankhead rail station, which MARTA is now in the process of expanding to accommodate larger train consists.**

**Further highlighting the significance of this connection, the state of Georgia's FY22 state budget includes the first ever line item for MARTA, in which MARTA will receive $6 million to support the positive economic impacts of the Bankhead station expansion.**

**This will, of course, have far-reaching economic impacts beyond just MARTA. MARTA is not just helping attract new business, but it is also developing and attracting a new community model or way of living around its rapid rail service stations.**

**We are seeing young professionals and younger generations in general embracing public transportation in ways that we have not previously experienced, with a large percentage preferring to live near reliable, efficient, accessible and affordable public transportation, particularly heavy rail.**

**Transit-oriented development on former MARTA surface parking areas has proven hugely successful both in terms of attracting business and increasing residential and community development. Prime examples include residential community and misuse -- mixed-use developments at Avondale station, Edgewood Candler Park, King Memorial, and Chamblee stations, with developments also advancing at Art Center, North Avenue, and Bankhead stations.**

**MARTA's transit-oriented development projects have resulted in the development of at least 1,919 multifamily units, 379,300 square feet of retail, and roughly 2.8 million square feet of office space. And more is in progress and planned over the next 15 years.**

**These include additional locations providing 9,140 multifamily units, 80,000 square feet of retail space, and another 2 million square feet of office space, at an estimated cost of $4.75 billion.**

**Of course, the economic development potential is even greater as MARTA has other land holdings that we don't currently have -- we haven't currently fully evaluated as part of our real estate portfolio.**

**MARTA plans to spend more than $3 billion on capital improvement projects over the next ten years.**

**MARTA's largest capital expense includes approximately $680 million to replace our aging railcar fleet with more energy-efficient cars. We expect these cars to begin arriving in November of 2024.**

**MARTA continues to make other improvements in alternative energy consumption, including by electrifying its bus fleet. We currently have six electric buses, all of which are in service. And we are -- we have plans to add 31 more.**

**I would be remiss not to mention our EV partnership with Georgia Power. MARTA has worked in partnership with Georgia Power on advancing and building out EV infrastructure through the location of charging facilities at stations --**

**MADAM CHAIR PRIDEMORE: Please halt your testimony.**

**MR. HURLEY: MARTA has worked in partnership --**

**MADAM CHAIR PRIDEMORE: Thank you.**

**MR. HURLEY: Yes, ma'am.**

**MARTA has worked in partnership with Georgia Power on advancing and building out EV infrastructure through the location of charging facilities at stations and parking facilities.**

**Over 60 chargers have been installed at nine**

**stations as part of phase 1 with more to come. It should be noted that these stations are open to the public.**

**While MARTA, like others, is still feeling and recovering from the impacts of COVID-19, MARTA remains optimistic and encouraged by continued growth in ridership, which is currently projected to return to pre-pandemic levels around 2027 to 2028. MARTA has not included a fare increase in its current budget.**

**And, sure, MARTA's investment in its infrastructure and services have a great multiplying effect on economic development that increases Georgia Power's electric sales to new customers.**

**In previous rate proceedings, Georgia Power, the Commission, and others have recognized MARTA's unique value and importance in helping to make Georgia one of the best states to do business. I think I heard that in here a little earlier today.**

**MARTA's ability to continue offering reliable, efficient, accessible, and affordable public rail service is critical to attracting and maintaining business and growing our communities.**

**Thank you for listening and taking the time to hear from MARTA today. And we appreciate your**

consideration of our request.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Hurley. Sorry for the unknown noises.

MR. HURLEY: That's okay.

MS. STURM: Mr. Hurley is available for questions and cross-examination.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Sturm.

Commissioners?

COMMISSIONER MCDONALD: Mr. Hurley --

MR. HURLEY: Yes, sir.

COMMISSIONER MCDONALD: Your long-time service with MARTA, I was in the State House of Representatives at the time when MARTA was created. And I remember vividly when the vote came up to move MARTA forward. There was 90 votes and then House Speaker Tom Murphy cast the 91st vote that made the life in MARTA start.

MR. HURLEY: Thank you.

MADAM CHAIR PRIDEMORE: Any other Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Georgia Public Service Commission.

MR. THOMAS: No questions.

MADAM CHAIR PRIDEMORE: All right. I made

myself a new list. If I missed you on the new list, speak up, please.

Americans for Affordable Clean Energy.

MR. GALLOWAY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Commercial Group.

(No response.)

MADAM CHAIR PRIDEMORE: Did Commercial Group go? Did he leave?

Okay. Georgia Coalition of Local Governments.

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light.

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA.

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: Okay. GA Solar.

(No response.)

MADAM CHAIR PRIDEMORE: GA Solar.

(No response.)

MADAM CHAIR PRIDEMORE: Did he leave?

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Okay.

All right. Georgia Watch.

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: All right. Resource

Supply Management.

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club.

Ms. Ariza, I've got a -- I've got to do a hard cut for you --

MS. ARIZA: That's okay. I have --

MADAM CHAIR PRIDEMORE: Okay.

MS. ARIZA: -- four questions.

MADAM CHAIR PRIDEMORE: Okay. All right.

MS. ARIZA: Thank you. Good morning.

MADAM CHAIR PRIDEMORE: Thank you.

CROSS-EXAMINATION

BY MS. ARIZA:

Q For the record, Isabella Ariza on behalf of the Sierra Club. Good morning, Mr. Hurley.

A Good morning.

Q On page 8, starting in line 171 of your testimony, you discuss that MARTA was awarded federal funds to electrify your fleet; correct?

A Could you repeat the line?

Q 171. Starting 171 of page 8.

A Yes. That's correct.

Q Do those awards include some, but very limited, funds for the actual charging infrastructure?

A Yes, ma'am, it does.

Q Would you support having a utility program that will help you build that charging infrastructure?

A I'm supportive of using all the tools that allow MARTA to accomplish its goals, yes, ma'am.

Q How about having Georgia Power support you build the transmission and distribution at scale to fully power your entire electric vehicle project?

A Same answer. I'm supportive of all the tools that will help us accommodate our goals.

Q Okay. Mr. Hurley, has the increase in gasoline prices affected your finances?

A Yes, ma'am. Our fuel prices have gone up considerably. Probably 40 percent.

Q And final question, Mr. Hurley. Are you aware that staff believes that Georgia Power's electric vehicle infrastructure plans are not in the public interest?

A I am not aware of that, no, ma'am.

Q Do you believe that having the utility support electric vehicle infrastructure -- would you agree that that is in the public interest?

Do you have an opinion on that?

A My opinion is strictly based on being a finance person at MARTA. That I look to all the tools that can help MARTA accomplish its goals. And certainly moving to some sort of alternative energy is something that's one of our

goals.

MS. ARIZA: Okay. Thank you.

No further questions.

MADAM CHAIR PRIDEMORE: SACE.

Mr. Dowdy, I have a hard stop at 9 -- my clock says 9:22. IT says I have to have a hard stop at 9:27.

MR. DOWDY: I think that this will take two minutes at most.

MADAM CHAIR PRIDEMORE: Okay. I don't -- I'm not trying to rush you. I'm just letting you know that if I cut you off mid sentence you can come back.

MR. DOWDY: This is really just housekeeping. As you know, our witness Ronald L. Lehr on behalf of Southern Alliance for Clean Energy and Southface Energy Institute could not travel.

And so we requested that the parties agree to stipulate it in and we received no objections. And we thank the parties for that. And so I think all we need is the housekeeping to move his testimony and exhibits into the record.

And I have two corrections -- two minor corrections to the --

MS. STURM: I think we've stepped ahead.

MADAM CHAIR PRIDEMORE: Do you have --

MS. STURM: Do you have cross-examination?

MADAM CHAIR PRIDEMORE: -- cross?

MR. DOWDY: Oh, no, no. I thought you were calling my witness. No.

MADAM CHAIR PRIDEMORE: No, Mr. Dowdy.

MR. DOWDY: I see you --

MADAM CHAIR PRIDEMORE: Do you have cross for MARTA?

MR. DOWDY: We have no cross of MARTA.

MADAM CHAIR PRIDEMORE: Okay. We're crossing MARTA right now.

Resource Supply Management.

(No response.)

MADAM CHAIR PRIDEMORE: All right. Sierra Club.

MS. STURM: They already went.

MADAM CHAIR PRIDEMORE: Okay. All right. Let's go ahead and stop.

Let's stop. We have got too many moving parts right now. And that gives IT enough time to switch over.

MR. HEWITSON: Madam Chair, did you get to us?

Because I don't have any cross for Mr. Hurley, so we could excuse me.

MADAM CHAIR PRIDEMORE: Oh, you don't have

cross? I was going to start with you when we came back.

MR. HEWITSON: No. I don't want to make Mr. Hurley wait. We have no cross for Mr. Hurley.

MADAM CHAIR PRIDEMORE: If you have no cross for Mr. Hurley, all the better.

MR. HURLEY: Thank you for your time. Appreciate it.

MADAM CHAIR PRIDEMORE: All right. Do you have redirect?

MS. STURM: No. Thank you.

MADAM CHAIR PRIDEMORE: Okay. You're excused, Mr. Hurley. Thank you.

MR. HURLEY: Thank you, ma'am. I appreciate it.

(Witness excused.)

MADAM CHAIR PRIDEMORE: Okay. Now we're in recess for committees.

(A recess was held from 9:24 a.m. until 9:51 a.m.)

MADAM CHAIR PRIDEMORE: Okay. We are back on the record -- okay. We are back on the record in Docket No. 44280: Georgia Power Company's 2022 rate case.

We are going to start this next segment with public witness testimony. And in order of sign-in,

we're going to start with Cynthia Pryor.

MS. PRYOR: I'm here. Good morning, everybody.

MADAM CHAIR PRIDEMORE: Good morning.

MS. PRYOR: Okay. Georgia Power, I'm 65 years of age. I've been paying electric bills for 40 years. Never had a shutoff or late on my bill.

I am now a senior on a fixed income and can't afford an increase on my bill. I would implore you not to raise my bill and actually give back to customers who have been loyal to you, and also give discounts to seniors and people with disabilities.

Georgia Power Company, your price is way too high. You need to cut it.

Thank you.

MADAM CHAIR PRIDEMORE: Khateb El.

MR. TIBBS: Khateb El. You can call me Mr. Tibbs.

Good morning, everyone.

MADAM CHAIR PRIDEMORE: Good morning, Mr. Tibbs.

MR. TIBBS: I'm here to represent the folks who could not be here this morning. I'm getting old, running up and down these steps. My feet is hurting. I'm wearing my Sunday shoes, arguing about the rates which y'all are trying to employ upon the citizens of

Georgia.

Now, last night, after running all day, getting back to my feet, I had to go home and soak. But when I went to soak them, I realized I had to plug that little bath into -- bath foot thing into the socket. I said: I can't even -- my feet cannot even get the nourishment it need, unless I have a connection to power.

So I'm saying this: This is something that don't happen every day, but things that you take for granted. So Georgia Power affects everything. Every toy that my grandchildren and my five great-grandchildren has operates on some type of electrical system.

I cannot even get money these days, unless I'm dealing with some type of putting my card in the machine and swiping it. And God help me when systems go down 'cause, you know, I'm not sleeping on a mattress full of money. My money goes into a bank account.

So I'm saying everything. Y'all want us to have electric cars, which will -- yes, will help the whole ecology. That's going to be electric. So we're a captive audience.

And if y'all are in position to give us some

leniency, maybe we can help understand how electric affects everything and for us to move forward with Georgia Power and the citizens interacting.

But do not take advantage of us because we are on limited income. My daughter just making settlement on her first house. She has five girls. The last thing she need to deal with with all their cell phones and iPads is a electric bill rate.

Thank you for your time and have a blessed day. And happy Veterans Day to all the veterans.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Tibbs.

COMMISSIONER MCDONALD: You wouldn't want to arm wrestle for that jacket, would you?

MADAM CHAIR PRIDEMORE: Neil Sardana.

MR. SARDANA: Hello, Commissioners and Georgia Power. So I just wanted to -- well, I'm speaking here on behalf of myself and just wanted to add to the comments I gave last time.

You know, we know that Georgia Power has a significant amount of profit it makes in our state as, you know, the largest utility provider and a monopoly utility here in Georgia. And, you know, that's precisely why y'all, as the Commission, do exist, to kind of rein them in and keep them under control to keep the company from, you know,

exploiting its customers and charging, you know, whatever outrageous fees they would like to, or rates, whatever they would like to, you know, as a monopoly.

You know, Georgia Power provides an essential service and it's, you know, without any competition. You know, it's absolutely y'all's -- you know, we need y'all to kind of help rein them in to protect us.

And one thing I was thinking, too, is Georgia Power has to spend millions of dollars on advertising on TV. And, to me, this is something I realize is, like: They don't have any competitors. They don't need to advertise themselves in order to find customers.

Yet, our -- you know, we, as customers, and the profits that they make off of us, are spending all this money to advertise to us. And I question why that is. Like, you know, you don't -- it's not like I can pick up one day and say: You know, I don't like Georgia Power. I want to go somewhere else.

But much of the profits that I pay and every other customer pays has to go towards -- whether it's, you know, those types of spending or to some of their charitable, you know, contributions and

whatnot.

And so I'd like to, you know, ask that you consider in this process where they're, you know, requesting even more profit from customers, you know, in a time where inflation is out of control, you know, as many have been claiming. You know, as, you know, prices for everything are going up, you know, that -- the economy is struggling, that we pay attention to the customers and to the people of this state and the needs that they have.

And let's not just give Georgia Power a few extra, you know, millions of dollars just so that they can spend it on advertising or whatever else they like. So that we can protect our state and its economy and its people.

So I just want you to consider that when you're considering, you know, how much money you provide them with using our -- our hard-earned dollars.

Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Sardana.

Wan Smith.

MS. SMITH: Good morning, Commission. As a continuation of my comments on yesterday, I just want to reiterate that I am not here to ask for favor or benevolence.

**In September, a story came out that Georgia Power Company will pay at least 76 million to settle a lawsuit with the co-owner over who will pay for cost overruns on Plant Vogtle construction.**

**What about our lawsuit? The Public Service Commission is supposed to protect us. And instead of giving us money back for the overrun, like a disgruntled partner, who, of their own volition, participated and went into business with Georgia Power, but a court thought that there was so much mismanagement that they were awarded $76 million.**

**Instead of us either canceling Vogtle, instead of us saying, no, we won't give you more money when Units 3 or 4 come on, we are considering raising rates.**

**And so what I believe is happening here and the crux of what Georgia Power Company is doing, equates to fear mongering and extortion. We continue to hear that the grill -- the grid will fail unless you give us more money. Feed me. Feed me. Give us more money or this grid will be like other insufficient grids all across the United States and the reality of our infrastructure will be less than what we need it to be.**

**It feels like Little Shop of Horrors or a**

dystopian novel. It feels like we're being held captive.

And so, again, I'm not here to ask for favor or benevolence. I believe all five of you are Republicans and that the Republican party stands on principles that espouse lower taxes, free market capitalism, and deregulation of corporations.

Well, in a free market economy, this bird called Georgia Power would not fly. It wouldn't. If we had the option to opt in and to hold them accountable as ratepayers, they would not be able to do this.

So I would ask you to look to one of your colleagues, an elected official by the name of Ben Raffensperger. And when the entire country was in upheaval, and as a Republican he had an opportunity to stand on his principles. And in some instances, some would say that he was forced to go with party or principles.

As a Republican who has principles and values, in the faith of backlash, he chose to do what was right by his principles and by the people. And so this isn't about party. This isn't about anything else.

But you all, as individuals, have an oath that

you took as public servants to ensure we have safe, reliable, and affordable electricity. And to ensure that we are protected by the monopoly because it is not deregulated.

And so I ask that as folks who have a "R" next to their name, that you would consider that this is not a free market economy, that this is not deregulated.

And that if we could choose, we wouldn't. And that somebody got $76 million because of the poor mismanagement of Georgia Power.

Thank you all.

(Applause.)

MADAM CHAIR PRIDEMORE: Reverend William Flippin, Jr.

THE WITNESS: Thank you, Commissioner, for this opportunity. I just want to reiterate what my friend Neil Sardana and also Reverend Wan Smith just talked about.

I am a faith leader, ELCA pastor down in Macon, Georgia, but I reside in the greatest city in the world, Atlanta, Georgia.

In talking to members of my church, which is predominantly white, predominantly Republican, we are always prepared for -- I am prepared for in the

summer months for the hike that comes with Georgia Power. But this year we saw the realties of giving at its lowest level because of inflation for everyone. And to even think about a hike or rate of 12 percent, 9 percent, or what have you, is, to me, insensitive to what's going on in the country. Also, with the necessities of life, liberty, and the pursuit of happiness.

The problem I have is that Georgia Power energy, you're required to have that to get into any dwelling, housing, home, apartments. And I'm standing here believing that -- before you get to the bullhorns, which we're prepared to do; before we get to the protests, which we're prepared to do; before we go to the riots, which we're prepared to do, that great movements in history start with negotiations.

Even Martin Luther's Ninety-Five Theses started with negotiation. Even Dr. Martin Luther King, Jr., believe it or not, believed in negotiation first before protest.

So we're standing here not begging, but asking for sensitivity. The thing that I am most passionate about is the equity of the energy burden with black, brown, yellow. When folks pay 60 percent or more of their total income on energy bill, that's considered

a high energy burden. So right now you're asking for double that, despite Georgia Power touting that Georgians have some of the lowest electricity rates in the country.

So we stand here to give warning of the moral arc of the universe and we'll continue to bend toward justice. That we are -- we are together as a coalition. Silence on these issues will not dissipate and we will be on you.

This is not politics. This is not right wing, left wing. But this is about the moral mandate that we all have as Georgians, a place that we love.

And we will continue to rise up as a people. We are rising up people. As Maya Angelou says: We are rising up people. We don't want the rate hike to rise up, but we are going to continue to rise.

Thank you so much for this opportunity.

(Applause.)

MADAM CHAIR PRIDEMORE: Vincent Fort.

MR. FORT: Madam Chair and the Commission, it's good to be with you. I stand here speaking up for people who don't have the opportunity to come down here and speak for themselves because they're working, most of them, unable to be here.

There are people out here who can't hire

lobbyists, who can't hire folk with the -- them leather briefcases and them great suits. There are people out here who don't have anybody to speak up for them. And I want to just take a minute to speak up for them.

Sixty-four percent of people in this country, regular folk, live paycheck to paycheck. What you will do on this rate case will determine whether that paycheck to paycheck breaks.

Now, Georgia Power, I read Georgia Power make 11 percent profit. In a period of inflation, when a company makes that much money and then say they got to get in my pocket for $200 more a year, you know what that amounts to in this period of super inflation? That amounts to price gouging. Ain't no other way to say it.

And there are folk in my community -- I'm here to talk about those folk, as I said, who can't speak for themselves, who can't hire lobbyists, but especially senior citizens. They don't -- many of them don't have a paycheck. All they have is that social security check. And there are some folk who want to cut that. Lord help.

So I'm asking you, I'm pleading with you, in this period of economic upheaval, don't do this to

regular folk. Don't do this to me. I'm 66 years old. I'm looking at y'all want to take more money out of my pocket.

But I'm not here for myself. I can find a way to make a way. But you have to think about all those people who are going to get cut off. All those people who are turning down the thermostat. All those people who going to go cold this winter. All those people who don't have your telephone numbers and don't have telephone numbers of these big shots. They can't call you for help.

Y'all going to be warm this winter. Y'all going to be -- y'all ain't going to have to put a sweater on like a lot of these folk do.

So I'm just imploring you: Don't let Georgia Power own you anymore. Tell them they make enough profit. Tell them we don't want to pay for Plant Vogtle no more.

Tell them we don't want to pay for their coal ash cleanup. Tell them that you are standing up for regular folk this time.

Thank you.

(Applause.)

MADAM CHAIR PRIDEMORE: K. Hanifa.

MS. HANIFA: Good afternoon. My name is Karima

Hanifa and I am one of those regular people that he's talking about. Just a regular citizen here in the state of Georgia.

I was looking at my bill yesterday afternoon. So normally I pay between 84 and $97 a month for electricity. We live in a single-family home. It's just me and my husband. We don't have kids and we cut the TVs off at night. All the lights in the house are off at night.

When I started looking at the 12 percent increase, it would cost me a little over or close to $10, $11.33 every month.

And so I'm a community organizer here in the state of Georgia and what I do is serve individuals in marginalized communities. So the area that I concentrate on is Adamsville.

I live in Cobb County. I live in Mableton. But the area that I serve is the Martin Luther King area, an area that is a food desert. An area -- when I say food desert, an area where there aren't many grocery stores, but there are lots of gas stations. So there isn't a lot of options for healthy food.

An area where there are -- it's -- there are high levels of impoverished people, where people are struggling to pay a minimal 700, $800 a month for

their rent. Where I live in Cobb County, I am charged double that amount.

And so in representation of the community that lives below status quo, those individuals that are struggling, including my mother, who turned 70 on October the 24th. As a senior citizen who does own her home, but is still required to pay, of course, her electrical bill every month.

And when I think about there not being a lot of options, it's true. I can't just wake up in the morning and decide: Oh, I'm going to use a different company.

Because where I work -- I mean, where I live, that is the company that they use. So I don't have an option. There isn't an option. I can't say -- you know, when we think Wi-Fi or other resources that are available to us, we can say: Oh, I want to use a different -- I don't want to use AT&T. I want to use Verizon. I don't have that choice. It is Georgia Power.

And as I became involved in this movement, after I left the meeting on last night, I want you to know that I left the meeting and I went to Georgia Power on -- off of South Cobb Parkway and I placed signs in the yard outside that said: Please do not

raise the bill.

It was me. And it is serious because I feel like I'm pinching pennies every month just to survive out here with the job that I do have.

But there are people who are not employed. There are people who do live off of social security. There are people who are working at McDonald's, that are working warehouse jobs, that are just barely making it. But we all know that your refrigerator does not work if it does not have electricity; right?

And so I am -- I am imploring you all today to not raise the rate here in the state of Georgia.

Thank you so much.

MADAM CHAIR PRIDEMORE: Chassidy Malloy.

MS. MALLOY: Good morning, Commissioners. My name is Chassidy. I am here from Savannah, Georgia, on the coast. Some thoughts and some perspectives that I've gathered just from listening to folks this time and I was here in September. You know, what does it cost if you were to vote no to this rate increase?

What does it really cost Southern Company?

As I understand it, they are operating in a surplus right now. As I understand it, they're in the black. The stakeholders seem to be happy.

There is no negative impact to simply saying: You know what, no. Not this time.

But there is a negative impact when it comes to the people -- the average, you know, Jack and Jane, who are here today providing testimony and providing public comment to say this is going to have a detrimental impact on the regular person in the state.

As many people have said, and I'll echo again, it's not like many of us have alternatives when it comes to where we get our energy from and where we get our power from. So with that in mind, and knowing that there are many communities, not just here in the Metro area, but across the state of Georgia who are energy burdened as it is, and knowing that this will be an additional increased burden in those folks who are already struggling, those who are already struggling to pay their utilities bills, to pay on time so they're not impacted by late fees, to say: You know, maybe not this time.

This is definitely, as many people have said, a time where everyone is, you know, holding a little tighter to that pocketbook for good reason and for good cause. And to do this in a time where company is doing very -- they're fiscally stable -- doesn't

seem like it's prudent. And it does seem morally irresponsible to put that additional burden on folks who are already struggling.

And so, as always, I just really implore upon you all to take these comments to heart and to listen to these folks and know this impact is real and it's going to hit a lot of people, especially those who are already marginalized, who are already low income, who are already struggling the most.

It is a responsibility, as community leaders, as, you know, officers who are elected to the state to make sure. You're a Public Service Commissioner. Your job is to serve and look out for the best interest of the public, to keep that in mind, and always make move and make decisions that are in the best interests on behalf of the people.

I thank you for your time and the opportunity to speak. Thank you.

(Applause.)

MADAM CHAIR PRIDEMORE: Tia Brightwell.

MS. BRIGHTWELL: So I'm not crying today. Hey, y'all. How are y'all doing?

So I came back from Savannah, Georgia. How are y'all doing?

COMMISSONER SHAW: Good.

**MS. BRIGHTWELL: Good, good. And I brought my boys with me, too.**

**MADAM CHAIR PRIDEMORE: Nice.**

**MS. BRIGHTWELL: Right, right.**

**Wow. We just went through an amazing race; right, that just happened November 8th that I feel like my organization and myself played a big part in. And one thing I said -- Stacey Abrams was so nice to take a picture with me. I didn't look like this, though.**

**I was scared because I felt like she was taking a picture. She was like: You stand here. Take the picture.**

**I was like: Okay.**

**So my picture is really ugly if you follow me on social media. But, yeah. So it was an ugly picture, but I was grateful to meet her, right, because she was running for governor.**

**My kids can go back to school and say: My mom was in the room with Stacey Abrams. How cool is that?**

**They can go back now and say: My mom stood in front of the Commissioners and she did not cry. I'm not crying with y'all today.**

**Okay. We're asking you nicely to not let this**

increase take place. I feel like I can speak on behalf of God, if you all serve him like I feel like you do; right?

My family, I brought them with me. And then my community. People who could not be here today, could not drive three hours. Those people.

The last time coming before you I almost got in an accident; right? So that means that God wants me to be here.

Figure that out. Don't let this increase happen, because we need you. Say hi to my boys, please. They're not going to speak or anything. But just say hi.

Jamari is 16 and Donald is 14. And they go to Savannah High School. Please tell them that I gave a shout out, too. Savannah High School, Dr. Jenkins; okay?

MADAM CHAIR PRIDEMORE: Hi, boys.

MS. BRIGHTWELL: And I didn't cry.

MADAM CHAIR PRIDEMORE: Chuck Eyler.

COMMISSIONER MCDONALD: Did you drive from Savannah in three hours?

MR. EYLER: It takes more three hours.

COMMISSIONER MCDONALD: Did you break the law?

MS. BRIGHTWELL: No. I took the way the GPS

told me, too. Really.

MADAM CHAIR PRIDEMORE: Chuck Eyler.

MR. EYLER: Hi. Good morning. I also drove from Savannah. You can't do it in three hours. You can get here, though.

Good morning, Commissioners. We have a problem. We are squeezing people who are already squeezed too far.

Wages have not increased; expenses have. All of them. Housing costs, health care, transportation. You see it. We all see it.

I'm a senior on a fixed income. The squeeze is on. My question is: Is this rate hike unconscious cruelty or is this cruelty on purpose?

Have you ever had to weigh your power bill with other expenses and make sacrifices to pay it?

Is it impossible for you to imagine what that is like?

I saw a political ad yesterday that described reckless spending as the worst crime imaginable. I wonder how much that ad cost. There's so much wasted high-level spending going on, multiple million.

How much was spent on advertising for this recent election just in Georgia? How much does Georgia Power spend on its green washing ads? Those

pretty ads.

Never any pollution in them, no coal ash, no environmental degradation, endangering health. The Georgia Power advertising camera never looks that way.

The real problem: Old habits and ways of doing things keep going. Systems that reinforce wastefulness keep going.

I came here from Savannah. I stayed in a motel last night. The air conditioning was set to meat freezer temperature in the room when I arrived. I don't know why. I turned it up to 78.

There is 102 rooms in that motel. How many motels and hotels do this in the summer across Georgia?

We're wasting money and resources at massive scales when adding -- then adding billing to people who have nothing to do with it and have no say. It's taxation without representation. And it's on a path to take away liveable conditions on earth.

With great power comes great responsibility. I'm going to bring Marvel movies to you here. To use intelligence, knowledge, and resources at hand.

What's the smartest way forward? What's the best for all of us to sustain our precious living

earth? Rate hikes are the wrong way to solve our problem here.

Thank you for your time.

(Applause.)

MADAM CHAIR PRIDEMORE: Shemika Simmons.

MS. SIMMONS: I bring you guys greetings from Savannah, Georgia. My name is Shemika Simmons.

I am here just to let you guys know that I am the working class poor. I represent the working class poor. In Savannah, Georgia, 24 percent of Savannah Georgians make income below poverty.

So an increase for them can be a lights out for them. Do we really want that? It's about to get cold. The temperature is changing right now and people just can't afford it.

We're trying to work through a pandemic. And I believe that you guys' motto is: A citizen wherever we serve. So we need you guys to really think about it and take it into consideration what everybody is saying up here.

At this time -- and I don't know when. At this time, we can't afford it. I'm here, but I'm pretty sure that a lot more people would love to be here. They just can't afford to be here.

I deal every day with the working class poor.

They can't afford to take off and be here. But I'm here and I'm representing them.

And this is real. Life is real. When rates go up, lights go out. You guys know that. I know that. You know that. We all know that.

And I'm pleading with you guys: Please don't do this to us. We can't afford it. You're hearing me. I know you're hearing me.

Are your hearts hearing me? Are your minds really hearing me?

You guys represent Georgia Power. So if you're for the people, I need you to be for the people. And I need you guys to live up to that coined phrase that you guys always say and always advertise. For the people. We serve the people.

I need you to do that. Thank you.

(Applause.)

MADAM CHAIR PRIDEMORE: Donald Walker.

(No response.)

MADAM CHAIR PRIDEMORE: Donald Walker.

(No response.)

MADAM CHAIR PRIDEMORE: Jamari Walker.

(No response.)

MADAM CHAIR PRIDEMORE: Jamari Walker.

MS. SMITH: Those are the boys.

MADAM CHAIR PRIDEMORE: Okay.

All right. Anyone else who did not sign in?

(No response.)

MADAM CHAIR PRIDEMORE: Okay.

COMMISSIONER MCDONALD: Madam Chair, I want to speak to my friend, Senator Vincent Fort.

Both of us served in the general assembly. Once a senator, always a senator, right, Senator?

MR. FORT: Absolutely.

COMMISSIONER MCDONALD: Couple things. Here's my business card. It has my personal cell phone on number on it.

It's not a state cell phone. It's my personal cell phone. And it's on my business card.

Number two, I want to go on record because I -- if we did nothing, zero, if we adjourned today and did nothing, it's going to be a cold winter. And there's going to be some -- some heat that is going to be very, very hard to come by because, number one, basically, the price of natural gas.

Does this Commission control the price of natural gas? No, we don't. The Georgia general assembly years ago deregulated natural gas. So it is a market-driven situation that we have no control over, as far as the price of natural gas is

concerned.

The price of fuel, we have no control over the price because the general assembly years ago suggested that -- by law, that the cost of fuel, whether it's oil, coal, whatever -- the cost of generating fuel is a pass-through.

Georgia Power makes zero money on the cost of fuel. It's just passed on from the cost of fuel to the customers' usage. So I want you to understand that.

It's cold now, but it's not as cold as it's going to be this winter. If you go back to the record, I said six months ago -- six months ago -- that we're going to have a hard, cold winter and it's going to impact the people of Georgia and everywhere else.

And we feel for you. We understand what it is. But there are things that we do not have control over that are going to impact. And it's going to make your cost of bill -- my bill, your bill -- go up.

We talk about fixed-income people and aging people. The Senator is a young man. He ought to say sir to me because I'm so much older than he is. Because I'll be 84 Thanksgiving Day.

But my concern is for the people of Georgia and

for them to have the opportunity. Number one, you can't do without water. That's a fact. And electricity is the second thing that it's difficult to do without.

How many of us turn our TV off when your Dish Network goes up $4 a month on your TV? How many people get rid of this when you've got a price increase on your cell phone?

We have no control. So we have some responsibility with ourselves and what we decide to use and how we spend those few dollars that we have. I just wanted to be up-front, very on fact.

Pastor, you understand this very well. That the inflation -- we didn't cause the inflation to go up to 8 percent or more. It wasn't at this Public Service Commission.

But we are responsive to what you say. We're responsive to what happens with the utility that we regulate. And I hope that we will find some good common ground by the end.

Thank you.

MR. VINCENT: With all due respect, Commissioner, your personal cell phone number on your card --

MADAM CHAIR PRIDEMORE: Would you please go to

the microphone, Mr. Fort?

MR. FORT: Absolutely.

MADAM CHAIR PRIDEMORE: Thank you.

MR. FORT: With all due respect, Mr. Commissioner, your personal cell phone on your card don't mean a whole lot to these folk. I'm sure you got Georgia Power's cell -- Georgia Power's phone numbers on your phone. I'm sure Georgia Power has your number on their phone.

COMMISSIONER MCDONALD: I don't have yours.

MR. FORT: No, you don't. But I want to tell you, I wish you'd give it all to all of these folks who done come to the microphone.

All them folk -- no. Hold it down.

All them folk. All I'm hearing in Atlanta, Decatur and all over this state. When their power get cut off, I hope they could call you.

So don't be cavalier with what I say, Mr. Chair.

UNKNOWN PERSON: I want to know when the next election for y'all is.

MR. FORT: Mr. Commissioner, this is very serious business. And it doesn't stop here. People are going to hold you accountable going forward. Lord knows.

Because, you know, as I said, you going to be warm this winter. There's going to be a whole lot of folk who have -- who going to be in the dark. And they're going to be cold.

And I want y'all to remember that. It's not just the -- something for Vincent Fort to throw out there. That's the reality.

I'm going to get calls of folk wanting help. And I want to call -- I'll call your cell phone in that case, Mr. Commissioner.

So I appreciate you so much. Thank you.

(Applause.)

MADAM CHAIR PRIDEMORE: That concludes -- oh, Commissioner Shaw.

COMMISSONER SHAW: I just wanted to say, particularly for all of those that are from Savannah and Macon and other places like me that are going to be traveling south into this bad weather, y'all be careful on the roads today.

UNKNOWN PERSON: Thank you.

MADAM CHAIR PRIDEMORE: That concludes the public witness time. We were under an hour. So that means that we do a ten-minute wait period.

So ten-minute wait period begins now at 10:28. We'll be back at 10:38.

(A recess was held from 10:28 a.m. until 10:38 a.m.)

MADAM CHAIR PRIDEMORE: All right. We're back in.

Next panel, United States Department of Defense and all other Federal Executive Agencies.

MS. MEDLYN: Okay. Could you both please stand and raise your right hands.

Thereupon,

LARRY BLANK, Ph.D.,
MAUREEN RENO,

having been duly sworn, testified as follows:

MR. BLANK: Yes, ma'am.

MS. RENO: I do.

MS. MEDLYN: Be seated.

DIRECT EXAMINATION

BY MS. MEDLYN:

Q Dr. Blank, I will start with you. Could you please state your name and how you're employed.

A My name is Larry Blank. I am principal of TahoEconomics, a consulting firm I established in 1999. I'm also a professor of economics at New Mexico State University, where I also help to run the Center for Public Utilities.

Of course, my appearance here is on behalf of the federal government. And my opinions are my own and do not reflect those of New Mexico State University.

Q On October 20th, 2022, did you cause to be prefiled 18 pages of direct testimony?

A Yes, I did.

Q Do you have any corrections to your testimony?

A I have no corrections.

Q Okay. If I were to ask you the same questions today, would your answers be the same?

A Yes, they would.

MS. MEDLYN: Okay. I would -- Madam Chair, I would ask that Dr. Blank's testimony be copied into the record as if given orally from the stand?

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimony of Dr. Larry Blank follows:)

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **IN RE: GEORGIA POWER COMPANY'S 2022 RATE CASE** | **)**<br>**)**<br>**)** | **DOCKET NO. 44280** |

# DIRECT TESTIMONY

# OF

# LARRY BLANK

**ON BEHALF OF**

**THE UNITED STATES DEPARTMENT OF DEFENSE**
**AND**
**ALL OTHER FEDERAL EXECUTIVE AGENCIES**

**October 20, 2022**

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## I. IDENTIFICATION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Larry Blank. My business address is TAHOEconomics, LLC, 6061 Montgomery Road, Midlothian, TX 76065. My email address is LB@tahoeconomics.com.

**Q. WHERE ARE YOU EMPLOYED?**

A. I am the principal of TAHOEconomics, LLC ("Tahoe"), a Texas-registered consulting firm I founded in August 1999 (originally in Nevada), specializing in most policy and ratemaking facets of regulated utility industries. I am also a Professor of Economics and Associate Director with the Center for Public Utilities in the College of Business at New Mexico State University ("NMSU"). For the purposes of this proceeding, I have been engaged through Tahoe, the expert opinions expressed herein are my own, and nothing in this testimony necessarily reflects the opinions of NMSU.

**Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR BACKGROUND AS IT IS RELEVANT TO THIS TESTIMONY.**

A. I have served the public in various capacities for over thirty-five years. I received a Ph.D. in Economics from The University of Tennessee in 1994, specializing in Industrial Organization & Public Policy (including regulatory policy), Econometrics, and Finance. I previously served as an Economist with the National Regulatory Research Institute ("NRRI") at Ohio State University and later as the Manager of Regulatory Policy & Market Analysis with the Regulatory Operations Staff of the Nevada Public Utilities Commission. As a consultant, I have served a variety of clients including government agencies, utility customers, and utility companies. I have served as an expert witness and/or advisor in over 150 rate cases and rulemakings of various types. I have previously filed written testimony

in the following utility regulatory commission jurisdictions: Alaska, Arizona, Arkansas, Colorado, Delaware, Georgia, Kansas, Montana, Nevada, New Hampshire, New Mexico, Oklahoma, Texas, and the Federal Energy Regulatory Commission. At NMSU, I direct the Masters of Economics program, a professional Graduate Certificate Program in Public Utility Regulation & Economics, and I help deliver nationally recognized rate case training programs through the NMSU Center for Public Utilities. These professional training programs are attended by hundreds of regulatory professionals from across the United States and are endorsed by the National Association of Regulatory Utility Commissioners ("NARUC"). My resume is attached as Exhibit LB-1.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am testifying on behalf of the United States Department of Defense and all other Federal Executive Agencies.

## II. PURPOSE AND SUMMARY

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I am offering recommendations to improve upon certain rate schedules proposed by Georgia Power Company ("Georgia Power" or the "Company").

**Q. PLEASE SUMMARIZE YOUR REVIEW AND RECOMMENDATIONS.**

A. First, I address the Customer Baseline Load ("CBL") reduction criteria. I would like the Commission to consider a revision to the Real-Time Pricing ("RTP")[1] tariff schedules to allow for CBL reductions based on two years of historical load data, and to allow RTP customers to use back-up service, which would firm up reliable on-site customer generation

[1] Georgia Power currently has two RTP rate schedule offerings: Real Time Pricing – Day-Ahead Schedule and Real Time Pricing – Hour-Ahead Schedule). *See* MFR F-1.

for a CBL load reduction. I will explain the detailed tariff language modifications necessary to allow these options.

Second, I offer recommendations for the return on equity ("ROE") earnings band. The Commission should consider some modifications to the ROE band and earnings sharing design. Specifically, an alternative for consideration would be to increase the percentage sharing of earnings above the band with customers (e.g., from 80% to 95%). This would allow for larger refund relief to customers in years the Company has healthy earnings.

Third, I address the Company's proposed across-the-board rate increase and advocate for the importance of movement toward cost-based rate changes. This will help to mitigate the likelihood of large disparities between rates and costs before the next rate case. The Commission should consider ordering movement toward cost-based rates in this case rather than the across-the-board increase proposed.

Finally, I ask the Commission to order inclusion of schedules, similar to the Minimum Filing Requirement ("MFR") schedules, for the next rate case that match the actual revenue proposed by the Company for the first, second and third years of its three-year Alternate Rate Plan ("ARP") so that these schedules better match the increases requested by the Company under the ARP. Likewise, if the Company proposes a levelized rate increase, as is the case in the current proceeding,[2] then the Company should file similar MFR schedules that match the rate increases on a levelized basis.

[2] Tr. at 204:1-13 (Abramovitz, Adams, Houston, and Robinson Dir. at 9), Table 1 and description thereof (Sept. 27, 2022).

## III. RTP CUSTOMERS AND TARIFF TERMS FOR CBL REDUCTION

**Q. WHAT ARE THE CURRENT CRITERIA USED BY GEORGIA POWER TO CONSIDER CUSTOMER APPLICATIONS FOR CBL REDUCTION?**

A. These criteria are found in "Special Provisions" Section C – *CBL Revisions* of the RTP rate schedules. Noteworthy for discussion here is the last statement in that section:

> If an existing RTP customer, without approved load removal, wants to come off RTP in an attempt to lower the CBL level, the customer must remain off RTP for a full twenty-four months. The new CBL would be established using current methods as previously described in this tariff.

Although load removal verification is covered in earlier language within Section C, missing is the possibility that customers through time may simply achieve load reductions that can be documented through historical meter data. Also missing is the possibility that a customer may invest in on-site generation capacity producing at least 6,000 hours of firm power each year, such as a combined heat and power ("CHP") plant. If combined with the purchase of Georgia Power back-up service, such a CHP has the potential to provide firm power to serve base load when combined with Georgia Power back-up service and should be considered for a CBL reduction. These circumstances are worthy of CBL reduction and will require some tariff language revisions.

**Q. IS THE REQUIREMENT TO COME OFF RTP FOR TWO YEARS TO REDUCE CBL A CONCERN FOR CUSTOMERS?**

A. Yes. The provisions in the RTP tariffs do not allow for CBL reduction assessment based on historical load unless the customer were to "come off RTP" for two years. One reason for coming off RTP for two years may be to collect sufficient load data for consideration in establishing new CBL levels. However, it is not clear why it is necessary to come off

RTP to assess the load shape data of the customer when those data already exist for an RTP customer. If a customer currently has two years in which actual loads have been below the CBL demand in many hours throughout the year, that should be sufficient reason for a reassessment of the CBL load shape.

Another consideration is that customers whose historical rate schedule has been discontinued, for example, Time Of Use – Revenue Neutral Schedule ("TOU-RN") customers, may lose their revenue-neutral rate schedule if they were to "come off RTP" for two years. In other words, these customers may be required to change their underlying rate schedule to receive RTP service in the future. These customers would be unduly harmed by virtue of their desire to have their CBL levels reviewed.

**Q. WHAT HAPPENS WHEN A CUSTOMER'S LOAD IS BELOW THE CBL LEVEL?**

A. The customer pays for the unused portion of the CBL under the non-RTP standard service rates but then receives a credit for the unused energy based on the interval power price marginal costs because Georgia Power either does not need to procure that energy or can sell excess energy into the market.

**Q. IF A CUSTOMER HAS MANY HOURS IN WHICH ITS LOAD IS BELOW CBL, DOES THIS SEND THE APPROPRIATE PRICE SIGNALS TO THE CUSTOMER AS YOU WOULD EXPECT WITH A REAL-TIME PRICING OPTION?**

A. No. This is a perverse scenario in which the customer is not fully seeing the real-time and marginal pricing incentives and Georgia Power is crediting the customer for the unused

portion of the CBL power. The Commission should allow the opportunity for CBL reduction in circumstances such as this.

**Q. IS THE REQUIREMENT TO COME OFF THE RTP TARIFF FOR TWO YEARS TO REDUCE CBL PROBLEMATIC FOR THE MILITARY BASES?**

A. Yes. Most of these customers are Multiple Load Management ("MLM") customers, but the MLM rate schedule no longer exists because it was discontinued in the last rate case. When the MLM rate schedule was discontinued in the 2019 rate case, MLM customers were moved to the TOU-RN rate schedule to calculate the Standard Bill within the RTP rate schedules using CBL billing determinants. Because the MLM schedule no longer exists, it is not clear where these customers would take service if they came off RTP for two years in an attempt to reduce their CBL. Some other rate schedule may cause significantly higher billing because these customers may lose the revenue neutrality promised in the last rate case.

**Q. DO YOU HAVE A TARIFF LANGUAGE RECOMMENDATION FOR THE COMMISSION?**

A. Yes. I recommend the Commission consider approving the following revision to the previously quoted provision in both the RTP Day-Ahead ("RTP-DA") and RTP Hour-Ahead ("RTP-HA") rate schedules:

> If an existing RTP customer, without approved load removal, wants to ~~come off RTP in an attempt to~~ lower the CBL level, the customer must ~~remain off RTP for a full twenty-four months.~~request reassessment of the CBL shape on an hourly basis. Such reassessment of the CBL shape by Georgia Power shall be based on twenty-four months of historical hourly metered load data for that customer. The

new CBL would be established using current methods as previously described in this tariff. [3]

**Q. IF GEORGIA POWER PROVIDES A GOOD REASON AS TO WHY THE TWO YEARS OF DATA ANALYSIS SHOULD BE PROSPECTIVE, CAN THIS BE DONE WITHOUT THE CUSTOMER COMING OFF RTP?**

A. Yes. For example, as an alternative to my recommendation to use historical load data, the customer could request prospective analysis without being forced to move off of RTP.

**Q. DOES A CBL REDUCTION FOR ONE CUSTOMER POTENTIALLY CAUSE AN UNDUE COST SHIFTING TO OTHER CUSTOMERS?**

A. No. If the customer's load profile supports a reduction in CBL, the reduction in the customer's actual load also supports a reduction in cost allocation to that customer. Therefore, there is no undue cost shifting onto other customers.

**Q. DOES A CBL REDUCTION FOR ONE CUSTOMER POTENTIALLY CAUSE A REVENUE SHORTFALL FOR GEORGIA POWER?**

A. There is a possibility that a CBL reduction could cause a short-term reduction in revenue that temporarily may be foregone; however, this is true with any customer who currently qualifies for a CBL reduction as well as other customers on standard tariffs who alter their energy usage and demand. Some customers on the system may increase their demand for electricity and others may decrease their demand, but with the diversity on the Georgia Power system, these effects tend to balance each other, and any differences will be corrected in the next rate case. It is more important that customers who increase their demand, pay for that increased demand, and those customers who decrease their demand should not be forced to pay for unneeded electricity service.

[3] Strikethrough font reflects proposed deletions; underlined font reflects proposed additions.

**Q. CAN YOU EXPLAIN WHY CUSTOMER ON-SITE GENERATION CAPACITY SHOULD BE CONSIDERED FOR A CBL REDUCTION?**

A. RTP customers who invest in on-site generation capacity should be considered for a CBL reduction as long as the customer subscribes to and pays for Georgia Power Back-Up Service Schedule "BU." Failure of an RTP customer with on-site generation to produce power would then be automatically billed under the CBL Standard Bill, pursuant to the RTP rate schedule. The addition of such a CHP plant will bring additional firm generation capacity to Georgia Power's service territory, benefiting other customers.

**Q. DOES THIS TYPE OF GENERATION CAPACITY INVESTMENT BY AN RTP CUSTOMER QUALIFY FOR CONSIDERATION OF A CBL REDUCTION UNDER THE CURRENT TARIFF LANGUAGE?**

A. No. The qualifying examples for a possible CBL reduction within the RTP rate schedules include load reductions due to customer equipment removal but not the installation of firm generation capacity that reduces load.

**Q. DO RTP CUSTOMERS QUALIFY FOR GEORGIA POWER'S BACK-UP SERVICE?**

A. The applicability section of the Back-Up Service Schedule states:

> Applicable upon request as a modification of the rate schedules for Power and Light (PL), and Full Use Service to Governmental Institutions (G), if the customer is a PURPA qualifying facility, or has customer-owned generation that normally operates at least 6,000 hours per year.

There is no mention of RTP rate schedules, but there is a reference to Public Utility Regulatory Policies Act ("PURPA") qualifying facilities ("QFs"), which a customer's CHP may satisfy. Therefore, it appears that RTP customers may not qualify to subscribe to back-up service unless perhaps a case can be made that the customer generation is a

PURPA QF. When asked about this applicability at the hearing, Georgia Power's rate design witness, Mr. Legg, indicated that he would need to check and added: "You know, off the top of my head, I don't know. We'd have to discuss the specifics of the account."[4]

**Q. CAN YOU SUGGEST A POSSIBLE REASON WHY RTP CUSTOMERS MAY NOT QUALIFY FOR BACK-UP SERVICE?**

A. Georgia Power can also address this question in its scheduled rebuttal testimony, but one reason may be a perspective that customer generation does not serve load within the customer's CBL, but instead is viewed as simply part of the RTP portion of the customer's load.

**Q. DO YOU AGREE WITH SUCH A VIEW?**

A. No. Firm generation capacity such as a CHP plant will change the load shape of the customer on the Georgia Power grid. If allowed to subscribe to and pay for Georgia Power's back-up service, then there is no concern regarding reliability of the customer's CHP capacity, nor is there a concern for insufficient revenue in the event that the customer stops producing power. This is because the Georgia Power Back-Up Service Schedule requires at least 6,000 hours of power and will bill for incremental back-up power not produced by the customer's CHP under the RTP rate schedule Standard Bill rates used for the CBL portion of load. This will require additional Georgia Power metering of the customer's generator and other RTP customer-specific terms within the back-up service contract.

**Q. WHY SHOULD RTP CUSTOMER-SITED GENERATION UNDER BACK-UP SERVICE BE CONSIDERED BASE LOAD CAPACITY?**

[4] Tr. at 1175:16-18 (Legg Cr.) (Sept. 29, 2022).

A. BU mandates a minimum of 6,000 operating hours per year. That is, the customer's generator must operate above a 68% annual capacity factor, which is consistent with other base load generation capacity. Intermittent generation or generation not operating in this fashion will not qualify for back-up service and, therefore, would not qualify for a CBL reduction under my recommendation. Therefore, any concern that the customer may not operate its generation in a reliable manner is not an issue because that customer will not stay on BU and will lose its CBL reduction.

**Q. ARE THERE COMPONENTS IN THE DESIGN OF THE GEORGIA POWER BACK-UP SERVICE THAT NEED TO BE CAREFULLY CONSIDERED TO ALLOW AN RTP CUSTOMER TO SUBSCRIBE TO BACK-UP SERVICE WHILE STILL MAINTAINING THE DISTINCTION BETWEEN CBL AND RTP LOAD?**

A. Yes. The Back-Up Service Schedule includes the following four defined service categories: Standby Reserve Capacity, Back-Up Power, Supplementary Power, and Maintenance Power. The rates for Standby Reserve Capacity are specified within the BU rate schedule and should not pose any difficulty. On the other hand, Back-Up Power, Supplementary Power, and Maintenance Power all reference the otherwise applicable rate schedules of the rate classes that currently qualify for BU. Back-Up Power is defined as "energy or capacity to replace energy generated by a customer's own equipment when that equipment is not in service." Supplementary Power is defined as "energy or capacity supplied by the Company to the customer in addition to that which is normally generated by the customer's equipment." Maintenance Power is defined as "energy or capacity

supplied by the Company when the customer's generation is not available during the designated maintenance period."

For RTP customers, this is somewhat more complex in that there needs to be a separation between CBL power and applicable rates and RTP marginal rates. I recommend that Back-Up Power and Maintenance Power be billed under the CBL rates (i.e., standard rates of the RTP customer). To bill RTP customers under CBL rates for Back-Up Power will require additional metering by Georgia Power to measure the output of the customer's generation capacity, but will protect Georgia Power and other customers from misuse of the BU rate schedule and ensure that the CBL reduction does not result in undue access to RTP marginal prices nor create a revenue recovery risk. This type of separate metering is common under standby tariffs designed by other utilities. Supplementary Power would be split between the CBL load shape and RTP marginal pricing no differently than the way it currently is done within the RTP rate schedules.

**Q. IS THE ADDITIONAL METERING WITH RTP CUSTOMERS REASON TO DENY BACK-UP SERVICE FOR RTP CUSTOMERS SEEKING TO REDUCE THEIR CBL?**

A. No. Although there is an added complexity in terms of metering, it is not a reason to disallow participation by RTP customers. It is common for other utilities to require additional submetering of customer-sited generation when rate design requires it, which would be the case with RTP customers on back-up service.

**Q. DOES THE ADDITION OF FIRM GENERATION BY A CUSTOMER BRING SYSTEM RELIABILITY BENEFITS TO OTHER CUSTOMERS?**

A. Yes. Having firm generation capacity embedded with customer load adds diversity to the grid generation fleet and added reliability to the Georgia Power system.

**Q. WHAT TARIFF LANGUAGE CHANGES WOULD BE NEEDED TO ALLOW FIRM CHP CAPACITY TO BE CONSIDERED FOR A CBL REDUCTION?**

A. First, the Back-Up Service Schedule applicability section would be revised to add the RTP-DA and RTP-HA rate schedules. Second, the "Back-Up Power" rate description would need to add "RTP CBL rates." The "Supplementary Power" rate definition would add "RTP CBL rates" and "RTP hourly price" under the normal RTP CBL load shape. Maintenance Power would be priced as specified within the Back-Up Service contract. Finally, the CBL Revisions (Section C of Special Provisions) to RTP-HA and RTP-DA would be revised to include customer-sited generation in which the customer is subscribed to Georgia Power Back-Up Service as an allowance for CBL reduction consideration.

**Q. ARE YOU RECOMMENDING THESE REVISIONS TO THE TARIFF LANGUAGE WITHIN THE BACK-UP SERVICE SCHEDULE AND RTP SCHEDULES?**

A. Yes.

## IV. ROE EARNINGS BAND AND SHARING MECHANISM

**Q. DID YOU TESTIFY ON THE EARNINGS BAND IN GEORGIA POWER'S 2019 RATE CASE?**

A. Yes.

**Q. WHAT WAS YOUR RECOMMENDATION IN THE LAST RATE CASE?**

A. At that time, I recommended the Commission reduce the width of the ROE band to 100 basis points (1.0%); that is, 50 basis points above and below the target approved ROE.

**Q. ARE YOU REVISING THIS RECOMMENDATION?**

A. If the Commission adopts a target ROE below the 11% proposed by the Company, such as 10%, then I would alter my recommendation to 100 basis points above the target ROE before sharing with customers takes place. In other words, 11% could serve as the top end of the earnings band.

**Q. WHAT IS GEORGIA POWER PROPOSING FOR THE EARNINGS BAND IN THIS CASE?**

A. As set forth in the Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson:

> The Company is proposing to continue the ROE band of 9.5%-12.0%, which was approved by the Commission in the 2019 base rate case. The earnings band defines a reasonable range of return within which the Company is allowed to earn. Earnings below this band could indicate a rate adjustment is necessary, whereas earnings above this band would trigger the sharing mechanism whereby 80% of the excess earnings above 12.0% is returned to benefit customers. The sharing mechanism provides direct financial benefits to Georgia Power customers. Since 2013, customers have received the benefit of approximately $297 million through the sharing mechanisms. [5]

**Q. ARE YOU PROVIDING AN ALTERNATIVE RECOMMENDATION IN THIS CASE?**

A. Yes. As an alternative consideration, I recommend the Commission eliminate the 20% retention of earnings above the band or greatly reduce this retention by the Company. That is, given the sufficient width of the earnings band, which is beneficial to Georgia Power, the Company would now share 100% of the earnings in excess of the band. If the Commission believes that it is important to retain some incentive to achieve earnings above

[5] Tr. at 208:5-12 (Abramovitz, Adams, Houston, and Robinson Dir. at 13) (Sept. 27, 2022).

the band, then the amount retained by the Company could be reduced to 5%. If the Commission reduces the amount retained to 5% for Georgia Power, the Company would still retain $5 million for every 50 basis points above the band. This $5 million calculation is based upon the statement of Mr. Abramovitz at hearing that 50 basis points represents about $100 million.[6]

**Q. HOW MUCH DOES GEORGIA POWER RETAIN AS A RESULT OF THE EARNINGS BAND?**

A. For every 50 basis points (or 0.5%) above the last awarded ROE of 10.50%, Georgia Power earns about an additional $100 million. In other words, actual earnings at 12.0% under the current earnings band will generate $200 million in additional earnings above the proposed 11.0% ROE. Therefore, giving the full amount above the band to customers is a fair balance. As stated by the Company as quoted above, customers have only received $297 million since 2013.

**Q. IF CUSTOMERS HAD RECEIVED 100% OF THE EARNINGS ABOVE THE BAND SINCE 2013, HOW MUCH MORE WOULD HAVE THAT BEEN?**

A. The customers would have obtained a full amount of $380 million, or $84 million more.[7] This additional sharing would have provided extra relief to customers, but less than the amounts retained by the Company above the target approved ROE.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE EARNINGS BAND.**

[6] Tr. at 265:4-15 (Abramovitz Cr.) (Sept. 27, 2022).
[7] Calculated from data provided by the Company in Data Request Response STF-PIA-3-2 Attachment.

A. I recommend that the Commission either narrow the band around the target ROE determined in this case and/or eliminate or reduce the 20% retained by the Company for amounts above the band.

**Q. DO YOU BELIEVE THAT THE CONSTRUCTIVE REGULATORY ENVIRONMENT IN GEORGIA IS RETAINED WITH THE ADOPTION OF YOUR RECOMMENDATION?**

A. Yes. I have suggested a 100 basis point band above the target ROE approved by the Commission. This 1.0% earnings band is worth $200 million to the Company and will be viewed as very constructive while still giving opportunities to customers to receive refunds, which are helpful interim rate relief for customers during the ARP years and good for public perception.

## V. RATE CLASS COST OF SERVICE AND RATE DESIGN

**Q. WHICH WITNESS SPONSORS THE GEORGIA POWER CLASS COST OF SERVICE STUDY ("CCOSS")?**

A. Mr. Lee Evans is sponsoring the CCOSS for Georgia Power.

**Q. DO YOU HAVE ANY RECOMMENDED CHANGES TO THE CCOSS?**

A. Not at this time.

**Q. DOES THE CCOSS SUPPORT THE ACROSS-THE-BOARD INCREASE PROPOSED BY GEORGIA POWER?**

A. No. The evidence produced by the CCOSS suggests that the rate increases to individual rate groups should be somewhat different, as reflected in Mr. Evans' Direct Testimony, and GPC Exhibits 27-30 (Exhibits LPE-1 through LPE-4).

**Q. WHAT DO YOU RECOMMEND THE COMMISSION ORDER?**

A. I recommend the Commission order implementation of the rate adjustments based on the CCOSS produced by Georgia Power. Alternatively, the Commission should consider movement toward cost of service to avoid significant departures from cost of service that may be more difficult to address in the next rate case.

**Q. WHY MAY THE CURRENT DEPARTURES FROM COST OF SERVICE BECOME GREATER IN THE NEXT RATE CASE IF AN EQUAL, ACROSS-THE-BOARD INCREASE IS APPLIED NOW?**

A. Based on my experience, public utility commissions that approve across-the-board increases when there is a need for cost of service adjustments tend to find larger departures from cost-based rates that need to be contended with in the next rate case. It would be better to address this now with movement toward cost-based rates to avoid a larger deviation in the next rate case.

**Q. ARE COST-BASED RATES IMPORTANT TO MAINTAINING AN ATTRACTIVE BUSINESS ENVIRONMENT WITHIN THE STATE OF GEORGIA?**

A. Yes. Existing and new industries, businesses, and government entities looking for locations to site their next expansion typically include an assessment of energy costs in each potential location across the nation. Therefore, it is important that the State of Georgia remain competitive in electricity rates for commercial and industrial customers, and the proper way to do that is with consideration of the cost of serving those customers.

## VI. PROPOSED RATES AND MINIMUM FILING REQUIREMENTS

**Q. HAS THE COMPANY PROPOSED A LEVELIZED APPROACH FOR THE BASE RATE INCREASE IN 2023 TO COVER THE THREE-YEAR ARP?**

A. Yes.

**Q. DO THE SCHEDULES FILED TO SATISFY THE MINIMUM FILING REQUIREMENTS MATCH THE LEVELIZED RATE INCREASE PROPOSED BY GEORGIA POWER?**

A. No. The MFR schedules are based on the test-year 12 months ending July 31, 2023,[8] thereby including the incremental first year of the three-year rate plan, but do not include the full amount of the Company's proposed one-time levelized increase for traditional base rates to be effective January 1, 2023. For example, the proposed tariff rate schedules found in MFR Item F-1 do not include the rates that would become effective if the Commission approves the levelized traditional base rate revenue increase found in Table 1 of the Direct Testimony of Abramovitz, Adams, Houston, and Robinson.[9] Similarly, MFR Items F-3 and F-4, containing billing comparisons between present and proposed rates and revenue proof, do not utilize rates based on the one-time levelized increase proposed to be effective January 1, 2023.

**Q. DOES THE LACK OF SCHEDULES USING RATES PROPOSED UNDER THE LEVELIZED APPROACH MAKE ASSESSMENT DIFFICULT?**

A. Yes, it is difficult to fully assess the Company's rate proposal without knowing the rates and revenue implications and bill impacts for each individual rate class.

**Q. DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION TO ORDER SCHEDULES FOR THE NEXT RATE CASE IF GEORGIA POWER ELECTS TO CONTINUE OR MODIFY ITS ALTERNATE RATE PLAN?**

[8] *See* Tr. at 0906:9-11 (Legg Dir. at 4) (Sept. 28, 2022).
[9] Tr. at 204 (Abramovitz/Adams/Houston/Robinson Dir. at 9).

A. Yes. I recommend that the Commission order in this case a requirement for Georgia Power in its next rate case to include the proposed rates, tariff rate schedules, and the schedules found within MFR Items F-3 and F-4 at the revenue levels actually proposed by the Company. If the Company is proposing a one-time, levelized, first-year base rate adjustment, as it has in this case, then the Company should provide additional corresponding schedules that match its levelized revenue proposal. If the Company is proposing multi-year base revenue adjustments, then it should provide in its application what those rates are, along with the corresponding schedules. Without those matching schedules, it is not clear what the Company is asking the Commission to approve for implementation in each of the effective rate years.

**Q. ARE YOU ASKING THE COMMISSION TO CHANGE THE MFRs?**

A. No, just to order the Company to provide schedules found within the MFRs that match the revenue proposal(s) of the Company.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

BY MS. MEDLYN:

Q Dr. Blank, on October 20th, 2022, did you also cause to be prefiled one exhibit?

A Yes, I did.

Q Do you have any corrections to your exhibit?

A I have one correction on that exhibit. And it deals with the page numbering. The last two pages will reflect an error on -- there aren't actually 15 pages in this exhibit. And so the numbering is inconsistent with regard to the total pages.

So the page numbers are correct, but the total page numbers is 15. That's the only correction I have.

MS. MEDLYN: Okay. I would ask that the exhibit be marked as DODFEA 1.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as DODFEA Exhibit 1.)

BY MS. MEDLYN:

Q Dr. Blank, have you prepared a summary of your testimony?

A I have.

MS. MEDLYN: Can you read it, please.

DR. BLANK: Good morning Madam Chair, Commissioners. My name is Larry Blank. Today I'm providing expert testimony on behalf of the customers

of Georgia Power that are a part of the U.S. Department of Defense and all other Federal Executive Agencies. This includes several military bases and other federal entities that are customers of Georgia Power.

In my testimony I first offer two recommendations for the customer baseline load, also known as CBL; determination criteria found within the day-ahead and hour-ahead real-time pricing tariff schedules, or RTP tariff schedules.

Currently, CBL reductions are only considered if the customer has physically removed the electric load equipment from the customer's site, or, alternatively, the customer elects to remove themselves from the RTP rate schedule for a period of two years before reassessment of load can be considered.

My first CBL recommendation would allow for the consideration of CBL reductions based on two years of historical load data, rather than forcing customers to remove themselves from RTP. Removal of the customer from RTP is not necessary to perform a two-year assessment of the customer's load.

My second CBL recommendation is to allow RTP customers with qualifying on-site generation

capacity to pay for Georgia Power backup service, which would firm up the on-site customer generation, allowing for consideration of a CBL load reduction.

Now, to qualify for Georgia Power's backup generation -- I'm sorry. To qualify for Georgia Power's backup service, the customer's generation must operate at least 6,000 hours per year, which is over a 68 percent capacity factor.

The customer will pay for standby reservation. So they will pay a standby reservation capacity charge each month. And for backup power, when that backup power is needed or maintenance power is needed, the customer will pay the standard bill rates currently charged, the customer's CBL load within the RTP rates.

This rate design will protect Georgia Power and other customers against cost shifting and will bring additional reliability in having generation embedded with customer load. I provide the detailed tariff modifications necessary to allow these options within my written testimony.

In my secondary of testimony, I offer recommendations for the ROE earnings band. The Commission should consider some modifications to the ROE band and earnings sharing design.

**Specifically, an alternative for consideration would be to limit the band above the target ROE to 100 basis points and increase the percentage sharing of the earnings above the band with customers. For example, from 80 percent to 95 percent. This would allow for larger refund relief to customers in those years the company has healthy earnings.**

**Third, I address the company -- I'm sorry. I address the proposed across-the-board rate increase and advocate for the importance of movement toward cost-based rate changes. This will help to mitigate the likelihood of large disparities between rates and costs before the next rate case. The Commission should consider ordering movement toward cost-based rate in this case, rather than the across-the-board increase proposed.**

**Finally, I ask that the Commission order Georgia Power in its next rate case to include schedules similar to those found in the minimum filing requirement schedules that match the actual revenue proposed by the company for the first, second, and three years of its three-year alternative rate plan so that these schedules better match the increases actually requested by the company under the ARP.**

Likewise, if the company proposes a levelized rate increase, as is the case in this proceeding, then the company should file similar MFR schedules that match the rate increases on a levelized basis.

And that concludes my summary.

MADAM CHAIR PRIDEMORE: Questions from Commissioner for Dr. Blank?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Georgia Power Company.

I'm sorry. Georgia Public Service Commission.

MR. WALSH: No cross, Madam Chair.

MADAM CHAIR PRIDEMORE: Okay. Americans for Affordable Clean Energy.

MS. LYNDALL: No questions, Ms. Chairman.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Government.

MS. BROWN: No questions.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light.

MS. KYSOR: No questions.

MADAM CHAIR PRIDEMORE: GASEIA.

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar.

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch.

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: MARTA.

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management.

Yes, Mr. Clarkson.

CROSS-EXAMINATION

BY MR. CLARKSON:

Q Good morning, sir.

A Good morning.

Q You're not just describing in theory here; there are military bases out there that have CBLs that are too high on their RTP rate.

Is this a real-world problem?

A We have studied load data for at least one of our military bases, which would suggest that some reconsideration of the CBL level should take place. However, the way the rules are currently designed, for consideration of a CBL reduction for that type of customer, the customer would have to remove themselves from the RTP tariff for two years before that consideration by Georgia Power would take place.

Q Well, to be effective, they would have to reduce the load for two years; isn't that also correct?

A Well, using an example where the load, in our opinion, already is below, that load which establishes the CBL. And what that means is during certain -- there are many hours the CBL is actually above the load of the customer.

So we feel that that already -- that condition already exists and that's part of my recommendation is to use historical -- use historical load data to reassess the CBL. So during that two-year period it's not as though the customer would necessarily be trying to reduce its load during that two-year period. But if its conditions remain the same, then after that two-year period presumably there would possibly be a CBL reduction. But you would have to wait two years off of the RTP.

Q Now, would it surprise you to know that a lot of RTP customers who have that same problem that the CBL is too high?

A It would not surprise me.

Q Are you aware this rate is used for colleges, prisons, hospitals?

A I believe there's a large number of customers who are on RTP with an established CBL.

Q Yes. So then you would agree we have the same problem; there's a lot of other customers that the military bases have that the CBL is too high and it's very difficult

to adjust it downward with the power rule?

Is that where we are?

A Yes. I mean, it's -- well, first of all, I haven't studied other customers. It would not surprise me. My testimony is that it wouldn't surprise me that there may be other customers with this same situation.

And, again, yeah, the current rules, as I understand it, require the customer to remove themselves from RTP. And I'm not seeing why that is necessary to reassess the load of those customers.

Q Do you agree that the purpose of RTP -- the purposes is not only to reflect true costs to the customer in real-time, but also to encourage customers to make a response by cutting load during times of peak pricing?

A Yes. Whether it's the hourly or day-ahead RTP pricing for that incremental load above CBL, the customer now has exposure -- exposure to marginal price fluctuations and variability. And it forces those customers to manage their load accordingly so as to be more efficient in their use of electricity, which also brings benefits to other customers.

Q So we can say, can we not, that a CBL too high is removing certain amounts of load that could have been otherwise responsive?

And so now these loads do not respond to the

prices?

MR. HEWITSON: Madam Chair, that's not in Dr. Blank's testimony. And I do believe that we've let Mr. Clarkson go pretty long with friendly cross.

MADAM CHAIR PRIDEMORE: I'm less concerned about the time I give him for friendly cross. I'm more concerned about the fact that there's not questions. I'm getting comments, but there's not questions.

So ask questions what's in his testimony.

MR. CLARKSON: Yes, yes.

BY MR. CLARKSON:

Q Question. In the absence of demand response, we're looking at peaking generation and battery backup, are we not.

MR. HEWITSON: Madam Chair, could we point to where that is in Dr. Blank's testimony before we ask questions?

Because I don't believe it is in Dr. Blank's testimony.

MADAM CHAIR PRIDEMORE: Mr. Clarkson, can you cite a page number and a line number?

MR. CLARKSON: I cannot. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Clarkson.

Sierra Club.

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE.

MR. DOWDY: No questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Georgia Power Company.

CROSS-EXAMINATION

BY MR. HEWITSON:

Q Dr. Blank, good morning.

A Good morning, sir.

Q Steve Hewitson on behalf of Georgia Power.

MR. HEWITSON: And, Ms. Reno, good morning, as well. I don't want to ignore you, but I'm just going to ask questions to Dr. Blank.

BY MR. HEWITSON:

Q Dr. Blank, you mentioned the constructive regulatory environment on page 15 of your testimony. Do you believe it is important to maintain the constructive regulatory environment here in Georgia?

A Yes. I do believe that that is important, yes.

Q Okay. And do you --

A And it's important to our federal installations here, as well.

Q And do you agree that alternative rate plans, like the three-year plans we've had in Georgia, help foster the constructive regulatory environment here in Georgia?

A It certainly does foster and it is a characteristic of the Georgia Power -- the regulation of Georgia Power that is recognized by others, including bond rating agencies.

Q And you are aware that in Georgia, at least, adoption of a multi-year rate plan must be done by consent of the parties or consent of the utility Georgia Power in this case?

A Yes. That's my understanding. Otherwise, the alternative would be for Georgia Power to revert back to traditional rate cases.

Q And one of the hallmarks of the alternative rate plans in Georgia has been the earnings band; right?

A That is one important component, yes.

Q And would you agree that multi-year rate plans with earning bands are supportive of constructive regulatory environments?

A Yes, I do. Because of the -- as I said, it's one component -- one important component. And it helps to balance the other components of the multi-year rate plan.

Q One of your recommendations is that the Commission eliminate or reduce the 20 percent of earnings above the band that the company is allowed to retain under the current ARP sharing mechanism; right?

A Yes. That's one of my recommendations.

Q And going back to 2013, the ARP that came out of that rate case provided that Georgia Power shared earnings above the band with customers so that two-thirds went to customers and a third was retained by the company; right?

A I don't recall that, but I'll accept that, yes.

Q The sharing mechanism in the 2019 rate case moved that to be 80/20; right?

80 percent goes to the benefit --

A Yes.

Q -- of the customers and 20 percent to the company; right?

A I recall that from the 2019 case, yes.

Q Okay. Do you recall that each of those sharing mechanisms was done as a settlement -- part of a settlement to which the company agreed?

A Yes.

Q Is it your understanding that change in the earnings band in this rate case, and, likewise, a change to what happens to earnings above the band would similarly require an agreement?

A An agreement --

Q By the company.

A It would require -- a settlement agreement?

Q Either a settlement agreement or agreement by

the company for what happens within the earnings band or even above the earnings band.

A If you are asking whether the customer has the authority to change that, I'm not sure. I -- I think that's beyond my legal understanding, yes.

Q Fair enough, Dr. Blank.

Turning to your RTP recommendation. In the 2019 rate case, you opposed Georgia Power's request to increase from 12 months to 24 months the requirement for how long an existing RTP customer seeking to lower their CBL had to be off RTP; right?

A I'd have to look back, but that sounds correct, yes.

Q And your recommendation now is that customers wishing to reduce their CBLs should not have to come off RTP; is that right?

A Yes. That's correct.

Q Would you also support the opposite; that if a customer had 24 months of historical meter data showing that they're above the CBL, the company should be able to increase their CBL?

A Yes. I think it should be symmetrical. On reassessments in -- I thought that's what Georgia Power already does, but I may be incorrect in that assumption.

I thought that Georgia Power does monitor their

RTP customers. And if a customer's load has grown, for example, that there might be a reassessment by Georgia Power and perhaps a renegotiation with that customer.

But perhaps I'm wrong in that presumption. But I agree with that concept that it should be -- it should be symmetrical because customers change. Their loads change for a variety of reasons because some customers may reduce load. Again, for a variety of reasons.

And others customers may grow through expansion of their on-site operations. And that should trigger a CBL reconsideration.

MR. HEWITSON: Okay. Thank you, Dr. Blank. That's all I have for you this morning.

DR. BLANK: Thank you, sir.

MADAM CHAIR PRIDEMORE: Redirect for Dr. Blank.

MS. MEDLYN: No redirect.

MADAM CHAIR PRIDEMORE: Okay. Let's go ahead with the summary for Ms. Reno.

MS. MEDLYN: I need to do some of the preliminary questions. I just swore her in. Sorry about that.

MADAM CHAIR PRIDEMORE: That's okay.

DIRECT EXAMINATION

BY MS. MEDLYN:

Q Okay. Ms. Reno, could you please state your

**name and how you're employed.**

**A Yes. My name is Maureen Reno. I'm an economist with the specialization of public utility economics and finance. I'm founder and principal of Reno Energy Consulting Services, LLC.**

**Q Okay. On October 20th, 2022, did you cause to be prefiled 49 pages of direct testimony in this docket?**

**A Yes.**

**Q Do you have any corrections to your testimony?**

**A No, I do not.**

**Q If I were to ask you the same questions today, would your answers be the same?**

**A Yes.**

**MS. MEDLYN: Madam Chair, I would ask that Ms. Reno's testimony be copied into the record as if orally -- given orally from the stand?**

**MADAM CHAIR PRIDEMORE: So moved.**

**(Whereupon, the prefiled direct testimony of Maureen Reno:)**

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **IN RE: GEORGIA POWER COMPANY'S 2022 RATE CASE** | **)**<br>**)**<br>**)** | **DOCKET NO. 44280** |

# DIRECT TESTIMONY

# OF

# MAUREEN L. RENO

**ON BEHALF OF**

**THE UNITED STATES DEPARTMENT OF DEFENSE**
**AND**
**ALL OTHER FEDERAL EXECUTIVE AGENCIES**

**October 20, 2022**

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APPENDIX A: CURRICULUM VITAE AND QUALIFICATIONS

APPENDIX B: EXHIBITS

## I. INTRODUCTION AND QUALIFICATIONS

**Q. PLEASE STATE YOUR FULL NAME, OCCUPATION, AND BUSINESS ADDRESS.**

A. My name is Maureen L. Reno. I am an economist with a specialization in public utility economics and finance. I am the founder and principal consultant of Reno Energy Consulting Services, L.L.C. My business address is 19 Hope Hill Road, Derry, New Hampshire 03038.

**Q. PLEASE SUMMARIZE YOUR EDUCATION.**

A. I received a Bachelor of Arts degree in Economics from the University of Maine at Orono, Maine in 1996. In 1998, I earned a Master of Arts degree in Economics from the University of New Hampshire in Durham, New Hampshire, where I also completed all course work and examination requirements for the Ph.D. degree in economics, except for my dissertation. My areas of academic concentration included industrial organization and environmental economics.

**Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?**

A. I have over 20 years of professional experience in the regulated utilities and energy sectors. From 2001 to 2011, I served as a utility analyst and program manager with the New Hampshire Public Utilities Commission advising the Commissioners on regulated utilities' cost of capital and return on equity ("ROE"). From 2011 to 2012, I served as a Senior Energy Economist with the Union of Concerned Scientists, advising on the intricacies of the regulated utility industry and helping to develop alternative financing programs for renewable energy investments. Since 2012, I have served as an independent consultant to multiple firms, including Exeter Associates, Inc. and TAHOEconomics, LLC on utility cost of capital, ROE, and capital structure;

Stephenson Strategic Communications, LLC on federal climate and energy policy; and TrueLight Energy, LLC on regulated utility rate impacts and energy markets.

**Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE A PUBLIC REGULATORY COMMISSION?**

A. Yes. My testimony was presented and accepted in more than 20 rate proceedings in several states, to include Alaska, Arizona, Georgia, Missouri, New Hampshire, New Mexico, Oklahoma, and Texas, on a wide range of issues concerning regulated utilities, retail and wholesale energy markets, and renewable energy. (See Appendix A for my curriculum vitae and qualifications.)

**Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?**

A. Yes. I served as an expert witness on cost of capital, ROE, and capital structure for the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") in Docket No. 42516 in Georgia Power Company's 2019 Rate Case.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A. I am serving as an expert witness on cost of capital, ROE, and capital structure on behalf of the DoD/FEA. DoD/FEA is a large customer of Georgia Power Company ("Georgia Power" or "Company") and maintains military installations in Georgia, including: Fort Benning, Dobbins Air Force Base, Fort Gordon, Fort Gillem, Fort Stewart, Hunter Army Airfield, Robins Air Force Base, U.S. Marine Corps Logistics Base Albany, and U.S. Naval Submarine Base Kings Bay, among others. Georgia Power also provides service to several civilian FEA accounts including to the National Security Agency's Georgia Cryptologic Center (GCC).

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. My testimony is organized into eight sections, including this one. In Section II, I present the purpose of my testimony; summarize Georgia Power's proposed ROE, capital structure, and rate of return ("ROR") in the context of Commission precedent; and provide my ROE recommendation. In Section III, I discuss current economic and financial conditions that are affecting investors' opportunity cost of capital (in general and specifically for utility companies). In Section IV, I evaluate the Company's proposed capital structure and provide my own recommendation for cost of debt. In Section V, I explore different types of risks for regulated electric utilities, and I evaluate Georgia Power's business and economic position to determine whether such risks are effectively captured in my sample proxy group and ROE recommendation. In Section VI, I describe the methodologies that I applied to develop my cost of equity findings and ROE recommendation. In Section VII, I address Company witness Mr. James M. Coyne's ROE flotation cost adder. Finally, in Section VIII, I summarize my conclusions and provide my recommendations to the Commission.

## II. PURPOSE AND SUMMARY OF RECOMMENDATIONS

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to recommend, for ratemaking purposes in this case, an overall ROR and a fair ROE for Georgia Power. I accept the Company's capital structure for ratemaking purposes. My recommendation for the ROE is set forth according to the standards in Bluefield Water Works v. Public Service Commission, 262 U.S. 679, 692-93 (1923) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 605 (1944). In Bluefield and Hope, the U.S. Supreme Court established the principle that a public utility may be allowed to earn a return comparable to a return on investments in other enterprises having similar risks that allow the utility, under

efficient management, to maintain financial integrity, the opportunity to attract capital on reasonable terms, and to maintain a satisfactory credit rating.

**Q. WHAT ARE THE ROE AND ROR THAT THE COMPANY IS REQUESTING IN ITS FILING?**

A. The Company's cost of capital witness, Mr. Coyne, is recommending that the Commission allow an opportunity for Georgia Power to earn an ROR of 7.70%.[1] This ROR is based on a regulated capital structure of 56% equity and 44% long-term debt, with a cost of debt of 3.53% and an ROE of 11.0%.[2] Although he is not recommending a ROE range, Mr. Coyne's recommended ROE of 11.0% is within his models' range of 8.99% to 13.55%.[3] This proposed overall cost of capital is based on the average of Georgia Power's estimated capitalization for the 13 months ending July 31, 2023.[4] These recommendations are shown in Table 1.

**Table 1. Requested Weighted Average Cost of Capital**
**Georgia Power Company**

| | Weight | Cost of Capital | Actual Weighted Cost |
|---|---|---|---|
| **Long-Term Debt** | 44.18% | 3.53% | 1.56% |
| **Common Equity** | 55.82% | 11.00% | 6.14% |
| **Total Capitalization** | 100.00% | | 7.70% |

*Source: GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedule 2, WP1).*

**Q. SHOULD THE COMMISSION REJECT MR. COYNE'S ROE RECOMMENDATION?**

A. Yes. Mr. Coyne's ROE recommendation does not comport with his own data. An objective analysis of his data would yield a lower ROE. Mr. Coyne skews his analysis

[1] Tr. at 221:20-24 (Abramovitz, Adams, Houston and Robinson Dir. at 26) (Sept. 27, 2022).
[2] GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedule 2, WP1).
[3] Tr. at 0673:4-11 (Coyne Dir. at 45) (Sep. 28, 2022).
[4] Tr. at 221:20 - 222:1-2 (Abramovitz, Adams, Houston and Robinson Dir. at 26) (Sept. 27, 2022) and GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedule 2, WP1).

through the over-emphasis and overreliance on inputs with an upward bias. For example, he relies exclusively on earnings growth estimates, which has the effect of inflating his Discounted Cash Flow ("DCF") model results as well as his Capital Asset Pricing Model ("CAPM") results. Relying exclusively on earnings growth estimates also inflates his estimated total market risk premium, a key input in his DCF-based CAPM. (By contrast, I rely on earnings growth estimates, dividend growth, book value growth, and sustainable growth, the combination of which produces results that are more accurate.)

Mr. Coyne relies heavily on interest rates that do not reflect current trends in financial markets or investors' expectations of inflation and economic growth. His historical interest rates and forecasted interest rates that he uses in his CAPM and Risk Premium Analysis reflect market conditions from earlier this year. (By contrast, I rely on current market data; specifically, the 90-day period ended August 31, 2022, which produces results that are more up to date and accurate.) In his Expected Earnings approach, Mr. Coyne merely reports estimated book value returns as reported by *Value Line* without consideration of investors' valuation of such expected returns. Finally, Mr. Coyne proposes a flotation cost adder based on new stock issuances by his proxy group companies without further consideration of whether Southern Company plans to issue new stock in the near future.

**Q. WHAT ARE THE CURRENT AUTHORIZED ROR AND ROE FOR GEORGIA POWER?**

A. On December 17, 2019, the Commission approved a settlement in Docket No. 42516 authorizing an ROR or weighted average cost of capital ("WACC") of 7.70% based

upon a 4.14% cost of debt, an authorized ROE of 10.5%, and an authorized regulatory capital structure of 44.0% long-term debt and 56.0% equity.[5]

**Q. IS GEORGIA POWER REQUESTING APPROVAL OF AN ALTERNATE RATE PLAN IN THE CASE?**

A. Yes. Georgia Power filed its three-year Alternate Rate Plan ("ARP") requesting approval from the Commission of increases to the Company's base rates of $889 million in 2023, $107 million in 2024, and $45 million in 2023.[6] This proposal includes increases to the Company's cost of debt and resulting ROE, while maintaining the same capital structure from the original filing, as shown in Table 2 below.

Table 2. Georgia Power–Proposed Weighted Average Cost of Capital over Time

| | Period Ending December 31, 2023 | | | Period Ending December 31, 2024 | | | Period Ending December 31, 2025 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Weight | Cost | Weighted Cost | Weight | Cost | Weighted Cost | Weight | Cost | Weighted Cost |
| Long-Term Debt | 44.0% | 3.53% | 1.55% | 44.00% | 3.58% | 1.58% | 44.0% | 3.66% | 1.61% |
| Common Equity | 56.00% | 11.0% | 6.16% | 56.00% | 11.0% | 6.16% | 56.0% | 11.0% | 6.16% |
| Total | 100.00% | | 7.71% | 100.00% | | 7.74% | 100.00% | | 7.77% |

Note: Amounts may not add up due to rounding. GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedule 2, Workpapers 2-4).

**Q. WHAT DO YOU RECOMMEND AS THE APPROPRIATE ROR AND ROE FOR GEORGIA POWER?**

A. For Georgia Power, I accept the Company's proposed capital structure and recommend an overall ROR of 6.85%, based on an ROE of 9.47%, an embedded cost of long-term debt of 3.53%, and an assumed capital structure comprised of 44.18% long-term debt and 55.82% common equity. I recommend that the Commission reject the Company's

[5] *Order Adopting Settlement Agreement as Modified* in PSC Docket No. 42516, Findings of Fact items 2 and 3, at 5-6, February 6, 2020. The settled cost of debt and resulting WACC were not provided in the order explicitly. The WACC is for illustrative purposes only and is based on the capital structure and ROE provided in the order and the Company's cost of debt provided in its initial filing.

[6] Rate Case Supplement Filing Letter dated August 22, 2022 at 3.

recommendation of adjusting the cost of debt over the three years included in the ARP. Thus, my calculations and recommendations for the duration of each year in the ARP are shown in Table 3.

| Table 3. Reno Proposed Weighted Average Cost of Capital<br>Georgia Power Company | | | |
|---|---|---|---|
| | Weight | Cost of Capital | Actual Weighted Cost |
| **Long-Term Debt** | 44.18% | 3.53% | 1.56% |
| **Common Equity** | 55.82% | 9.47% | 5.29% |
| **Total Capitalization** | 100.00% | | 6.85% |

*Source: GPC Exhibit* 3 *(APA/SPA/ADH/MBR/3, Schedule 2, WP1).*

**Q. WHAT IS THE BASIS OF YOUR ASSUMED CAPITAL STRUCTURE?**

A. For the purposes of computing overall ROR or WACC, I have accepted the Company's proposed capital structure level of 44.18% debt and 55.82% common equity. I am not recommending an alternative capital structure; however, if the Commission were to order a different capital structure based on evidence from other parties, my calculated overall ROR would change.

**Q. WHAT IS THE BASIS OF YOUR RECOMMENDED ROE FOR GEORGIA POWER?**

A. My ROE recommendation is based on the maximum of my ROE range of 8.81% to 9.47%, derived from my market-based cost of equity methodologies using a proxy group of comparable risk companies. I recommend an ROE based on the maximum of my range because it represents a fair and reasonable ROE for Georgia Power in light of the Company's risk and investors' current valuation of public utilities and equity assets in general.

## III. MACROECONOMIC CONDITIONS

**Q. WHY IS IT IMPORTANT TO CONSIDER MACROECONOMIC CONDITIONS IN DEVELOPING A RECOMMENDED ROE?**

A. Investors consider both economic and monetary conditions when assessing the opportunity costs of their investments. Global, national, and regional economic conditions affect investor expectations regarding investment returns, as measured by stock prices, interest rates, and sustainable dividend growth.

**Q. HOW WOULD YOU DESCRIBE CURRENT NATIONAL ECONOMIC CONDITIONS?**

A. In general, the economic signals are mixed. Recent economic growth, as measured by real Gross Domestic Product ("GDP"), shows that the U.S. economy is slowing down after experiencing a post-COVID-19 pandemic rebound. In 2021, real GDP growth reached an annual high of 5.7%, only to fall by 0.6% during Q2 2022, marking the second quarter of decline.[7] In contrast, unemployment continued to hold at 3.5% through July.[8] Inflation remains the primary concern in the economy, as supply chain and labor market shortages and fuel prices continue to drive up prices from 4.7% in the Consumer Price Index ("CPI") in 2021 to 8.5% in Q2 2022.[9]

To thwart inflationary pressures, the Federal Reserve Bank's Open Market Committee ("Federal Reserve" or "FOMC") decided to increase the target range for the Federal Funds rate 75-basis points on September 21, 2022 for the fourth time this year, resulting in a Federal Funds target range of 3.0% to 3.25% and the FOMC "… anticipates that ongoing increases in the target range will be appropriate."[10] In its press release, the FOMC also expresses that it will continue reducing its holdings of U.S.

[7] *See* Exhibit_(MLR-1).
[8] *Id*.
[9] *Id*.
[10] Federal Reserve, *Press Release*, September 21, 2022.

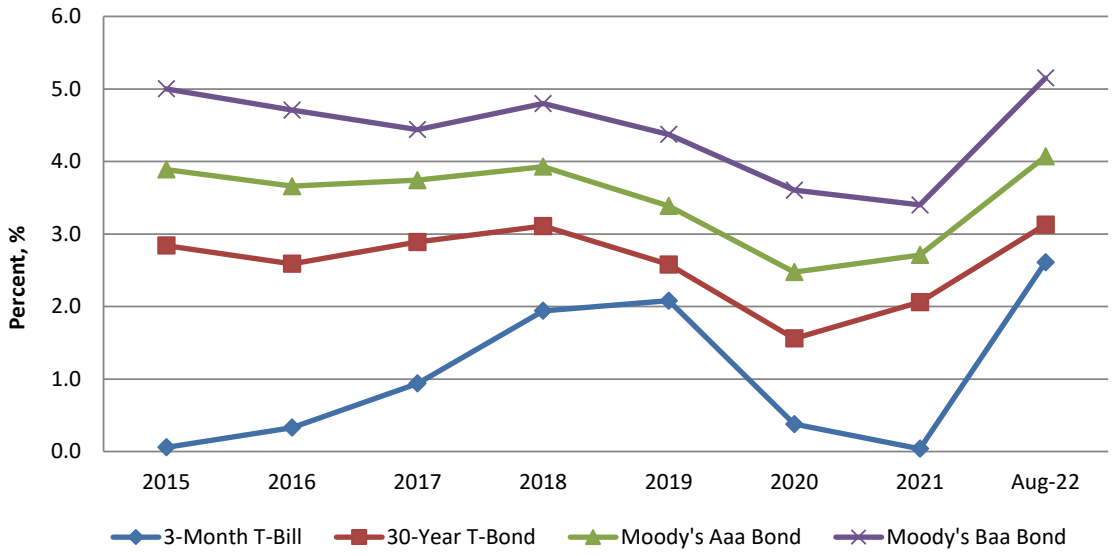
Treasury securities and agency debt and agency mortgage-backed securities. "The Committee is strongly committed to retuning inflation to its 2 percent objective."[11] The FOMC lists supply and demand imbalances related to the pandemic, higher food and energy prices, and broader price pressures as causes for inflation. The FOMC also expresses concern regarding the military operations in Ukraine by Russia, which will likely create additional pressure on inflation and suppress economic growth.[12]

**Q. HOW HAVE FINANCIAL CONDITIONS CHANGED IN RECENT YEARS?**

A. In general, interest rates are increasing from the historical lows reached in 2020 and 2021. Specifically, yields on short-term Treasury bonds are increasing in response to actions made by the FOMC. Yields on long-term Treasury bonds and corporate bonds are also increasing, albeit at a slower pace. As I will discuss in greater detail later in my testimony, yields on long-term bonds are not only determined by monetary policy but also investors' expectations of long-term inflation and economic growth. Figure 1 below shows how different market costs of capital have changed for the period 2015 through 2022.[13]

[11] *Id*.
[12] *Id*. *See also Immediate Release: Department of Defense Statement on Additional Military Assistance for Ukraine*, issued on February 26, 2022. This DoD press release refers to Russa's actions as an "unprovoked attack." https://www.defense.gov/News/Releases/Release/Article/2947554/department-of-defense-statement-on-additional-military-assistance-for-ukraine/.
[13] *See* Exhibit_(MLR-2a).

**Figure 1. Interest Rates and Bond Yields, 2015 to 2022**



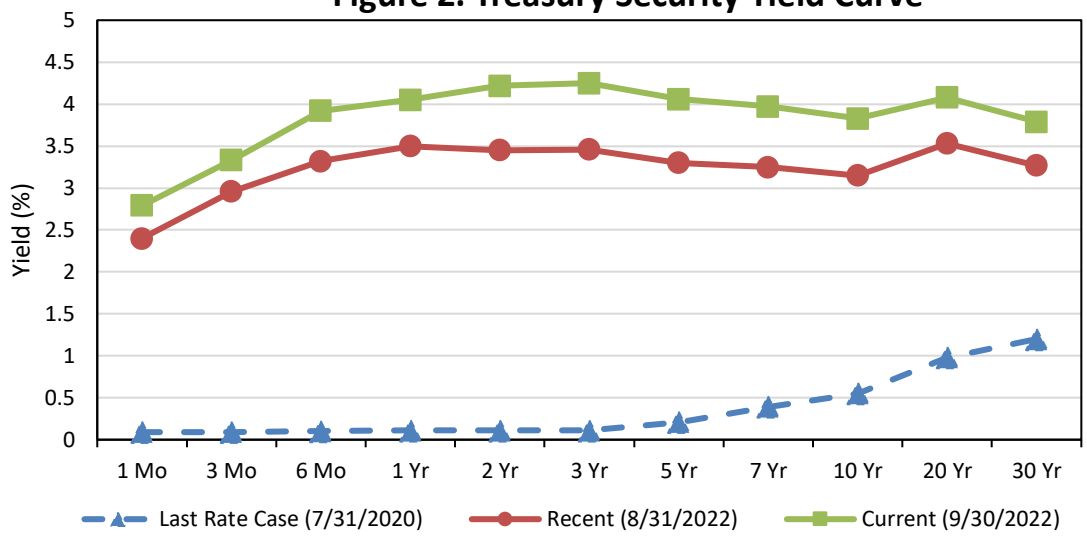

Source: Economic Indicators, August 2022 Prepared for the Joint Economic Committee by the Council of Economic Advisors and https://fred.stlouisfed.org

Yields on long-term bonds (reference the 30-Year Treasury Bond, or 30-Year T-Bond, shown in red with square marker in Figure 1) were 2.06% in 2021 and increased to 3.13% in August 2022. The cost of debt for Moody's Investors Service ("Moody's") Baa-rated corporations was 5.15% in August 2022. Moreover, short-term interest rates (reference the 3-Month U.S. Treasury Bill, or 3-Month T-Bill, shown in blue with diamond marker in Figure 1) have rebounded from near 0% to 2.61% in August 2022.

It is crucial to note that changes in short-term interest rates are the result of the FOMC's policy actions, specifically, FOMC's increase in the Federal Funds rate and deployment of its quantitative tightening program to maintain its employment and inflation goals. By contrast, long-term interest rates are primarily determined by market forces, including investor expectations of future levels of inflation and economic growth. Figure 2 below shows the yields on the different types of T-Bills and T-Bonds,

which is referred to by financial analysts as the "yield curve." The yield curve reflects the bond market's consensus opinion of future financial market conditions, such as levels of inflation and interest rates. At the end of the test year in the Company's last rate case (July 31, 2020), the yield curve presented an upward-sloping trend. In other words, the yields on short-term T-Bills were near historic lows, while the yields on some long-term T-Bonds were increasing, showing that investors were expecting economic growth in the long term. However, the current (September 30, 2022) yield curve shows that yields on long-term T-Bonds are slightly lower than the yields on short-term T-Bills. This suggests that investors are anticipating a sustained economic slowdown, consistent with the current decrease in GDP over Q1 and Q2 2022.

**Figure 2. Treasury Security Yield Curve**




Source: www.treasury.gov

Another measure of the collective views of investors regarding long-term inflation expectations is the Treasury Inflation-Protected Securities ("TIPS") spread, or the difference between yields on long-term nominal Treasury securities and long-term

TIPS. The yield on a long-term conventional Treasury bond pays its holder a fixed nominal coupon and principal to compensate the investor for future inflation, and it includes the real rate of interest and the inflation compensation. For TIPS, the coupons and principal both rise and fall with inflation, as measured by the CPI. The published yield includes only the real rate of interest. Therefore, the difference, roughly speaking, between the prevailing yields on these two types of Treasury securities reflects the inflation compensation over that maturity horizon that is expected by bond investors. The 90-day average difference in the yield on the 30-year Treasury Bond and 30-year TIPS for the period ended August 31, 2022 equals 2.32% and represents the market's most recent expectations of long-term inflation.[14] In other words, this confirms that investors are anticipating that the rate of inflation over the long term is expected to stabilize at a higher rate than the FOMC's goal of 2.0%, which may further feed fears of a sustained economic downturn on the horizon.

The prospect of a sustained economic downturn on the horizon creates uncertainty and reinforces investors' expectations of a low opportunity cost of purchasing utility stocks, as demonstrated by my cost of equity study estimates.

**Q. WHAT ARE THE ECONOMIC EXPECTATIONS FOR THE U.S. IN THE NEAR FUTURE?**

A. Economic growth is expected to slow down in the near term in response to high inflation and aggressive actions by the Federal Reserve. As the Federal Reserve eases or even reverses its monetary policy (by reducing short-term interest rates, etc.) in response to lower inflation, the economy is expected to rebound slightly in the longer term. Specifically, according to the Q3 2022 edition of *Survey of Professional Forecasters* by the Federal Reserve Bank of Philadelphia, economic growth, as

[14] *See* Exhibit_(MLR-2c).

measured by real GDP, is expected to remain near 1.2% during Q4 2022 and 1.1% during Q1 2023. Long-run economic growth beyond 2023 is expected to rebound slightly to an annual rate of approximately 2.3% in 2024 and then decrease slightly to 2.1% in 2025.[15]

Over the next year, inflation is expected to fall to moderate levels, with the CPI remaining near 3.2% in 2023 and then falling to 2.5% in 2024. The data show that analysts expect the national unemployment rate to increase slightly to about 3.9% on average in 2023 and remain at 3.9% in 2024 and 2025.

**Q. HOW DO THE STATE OF GEORGIA AND THE U.S. SOUTHEASTERN ECONOMIES COMPARE TO THE NATIONAL ECONOMY?**

A. According to the Federal Reserve Bank of Atlanta ("Atlanta Fed"), the regional economy, including Georgia and multiple neighboring states in the Southeast, expanded in recent weeks, but mixed signals remain. For instance, labor markets remain tight, causing some business leaders to automate certain tasks. Also, there remains a lack of affordable housing and the cost of living remains high.[16] The Atlanta Fed reports that some business owners expect to lay off employees later this year or in 2023 due to slowing demand. Although costs for gasoline, freight shipping, and some inputs have softened, consumers continue to face rising prices for rent, utilities and food.[17]

**Q. HOW DOES THE U.S. MILITARY IMPACT GEORGIA'S ECONOMY?**

[15] *See* Exhibit_(MLR-3). *Survey of Professional Forecasters*, Research Department, Federal Reserve Bank of Philadelphia Third Quarter 2022, at 9 and 11.
[16] The Federal Reserve Bank of Atlanta serves the region designated as the Sixth District that includes Alabama, Florida, Georgia, and portions of Louisiana, Mississippi, and Tennessee.
[17] *Beige Book Picks Up Mixed Signals from the Southeast Economy*, Federal Reserve Bank of Atlanta September 8, 2022. https://www.atlantafed.org/economy-matters/regional-economics/beige-book/2022/09/08/beige-book-southeast-economy-mixed-signals.

A. According to the DoD's Office of Local Defense Community Cooperation, Georgia ranks tenth in the nation for receiving DoD funds at $15.8 billion in 2020, contributing 2.5% of state GDP, or $1,472 per resident.[18] Half of these funds ($8.7 billion) were attributed to contract spending, while the remaining amount ($7.1 billion) was spent on personnel totaling 131,696 individuals, the majority of which are U.S. Army personnel (63%).[19]

**Q. WHY IS THE GEORGIA ECONOMY IMPORTANT TO INVESTORS?**

A. In general, investors are aware of current regional and national economic conditions and know that the Company operates in Georgia, where economic indicators are currently exhibiting signs of an economic slowdown. Investors will also gauge the Company's prospects for sales growth as they consider the state's economy. Investors would likely compare the Georgia economy to the economies of other states when deciding whether to invest in a similar utility company located elsewhere, all else being equal.

**Q. HOW DO INVESTORS VIEW UTILITY STOCKS?**

A. In general, investors view utility stocks as a safe-haven investment, particularly during times of uncertainty, because of the industry's defensive fundamentals and high dividend yields. *Value Line Investment Survey* reports that the average dividend yield of the electric utility industry is 3.4%, 130 basis points above the median of all dividend-paying issues in its survey.[20] Thus, utility stocks have performed better than the overall stock market. According to a recent *Standard & Poor's ("S&P") Capital IQ* report, "the S&P 500 Utilities index has increased 3.4% in 2022 through August, outperforming the S&P 500's 17% decline against a backdrop of mixed economic data

[18] *Defense Spending by State: Fiscal Year 2020*, U.S. Department of Defense, Office of Local Defense Community Cooperation, at 38. Defense Spending by State, Fiscal Year 2020 (oldcc.gov).
[19] *Id*.
[20] *Electric Utility (East) Industry*, Value Line Investment Survey, August 12, 2022, at 131.

high but slowing inflation and tepid retail sales. The Dow Jones Industrial Average and Nasdaq Composite indexes are down 13.3% and 24.5%, respectively."[21] Also, Southern Company's stock value increased by 13.4% from January 1, 2022 to September 20, 2022. Mr. Coyne acknowledged that utilities have done better than the overall market this year due to this flight to safety.[22]

## IV. RATE OF RETURN AND CAPITAL STRUCTURE

**Q. PLEASE SUMMARIZE THE PROCESS OF ESTIMATING THE COMPANY'S COST OF CAPITAL.**

A. The overall cost of capital is comprised of the costs of long-term debt and equity capital. The first step in estimating the cost of capital is to determine the appropriate capital structure. Long-term debt costs are computed using the Company's actual embedded costs for a certain time period (e.g., the test year ending July 31, 2023). Unlike the debt component of the capital structure, the equity cost rate must be estimated. The overall WACC is computed by weighting individual costs of debt and equity capital by their respective proportions of total capitalization and summing the result.

The capital structure is important because investors may view a high reliance on debt as risky (referred to as financial or leverage risk). Investors may view a high reliance on debt as risky because it can contribute to earnings volatility. This can thereby lead to a higher required ROE relative to similar investment opportunities. However, excessive equity, while reducing financial risk, may increase the overall cost of capital (and therefore return on rate base) for customers.

[21] *Utilities outperform most S&P 500 sectors in August, expanding valuation premium*, S&P Capital IQ, September 9, 2022, at 1.
[22] Tr. at 0719:14 - 0720:15 (Coyne Cr.) (Sept. 28, 2022).

**Q. WHAT CAPITAL STRUCTURE AND COST OF DEBT IS GEORGIA POWER REQUESTING FOR USE IN THIS CASE?**

A. The Company is requesting a regulated capital structure of 55.82% common equity and 44.18% long-term debt for establishing new return rates in this case.[23] Based on this capital structure—a proposed embedded cost of long-term debt of 3.53% and an ROE of 11.0%—Georgia Power is requesting that the Commission provide the Company an opportunity to earn an ROR of 7.70%.[24]

The Company's adjusted and estimated total capitalization of $35,954,497,000 for the average of the 13-month period ending July 31, 2023 includes $19,954,803,000 in common equity, less other comprehensive income and long-term debt of $15,793,694,000.[25] The long-term debt component includes $1,997,810,000 in Pollution Control Bonds; $9,075,087,000 in Senior Notes; $4,831,107,000 in U.S. Department of Energy loans; and $304,918,000 in Power Purchase Agreement Capitalized Leases; less a series of gains and losses associated with debt issuances and reacquired debt and hedges totaling $415,227,000.[26]

**Q. WHAT IS THE BASIS OF THE COMPANY'S PROPOSED COST OF LONG-TERM DEBT OF 3.53%?**

A. Georgia Power's proposed cost of long-term debt of 3.53% is the Company's estimated average for the 13-month period ending July 31, 2023.[27]

**Q. DOES THE COMPANY USE THE 3.53% COST OF DEBT FOR EVERY YEAR OF THE ARP?**

[23] GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedules 2 and 3, WP1).
[24] GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedule 2, WP1).
[25] GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedules 2 and 3, WP1).
[26] GPC Exhibit 3 (APA/SPA/ADH/MBR-3, Schedule 3, WP3 and WP4).
[27] GPC Exhibit 3 (APASPA/ADH/MBR-3, Schedule 2, WP1).

A. No. As shown in GPC Exhibit 3 (APA-SPA-ADH-MBR-3, Schedule 2, Workpapers 1-4), the Company is proposing to increase both the amount of long-term debt and the cost of long-term debt for each of the years of the ARP (i.e., the periods ending December 31, 2023; December 31, 2024; and December 31, 2025). For ratemaking purposes, the Company is proposing to use a cost rate of 3.53%, 3.58%; and 3.66%, respectively, for these periods.

**Q. DO YOU RECOMMEND THAT THE COMMISSION ACCEPT THE COMPANY'S REQUESTED LONG-TERM COST OF DEBT?**

A. No. While I agree that Georgia Power's proposed cost of debt for the test year is reasonable, market and economic indicators do not support the increasing cost of debt proposed in the Company's ARP. In its cost of debt for the ARP, the Company is assuming that interest rates on long-term debt will increase over the next three years. However, long-term interest rates in general may pivot after reaching a peak. As mentioned earlier in my testimony, investors are anticipating that the rate of inflation is expected to stabilize at a slightly higher rate than the FOMC's goal of 2.0%, which may further feed fears of a sustained economic downturn on the horizon. In turn, investors are expecting the FOMC to pivot its monetary policy from increasing its short-term interest rate to maintaining or even decreasing such a rate. Moreover, long-term debt costs are also tied to these expectations of a sustained economic downturn, which are currently at or below short-term interest rates. During the ARP period (through December 31, 2025), the cost of long-term debt for the Company could remain relatively stable, could decrease, or could increase. At this time, these costs are unknown. Therefore, allowing the Company an increase in debt costs over the next three years will expose ratepayers to increasing costs. I recommend that, for purposes

of the ARP, the Commission order the Company to use the cost of long-term debt for the test year (i.e., 3.53%).

## V. COST OF COMMON EQUITY CAPITAL

**Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ROE?**

A. For ratemaking purposes, the cost of equity must be estimated because it cannot be directly observed, and it varies with changing expectations of financial market conditions. The cost of equity is the long-term annualized market return investors (in general) expect when they purchase equity shares of a particular company. It reflects the risk factors of that investment as compared to alternative investment opportunities and to investors' current opportunity cost of investing in the securities of that company (i.e., the investors' risk-adjusted alternatives).

Because Georgia Power is a wholly-owned subsidiary of Southern Company and is not a publicly traded company, it is not possible to directly apply cost of equity models to the Company. As an alternative, I calculate an estimate of Georgia Power's cost of equity by deriving average expected market returns for a proxy group of regulated electricity companies with comparable risk.

**Q. PLEASE BRIEFLY DESCRIBE HOW MR. COYNE CHOOSES THE COMPANIES FOR HIS UTILITY PROXY GROUP.**

A. Mr. Coyne begins with a group of 36 investor-owned domestic electric utilities covered by *Value Line*. He then applies a series of criteria for his utility proxy group, which includes companies that consistently pay quarterly cash dividends; maintain an investment grade long-term credit rating (BBB- or higher rating from S&P), have positive earnings growth; own regulated electric generation assets; no recent (within six months) involvement in a merger or other transformative transaction; and 60% of

revenue and net operating income from regulated operations and 80% from regulated electric operations from 2019 to 2021.[28] He also excludes Southern Company to avoid the circular logic that would otherwise occur from including the parent company in the proxy group.

**Q. DO YOU MAKE ANY CHANGES TO MR. COYNE'S UTILITY PROXY GROUP?**

A. No. I use Mr. Coyne's utility proxy group because the companies in his proxy group meet criteria that I would have employed, such as a credit-rating criteria that require companies in the sample to have an investment-grade credit rating. The majority of companies in his proxy group have an A- or BBB+ S&P credit rating.[29] I typically also require companies in my sample to have no ongoing involvement in a major merger or acquisition, and no cuts in dividend payments during the past six months; and the companies in Mr. Coyne's proxy group meet these criteria as well. I typically exclude firms involved in any significant merger or acquisition activity because the market values of such firms differ significantly from those companies not involved in such activities. This difference would be reflected in a company's stock price and dividend yields, which would distort the estimated cost of equity. I also exclude companies that have recently cut dividend payments to shareholders because such a management decision is usually perceived by investors as a sign of financial distress.

**Q. PLEASE DESCRIBE GEORGIA POWER AND ITS OPERATIONS.**

A. Georgia Power distributes its own generated power to 2.7 million retail and wholesale customers throughout Georgia.[30] The Company owns 14,541 megawatts of regulated

[28] Tr. at 0650:1-19 (Coyne Dir. at 22) (Sept. 28, 2022).
[29] *See* Exhibit_(MLR-4).
[30] Tr. at 0649:16-23 (Coyne Dir. at 21) (Sept. 28, 2022).

generation assets, including nuclear, coal, oil, gas, hydroelectric, and solar generation facilities.[31]

**Q. PLEASE DISCUSS THE DIFFERENT TYPES OF RISK THAT A REGULATED MONOPOLY, SUCH AS AN ELECTRIC UTILITY, MAY FACE.**

A. An investor's expected return on an investment is composed of the risk-free rate and different types of risk, to include inflation risk, interest rate risk, business risk, financial risk, and regulatory risk.

The risk-free rate is the level of return investors can achieve without assuming any risk. In general, most investors agree that a U.S. Treasury bond is an asset perceived by the market as having relatively less risk than other market instruments because the federal government's access to tax proceeds to fulfill its debt obligations and strong credit rating makes Treasury securities practically default-free. However, Treasury bonds are not absolutely risk-free because they incorporate a risk premium associated with interest rate risk, which is the premium investors require to compensate them for the forgone opportunity cost of an alternative, higher interest rate later.

Inflation risk, also called purchasing power risk, is the chance that the cash flows from an investment will not be worth as much in the future because of changes in purchasing power due to inflation.

Interest rate risk is the risk that arises for investors from the variability in returns caused by fluctuating interest rates, which depends on how sensitive an asset's price is to interest rate changes in the market. For bonds, for example, its sensitivity depends on the bond's time to maturity and the coupon rate of the bond.

[31] *Id.*

Business risk, as perceived by investors, includes all the operating factors that increase the probability that expected future cash flows accruing to investors may not be realized. Business risk would include such factors as sales volatility and operating leverage. A utility's business risk is a function of factors such as customer base diversity, necessary capital expenditures, the regional and national economy, and the regulatory environment in which the utility operates.

Financial risk relates to the capital structure of a company, including its fixed contractual obligations and ability to pay interest on its debt and refinance that debt when it is due. Credit-rating agencies assess the financial health of a company through the use of key financial ratios that measure the extent to which a company can pay its debt, including principal and interest. Corporate rating designations that are commonly used are shown in Table 4, which identifies rating categories used by S&P, Fitch Ratings, Inc. ("Fitch"), and Moody's for investment grade issuances.

**Table 4. Rating Categories (Investment Grade)**

| S&P and Fitch | Moody's |
|---|---|
| **AAA** | Aaa |
| **AA+** | Aa1 |
| **AA** | Aa2 |
| **AA-** | Aa3 |
| **A+** | A1 |
| **A** | A2 |
| **A-** | A3 |
| **BBB+** | Baa1 |
| **BBB** | Baa2 |
| **BBB-** | Baa3 |

One of the key financial ratios used by credit-rating agencies is the debt ratio. The higher the portion of the capital structure that is comprised of debt or leverage, the higher the risk of default on those debt obligations.

Regulatory risk is based on the investor's perceived understanding of the current regulatory environment along with possible changes to that regulatory environment. How regulators treat regulatory lag is one example of regulatory risk. To the extent that companies face a time lag between incurring expenses and cost recovery, such risk is best measured by choosing a proxy group of companies that face similar regulatory oversight and earn the majority of their revenues from regulated operations.

**Q. IN YOUR VIEW, DOES GEORGIA POWER FACE GREATER INFLATION RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?**

A. No. As mentioned previously, the risks associated with current inflation trends are shared by all businesses and, as a result, are reflected in my proxy group's calculated costs of equity.

**Q. IN YOUR VIEW, DOES THE COMPANY FACE GREATER FINANCIAL RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?**

A. No. Georgia Power does not face greater financial risk than the proxy group of regulated electric utilities, because it has similar issuer credit ratings to the proxy group. Specifically, Georgia Power has an S&P issuer credit rating of BBB+, a Moody's issuer credit rating of Baa1, and a Fitch issuer debt rating of BBB.[32] Moreover, Georgia Power's proposed debt to total capital of 44.18% is lower than the proxy group's debt to total capital ratio average of 53.61%.[33]

**Q. IN YOUR VIEW, DOES THE COMPANY FACE GREATER BUSINESS RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?**

A. No. The fundamental comparison here is to the sample group; I see nothing particularly unique that would demonstrate conclusively that Georgia Power has greater business

[32] Tr. at 0789:12-26 – 0790:1-18 (Fetter Dir. at 4-5) (Sep. 28, 2022).
[33] *See* Exhibit_(MLR-4).

risk than its peers in the sample group. Every utility is different, but compared to the sample, the Company has similar business risk.

**Q. DO THE COMPANY WITNESSES IDENTIFY OTHER TYPES OF BUSINESS RISK?**

Yes. Mr. Coyne summarizes a series of S&P reports that identify the cause of recent utility downgrades due to weak financial measures and environmental, social, and governance ("ESG") related risks.[34] Mr. Coyne also mentions that Georgia Power is projecting a capital spending program through 2026 that will require the Company to maintain continuous access to capital markets.[35] As I will address in greater detail later in my testimony, the Company addresses ESG and other risks through a series of adjustment clauses, its ARP, and earnings band. Furthermore, the Company has consistently earned an ROE that either meets or exceeds its earnings band and maintains a lower debt ratio than the proxy group.

**Q. IN YOUR VIEW, DOES THE COMPANY FACE GREATER REGULATORY RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?**

A. No. In its current filing, the Company is requesting to continue an ARP that was last approved in the Company's 2019 rate case and is similar to the ARP Georgia Power has had in place since 1995. The specific ARP involves two step increases during a three-year period. The Company requests increases of $889 million, $107 million, and $45 million to become effective January 1, 2023, January 1, 2024, and January 1, 2025, respectively.[36] The proposed rate adjustment includes levelized increases of $762 million for traditional base rates and $5 million for the traditional costs of the Environmental Compliance Cost Recovery ("ECCR") tariff, effective January 1, 2023.

[34] Tr. at 0644:5-23 (Coyne Dir. at 16) (Sept. 28, 2022).
[35] *Id*. at 0670:4-17.
[36] Rate Case Supplemental Filing Letter dated August 22, 2022, at 3.

As directed by the Commission, the Company's base rates will be separately adjusted to account for the cost recovery of Plant Vogtle Units 3 and 4 per Docket No. 43838 and following the prudence review as provided in the Vogtle VCM 17 Order.[37]

For each year 2023 through 2025, the Company requests recovery of the Coal Combustion Residuals Asset Retirement Obligation ("CCR ARO") compliance costs through annual increases in the ECCR tariff through required annual compliance filings. Therefore, the CCR ARO compliance costs are not included in the proposed levelized ECCR tariff amount over the three-year ARP period.[38]

Similarly, the Demand Side Management ("DSM") tariffs will be adjusted annually to collect the Commission-approved DSM costs addressed in Georgia Power's DSM certification proceeding in Docket No. 44161 ("2022 DSM Certification"). The Company will also continue the true-up of actual revenues collected and expenses incurred under the DSM tariffs through required annual compliance filings. Therefore, like the CCR ARO compliance costs, the proposed costs to be recovered through the DSM tariffs are not levelized over the three-year ARP period. The annual changes in the ECCR and DSM tariffs will have a corresponding effect on the Municipal Franchise Fee ("MFF") tariffs in 2024 and 2025.[39]

**Q. IS THE REDUCTION IN REGULATORY RISK ASSOCIATED WITH THESE NON-BASE RATE TARIFFS ALREADY INCORPORATED IN YOUR ROE ESTIMATES?**

A. No. I use Mr. Coyne's proxy group, which includes utilities from across the U.S. with different state regulatory regimes that may or may not include rate adjustment riders, clauses, or mechanisms that are like the ECCR and DSM tariffs. Regulatory Research

[37] Tr. at 204:11-14 – 205:1-2 (Abramovitz, Adams, Houston and Robinson Dir. at 9-10) (Sept. 27, 2022).
[38] *Id*. at 205:3-9.
[39] *Id*. at 205:16-21.

Associates ("RRA") reports that Georgia Power is one of the 13% of utilities in the United States that has an adjustment clause for traditional generation cost recovery.[40] In this case, the adjustment clause is the nuclear construction cost recovery tariff that enables the Company to earn a cash return on construction work in progress related to Vogtle Units 3 and 4. The report also shows that Georgia Power is one of the 28% of utilities in the nation with an adjustment clause that allows for the recovery of environmental compliance costs in between general rate cases.[41]

**Q. WHAT OTHER GEORGIA POWER-SPECIFIC CHARACTERISTICS REDUCE REGULATORY RISK?**

A. Investors consider Georgia's regulatory environment to be significantly less risky compared to other states. S&P's RRA Regulatory Focus considers Georgia as "Above Average/2," a ranking awarded to a select few states.[42] According to RRA, Georgia finds itself in the minority of state jurisdictions (23%) that use a forecasted test year, and one of less than half of states with a multi-year rate plan. Also, Georgia is one of less than half of states with earnings sharing, whereby Georgia Power is currently allowed an ROE within a band of 9.5% to 12%, which was approved by the Commission in the 2019 base rate case.[43] If Georgia Power's actual ROE is greater than 12%, the Company is permitted to keep 20% of the overearnings and customers receive 80% of revenues. Due to Georgia's constructive regulatory environment and low regulatory risk, Georgia Power has consistently earned actual ROEs within or above

[40] *Regulatory Focus Topical Special Report, Adjustment clauses: A state by state overview*, Regulatory Research Associates, S&P Global Market Intelligence, July 18, 2022, at 4 and 18-19.
[41] *Id.*
[42] Georgia shares the "Above Average/2" with Florida, Pennsylvania, and Wisconsin. All four states are ranked below only Alabama, which has the ranking title of "Above Average/1." *Regulatory Focus-Quarterly State Regulatory Evaluations*, Regulatory Research Associates, S&P Global Market Intelligence, October 15, 2022, at 7. See also Tr. at 0681:6-20 (Coyne Cr.) (Sept. 28, 2022).
[43] Tr. at 208:1-12 (Abramovitz, Adams, Houston and Robinson Dir. at 13) (Sept. 27, 2022).

this band in recent years. Specifically, the Company's actual ROE was 11.89% in 2019 and 12.09% in 2020.[44]

**Q. HOW DO INVESTORS VIEW REGULATED MONOPOLIES LIKE ELECTRIC UTILITIES?**

A. According to *Value Line*, equities in the electric utility industry have fared far better than the broader market averages of late; thus, this industry is living up to its reputation as a defensive haven. Electric utility stocks have historically been known for their earnings predictability, good dividend growth and low-price volatility. Therefore, investors are willing to pay higher stock values for these types of stocks.[45]

## VI. METHODOLOGIES

**Q. WHAT METHODOLOGIES DO YOU USE TO DERIVE YOUR COST OF EQUITY RECOMMENDATION?**

A. I use variants of the Constant-Growth DCF model to form the basis of my recommendation of a 9.47% ROE for Georgia Power.

**Q. WHAT IS THE PREDOMINANT ROE MODEL UTILIZED BY REGULATORY BODIES IN THE UNITED STATES?**

[44] Order on Georgia Power Company's 2020 Annual Surveillance Report, Docket No. 42516, dated July 22, 2021. *See* also Summary Report on Georgia Power Company's 2021 Annual Retail Surveillance Report, issued July 8, 2022, at 3. "Similar to the ASR for the 12 months ended December 31, 2020, the Company's 2021 ASR filing omits making an adjustment to remove stock-based compensation expense that had been made in previous ASRs until 2019. As discussed below, if an adjustment to remove stock-based compensation expense was made for 2021, the ASR results would be an equity return of 12.29%, which is above the top end of the earnings range and above the 12.09% reported by GPC in its 2021 ASR filing. If an adjustment to remove stock-based compensation expense was made for 2021 on a retail jurisdictional basis, the Company would have earnings of 12.29% ROE, and excess revenues of $47.542 million. Approximately 40%, or $19.017 million would be applied to regulatory assets related to CCR ARO, 40% or $19.017 million would be refunded to ratepayers, and 20%, or $9.508 million would be retained by the Company. The refund to ratepayers would be $13.350 million more ($19.017 million vs. $5.667 million if the adjustment to remove stock-based compensation expense had continued to be made)."

[45] *Electric Utility (Central) Industry*, Value Line Investment Survey, June 10, 2022.

A. For decades, the Federal Energy Regulatory Commission ("FERC") and public utility commissions across the United States have relied primarily on the DCF model to develop a range of returns earned on investments in companies with corresponding risks for purposes of determining the ROE for regulated entities.[46] Although I use variants of the Constant-Growth DCF model, the CAPM and Empirical CAPM ("ECAPM"), and the Comparable Earnings Model ("CEM") to provide an average ROE of 9.38%, I rely on my Constant-Growth DCF to form the basis of my recommendation of a 9.47% ROE for Georgia Power.

**A. <u>Constant-Growth Discounted Cash Flow Model</u>**

**Q. PLEASE DESCRIBE THE CONSTANT-GROWTH DCF MODEL.**

A. The Constant-Growth DCF model is based on the dividend discount model first proposed by J.B. Williams in 1938.[47] The model is based on the premise that since cash dividends are the only income from a share of stock held to infinity, the value of that stock will be the present value of its stream of dividends, where the discount rate is the market's required return. The model can be modified to take into account the (more common) situation whereby shares of stock are bought and sold, producing capital gains income in addition to dividend income. In order to simplify the mathematics of the model, expected future dividends are represented by applying a constant growth rate to the current observable dividend. Mathematically, the present value of an asset (common stock) is expressed as:

$$P_0 = \frac{D_1}{(K-g)},$$

Where:

[46] FERC has recently stopped relying solely on the Two-step DCF since issuing the Coakley Briefing Order on October 16, 2018. Jim O'Reilly, *FERC and Electric ROEs – 2022 Update: Recently concluded cases*, RRA Regulatory Focus, S&P Global Market Intelligence, at 5.
[47] J.B. Williams, *The Theory of Investment Value* (1938), at 45-48.

$D_1$ is the dividend payment in one year from today or the expected dividend;
$K$ is the rate of return used by investors to discount future dividends; and
$g$ is the growth rate of the dividend payment.

The estimated cost of equity, $K$, is specified as:

$$K = \frac{D_1}{P_0} + g \ ,$$

Where:

$D_1$ is the expected dividend, represented by $D_1 = D_0 (1 + g)$,

Where:

$D_0$ is the current annual dividend per share.

Therefore, the market ROE capital is the sum of the dividend yield (anticipated dividend payments divided by the market price) and the expected growth in dividend income.

**Q. PLEASE DESCRIBE HOW YOU DERIVE THE DIVIDEND YIELD COMPONENT OF YOUR DCF ANALYSIS.**

A. The dividend yield in my DCF analysis is the annual dividend per share over the next 12 months, divided by the stock price average for different historical periods ended August 31, 2022. I first calculate my dividend yields using the 30-day average of closing stock prices. I also use a 90-day average of closing stock prices for capturing longer market trends.

In general, the most recent price of a security can be used to calculate the dividend yield because it represents current valuations in equity markets, calculating an average over time to mitigate any irregularities as necessary; however, using the average of a range of dates (e.g., 30 and 90 days) helps reduce the bias that might occur from day trading-driven irregularities or short-term volatility. The average 30-calendar

day stock price for my sample is $78.69 per share, which is more than the 90-calendar day average stock price of $75.32 per share.[48]

I then estimate the expected dividend yield by applying the growth rate component of my Constant-Growth DCF analysis. I use three variants for calculating the growth rate component that I will discuss later in my testimony. These methods produce a range of expected (year-ahead) dividend yields from 3.37% to 3.54% using my sample.[49]

**Q. PLEASE DESCRIBE THE GROWTH RATE COMPONENT OF YOUR DCF ANALYSIS.**

A. My first set of growth rates is based on published earnings per share ("EPS") forecasts because investors typically view earnings growth as an indicator of future dividend growth. Investors also incorporate other sources of information when setting their expectations of dividend growth, which I will discuss shortly.[50]

I calculate the estimated earnings growth rates by taking the average of analysts' forecasts (which typically cover roughly the next five years) from *Value Line*, Yahoo Finance, Zacks, and CNN Money. The Yahoo Finance, Zacks, and CNN Money websites, which are publicly available, report results incorporating forward-looking surveys of securities analysts' EPS projections. *Value Line*, in contrast, uses a historical base period average value for 2019-2021 and a forecast of 2025-2027 to calculate its growth rates, and is not a survey. The average expected earnings growth rate using my sample of companies is 5.77%.[51] When I use only expected EPS growth rates, my proxy group median DCF results range from 9.35% to 9.47%.

[48] *See* Exhibit_(MLR-5a) through Exhibit_(MLR-6f).
[49] *Id*.
[50] J.B. Williams, *The Theory of Investment Value* (1938), at 47.
[51] *See* Exhibit_(MLR-5a) and Exhibit_(MLR-5c).

I also develop an alternative growth rate by averaging *Value Line's* dividends per share ("DPS") and book value per share ("BVPS") estimates with the previously estimated earnings growth rate projections weighted equally. I include these three components of growth in my alternative analysis because investors are not only concerned with dividend growth but also earnings and book value growth as an assurance that dividend growth will be sustained. Moreover, dividend growth rates are more stable than expected earnings growth. These calculations produce an average growth rate of 5.27%.[52]

**Q. DO YOU REACH THE SAME RESULTS AS MR. COYNE? IF NOT, WHY DO YOUR RESULTS DIFFER FROM HIS RESULTS?**

A. No. Mr. Coyne only uses EPS growth rates in his DCF analysis that range from 7.99% to 9.99%. When I use only expected EPS growth rates, my proxy group median DCF results range from 9.35% to 9.47%. However, when I incorporate DPS, BVPS and EPS growth estimates in my Constant-Growth DCF, my results range from 8.82% to 8.98%.

**B. <u>Sustainable-Growth Discounted Cash Flow Model</u>**

**Q. DO YOU EMPLOY OTHER METHODS TO DERIVE GROWTH RATES IN YOUR DCF MODEL?**

A. Yes. I also use the sustainable growth method to estimate the rate of dividend growth. The standard DCF model assumes only one source of equity financing, namely the retention of earnings. Growth in earnings and dividends, however, can also be achieved by the sale of new common equity.[53] The basic Constant-Growth DCF model of:

[52] *See* Exhibit_(MLR-5b) and Exhibit_(MLR-5d).

[53] This expanded version of the DCF model allows for the value of stocks to vary from book values. If the stock prices equal book value, then the equity held by new shareholders is equal to the funds they invest and the existing shareholders' equity is not changed. If, however, stock prices are greater than book value, a portion of the funds accrues to the existing shareholders, thereby increasing their expectations of dividend growth in the future. See David Parcell, *The Cost of Capital – A Practitioner's Guide* (2010), at 144-145.

$$K = \frac{D_1}{P} + g$$

can be rewritten to assume that external sources of financing influence investor expectations of dividend growth and is represented as the following:

$$K = \frac{D_1}{P} + br + sv$$

Therefore:

$$G = br + sv,$$

Where:

*G* is the retention growth rate;
*r* is the earned rate of return;
*b* is the portion of retained earnings or 1 minus payout ratio;
*s* represents the funds raised from the sale of stock as a fraction of existing common equity; and
*v* is the fraction of funds raised from the sale of stock that accrues to current shareholders.

I use *Value Line* expectations regarding retention ratios and ROEs for five years into the future to derive estimates for *b* and *r*, which in turn are used to calculate the expected internal growth component, *br*. To incorporate external financing growth, *sv*, I use *Value Line* data to derive the market-to-book ratio (which is an actual, observed figure) and expected growth in the number of outstanding shares. The average sustainable growth rate for my proxy group is 4.98% (30-day stock prices) and 4.91% (90-day stock prices).[54]

**Q. DO YOU APPLY A REASONABLENESS SCREEN TO YOUR INDIVIDUAL ROE RESULTS USING THE DCF METHOD?**

A. Yes. After adding the growth-rate estimate and the dividend-yield estimates for each company in my proxy group to obtain the individual ROE estimates, I examined my results for reasonableness. In lieu of relying on the average of my proxy group results

[54] *See* Exhibit_(MLR-6c) and Exhibit_(MLR-6f).

for each model, I use the median. The median is the middle value of a set of data and is not skewed by outliers.

**Q. PLEASE SUMMARIZE YOUR DCF MODEL RESULTS.**

A. As shown in Table 5, I employ three different methods for deriving the growth rate in the DCF model, yielding three sets of estimates of the ROE for my proxy group. First, I use the Constant-Growth DCF model using only EPS growth rates. When I assume that investors are only concerned with earnings growth when valuing a company's stock, thereby only using EPS growth in the DCF model, I derive ROE estimates of 9.35% (30-day stock prices) and 9.47% (90-day stock prices).[55]

Second, I use the Constant-Growth DCF model using EPS, DPS, and BVPS growth rates. Once I allow for other sources of growth, such as DPS and BVPS growth rates, to influence investors' expectations of the return on a particular equity, my analyses yield lower results. For instance, adding DPS and BVPS growth rates results in median ROE estimates of 8.82% (30-day stock prices) and 8.98% (90-day stock prices).[56]

Third, I use the sustainable-growth DCF model. When I allow for both internal and external funding sources to drive growth in investor income, for my sustainable growth rate model, I derive median ROE results of 8.15% (30-day stock prices) and 8.18% (90-day stock prices), after adjusting for reasonable growth rates.[57] The overall range of ROE estimates using my DCF is 8.15% to 9.47%, with an average of 8.69%.

[55] *See* Exhibit_(MLR-5a) and Exhibit_(MLR-5c).
[56] *See* Exhibit_(MLR-5b) and Exhibit_(MLR-5d).
[57] *See* Exhibit_(MLR-6c) and Exhibit-(MLR-6f).

| Table 5. Reno Constant Growth DCF Results (Median Results) | | | |
|---|---|---|---|
| **Estimated Return on Equity** | | **ROE** | |
| DCF Methodology | 30-Day Stock Price | 90-Day Stock Price | Average |
| Constant Growth DCF (EPS Growth) | 9.35% | 9.47% | |
| Constant Growth DCF (DPS, EPS and BVPS) | 8.82 | 8.98 | |
| Sustainable Growth DCF | 8.15 | 8.18 | |
| **DCF Range** (Min. & Max.)[1] | **8.15%** | **9.47%** | **8.81%** |

[1] ROE range (minimum and maximum values) for the 30-day and 90-day DCF results.

**Q. DO YOU REACH THE SAME RESULTS AS MR. COYNE? IF NOT, WHY DO YOUR RESULTS DIFFER FROM HIS RESULTS?**

A. Table 5 above shows my proxy group median DCF results that range from 8.15% to 9.47% with an average of 8.81%. These results are similar to Mr. Coyne's DCF results using his "mean" earnings growth rates that range from 8.88% to 9.09%.

**Q. DOES YOUR METHODOLOGY FOR CALCULATING THE DCF GROWTH RATE DIFFER FROM THAT OF MR. COYNE?**

A. Yes. The major differences in our Constant-Growth DCF methodologies are that Mr. Coyne relies on earnings growth rates and calculates his ROE estimates using growth rates based on his lowest ("Mean Low"), average ("Mean"), and highest growth rates ("Mean High"). Applying Mr. Coyne's methodology of using a growth rate comprised of only EPS growth yields over the 30-day and 90-day periods is consistent with my analysis, which generates ROE results of 9.35% and 9.47%, respectively, as shown above in Table 5. However, because the DCF estimate is derived from the concept that cash dividends are the only income from a share of stock, in principle, the growth component should only include dividends. Investors, however, are also concerned about whether dividends are sustainable, and they realize that dividend growth sustainability is affected by earnings and book value growth. As a result, investors may not necessarily use a single growth estimate when valuing a utility's stock. Therefore,

I believe it appropriate to include other measures for the growth component in my analysis

**Q. WHY ARE MR. COYNE'S DCF GROWTH RATES PROBLEMATIC AND WHAT EFFECT DO THEY HAVE ON HIS DCF RESULTS?**

A. Mr. Coyne's Constant-Growth DCF analysis places great weight on results derived using the highest growth rates, thereby inflating his overall DCF-based results. Specifically, Mr. Coyne calculates a series of Mean Low ROE, Mean ROE, and Mean High ROE estimates, with each using a particular growth rate. For instance, the Mean Low ROE estimate uses only the minimum of his three sets of earnings growth rates that include estimates from *Value Line*, Yahoo Finance, and Zacks, and his Mean High ROE estimate employs the highest growth rate. His Mean ROE estimate uses the mean or the average of all three of his growth rates. For instance, his Constant-Growth DCF yields a range of ROE estimates from 7.99% (Mean Low) to 9.99% (Mean High) while his Mean ROE results range from 8.88% to 9.09%.[58] These results using the Mean growth rates are similar to the average of my DCF results of 8.81%. Despite these results, Mr. Coyne places more weight on the DCF results employing the highest growth rates.

**C. <u>Capital Asset Pricing Model</u>**

**Q. DO YOU USE ANY OTHER METHODOLOGIES TO ESTIMATE THE ROE FOR THE COMPANY?**

A. Yes. Like Mr. Coyne, I apply the CAPM; however, I also employ an ECAPM to derive a total of six ROE estimates.

**Q. DESCRIBE THE CAPM.**

[58] Tr. at 0656, Fig. 7 (Coyne Dir. at 28) (Sept. 28, 2022).

A. The CAPM is a version of the "risk premium" approach that is rooted in modern portfolio theory. It recognizes that common equity capital is riskier than debt from an investor's perspective because debt holders are typically paid before shareholders, and as such, investors require higher returns on stocks than on bonds to be compensated for the additional risk.[59] The cost of common equity is represented by the following equation:

$$K_e = R_f + \beta_s * RP ,$$

Where:

$K_e$ is the cost of equity;

$R_f$ is the yield on risk-free securities;

$RP$ is the equity risk premium ("ERP") demanded by shareholders to accept equity relative to debt; and

$\beta_s$ or Beta coefficient ("Beta") is a company-specific measure that reflects the movement in a company's stock price relative to movements in a composite group of companies representing the stock market. Beta measures the investment risk that cannot be eliminated by holding a diverse portfolio of assets.

**Q. PLEASE DESCRIBE THE RISK-FREE RATE YOU USE IN YOUR CAPM ANALYSIS.**

A. The first term in the CAPM is the risk-free rate ($R_f$). I use the yield on the 30-year Treasury bond observed over a recent 90-day period ended August 31, 2022 of 3.16%, based on recent market information.[60] I also include in one of my CAPM analyses the Kroll (formerly Duff & Phelps) Normalized Risk-Free Rate of 3.50%.[61]

[59] The CAPM is generally superior to the simple risk premium method because the CAPM recognizes the risk of a particular company or industry through the use of betas, whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.
[60] Federal Reserve, *Selected Interest Rates (Daily),* available at https://www.federalreserve.gov/releases/h15/.
[61] *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher, Effective June 16, 2022*, Client Alert, issued June 15, 2022.

**Q. DOES YOUR RISK-FREE RATE DIFFER FROM THE RISK-FREE RATE USED BY MR. COYNE?**

A. Yes. Mr. Coyne uses the forecasted yield on 30-year Treasury bonds for 2023-2027 of 3.40% provided by *Blue Chip Financial Forecasts* ("*Blue Chip*"). He also considers CAPM results applying the 30-day average yield (as of April 30, 2022) on 30-year T-bonds of 2.72%.[62] This 30-day average no longer reflects current market rates of 3.16%, using the 90-day average of the yield on the 30-year Treasury bond, ended August 31, 2022. Mr. Coyne's risk-free rates are also lower than the published forecast of the expected risk-free rate of 3.50% published by Kroll.

**Q. HOW DO YOU CALCULATE THE ERP?**

A. In each of my three CAPM analyses, I use different estimates of the ERP that range from 5.50% to 7.46%. For the high end of this range, I use the Kroll estimate of historical arithmetic average real market return over the period 1926 to 2021, which is the total return on common stocks (S&P 500) including capital appreciation, less the income returns on Treasury bond investments.[63]

Kroll also provides an updated Ibbotson & Chen supply-side model, which found that the market risk premium based on the S&P 500 was influenced by an abnormal experience of price-to-earnings ("P/E") ratios relative to earnings and dividend growth over the last 30 years. Thus, Kroll adjusted this market risk premium and published a long-horizon supply-side ERP of 6.22%.[64]

Kroll also recommends a forward-looking ERP that was derived in conjunction with a normalized risk-free rate. Thus, my final CAPM analysis uses the Kroll

[62] Tr. at 0659:8-11 (Coyne Dir. at 31) (Sept. 28, 2022).
[63] *See* Exhibit_(MLR-7a). *See also* Kroll*, 2022 SBBI Yearbook, Stock, Bonds, Bills and Inflation*, Exhibits 10.8 and 10.9, at 199.
[64] *See* Exhibit_(MLR-7c) and Exhibit_(MLR-7d). *See also* Kroll*, 2022 SBBI Yearbook, Stock, Bonds, Bills and Inflation*, Exhibit 10.14, at 210.

Recommended U.S. ERP of 5.50% and Normalized Risk-Free Rate of 3.50%.[65] Therefore, the estimated ERP used across my three CAPM methods ranges from 5.50% to 7.46%. This range is within the historical range of 5% to about 8% found in the finance literature.[66]

**Q. DO YOU CALCULATE YOUR ERP IN THE SAME WAY AS MR. COYNE?**

A. No. While I rely on historical market return data, Mr. Coyne places greater emphasis on market returns using the S&P 500 Index. Although the S&P 500 is a popular index used by the investment community to estimate overall market returns, Mr. Coyne uses the DCF with forecasted earnings, yielding market returns that overestimate expectations of market risk. Moreover, the stock price and dividend yields are based on the spot price for a single day—April 30, 2022. Therefore, the average total market return from his three data sources (S&P, Bloomberg Professional Services *("*Bloomberg*")*, and *Value Line*) is 15.18%.[67]

**Q. WHY ARE YOU CONCERNED ABOUT MR. COYNE'S TOTAL EXPECTED MARKET RETURNS?**

A. Mr. Coyne's total expected market return estimates are driven upward by his spot price and earnings growth inputs. His estimates far exceed investors' current expectations of equity returns and only serve to inflate his average equity risk premium ("ERP") and resulting ROE estimates. Market analysts have recently stated that the current expectations of annualized U.S. equity market returns range from 5% to 8%. Moreover, the Federal Reserve Bank of Philadelphia reported earlier this year that the average

[65] *See* Exhibit_(MLR-7e) and Exhibit_(MLR-7f). *See also Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher, Effective June 16, 2022*, Client Alert, issued June 15, 2022.
[66] Richard Brealy, *et al.*, *Principles of Corporate Finance,* 2017, at 164.
[67] Tr. at 0661, Fig. 8 (Coyne Dir. at 33) (Sept. 28, 2022).

(mean) forecast of expected stock returns (S&P 500) over the next ten years is 6.91%, with a maximum of 10.4%.[68]

**Q. HOW DO YOU ACCOUNT FOR THE VARIABILITY IN EQUITY MARKETS?**

A. To capture investors' expected equity market returns, I focus on longer trends in stock market returns from 1928 to 2021. This period shows annual stock returns over multiple business cycles, avoiding the influence of any given period.[69]

**Q. HOW DO YOU ADJUST THE EQUITY RISK PREMIUM TO ACCOUNT FOR COMPANY-SPECIFIC RISK?**

A. I multiply company-specific betas by the ERPs to account for company-specific risk. Specifically, I rely on *Value Line* betas because *Value Line* is widely used by the utility regulatory community and investment community in general. It is also known that *Value Line* adjusts its betas to account for the long-term tendencies of stocks to converge to a beta of one (1.0).[70] As a result, *Value Line* betas tend to have higher values than betas provided by some other sources. The average *Value Line* beta for my proxy group is 0.86. A beta value of 0.86 means that the stock price movement is less than the movement, in percentage terms, of the overall stock market. The price of electric utility stock is, therefore, less volatile than the overall market.

**Q. DO YOUR BETA MEASURES DIFFER FROM MR. COYNE'S BETAS?**

A. Yes. Although we both use the *Value Line* electric utility beta coefficients, our proxy group averages differ slightly because Mr. Coyne's data is stale and does not reflect

[68] *Survey of Professional Forecasters: First Quarter 2022* Federal Reserve Bank of Philadelphia at 19, Table 9.
[69] A business cycle typically includes an expansion and a recession that can vary in duration. Visit the following website for more information. US Business Cycle Expansions and Contractions | NBER.
[70] Marshall Blume investigated the regression tendency of betas and reached the conclusion that betas have the tendency to approach a value of one (1) over time. That is, high-beta portfolios tend to decline over time toward one (1), while low-beta portfolios increase to one (1). Marshall Blume, "Betas and Their Regression Tendencies," *Journal of Finance* (1975), at 785-796.

current market conditions. If he were to update his proxy group betas, his average *Value Line* betas would decrease from 0.88 to 0.86. He also uses beta coefficients from Bloomberg, resulting in a proxy group average beta of 0.85.

## D. Empirical Capital Asset Pricing Model

**Q. DO YOU PERFORM ADDITIONAL CAPM ANALYSES?**

A. Yes. The simple CAPM has been criticized for underestimating the ROE for companies with betas less than 1 and overestimating the ROE for companies with betas greater than 1. Therefore, use of the ECAPM has gained popularity as a means to correct this under- or over-estimation problem, by applying an adjustment factor to increase the intercept and reduce its slope.

**Q. PLEASE EXPLAIN THE ECAPM THAT YOU USE IN YOUR ANALYSES.**

A. The ECAPM that I apply includes an adjustment factor "x" as shown in the following modified CAPM equation.

$$K_e = R_f + x(RP) + (1 - x)\beta(RP)$$

Where:

The *x*-term multiplied by the risk premium increases the intercept (the risk-free rate), while (*1-x*) decreases the slope of the equation.

**Q. HOW IS THE VALUE OF x DETERMINED?**

A. "x" is equal to 0.25, such that (1-x) is 0.75. Therefore, the only difference between the traditional CAPM and the ECAPM is that the beta-adjusted ERP is weighted by 0.75, while the market risk premium is weighted by 0.25, resulting in the following equation.

$$K_e = R_f + 0.25(RP) + 0.75\beta(RP)$$

**Q. WHAT ARE THE RESULTS OF YOUR ECAPM ANALYSES?**

A. As shown in Table 6 below, applying the same risk-free rates, market risk premium, and betas from the proxy group, I estimate expected returns ranging from 8.43% to 9.84%.

| Table 6. Capital Asset Pricing Models – Estimated Return on Equity | | | | | |
|---|---|---|---|---|---|
| | ERP | Beta-Adjusted ERP | Risk-Free Rate | CAPM ROE | ECAPM ROE |
| CAPM (Hist. L-T ERP) | 7.46 | 6.42 | 3.16 | 9.58% | 9.84% |
| CAPM (Supply-Side ERP) | 6.22 | 5.35 | 3.16 | 8.51% | 8.73% |
| CAPM (Kroll Recommended ERP) | 5.50 | 4.73 | 3.50 | 8.23% | 8.43% |

**Q. DO YOU REACH THE SAME RESULTS AS MR. COYNE? IF NOT, WHY DO YOUR RESULTS DIFFER FROM HIS RESULTS?**

A. My results, shown in Table 6 above, are lower than Mr. Coyne's CAPM results, which range from 13.34% to 13.75%. His preference for inflated market ERPs exaggerates his CAPM estimates.[71]

**Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING MR. COYNE'S ROE METHODOLOGIES?**

A. Yes. In addition to Mr. Coyne's focus on earnings growth in his DCF, misuse of inappropriate and inflated market equity returns, and resulting estimated proxy group specific returns, as discussed earlier in this testimony, he also incorrectly applies his risk premium model ("RPM").

**Q. HOW DOES MR. COYNE APPLY THE RPM?**

A. Mr. Coyne's RPM is a composite of three models that are based on the concept of adding a premium to a low-risk debt asset like a bond to compensate an investor for assuming risk. He employs a Bond Yield Plus Risk Premium Analysis, which defines the ERP as the difference between the authorized ROE and the yield on 30-year Treasury bonds. He gathers monthly average allowed returns for vertically integrated electric utility rate proceedings between January 1992 and February 2022 and also

[71] Tr. at 0662, Fig. 9 (Coyne Dir. at 34) (Sept. 28, 2022).

calculates the average monthly 30-year T-bond yield over the same period. He then subtracts the T-bond yields from the average allowed returns to derive a monthly risk premium. Mr. Coyne then applies a regression analysis to estimate the relationship between the risk premium (dependent variable) and the risk-free rate (independent variable). He shows that there is a statistical, negative relationship between the 30-year T-bond yields and the ERP—that is, as T-bond yields fall, allowed returns increase. After estimating this relationship, he applies his regression coefficients to estimate his risk premiums using his three different bond yields, and then adds this risk premium to each of those bond yields to estimate his RPM results which range from 9.8% to 10.12%.[72]

**Q. WHAT IS PROBLEMATIC ABOUT MR. COYNE'S RPM MODEL OR BOND YIELD PLUS RISK PREMIUM ANALYSIS?**

A. A problem with Mr. Coyne's Bond Yield Plus Risk Premium Analysis is that he uses historically allowed ROEs as an input to calculate the risk premium and ultimately investors' expected ROEs, which may introduce a circularity problem.

**E. <u>Comparable Earnings Model</u>**

**Q. DO YOU EMPLOY OTHER METHODOLOGIES FOR YOUR ROE ESTIMATE FOR THE COMPANY?**

A. Yes. I use the Comparable Earnings Model ("CEM"). A CEM estimate is derived from the "corresponding risk" standard of the <u>Hope</u> and <u>Bluefield</u> cases and is based on the economic concept of opportunity cost. The cost of capital is an opportunity cost whereby a company's return represents a return available from alternative investments of similar risk. I use the CEM by examining realized ROEs for my proxy group and comparing investor acceptance of these returns via corresponding market-to-book

[72] Tr. at 0665, Fig. 11 (Coyne Dir. at 37) (Sept. 28, 2022).

("M/B") ratios. The M/B ratio is the stock price divided by the BVPS and shows the degree to which a given level of ROE equals the cost of capital. An M/B of greater than one (1) shows that a company can attract new equity capital without dilution.

Using market-based information via the M/B ratios, I show that historical ROEs have attracted investors to purchase shares of utility stock. I calculate historical M/B ratios using average annual stock prices and the *Value Line* reported BVPS data from 2012 through 2021.[73] My results show that the companies in my proxy group were successful in attracting investors, given reported historical, book value-derived ROEs. Even in cases where a company's ROEs were as low as 7.23% (as in the case of Duke Energy Corp.), that company's stock was valued higher than book value, as demonstrated by M/B ratios of greater than one (1) at 1.35. For my proxy group, the median M/B ratio is 1.74 and the median historical ROE is 9.85%. By way of comparison, the median *Value Line* forecasted ROE (2025-2027) for my sample is 10.50%.[74]

**Q. DOES MR. COYNE ALSO EMPLOY THE CEM?**

A. Yes. He relies on the projected ROE for his proxy group companies as reported by *Value Line* for the period 2025-2027. Mr. Coyne then adjusts those projected ROEs to account for the fact that the ROEs reported by *Value Line* are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the entire period. His Expected Earnings analysis results in a mean of 11.03% and a median of 11.08%.[75]

**Q. WHY ARE MR. COYNE'S CEM AND RESULTING ROE ESTIMATES PROBLEMATIC?**

[73] *See* Exhibit_(MLR-8c).
[74] *See* Exhibit_(MLR-8e).
[75] Tr. at 0667, Fig. 12 (Coyne Dir. at 39) (Sept. 28, 2022).

A. Mr. Coyne merely reports the book value returns as reported by *Value Line* when the ultimate goal should be to estimate investors' return expectations for investing in an electric utility stock.

**Q. HOW DO YOUR CEM RESULTS RELATE TO YOUR DCF, CAPM, AND ECAPM RESULTS?**

A. My CEM results demonstrate that my ROE estimates discussed earlier reflect current market expectations and will attract investors.

**Q. WHY IS YOUR ROE RECOMMENDATION OF 9.47% BASED ON A RANGE DERIVED FROM YOUR DCF METHODOLOGIES?**

A. I place more emphasis on my DCF-derived results because it is widely used by both the finance community and public utility commissions across the U.S. and yields more reliable results. It is a forward-looking model that directly incorporates investors' expectations of company dividend income through market pricing signals, particularly in the case of utility stocks where stock valuations are telling a different story than the general market.

The CAPM model, in contrast, is largely reliant on financial market outcomes complicated by monetary policy and near historically low interest rates. These low interest rates have persisted many years longer than originally anticipated. Despite current inflationary trends and recent decisions by the Federal Reserve to increase short-term rates, low interest rates on long-term bonds persist. However, I rely on my CAPM, ECAPM, and CEM results as a reasonableness check. Moreover, my recommendation of 9.47% is further supported by the average of all my models of 9.38%.

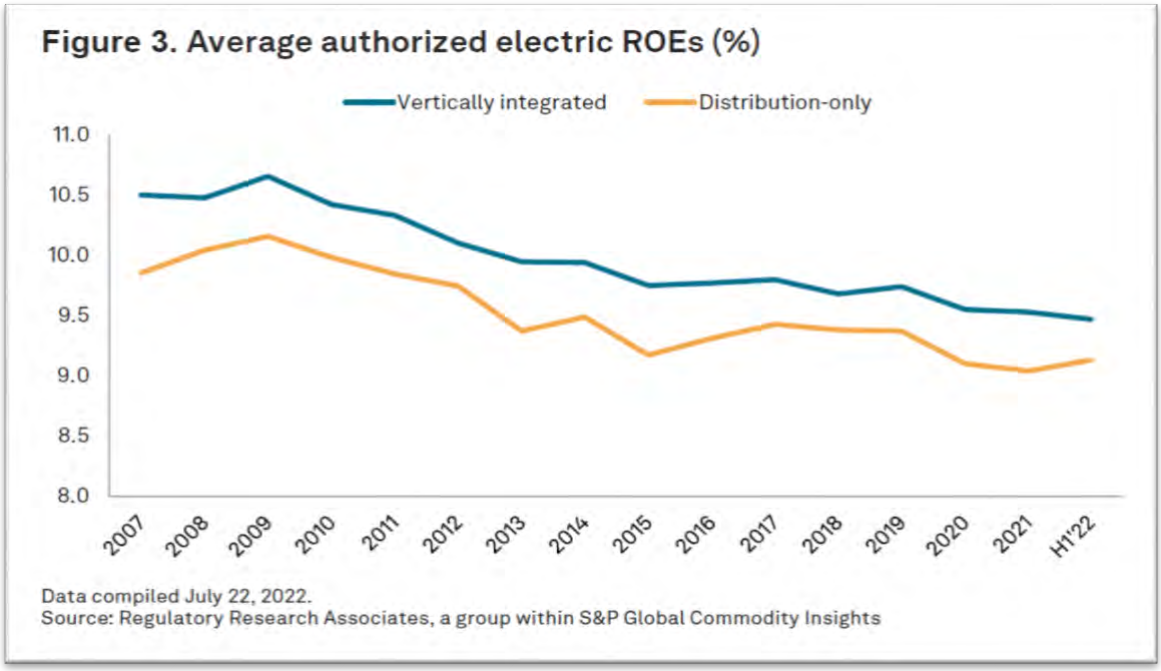
**Q. HOW DOES YOUR RECOMMENDATION COMPARE TO MR. COYNE'S RECOMMENDATION?**

A. My recommendation is based on the maximum of the range of my DCF results and closely matches the average estimates of all my models. In contrast, Mr. Coyne places equal weight on his results using his DCF, CAPM, Risk Premium, and Expected Earnings analyses to determine an average of 10.92% with a range of 8.99% to 13.55%. These results exclude flotation costs.

**Q. HOW DOES YOUR RECOMMENDATION COMPARE TO RECENTLY ALLOWED EQUITY RETURNS?**

A. RRA reports that the average allowed equity return for vertically integrated electric utilities in the first six months of 2022 was 9.46%, slightly lower than the average of 9.53% for 2021.[76] Figure 3 shows that the average allowed ROE for vertically integrated and distribution-only electric utilities has decreased over the last decade and continued to decline over the first half of 2022 (referred to as H1'22). The last time the average was near Mr. Coyne's recommendation of 10.92% (11.0% with flotation costs) was nearly 20 years ago.[77] My recommended ROE of 9.47% is only one basis point higher than the 2022 average allowed ROE for electric utilities. My recommendation is more in line with recent allowed equity returns than Mr. Coyne's recommendation because allowed ROEs in general have been below 11% since 2003.

[76] *RRA Regulatory Focus: Major energy rate case decisions in the US-January-June 2022*, S&P Global Market Intelligence, July 27, 2022, at 8. See also *Major energy rate case decisions in the US,* S&P Global Market Intelligence Excel file, Table 3.
[77] *Id*.




Source: *RRA Regulatory Focus: Major energy rate case decisions in the US-January-June 2022*, S&P Capital IQ, July 27, 2022 at 8.

**Q. HOW DOES MR. COYNE'S RECOMMENDATION COMPARE TO RECENTLY ALLOWED EQUITY RETURNS?**

A. Mr. Coyne's recommended ROE of 11.0% is 154 basis points higher than the average allowed ROE for electric distribution utilities in 2022. As reflected in Figure 3 above, authorized ROEs for electric utilities have been decreasing since the peak reached in 2009. Thus, if the Commission granted Mr. Coyne's recommended ROE, it would be an extreme outlier relative to the average allowed ROE for electric utilities throughout the U.S.

## VII. FLOTATION COSTS

**Q. DOES MR. COYNE'S RECOMMENDATION INCLUDE THE RECOVERY OF FLOTATION COSTS?**

A. Yes, Mr. Coyne modifies his DCF calculations to include a 2.47% allowance for flotation costs.[78] Specifically, in GPC Exhibit 23 (JMC-8.2), he shows how he adjusts the dividend yield of the DCF equation, which he claims would reimburse investors for direct issuance costs. Applying his 2.47% allowance for flotation costs yields an eight-basis point differential when calculating his DCF with the allowance compared to his DCF without the flotation cost allowance. He then applies his eight-basis point result to his other ROE estimates.

**Q. WHAT ARE FLOTATION COSTS?**

A. Flotation costs are the costs associated with the sale of common stock issuances that include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

**Q. WHY DOES MR. COYNE BELIEVE THAT AN ADJUSTMENT TO HIS ROE RECOMMENDATION TO ACCOUNT FOR FLOTATION COSTS IS NECESSARY?**

A. Mr. Coyne states that the allowed ROE is the only ratemaking mechanism through which it is appropriate to recover these necessary costs. Flotation costs are reflected on a utility's balance sheet as "paid in capital" and are not expensed on the utility's income statement. When a company issues common stock, flotation costs are incurred and netted against the proceeds from the issuance, reducing the amount available for investment in rate base by the amount of the flotation costs. If Georgia Power is denied the opportunity to recover its prudently incurred flotation costs through its allowed ROE, actual returns will fall short, and equity share value will be diluted.

**Q. DO YOU AGREE WITH MR. COYNE'S ADJUSTMENT FOR FLOTATION COSTS?**

[78] Tr. at 0668:17 – 0670:1-4 (Coyne Dir. at 40-42) (Sept. 28, 2022).

A. No, I do not. Mr. Coyne's estimate of a flotation cost adjustment is based on a review of other companies' typical flotation costs and academic literature and is not based on the Company or the parent's actual common stock issuance costs.[79] Although proxy group data are used for estimating the ROE for Georgia Power because the Company does not issue stock, when determining flotation costs, one should look to whether Georgia Power's parent company, Southern Company, is planning to issue new stock, and not the proxy group for the flotation costs determination. Inclusion of such flotation costs in the setting of base rates in this case should only be allowed for the public issuance of common stock by Southern Company (and therefore the incurrence of flotation expenses) in the foreseeable future. The setting of the ROE is, after all, a prospective concept.

**Q. DOES SOUTHERN COMPANY PLAN TO ISSUE NEW STOCK OVER THE TEST PERIOD?**

A. No. At hearing, Company witness Mr. Abramovitz confirmed that Southern Company does not currently plan to issue new stock during the 13-month test period.[80] *Value Line* also projects no increase in Southern Company's outstanding shares during the test period ending July 31, 2023, to remain at 1,070 million shares from 2022 to 2023. In fact, *Value Line* projects that the parent will not increase shares over the next five years.[81]

**Q. GIVEN THAT SOUTHERN COMPANY DOES NOT PLAN TO ISSUE NEW STOCK OVER THE TEST PERIOD OR THE FOLLOWING THREE YEARS, WHAT IS YOUR RECOMMENDATION?**

A. I recommend that the Commission reject Mr. Coyne's flotation cost adjustment.

[79] Tr. at 0775 (Coyne Cr.) (Sept. 28, 2022).
[80] Tr. at 0572:12-18 (Abramovitz Cr.) (Sept. 27, 2022).
[81] Southern Company Sheet, *Value Line Investment Survey*, August 12, 2022.

## VIII. SUMMARY AND RECOMMENDATION

**Q. WHAT DO YOU RECOMMEND FOR GEORGIA POWER'S OVERALL ROR AND AUTHORIZED ROE?**

A. For Georgia Power, I recommend an overall ROR of 6.85%, based on an ROE of 9.47%, an embedded cost of long-term debt of 3.53%, and a capital structure comprised of 44.18% long-term debt. As shown in Table 7 below, my ROE recommendation is based on the maximum of my recommended DCF range of 8.81% to 9.47% and represents a fair and reasonable ROE for Georgia Power for the reasons I have previously discussed.

My results are derived using a proxy group of electric utilities representing the opportunity cost of investing in Georgia Power assets. My results best represent the opportunity cost of capital that an investor expects under today's financial circumstances.

BY MS. MEDLYN:

Q Ms. Reno, on October 20th, 2022, did you also cause to be prefiled nine exhibits?

And, for clarification, you one exhibit in Appendix A and you have eight exhibits in your Appendix B?

A Yes.

Q Do you have any corrections to your exhibits?

A No, I do not.

MS. MEDLYN: Okay. I would ask that the exhibits be marked as DODFEA-2 through 10.

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were marked for identification as DODFEA Exhibits 2 through 10.)

BY MS. MEDLYN:

Q Ms. Reno, have you prepared a summary of your testimony?

A Yes, I have.

Q Read it now, please.

A Thank you.

MS. RENO: Good morning, Madam Chair and Commissioners. I'm testifying in regard to Georgia Power Company's request to return on equity, cost to debt, and overall rate of return using my own analysis.

I accept Georgia Power's proposed cost of

long-term debt of 3.53 percent, which is the company's estimated average over the 13-month period ending July 31st, 2023, which is the company's estimated average -- sorry. But I do not support the company's proposed -- proposal to increase the debt costs over the three-year period of the ARP.

I also accept the company's proposed capital structure of 55.82 percent equity and 44.18 percent debt -- long-term debt. But I disagree with the company's recommended return of 7.7 percent and the cost of common equity of 11 percent.

This recommendation by the company's witness, Mr. Coyne, is overstated based on his use of inputs with an upward bias. I also do not support his use of flotation costs that further increase his results.

Thus, I recommend an overall rate of return of 6.85 percent based on my common -- excuse me -- my recommended return on equity of 9.47 percent and embedded cost of long-term debt of 3.53 percent, and the company's proposed capital structure.

In determining my recommended return, I studied the current near term and forecasted financial markets. I also examined national and regional economic trends to assess investors' opportunity costs of investing in a share of a utility's stock,

also known as the cost of equity capital.

Investors are anticipating a sustained economic downturn in the near future. However, the Federal Reserve is more focused currently on controlling inflation and has reacted in kind by increasing the federal fund rate six times this year.

Therefore, short-term interest rates are expected to increase in the near term and we've seen this over -- so far this year.

In contrast, however, long-term interest rates, which incorporate investors' expectations of an economic downturn and inflation, are not moving in kind with short-term bond rates. Investors are responding to the volatility in financial markets and inflation by seeking more longer-term treasury bonds and also defensive stocks, such as -- such as utilities where such companies are providing a need to a captive customer base.

My cost of equity analysis employs Mr. Coyne's proxy group since I would have employed the same proxy group criteria.

My recommended ROE, return on equity, as I just stated before is 9.47 percent. It is the maximum of my range of my discounted cash flow results. This range is 8.81 percent to 9.47 percent.

I also estimate the average of all my models results and I include variants of the constant growth discounted cash flow model, the capital asset pricing model, the empirical capital asset pricing model, and the comparable earnings model to further support my recommendation.

These are the same models that the company's witness Mr. Coyne has used. And the average of all these results yield ROE estimates using these models of just 9.38 percent.

To get into further detail about these specific models, the discounted cash flow model has two components; the expected dividend yield and the growth rate. I calculate the dividend yield for each company in Mr. Coyne's proxy group by dividing the annual -- the annualized dividends by the average stock price for both 30 days, 90 days ending August 31st, 2022.

I then apply my average growth rates to the dividend yield to derive the expected dividend yield and add this dividend yield to each company's growth rate.

In addition to employing forecasted earning growth, such as Mr. Coyne does, I also incorporate other financial information. I use forecasted

dividend growth, expected book value growth and sustainable growth rates.

Because investors consider other information in assessing risk, in addition to just looking at and examining earning growth rates, my discounted cash flow model results range from 8.15 percent to 9.47 percent.

I also use, as Mr. Coyne does, the capital asset pricing model, which includes three components: The risk-free rate, the beta coefficient and the market risk premium.

The risk-free rate I use, I use basically two estimates, the first being a 90-day average of yields on 30-year treasury bonds over the period ending August 31st of this year. At that time my average was 3.16 percent.

The second risk-free rate that I employ is based on forecasts provided by Duff & Phelps. Their normalized rate of three and a half percent.

To estimate the equity risk premium, I subtract these risk-free rates from an overall estimated market return to derive a range for my market risk premium of 5.5 percent to 9.48 percent.

This is standard and also supported by additional evidence presented in my testimony that

investors are expecting these types of market risk premium within that range again of nine and a half -- excuse me -- of seven and a half and nine and a half percent.

I then multiply this market risk premium by Value line beta coefficients. Each beta coefficient represents the relationship between a specific company's stock to the overall market.

The proxy group -- excuse me. The proxy group average beta coefficient is 0.86, which shows the proxy group companies are less risky than the overall market. My capital asset pricing model results using these data points range from 8.23 percent to 9.58 percent.

I also employed a variant of this CAPM model called the empirical capital asset pricing model, which applies a three-quarter weight to the beta adjusted risk premium. It results in estimates ranging from 8.43 percent to 9.48 percent. Again, Mr. Coyne, the company's witness, uses the same exact models.

Finally, I used the comparable earnings model by examining realized return on equity for the proxy group comparing investors' acceptance of these returns via corresponding market-to-book ratios.

This ratio is an important indicator. It is basically the ratio of stock price divided by book-to-value per share and shows the degree to which a given return on equity equals the cost of capital.

In a case where market-to-book ratios are greater than one, it demonstrates that a company can attract new equity capital without delusion. So, for comparison, when you're looking at the proxy group of companies, the same proxy group that Mr. Coyne uses, the average historical market-to-book ratio is greater than one.

It's closer to two, being 1.74. That demonstrates that right now my estimates are overestimating required return on equity that investors are incorporating when they make their decisions to invest in more stock.

So, in conclusion, I'd recommend that the Commission authorize an overall rate of return of 6.85 percent using the test year capital structure that incorporates a cost on long-term debt of 3.53 percent and an allowed ROE of 9.47 percent, which corresponds to the maximum of my result -- of my range.

My recommendation is based on my range of 8.81 percent and 9.47 percent, as I was discussing

earlier, and as further supported by the average of all my models yielding the estimate of 9.38 percent.

My recommendation represents a conservative estimate of a fair and reasonable return on equity for Georgia Power Company and best represents the opportunity cost of capital that an investor expects under today's financial and economic circumstances.

And that concludes my summary.

MS. MEDLYN: Ms. Reno is available for questions from the Commissioners and cross-examination from the parties.

MADAM CHAIR PRIDEMORE: Unless you object, Ms. Medlyn, I think it's okay that we can excuse Dr. Blank.

MS. MEDLYN: Yes. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Dr. Blank.

DR. BLANK: Thank you, Madam Chair.

(Witness Blank was excused.)

MS. MEDLYN: I would actually ask that his exhibit be moved into the record as DODFEA 1.

MADAM CHAIR PRIDEMORE: Okay. So moved and marked.

(DODFEA Exhibit 1 was admitted into evidence.)

MADAM CHAIR PRIDEMORE: Questions from Commissioners for Ms. Reno?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Georgia Power Public Service Commission.

MR. WALSH: No cross.

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy.

MS. LYNDALL: No cross.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Government.

MS. BROWN: No cross.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light.

MS. KYSOR: No cross.

MADAM CHAIR PRIDEMORE: GASEIA.

MR. THOMASSON: No questions.

MADAM CHAIR PRIDEMORE: GA Solar.

MR. MORELAND: No questions.

MADAM CHAIR PRIDEMORE: Georgia Watch.

MS. COYLE: No questions.

MADAM CHAIR PRIDEMORE: MARTA.

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management.

MR. CLARKSON: No questions.

MADAM CHAIR PRIDEMORE: Sierra Club.

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE.

MR. DOWDY: No questions.

MADAM CHAIR PRIDEMORE: Georgia Power.

MR. MARZO: Yes, Madam Chair. I have got some questions.

CROSS-EXAMINATION

BY MR. MARZO:

Q Hello, Ms. Reno. Good to see you again. I think it was 2019 the last time we saw each other.

A Good morning.

Q Now, Ms. Reno, just as a precursor, would you all -- would you agree with me that estimating the cost of capital for the company, like Georgia Power Company, involves some degree of judgment which must be applied by experts?

A Yes.

Q Okay. And would you agree that the similar cases which underlie this effort and the ones which nearly all experts reference are the Hope Natural Gas and Bluefield Water Works cases?

A Yes. That's the standard that most return on equity analysts look to for guidance because it establishes the standard that the commission is to set a fair and reasonable return that not only allows the company an

opportunity to earn a return, but also under -- also to compare like comparable risk enterprises under efficient management to be able to maintain financial integrity and to also maintain a satisfactory credit rating.

Q Okay. Can you agree with me that the test themselves and the court cases themselves, they don't prescribe specific models or methods for the Commission to have to consider. That's something that experts come in with various judgment on which models or tests to use; correct?

A That's correct. But there's general agreement on which markets yield market-base -- which models, excuse me, yield market-based results, such as the capital asset pricing model, discounted cash flow model. Those tend to be the most common used. There's also the risk premium model, which is also another market-based model.

Q Okay. And I understand that you did generally the same analysis -- the same methods test that Mr. Coyne used; is that fair?

A For the most part. We do disagree on some key pieces of inputs. For example, in his discounted cash flow model, when he's looking at his growth rates -- and I use similar growth rates based on earnings growth.

One of the things I noticed in his method, though, is that he tends to cherry-pick the highest growth

rates for multiple sources. And I use those same exact sources, but I take an average. And so what that does is provide a fair representation of growth rates that investors are expecting when they're about to invest in a utility stock.

Other areas of disagreement, for example, with the capital asset pricing model, he further overestimates what investors are expecting today, in terms of market returns. For example, he estimates a total market return of 15 -- excuse me -- 15.18 percent, I believe, which far exceeds anything that -- far exceeds estimates that other analysts are projecting.

For example, the Federal Reserve, the Bank of Philadelphia, recently published in their survey of professional forecasters expected overall market return that is using the S&P 500 Index of -- I believe that average was closer to 9 percent or nine and a half percent with a maximum of maybe 10 percent, far lower than his estimates. So there are areas where we disagree.

Q Well -- and that's obvious, too, Ms. Reno because the recommendation is not the same; correct?

A That's correct.

Q Okay. So, I guess, my general point with my preliminary question was: Experts will use different models. They can disagree or agree as to what inputs to put

into those models; correct?

A Correct.

Q Okay. And you would expect that Mr. Coyne, for example, might take exception to the characterization that he cherry-picked certain inputs; correct?

You wouldn't be surprised if you saw rebuttal that he responded to that; correct?

A True.

Q Okay.

A That's essentially the only way I can really describe it, though.

Q Okay. Well --

A Because he basically uses the max. So if you want me to get into further detail about --

Q Not specifically. I do -- I mean, I have questions. I do have questions that will line up and will hopefully give you that opportunity.

So we can go through that approach. I would prefer that.

MR. MARZO: I'm not trying to interrupt the witness, Madam Chair. I'm just trying to be efficient.

MADAM CHAIR PRIDEMORE: Go ahead, Ms. Reno.

MS. RENO: Well, for example, we use the same sources for our earnings growth rates and discounted

cash flow model. And I'm referring to the constant growth.

I know the other experts in this case use the multi-stage DCF. And we don't need to go there right now for this discussion. But we -- both Coyne and I use the same exact -- we pull earnings growth rates from Zacks, Yahoo Finance. I also pulled growth rates from CNN Finance.

And what I tend to do to remove outliers or extreme variabilities in those growth rates is I tend to take the average. He does multiple estimates. He looks at the highest of those three sources, the average of those three sources and the lowest. Discounts the results using the lowest and the average and seems to focus more on the results using just the highest of those growth rates.

And that's essentially -- mainly I was a little harsh saying cherry-picking. But as an analyst, usually I don't pick the numbers. I tend to rely on averages and medians.

BY MR. MARZO:

Q Okay. Well, let's talk about that. So one of your criticisms is -- my understanding is that you criticize Mr. Coyne for relying exclusively on earnings growth estimate, which I think you just outlined; correct?

A Right.

Q Okay. And you contrast this with your reliance upon stated reliance on earnings growth estimates, dividend growth book value growth, and sustainable growth estimates; correct?

A That's correct. I provide these alternate data sources because investors also incorporate other pieces of information, such as dividend payout policy, in addition to earnings growth.

Q Now, could you turn to page 49 of your testimony. And I'll let you get there, but that's Table 7.

A Correct.

Q Now --

A Go ahead.

Q -- your recommendation in this case is to set the company's ROE at 9.47 percent, which is the top of your DCF range; is that correct?

A That's correct.

Q All right. Now, the 9.47 percent, that's the high end of your DCF results; correct?

A That's correct.

Q Okay. Now, your 9.47 is also your -- for the proxy group, the median group DCF results using the 90-day average stock prices and also the EPS growth rate projections; correct?

A Yes. That's correct. But I -- I think I know where this line of questioning is going.

Q Well, why don't you let me get there and ask the question, unless --

MR. MARZO: I'm just trying to be efficient. But I think we're getting outside of my questions, Madam Chair.

MADAM CHAIR PRIDEMORE: Okay. I agree. Please finish, Mr. Marzo.

BY MR. MARZO:

Q So your 9.47 percent ROE recommendation in this case is based on your DCF analysis that exclusively relies on earnings growth recommendations, but isn't that what you just criticized Mr. Coyne for doing?

A Well, my -- it's based on the maximum range and applying some judgment here. And my -- the average of all my models is actually slightly lower than that, but I applied some judgment. I provide a conservative estimate based on that maximum.

So for the sake of establishing a range, which all the other analysts -- well, most of the other analysts in this case provide, the maximum of that range happens to be 9.47.

Q Okay. And that happens to be based on the same sort of growth estimates that you criticized Mr. Coyne for;

correct?

A That's correct.

Q Okay. Now, you have -- you've accepted the company's capital structure for ratemaking purposes and you've also performed a comparable earnings analysis as you've done in past cases that you appear before this Commission; correct?

A Yes, I have.

Q Okay. And on page 49, you show three different comparable earnings methodologies. They appear center page.

Now, I understand you set your recommended ROE at the top of your DCF range, but can we agree that there are numerous other values on your chart and table and the Commission, in its own judgment, could choose to look and rely more on one of those; correct?

A Well, they can choose to do so. But they need to be aware or I would -- I would implore them to consider market-based results that are derived using the discounted cash flow model, the capital asset pricing model.

The comparable earnings methodology, however, is different in that it's based on accounting values that don't necessarily incorporate investors' expectations of returns in investing in utility stock.

And the purpose of -- there are a couple of reasons why I include this analysis. That is, I am aware of

past Commission precedent to rely on the comparable earnings methodology. But, also, if you -- if you read further in my testimony, I go into great detail explaining that what you're really trying to capture here is the market-to-book ratio. That is, investors' expectations of returns based on the ratio of stock prices --

MR. MARZO: Madam Chair --

MS. RENO: -- provided by accounting values.

MR. MARZO: I think we're jumping over my question again. And I know the witness doesn't want me to have to get to the next question, but I feel like we're going to be here all day if we're going to do it this way.

MADAM CHAIR PRIDEMORE: Ms. Reno, can you answer the gentleman's question?

MS. RENO: Repeat the question, please.

BY MR. MARZO:

Q Well, let me try to short form this. Can we agree that if the Commission in the exercise of its own judgment was inclined to set the ROE at the upper range of their comparable earnings test, rather than the upper range of the DCF range, it would set the ROE at 10.76 percent; is that right?

A Well, that wouldn't be within my judgment. Because I set my range on discounted cash flow model because

it is based on market information. It's a market-based methodology.

The comparable earnings model, on the other hand, incorporates accounting values, book values. And as I was starting to get into the detail a minute ago, a key piece of that analysis is also to incorporate the market-to-book ratios that right now are showing ratios greater than one, more or less closer to two, meaning that investors are currently earning -- are currently earning or receiving a return on equity that's greater than the opportunity cost of equity that is required.

Q And I know that you're saying that that's not your judgment. And my question was -- the Commission can look at your table. And as you referenced earlier, the Commission has historically looked at comparable earnings as part of the evaluations they've done in these rate cases.

And they could look at your table and if they're going to pick the high end of a range, they could pick the high end of your comparable earnings range, which is 10.76 percent; correct?

A Yes. If they choose to do so.

I just thought I'd further qualify that what's -- or implore them to consider the market-based methodologies.

MADAM CHAIR PRIDEMORE: But according to your

testimony, Ms. Reno, it is the 10.7 percent, right, based upon the gentleman's question?

MS. RENO: Yes.

MADAM CHAIR PRIDEMORE: Okay.

BY MR. MARZO:

Q And what we know just historically, Ms. Reno, for example, in the 2019 rate case, you recommended a 9.1 percent ROE and the Commission considered all the evidence in that case and ultimately decided on a 10.5 percent ROE; is that correct?

A That's correct.

Q Okay. In this case your recommendation is 37 basis points higher than it was in 2019. And I take that to mean that even though we are significantly apart as to what the estimate of our ROE should be, you and Mr. Coyne may both agree that the cost of capital has gone up since 2019?

A Yes.

Q Okay. Now, in your testimony you discuss the constructive regulatory environment as one of the characteristics that you feel reduces regulatory risk for Georgia Power; is that correct?

A That's correct.

Q And some of the items you discuss in your testimony as part of the constructive environment is

Georgia's 9.5 percent to 12 percent earnings band; is that correct?

A Yes. It reduces regulatory risk associated with a -- well, associated with Georgia Power that makes Georgia Power unique compared to the overall proxy group.

Go ahead.

Q Another item that you discuss in your testimony regarding the constructive environment in Georgia is also the ability of the company to earn within and above the band and share with customers; correct?

A That is correct. And I'll take this opportunity to add that the company has been over-earning, meaning earning a return that's greater than that 12 percent.

Q Yeah. And just to be clear, the company has earned as it's allowed to earn by this Commission's orders; correct?

A That's correct.

Q Okay. Now, as well as -- the final point you make about constructive environment is that the Commission is also favorably ranked by IRA as one of the more constructive regulatory environments, as well; is that correct?

A Yes. And compared to the proxy group that I used to derive my estimates, investors do consider Georgia

Power to have relatively lower risk for that reason.

Q Now, you state -- well, let me ask this. That's why -- would you agree with me that that's why it's important that whatever decision this Commission makes, it makes a decision that continues to preserve as that ranking and rating as a constructive regulatory environment; correct?

A Correct.

Q Okay. Now, on page 14, line 7 to 14, you state that investors will consider the competitiveness of Georgia's economy relative to other states; correct?

A Excuse me? What page are you on?

Q Page 14, line 7 through 14.

COMMISSIONER MCDONALD: Are you reading that from the testimony?

MR. MARZO: I'm asking -- I'm going to ask her a question.

COMMISSIONER MCDONALD: Are you reading that from the testimony?

MR. MARZO: It is in her testimony.

COMMISSIONER MCDONALD: Hasn't she sworn that what she said is --

MR. MARZO: Yes, sir.

COMMISSIONER MCDONALD: Thank you.

MR. MARZO: Would you like me to get to the

question?

I can get to the question if the witness is comfortable with me doing that.

MADAM CHAIR PRIDEMORE: He's giving her time to find it.

MS. RENO: So what are the lines number?

MR. MARZO: It's lines 7 to 4 -- 7 to 14.

MS. RENO: Okay.

Yes, sir.

BY MR. MARZO:

Q Okay. Can you --

A I see what I wrote.

Q Okay. And can we agree that the constructive regulation plays a significant role in the economic development of the state?

A Yes, it does.

Q And, you know, not to belabor or continue this point, but you're aware that Georgia is nationally ranked as one of the best places to do business; correct?

A Didn't someone state for the eighth year running or --

Q It's ninth.

A Ninth?

Q For the record, it's nine years running.

A Okay.

Q Do you believe that this Commission's constructive regulation has benefited Georgia in general and the Department of Defense here in Georgia in particular?

A What do you mean by Department of Defense in particular?

Q I'm asking: Has the Department of Defense, by having locations here in Georgia and the constructive regulation that's here in Georgia -- have they benefited from that?

Let me rephrase. Before you filed your testimony in this case, did you consult with any base commanders to get their views of how this Commission and the company constructively work together with them on their goals?

A No, I did not.

MR. MARZO: Okay. Madam Chair, that's all I have.

MADAM CHAIR PRIDEMORE: Redirect.

MS. MEDLYN: Just a few.

REDIRECT EXAMINATION

BY MS. MEDLYN:

Q Ms. Reno, why did you rely upon the DCF methodology in recommending your 9.47 percent ROE?

A Well, I relied on the DCF for a few reasons. It -- it -- first of all, it is a market-based methodology

that incorporates specific company financial information, how investors see the dividends going forward, looking at the payout, stock price valuations and their expectations of those cash flow growth rates.

Also, it tends to be the most widely used methodology across the U.S. at various state commissions. And, actually, there are some state commissions, in terms of their recommendation, will rely solely on that model. So as a general practice, that's why I base my model -- my results on that model.

I'll further add that that model produces the most consistent results. All the other witnesses for the most part that use -- that estimate their results using the constant growth DCF model come up with a range of the high eights, low nines.

So it -- it yields really consistent results. In contrast, some of the other models, like the capital asset pricing model, although another market-based model, tends to be more -- the results tend to be more dependent on what you're putting in, like there's a direct impact of whatever you're assuming for -- a risk-free rate, for example. So those are the reasons why I rely on the DCF to determine my range.

Q If the Commission were to award Georgia Power your recommended 9.47 percent ROE, in your opinion, would

that still maintain the constructive regulatory environment?

A Yes, I believe it would. Because I'm not recommending changes to other components that contribute to this constructive regulatory environment. I'm not making changes to the ARP, for example. That tends to have a greater impact in reducing the company's risk relative to the proxy group.

MS. MEDLYN: Okay. Thank you. That's all I have.

I ask that the witness be excused. And if we can move exhibits DODFEA 2 through 10 into the record.

MADAM CHAIR PRIDEMORE: So moved.

(DODFEA Exhibit 2 through 10 were admitted into evidence.)

MADAM CHAIR PRIDEMORE: Ms. Reno, you're excused.

MS. RENO: Thank you.

MADAM CHAIR PRIDEMORE: Thank you.

(Witness excused.)

MADAM CHAIR PRIDEMORE: Is the staff panel of Gorman/O'Donnell prepared?

Are you ready?

MR. WALSH: Yes, Madam Chair.

MADAM CHAIR PRIDEMORE: Okay. Go ahead and get

them in.

MR. WALSH: Gentlemen, you can remain standing while I swear you in.

Madam Chair, for the record, at this time the staff would like to call the panel of Michael Gorman and Kevin O'Donnell to the stand.

Raise your right hands.

Thereupon,

MICHAEL P. GORMAN,
KEVIN O'DONNELL,

having been duly sworn, testified as follows:

MR. GORMAN: I do.

MR. O'DONNELL: I do.

DIRECT EXAMINATION

BY MR. WALSH:

Q Mr. Gorman, I'm going to start with you. Could you please state your full name for the record and by whom you're employed.

A (Witness Gorman) My name is Michael Gorman. I'm employed by Brubaker & Associates as a principal regulatory economic analyst.

Q Mr. O'Donnell, same question to you. Could you please state your full name for the record and by whom you're employed.

A (Witness O'Donnell) Kevin O'Donnell. And I'm president and founder of Nova Energy Consultants in Cary,

North Carolina.

Q Okay. Mr. Gorman, I'm going to ask the next series of questions to you. On October 20th, 2022, did you prefile or cause to be prefiled 84 pages of public disclosure testimony in question-and-answer form?

A (Witness Gorman) Yes.

Q Do you have any changes or corrections that need to be made to that testimony?

A (Witness Gorman) I do not.

Q If I were to ask you the same questions today that are presented in your prefiled testimony, would your answers be the same?

A (Witness Gorman) They would.

MR. WALSH: Madam Chair, I ask that the public disclosure version of Mr. Gorman's testimony be copied into the record as if read from the witness stand?

MADAM CHAIR PRIDEMORE: So moved.

MR. WALSH: Thank you.

(Whereupon, the prefiled direct testimonies of Michael Gorman follows:)

**Public Disclosure Version**

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | | |
|---|---|---|---|
| **IN RE:** | **GEORGIA POWER COMPANY'S 2022 RATE CASE** | **)** **)** | **DOCKET NO. 44280** |

# DIRECT TESTIMONY

# AND EXHIBITS

# OF

# MICHAEL P. GORMAN

# (RATE OF RETURN)

**TRADE SECRET**

**ON BEHALF OF THE**
**GEORGIA PUBLIC SERVICE COMMISSION**
**PUBLIC INTEREST ADVOCACY STAFF**

**OCTOBER 20, 2022**

**Public Disclosure Version**

**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

| | | | |
|---|---|---|---|
| **IN RE:** | **GEORGIA POWER COMPANY'S 2022 RATE CASE** | ) ) | **DOCKET NO. 44280** |

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**Public Disclosure Version**

# DIRECT TESTIMONY OF MICHAEL P. GORMAN

## I. QUALIFICATIONS AND SUMMARY

### I.A. Qualifications

**Q. Please state your name and business address.**

A. My name is Michael P. Gorman. My business address is Brubaker & Associates, Inc., 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q. What is your occupation and by whom are you employed?**

A. I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q. Please describe your education and professional experience.**

A. My education and professional experience are detailed in my Exhibit___(MPG-1).

**Q. On whose behalf are you testifying?**

A. I am offering testimony on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("PIAS" or "Staff").

### I.B. Summary

**Q. What is the purpose of your testimony?**

A. My testimony will address Georgia Power Company's ("GPC" or "the Company" or "Georgia Power") overall rate of return including return on equity, embedded debt cost, and ratemaking capital structure.

**Q. Please summarize your recommendations and conclusions on rate of return.**

A. I recommend the Georgia Public Service Commission (the "Commission") award Georgia Power a return on common equity of 9.45%, within the range of 9.00% to 9.90%. This return on equity reflects GPC's current market cost of equity. I recommend the Commission approve a return on equity that reflects fair compensation for GPC's level of investment risk, and impose tariff rate charges on customers that are no more expensive than necessary to fairly compensate the Company and maintain its financial integrity and credit standing.

I also propose an adjustment to the Company's ratemaking capital structure once Vogtle Units 3 and 4 are placed in-service. I recommend the Commission adjust the Company's ratemaking capital structure to include a 51% common equity ratio for 2024 and 2025, down from the 56% common equity ratio currently approved. The Company's financial position will strengthen significantly with revenues from Vogtle Units 3 and 4 and a 56% common equity ratio would no longer be necessary to support the Company's financial integrity. This adjusted 51% common equity ratio reflects the Company's common equity ratio that the Commission approved in the 2013 rate case order, which is also generally consistent with ratemaking capital structures for other similarly situated regulated utility companies, and is adequate to support GPC's bond rating, financial integrity and credit standing, but at much lower cost to customers.

**Q. What is your recommended overall rate of return for GPC in this case?**

A. As shown on my Exhibit___(MPG-2), based on my recommended return on equity and the Company's proposed capital structure for the test year ending July 31, 2023 and calendar year 2023, I recommend a rate of return of 6.83%, and 6.84%, respectively. Starting in 2024, based on my recommended return on equity and adjusted capital structure reflecting a 51% common equity ratio, I recommend an overall rate of return of 6.57% and 6.61% for 2024 and 2025, respectively.

**Q. Please describe how your testimony is organized.**

A. My testimony is broken into several factors used to estimate a fair rate of return for Georgia Power, which will maintain its financial integrity and access to capital at the most reasonable costs possible to customers. My testimony is structured as follows.

First, I provide observable evidence on current market costs and regulatory support for financial integrity, credit standing, and access to capital.

Second, I review the Company's proposed ratemaking capital structure for the test year, the 12-month period ending July 31, 2023, and for year-end 2023, 2024, and 2025. As outlined below, I do not take issue with the Company's proposed ratemaking capital structure for the test year or for calendar year 2023. However, in 2024, after the new Vogtle generating units are expected to be placed in-service, I recommend adjusting the ratemaking capital structure to include a common equity ratio of 51%. This adjusted capital structure following the in-service date of Vogtle Units 3 and 4 will reduce GPC's cost of service, maintain its financial integrity and credit standing, and mitigate the impact on customers' rates by including the cost of these new nuclear units in retail cost of service.

Third, I estimate GPC's current market cost of equity using market-based cost of capital models to estimate the current market-required return on equity that investors require to assume the investment risk similar to GPC.

Fourth, I rely on my recommended rate of return to develop credit metrics, which demonstrate that my recommended rate of return for GPC will support its investment grade bond rating, and access to capital at reasonable cost.

Finally, I respond to GPC witness Mr. James Coyne's recommended return on equity in the range of 8.99% to 13.55%, and his point estimate of 11.00%, which includes a flotation cost adjustment of 8 basis points. I comment on his analysis and show that his recommended return on equity substantially exceeds the current market cost of capital for companies with investment risk similar to that of GPC. Mr. Coyne's recommended return on equity unnecessarily inflates GPC's claimed revenue deficiency, and would increase rates beyond a just and reasonable level.

# II. RATE OF RETURN

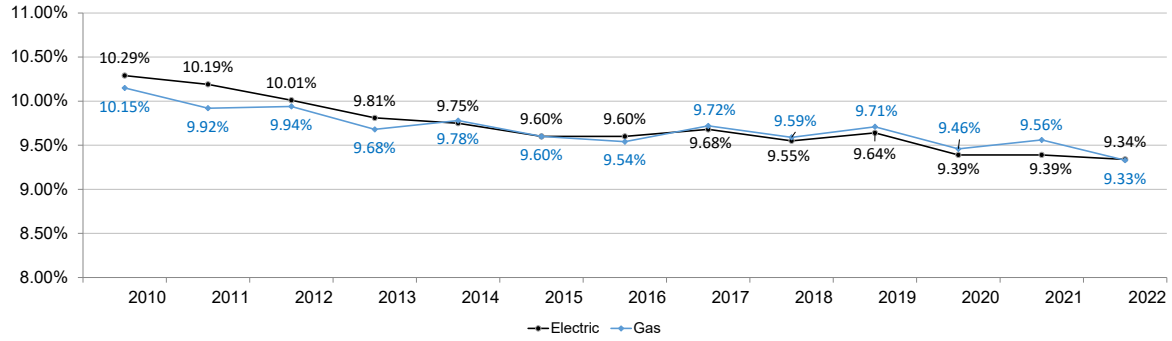
## II.A. Utility Industry Authorized Returns on Equity, Access to Capital, and Credit Strength

**Q. Please describe the observable evidence on trends in authorized returns on equity for regulated utilities.**

A. Authorized returns on equity are an important aspect available to utilities to produce revenues and cash flows adequate to support their credit standing and maintain their financial integrity, which supports their access to capital under reasonable terms and prices. Observing data on industry authorized returns on equity, trends and outlooks on credit standing, and ability to attract capital to fund large investments, provides clear evidence that industry authorized returns on equity have been judged by market participants to be fair and reasonable. With this as a backdrop, it is significant to observe that the industry authorized returns on equity for electric and gas utilities have ranged between 9.35% to 9.78% for the period 2014-2022 to date and, since 2020, the industry authorized returns on equity have averaged below 9.50%. These returns are summarized in Figure 1 below.

**FIGURE 1**

**Authorized Returns on Equity***
**(Exclude Limited Issue Riders)**




**ROE Distributions**[1/2]

| **Electric Utilities** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| <= Average | 51.7% | 55.0% | 51.0% | 50.0% | 56.3% | 56.5% | 53.1% | 59.5% | 47.4% | 45.5% | 33.3% | 31.4% | 50.0% |
| > Average | 48.3% | 45.0% | 49.0% | 50.0% | 43.8% | 43.5% | 46.9% | 40.5% | 52.6% | 54.5% | 66.7% | 68.6% | 50.0% |
| **Gas Utilities** | | | | | | | | | | | | | |
| <= Average | 56.4% | 31.3% | 45.7% | 47.6% | 50.0% | 50.0% | 53.8% | 70.8% | 47.5% | 51.5% | 51.4% | 46.5% | 55.6% |
| > Average | 43.6% | 68.8% | 54.3% | 52.4% | 50.0% | 50.0% | 46.2% | 29.2% | 52.5% | 48.5% | 48.6% | 53.5% | 44.4% |

Source and Notes:
[1] *S&P Global Market Intelligenc*e, RRA Regulatory Focus, Major Rate Case Decisions -- January - June 2022, July 27, 2022, p. 3.
[2] Download from S&P Global Market Intelligence, August 1, 2022.
* Electric Returns exclude Limited Issue Rider Decisions.
* RRA excludes the 2017 Alaska ENSTAR decision from its Industry Average.

**Q. Have utilities been able to access external capital to support capital expenditure programs?**

A. Yes. In Regulatory Research Associates' ("RRA") April 11, 2022 Utility Capital Expenditures Update report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

- Projected 2022 capital expenditures for the 47 energy utilities included in the Regulatory Research Associates representative sample of the publicly traded U.S.-based utility universe currently exceeds $154.2 billion, well above the $131.8 billion of actual investment spent in 2021 by the same companies. Much of the increased outlays are [sic] driven by federal support for infrastructure investment that was approved by congress [sic] and signed into law late in 2021.

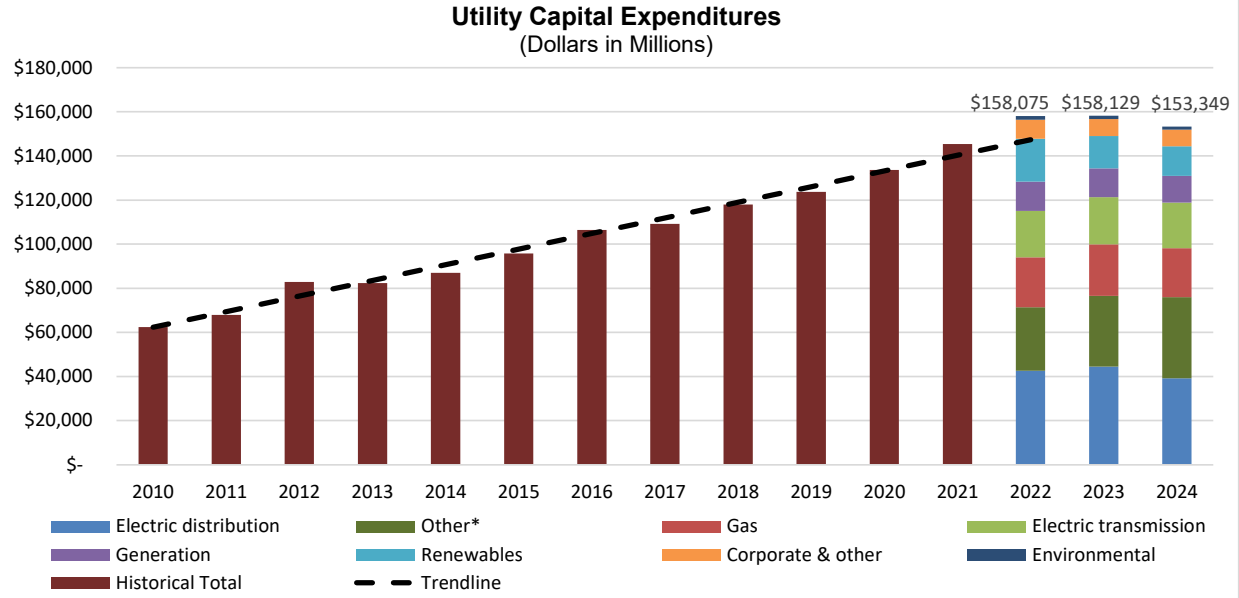
- Investment across these 47 energy utilities may rise 15% or more by the close of 2022.

- Across the small investor-owned water utility industry, total capex is forecast to increase 7.3% in 2022 to approximately $3.9 billion. The segment experienced modest growth of 4.9% in 2021.

- 2021 energy utility capital expenditures marked a record high, about 1.3% above the $130.1 billion invested in 2020. Investment in 2021 might have been even higher without the multiple supply chain issues associated with the ongoing coronavirus pandemic.[1]

As shown in Figure 2 below, capital expenditures for electric and natural gas utilities have increased considerably over the period 2021 into 2022, and the forecasted capital expenditures remain elevated through the end of 2023, albeit falling below current levels in 2024.

**FIGURE 2**




*Other category consists of utilities that do not report capital expenditures by category: Avangrid, Hawaiian Electric, PG&E and Portland General Electric.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, April 11, 2022, Tables 1 and 3.

As outlined in Figure 2 above, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future. This is clear evidence that the capital investments are enhancing shareholder value, and are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments. While capital markets embrace these profit-driven capital investments, regulatory commissions

[1] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility Capital Expenditures Update," April 11, 2022, at 5.

also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service at competitive tariff prices.

**Q. Is there evidence of robust valuations of regulated utility equity securities?**

A. Yes. Robust valuations are an indication that utilities can sell securities at high prices, which is a strong indication that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on my Exhibit___(MPG-3), utility valuation metrics show robust valuation of utility securities more recently compared to the historical period extending back to 2002. Specifically, *The Value Line Investment Survey* ("*Value Line*") tracks and projects various valuation metrics related to regulated utility securities, as well as non-regulated companies followed by *Value Line*. These valuation metrics are considered by market participants in assessing the investment risk characteristics of individual company stocks and industries, and are used by market participants to derive their required rates of return for making investments. All of these valuation metrics for electric utility stocks indicate robust valuations of utility stocks, which in turn support my finding that utilities' cost of capital is low by historical comparison and are competitive returns.

For example, my Exhibit___(MPG-3) shows a *Value Line* electric utility industry price-to-earnings ratio of 20.34x, compared to a 21-year average price-to-earnings ratio of around 17.25x (Page 1). The current price-to-earnings ratio for gas utilities is 19.32x relative to the 17-year average price-to-earnings ratio of 18.42x (Page 11). This strong price-to-earnings performance indicates stock prices relative to earnings have been robust. Robust stock prices, or higher stock prices, indicate lower cost of capital as investors are willing to pay more for future profits.

The market price-to-cash flow for electric utilities is currently 9.11x, compared to the 21-year average of 7.54x (Page 2). The market price-to-cash flow for gas utilities is currently 9.71x, compared to the 17-year average of 9.60x (Page 11). Again, high stock prices in relationship to utility cash flows indicate investors are willing to accept lower rates of return to invest in utility stocks.

Finally, the current market-to-book ratio for the electric utility industry is 2.00x, compared to the 18-year average of 1.71x (Page 3). The current market-to-book ratio for

the gas utility industry is 1.79x, which is comparable to the 17-year average of 1.82x (Page 11). Again, the market-to-book ratio indicates robust stock prices and low cost of capital to utilities.

The utility industry exhibits strong valuations in the marketplace, which is a clear indication that utilities have access to external capital markets under favorable conditions and at low costs.

**Q. Please describe the credit strength and financial integrity of the regulated utility industry.**

A. Credit ratings are reasonable assessments of the utility industry's financial integrity, because they indicate the utility's credit strength, which in turn provides strong evidence of the utility's ability to attract capital necessary to make infrastructure investments under reasonable terms and prices. Trends in credit ratings are an indication of whether or not the regulatory decisions have supported the utilities' ability to generate adequate revenue to recover their costs, produce adequate cash flows, and maintain credit strength. The primary factors in these regulatory decisions are the commissions' awarded returns on equity, allowed capital structure and development of depreciation rates.

As shown in Table 1 below, electric utilities' credit standing has remained very robust through the Tax Cuts and Jobs Act (2017) changes and impacts on cash flow starting around 2018, through the COVID pandemic, and up through current times. As shown below in Table 1, from approximately 2017 through 2022, over 80% of the regulated utility industry have bond ratings of BBB+ or stronger. Georgia Power currently has a BBB+ rating or equivalent from two of the three major bond rating agencies and a BBB rating from the third major bond rating agency.[2]

[2]Fetter Direct Testimony at 5.

**TABLE 1**

**S&P Ratings by Category**
**Electric Utility Subsidiaries**
**(Year End)**

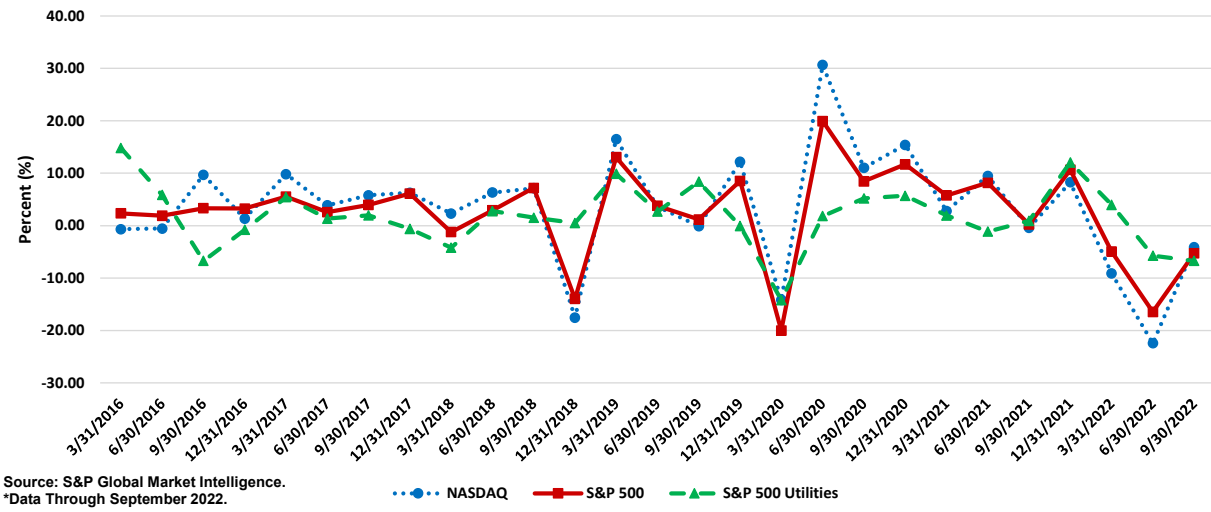
| Description | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **A or higher** | 12% | 12% | 11% | 13% | 13% | 13% | 10% | 10% | 8% | 14% | 14% | 10% | 10% |
| **A-** | 20% | 19% | 22% | 26% | 26% | 34% | 43% | 52% | 54% | 54% | 53% | 37% | 38% |
| **BBB+** | 24% | 28% | 28% | 25% | 28% | 24% | 32% | 21% | 22% | 18% | 19% | 35% | 35% |
| **BBB** | 26% | 24% | 22% | 26% | 23% | 18% | 4% | 7% | 13% | 12% | 3% | 16% | 16% |
| **BBB-** | 16% | 15% | 17% | 11% | 11% | 11% | 11% | 11% | 2% | 1% | 1% | 0% | 0% |
| **Below BBB-** | 2% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 10% | 1% | 1% |
| **Total** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** |
| **BBB+ or Above** | 56% | 59% | 61% | 63% | 67% | 71% | 85% | 82% | 84% | 87% | 86% | 83% | 83% |

Source: S&P CAPITAL IQ and Market Intelligence, downloaded 9/26/22.
Note: Subsidiary ratings used.

**Q. Please describe utility stock price performance over the last several years.**

A. As shown in Figure 3 below, S&P Global Market Intelligence ("MI") has recorded gas and electric utility stock price performance (excluding dividend yields) compared to overall market performance.

**FIGURE 3**
**Quarterly Price Returns**




Source: S&P Global Market Intelligence.
*Data Through September 2022.

Utility stocks have not exhibited the same volatility as the S&P 500, and have maintained strong valuation relative to overall market performance.

**Q. How should the Commission use this market information in assessing a fair return for GPC?**

A. Observable market evidence is quite clear that capital market costs are near historically low levels. While authorized returns on equity have fallen to the mid-9% range, utilities continue to have access to large amounts of external capital even as they are funding large capital programs. Furthermore, utilities' investment-grade credit ratings are stable and have improved due, in part, to supportive regulatory treatment. The Commission should carefully weigh all this important observable market evidence in assessing a fair return on equity for GPC.

## II.B. Federal Reserve's Impact on Cost of Capital

**Q. Are the monetary policy decisions and actions of the Federal Reserve, and of the Federal Reserve System's ("FRS") Federal Open Market Committee ("FOMC"), known to market participants, and is it reasonable to believe those decisions and actions are reflected in the market's valuation of both debt and equity securities?**

A. Yes. The Federal Reserve has been transparent on its efforts to support the economy to achieve maximum employment, and to manage long-term inflation to around a 2% level. The Federal Reserve in a September 21, 2022 press release, noted that recent indicators point to modest growth in spending and production, job gains have been robust, the unemployment rate has remained low, inflation remains elevated, reflecting supply and demand imbalances related to the pandemic, higher food and energy prices and broader price pressures. The Federal Reserve also noted that Russia's war against Ukraine is causing tremendous human and economic hardship, which is placing additional upward pressure on inflation and impacting global economic activity. The Federal Reserve noted that it is highly attentive to inflation risk.[3]

With this as a backdrop, the Federal Reserve announced that it will continue to seek maximum employment and a target inflation rate of 2% over the long-term. In support of those goals, the Federal Reserve announced it will raise the target range of the Federal Funds Rate ("FFR") from 2.50% to 3.25%, and that it anticipates ongoing increases to the FFR to achieve the target 2.0% inflation rate. The Federal Reserve also

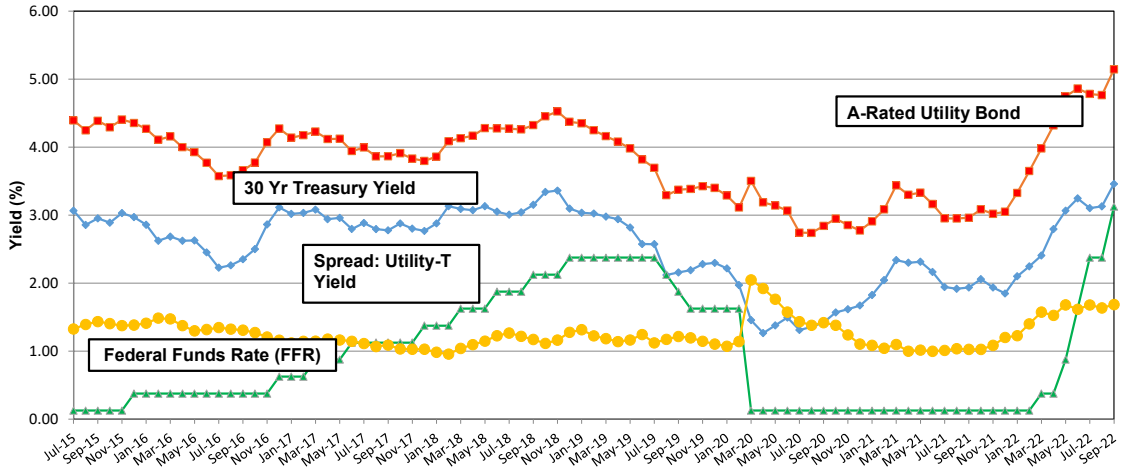
[3]Federal Reserve press release, September 21, 2022.

stated that it will continue to reduce its holding of Treasury securities, agency debt securities and agency mortgage backed securities, as outlined in the Size of The Federal Reserve Balance Sheet statement issued in May 2022. In that statement, the Federal Reserve outlined its intention to reinvest cash proceeds from dividends and coupons, but to gradually reduce its balance sheet holdings of these securities over time and intends to do so without a disruption of the markets. The Federal Reserve reiterated its strong commitment to returning inflation to the 2% rate objective.[4]

The trend in the Federal Reserve's monetary actions on the Federal Funds Rate is shown below in Figure 4.

**FIGURE 4**

**Timeline of Federal Funds Rate Changes Since 2015**




**Fed FFR Actions:**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | December 2015 | 0.25 | → | 0.50 | 11 | September 2019 | 1.75 | → | 2.00 |
| 2 | December 2016 | 0.50 | → | 0.75 | 12 | October 2019 | 1.50 | → | 1.75 |
| 3 | March 2017 | 0.75 | → | 1.00 | 13 | March 2020 | 1.00 | → | 1.25 |
| 4 | June 2017 | 1.00 | → | 1.25 | 14 | March 2020 | 0.00 | → | 0.25 |
| 5 | December 2017 | 1.25 | → | 1.50 | 15 | March 2022 | 0.25 | → | 0.50 |
| 6 | March 2018 | 1.50 | → | 1.75 | 16 | May 2022 | 0.75 | → | 1.00 |
| 7 | June 2018 | 1.75 | → | 2.00 | 17 | June 2022 | 1.50 | → | 1.75 |
| 8 | September 2018 | 2.00 | → | 2.25 | 18 | July 2022 | 2.25 | → | 2.50 |
| 9 | December 2018 | 2.25 | → | 2.50 | 19 | September 2022 | 3.00 | → | 3.25 |
| 10 | August 2019 | 2.00 | → | 2.25 | | | | | |

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

As shown in Figure 4, the Federal Reserve's recent increase to the Federal Funds Rate, currently at a 3.00% to 3.25% range, represents a higher Federal Funds Rate than the rate

[4] *Id.*

prior to the economic effects of the worldwide pandemic starting around March/April of 2020.

**Q. Do independent economists' outlooks for future interest rates align with the Federal Reserve's monetary policy?**

A. Yes. In its most recent report, *Blue Chip Financial Forecasts* outlines consensus economists' projections that reflect a rising risk of inflation, and likely continued monetary tightening of the Federal Reserve to fight inflation. *Blue Chip Financial Forecasts* indicated the likelihood that the Federal Reserve would increase the Federal Funds Rate in September as an effort to fight inflationary pressure, and noted that there is a high probability of the economy slowing down, possibly entering a recession, and notes a continued strong labor market. These outlooks and projections of short-term Federal Funds Rate, and long-term Treasury bond 30-year maturities, and U.S. economic outlook suggest inflation will impact interest rates over the intermediate term but are expected to moderate over the long term. All of this is illustrated in a comparison of interest rate and Gross Domestic Product ("GDP") projections over time as developed in Table 2 below.

**TABLE 2**

**Blue Chip Financial Forecasts**
**Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index**

| Publication Date | 3Q 2021 | 4Q 2021 | 1Q 2022 | 2Q 2022 | 3Q 2022 | 4Q 2022 | 1Q 2023 | 2Q 2023 | 3Q 2023 | 4Q 2023 |
|---|---|---|---|---|---|---|---|---|---|---|
| Federal Funds Rate | | | | | | | | | | |
| Oct-21 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.3 | | | |
| Nov-21 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.3 | 0.4 | | | |
| Dec-21 | **0.1** | 0.1 | 0.1 | 0.1 | 0.3 | 0.4 | 0.6 | | | |
| Jan-22 | | 0.1 | 0.1 | 0.3 | 0.5 | 0.7 | 0.9 | 1.1 | | |
| Feb-22 | | 0.1 | 0.2 | 0.5 | 0.8 | 1.0 | 1.3 | 1.5 | | |
| Mar-22 | | **0.1** | 0.2 | 0.6 | 1.0 | 1.3 | 1.6 | 1.8 | | |
| Apr-22 | | | 0.1 | 0.8 | 1.4 | 1.8 | 2.2 | 2.4 | 2.6 | |
| May-22 | | | 0.1 | 1.0 | 1.7 | 2.2 | 2.6 | 2.9 | 3.0 | |
| Jun-22 | | | **0.1** | 1.0 | 1.9 | 2.4 | 2.8 | 3.0 | 3.1 | |
| Jul-22 | | | | 0.7 | 2.4 | 3.1 | 3.5 | 3.5 | 3.5 | 3.4 |
| Aug-22 | | | | 0.8 | 2.5 | 3.2 | 3.5 | 3.5 | 3.4 | 3.3 |
| Sep-22 | | | | **0.8** | 2.5 | 3.4 | 3.6 | 3.6 | 3.5 | 3.4 |
| T-Bond, 30 yr. | | | | | | | | | | |
| Oct-21 | 1.9 | 2.2 | 2.3 | 2.4 | 2.5 | 2.6 | 2.7 | | | |
| Nov-21 | 1.9 | 2.2 | 2.3 | 2.4 | 2.5 | 2.6 | 2.7 | | | |
| Dec-21 | **1.9** | 2.1 | 2.2 | 2.3 | 2.5 | 2.6 | 2.7 | | | |
| Jan-22 | | 2.0 | 2.1 | 2.2 | 2.4 | 2.5 | 2.7 | 2.8 | | |
| Feb-22 | | 2.0 | 2.2 | 2.3 | 2.5 | 2.6 | 2.7 | 2.8 | | |
| Mar-22 | | **2.0** | 2.2 | 2.5 | 2.6 | 2.7 | 2.9 | 3.0 | | |
| Apr-22 | | | 2.3 | 2.6 | 2.8 | 3.0 | 3.2 | 3.3 | 3.3 | |
| May-22 | | | 2.3 | 2.9 | 3.1 | 3.2 | 3.4 | 3.5 | 3.5 | |
| Jun-22 | | | **2.3** | 3.0 | 3.3 | 3.4 | 3.5 | 3.6 | 3.6 | |
| Jul-22 | | | | 3.0 | 3.5 | 3.6 | 3.7 | 3.8 | 3.8 | 3.8 |
| Aug-22 | | | | 3.0 | 3.2 | 3.4 | 3.5 | 3.5 | 3.5 | 3.5 |
| Sep-22 | | | | **3.0** | 3.1 | 3.4 | 3.5 | 3.6 | 3.6 | 3.6 |
| GDP Price Index | | | | | | | | | | |
| Oct-21 | 4.2 | 2.9 | 2.5 | 2.5 | 2.5 | 2.5 | 2.4 | | | |
| Nov-21 | 5.7 | 3.4 | 2.7 | 2.6 | 2.5 | 2.4 | 2.3 | | | |
| Dec-21 | **5.9** | 4.6 | 3.4 | 2.8 | 2.7 | 2.5 | 2.5 | | | |
| Jan-22 | | 4.6 | 3.7 | 3.1 | 2.8 | 2.6 | 2.5 | 2.5 | | |
| Feb-22 | | 6.9 | 4.3 | 3.4 | 3.0 | 2.8 | 2.6 | 2.5 | | |
| Mar-22 | | **7.1** | 4.8 | 3.8 | 3.1 | 2.8 | 2.6 | 2.5 | | |
| Apr-22 | | | 4.8 | 5.1 | 3.7 | 3.0 | 2.8 | 2.6 | 2.6 | |
| May-22 | | | 8.0 | 5.6 | 4.0 | 3.4 | 3.0 | 2.8 | 2.6 | |
| Jun-22 | | | **8.1** | 5.9 | 4.6 | 3.5 | 3.1 | 2.8 | 2.7 | |
| Jul-22 | | | | 5.9 | 5.2 | 3.9 | 3.4 | 2.8 | 2.7 | 2.6 |
| Aug-22 | | | | 8.7 | 5.3 | 3.8 | 3.3 | 2.7 | 2.7 | 2.6 |
| Sep-22 | | | | **8.9** | 4.9 | 4.1 | 3.3 | 2.7 | 2.7 | 2.5 |

Source and Note:
*Blue Chip Financial Forecasts,* October 2021 through September 2022.
Actual Yields in Bold.

Further, the outlook for long-term interest rates in the intermediate to longer term is also impacted by the current Federal Reserve actions and the expectation that eventually the Federal Reserve's monetary actions will return to more normal levels. Long-term interest rate projections are illustrated in Table 3.

**TABLE 3**

**30-Year Treasury Bond Yield Actual Vs. Projection**

| Description | Actual | 2-Year Projected* | 5- to 10-Year Projected |
|---|---|---|---|
| 2018 | | | |
| Q1 | 3.02% | 3.63% | |
| Q2 | 3.09% | 3.80% | 4.2% - 4.4% |
| Q3 | 3.07% | 3.73% | |
| Q4 | 3.27% | 3.67% | 3.9% - 4.2% |
| 2019 | | | |
| Q1 | 3.01% | 3.50% | |
| Q2 | 2.78% | 3.17% | 3.6% - 3.8% |
| Q3 | 2.30% | 2.70% | |
| Q4 | 2.30% | 2.50% | 3.2% - 3.7% |
| 2020 | | | |
| Q1 | 1.88% | 2.57% | |
| Q2 | 1.38% | 1.90% | 3.0% - 3.8% |
| Q3 | 1.36% | 1.87% | |
| Q4 | 1.62% | 1.97% | 2.8% - 3.6% |
| 2021 | | | |
| Q1 | 2.07% | 2.23% | |
| Q2 | 2.26% | 2.77% | 3.5% - 3.9% |
| Q3 | 1.93% | 2.63% | |
| Q4 | 1.95% | 2.70% | 3.4% - 3.8% |
| 2022 | | | |
| Q1 | 2.25% | 2.87% | |
| Q2 | 3.04% | 3.47% | 3.8% - 3.9% |

Source and Note:
*Blue Chip Financial Forecasts,* January 2015 through August 2022.
*Average of all 3 reports in Quarter.

As outlined in Table 3 above, the outlook for increases in interest rates has jumped more recently relative to 2020 but is still relatively modest compared to time periods prior to the beginning of the worldwide pandemic. Indeed, today's relatively low capital market costs are expected to prevail at least in the short-term over the next five to ten years. While there may be some upward movement in the cost of capital, that upward movement is not expected to be significant. Importantly, the U.S. economy has largely recovered from the severe effects of the COVID-19 pandemic experienced in 2020. Capital markets continue to perform in a rational and economically logical manner at lower capital costs for safe investment sectors such as the utility industry.

## II.C. Market Sentiments and Utility Industry Outlook

**Q. Please describe the credit rating outlook for regulated utilities.**

A. The global economy has faced the extraordinary challenges of the novel coronavirus, which led to nearly a complete shutdown of the global economy. This unprecedented event has impacted all sectors and capital markets. However, regulated utilities have generally performed well during the COVID-19 pandemic with consistent access to capital markets.

Moody's Investors Service ("Moody's") views the regulatory environment for the U.S. utility companies to be supportive and maintains a stable outlook for the industry. Specifically, Moody's states:

> We are maintaining a stable outlook for the US regulated utilities sector based on our expectations that the regulatory environment will remain supportive of rate base growth and infrastructure investments and in mitigating the impact of extreme weather events. We anticipate that the regulated utility sector will remain resilient and benefit from the continuing US economic recovery.
>
> » **Regulatory environment to remain supportive.** We expect average aggregate rate base growth of around 6% in 2022 amid a supportive regulatory environment. Rate case outcomes and other regulatory actions have been remarkably consistent with our expectations over the past few years, despite extreme weather events and economic disruptions caused by the coronavirus pandemic.
>
> » **FFO-to-debt will be steady at current levels.** We estimate that the sector's aggregate industry funds from operations (FFO) to debt ratio will

> range between 14% and 15%, consistent with our projections last year for 2021. Our FFO-to-debt forecast incorporates our expectations for improving economic conditions in the US.
>
> » **Capital expenditures will remain high**. With a heightened focus on reducing carbon exposure, utilities continue to invest in new renewable generation capacity and to make up for accelerated coal-fired power plant retirements as well as to bolster transmission and distribution networks. Also, the frequency and severity of extreme weather events in 2021 are prompting many utilities to invest more in hardening their systems and enhancing the resilience of their operations amid rising physical climate risk.[5]

Similarly, Fitch Ratings ("Fitch") states the following:

> The sector outlook for North American Utilities, Power and Gas in 2022 is neutral, according to Fitch Ratings.
>
> Approximately 81% of rated entities in the sector have Stable Rating Outlooks based on an expectation that retail electricity sales will continue to strengthen and the regulatory environment will remain supportive.
>
> Key rating concerns include high natural gas prices, which will increase the fuel and purchased power costs for utilities and will be directly passed through to customers. Elevated capex, recovery of storm restoration costs and recovery of deferred coronavirus expenses will compound the pressure on customer bills. Declining O&M costs due to cost control initiatives and the ongoing energy transition to lower cost renewables should provide some offset.
>
> Fitch expects median FFO leverage for the sector to modestly improve to 4.5x in 2022 as utilities see a rebound in FFO from growth investments and recovery in retail sales. Parent holding companies will likely continue to look for asset monetization opportunities to supplement or replace equity needs to fund high capex. However, the improvement in leverage may not be enough to reverse the negative ratings trend for utility parent holding companies.
>
> Fitch expects liquidity of regulated utilities and parent holding companies to remain strong. The companies maintain large credit lines and benefit from unfettered access to capital markets. For competitive generators, robust FCF generation supports liquidity.[6]

[5] *Moody's Investors Service Sector Comment*: "2022 Outlook Stable On Sustained Regulatory Support for Robust Investment Cycle," November 4, 2021 at 1 (emphasis added).

[6] *Fitch Ratings*: "Neutral Outlook for North American Utilities, Power & Gas in 2022," December 9, 2021 at 1-2. (emphasis added).

S&P currently has a negative outlook for the regulated utility industry, because utility companies are operating with minimum financial cushion from their downgrade thresholds and their exposure to environmental, social and governance risk. Specifically, S&P states the following:

> **Key Takeaways**
>
> - For the second consecutive year rating downgrades outpaced upgrades for the investor-owned North American regulated utility industry, causing the median rating on the industry to fall to the 'BBB' category.
>
> - During 2021, credit quality was primarily pressured by weak financial measures and Environmental, Social, and Governance (ESG) credit risks. We expect that these risks will continue to pressure the credit quality of the industry in 2022.
>
> - Our outlook on the investor-owned North American regulated utility industry remains negative. We believe that 2022 could be the third consecutive year that downgrades outpace upgrades.
>
> - Recently, several new credit risks have emerged, including inflation, higher interest rates, and rising commodity prices. Persistent pressure from any of these risks would likely lead to a further weakening of the industry's credit quality in 2022.
>
> * * *
>
> **What's Behind This Fundamental Weakening Of Credit Quality?**
>
> Utility cash flows tend to be more stable and predictable than most other industries. Strategically, an increasing percentage of the industry has been managing their financial measures with only minimal financial cushion from their downgrade threshold. While this strategy of limiting excess credit capacity works well under ordinary conditions, when unexpected risks occur or base case assumptions deviate from expectations, the utility can become susceptible to a weakening of credit quality. This has been one of the primary drivers of the industry's weakening of credit quality over the past two years.
>
> * * *
>
> **Environmental, Social, and Governance (ESG) Credit Risks**
>
> During 2020 and 2021 the industry credit quality was constrained by many ESG-related credit risks. Unexpectedly, the industry faced several governance-related credit risks in 2020. We view these governance events

> as isolated incidents and do not believe that they will have broader implications for the larger utility industry. However, we do expect that physical and environmental risks will continue to constrain the industry's credit quality. Wildfires, severe winter storms, hurricanes, and tornadoes lead to higher costs that are either partially disallowed by regulators or are deferred for future recovery. Similarly, higher environmental costs can also result in higher costs that are either partially disallowed by regulators or are deferred for future recovery. Either outcome for physical and environmental risks typically results in weaker financial measures until the utility fully recovers such costs from customers. Because of climate change, we believe that these risks will continue to negatively affect credit quality in 2022.[7]

**Q. How is this observable market data used in forming your recommended return on equity and overall rate of return for GPC?**

A. Generally, authorized returns on equity, credit standing, and access to capital have been quite robust for utilities over the last several years. The COVID-19 pandemic has created challenges for the U.S. economy as a whole, including utility companies. However, the U.S. economy has largely recovered and utilities are expected to weather the economic downturn caused by the pandemic, and their financial strength will be restored as the economy continues to recover. In the meantime, it is critical that the Commission ensure that rates are increased no more than necessary to provide fair compensation and maintain financial integrity, and be especially concerned about rate impacts on the service area economies that are severely constrained due to current economic conditions.

## II.D. GPC Investment Risk

**Q. Please describe the market's assessment of the investment risk of GPC.**

A. The market's assessment of GPC's investment risk is described by credit rating analysts' reports. GPC's current corporate bond ratings of BBB+ from S&P, Baa1 from Moody's, and BBB from Fitch. The Company has a "Stable" outlook from all three credit rating agencies.[8]

[7] *S&P Global Ratings*: "For the First Time Ever, the Median Investor-Owned Utility Ratings Falls to the 'BBB' Category," January 20, 2022, at 1, 6 and 10. (emphasis added).

[8] Fetter Direct Testimony at 5. The Moody's Baa1 is equivalent to BBB+.

S&P's credit assessment of GPC is largely interconnected with its credit assessment of its parent company, Southern Company. Specifically, S&P states the following:

> **Outlook: Stable**
>
> The stable outlook for GPC reflects our outlook on the parent Southern Co. The stable outlook on Southern Co. reflects our expectations that the parent's consolidated financial measures will approximate funds from operations (FFO) to debt of 15%-16% over the next two years, coinciding with the approximate timeframe for the company to complete its complex nuclear construction projects.
>
> **Business Risk: Excellent**
>
> Our assessment of GPC's business risk largely reflects the company's large and diversified regulated utility operations in Georgia, and its effective management of regulatory risk. We view the company's regulatory risk management as effective, which is favorable for GPC's credit quality. Other aspects of the business risk include the size and quality of the company's service territory, and GPC's record of providing reliable electric services to its customers. In our view, these positive factors are offset by the construction and execution risks related to finishing the remainder of the company's construction activities for its two nuclear power projects, Vogtle Units 3 and 4 as well as the company's exposure to energy transition risks given its coal-fired fleet. Given the aforementioned factors, we view the company's business risk profile as being at the lower half of the excellent business risk profile category, supporting our use of a negative comparable ratings analysis modifier.
>
> **Financial Risk: Significant**
>
> We assess GPC's financial measures under our medial volatility table, reflecting its low-risk vertically integrated utility operations and effective management of regulatory risk. We expect FFO to debt of about 16% in 2021, averaging about 17% for 2022 and 2023. The company's FFO to debt for 2021 primarily reflects the combined effects of GPC's capital spending in 2021 of about $4 billion, which is about $550 million higher than in 2020, penalties on the company's Vogtle NCCR tariff, and negative discretionary cash flow over our forecast period. Our base case also reflects our expectation for parent Southern Co to provide equity as needed to support GPC's regulated capital structure. Improvements to the company's financial measures beyond 2022 assumes that Vogtle Units 3 and 4 are placed in service by the revised in-service dates. Under this

scenario, we view GPC's financial risk profile as being consistent with the significant financial risk profile category.[9]

Moody's also notes a "Stable" outlook for its Baa1 credit rating for GPC, also largely emphasizing the Company's progress and development of Vogtle Units 3 and 4. A summary of the highpoints of Moody's assessment of GPC includes the following:

[redacted][10]

In a May 2022 report, Fitch also noted concern about elevated business risk related to the construction and development costs of Vogtle Units 3 and 4. Fitch, like Moody's, noted ITAACs with the NRC, and expected near-term fueling of Vogtle Unit 3. Fitch also notes the current construction cap of $7.3 billion deemed reasonable by the Georgia PSC for the development of these two units. Fitch describes risk of further delays and ultimately the placing in-service of these two units and inclusion of all prudently incurred costs as being part of the execution risk, but notes that with the in-service date and ratemaking treatment, these costs will be mitigated.[11]

[9] *Standard & Poor's RatingsDirect, Summary:* "Georgia Power Co.," November 18, 2021 at 3-4, 6.

[10] *Moody's Investors Service*: "Georgia Power Company," Trade Secret STF-BAI-1-7 Attachment A, August 5, 2022.

[11] *Fitch Ratings*: "Georgia Power Senior Unsecured Notes BBB+," May 3, 2022.

**Q. Has the Commission approved any adjustments to GPC's retail rate-setting methodologies to support GPC's financial integrity during the development of the Vogtle 3 and 4 nuclear units?**

A. Yes. As described in more detail below, the Commission adjusted its ratemaking equity ratio to increase the common equity ratio to 56%, from roughly 51%, in an effort to strengthen the Company's financial integrity after the change in the federal tax law in 2018. This revised capital structure reduced the Company's reliance on debt and increased equity, which provided stronger cash flow coverages of debt obligations. The changing capital structure, however, increased GPC's overall rate of return and thus its revenue requirement, and this financial integrity assistance is then being paid for by customers in the form of increased bills.

In 2010, the Georgia legislature approved O.C.G.A. § 46-2-25(c.1), the implementation of a Nuclear Construction Cost Recovery ("NCCR") rider tariff which allows GPC to recover certain construction period financing charges on Vogtle Units 3 and 4. The Commission issued a certification order approving the collection of financing costs. Construction period carrying charges are based on rates at stated carrying charges, and applied to certification construction costs up to $4.4 billion.[12] For construction period carrying charges above the amount recovered through the NCCR, GPC is allowed to accrue Allowance for Funds Used During Construction ("AFUDC") charges, include those charges with plant costs, and recover them to the extent they are proven to be reasonable and prudent after the units are placed in-service and included in the development of retail rates.[13]

**Q. Has the Commission approved any other regulatory mechanisms to support GPC's energy transition risk?**

A. Yes. The Commission approved recovery of certain Coal Combustion Residual Asset Retirement Obligations ("CCR ARO") costs through the Environmental Compliance Cost

[12]Supplemental Information Review Stipulation. Paragraph 7.
[13]*Id*.

Recovery ("ECCR") tariff. Recovering these CCR AROs enhances the Company's cash flows and enhances assurance of full recovery of these CCR costs.[14]

In support of the development of Vogtle Units 3 and 4, the Commission has reached determination of construction costs up to $7.3 billion are assumed to be reasonable. [15] Further, the Commission approved an NCCR tariff that provides recovery of construction period financial charges from customers currently. The NCCR increases customer bills by charging them a certain portion of the construction period carrying charges at a stated NCCR rate of return.[16] The NCCR provides recovery of certain costs of Vogtle Units 3 and 4 development prior to these units being placed in commercial operation. This cost recovery enhances GPC's cash flows, and cash coverage of debt metrics and thereby supports its ability to maintain its investment grade bond rating.

## II.E. GPC's Proposed Capital Structure

**Q. What is GPC's proposed capital structure?**

A. GPC's witnesses Aaron Abramovitz, Sarah P. Adams, Adam D. Houston and Michael B. Robinson sponsored the Company's projected capital structure, which is shown below in Table 4. The proposed capital structure is based on the projected capital structure for the 12-month calendar test year period ending on July 31, 2023.

[14]GPC FERC Form 1, December 31, 2021 at pdf page 52.
[15]Order on the 17th Semi-Annual VCM Report. Paragraph 3. Page 11 of 20.
[16]*Id*. Paragraphs 7 and 9. Page 14 of 20.

**TABLE 4**

**GPC's Proposed Capital Structure**

| Description | Test Year 7/31/2023 | Year-End 2023/2024/2025 |
|---|---|---|
| Long-Term Debt | 44.18% | 44.00% |
| Common Equity | 55.82% | 56.00% |
| Total Regulatory Capital Structure | 100.00% | 100.00% |

Source: Exhibit___(APA/SPA/ADH/MBR-3, Schedule 2, Workpapers 1-4).

GPC panel witnesses Abramovitz, Adams, Houston and Robinson state that the Company's requested return on equity and the retail capital structure composed of 56% equity and 44% debt will maintain the Company's financial integrity and ensure its ability to raise capital at reasonable cost and upon reasonable terms for the benefit of customers.[17]

**Q. Is GPC's proposed ratemaking capital structure reasonable for ratemaking purposes?**

A. Not entirely. I do not contest the Company's proposed test year capital structure nor its proposed capital structure for calendar year 2023. Through year-end 2023, both Vogtle Units 3 and 4 will remain under development, which will continue to put financial stress on GPC's credit rating.[18]

However, the Company expects to place its Vogtle Unit 3 and common facilities in-service in first quarter of 2023, and to place Vogtle Unit 4 in-service by the fourth

[17]Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston & Michael B. Robinson at 7.

[18]GPC FERC Form 1, December 31, 2021 at pdf page 56.

quarter of 2023.[19] Starting in 2024 both Vogtle units will be in-service, and the Commission should adjust the ratemaking capital structure to include a common equity ratio of 51%, down from the 56%.

This capital structure adjustment is fair and reasonable for the following reasons:

1. The increased equity ratio while Vogtle Units 3 and 4 are being constructed is necessary to provide increased cash flow and maintain adequate credit metrics until Vogtle Units 3 and 4 are completed. After the construction is completed and these units are placed in-service, this credit metric support is no longer necessary.
2. Adjusting the ratemaking capital structure at the time Vogtle Units 3 and 4 are placed in-service will help mitigate the impact on customers' rates by including these new nuclear units' development in rates.
3. After the Vogtle Units are placed in-service, a lower common equity ratio is fair and reasonable because it will support GPC's financial integrity and credit standing, but at much lower cost to customers.
4. After the Vogtle Units are placed in-service, GPC's financial integrity will be very strong and its higher internal cash flow in proportion to its cash obligations will justify mitigating the impact on customers.
5. Rates charged to customers should be no more expensive than necessary to provide fair compensation and maintain financial integrity and credit standing. This objective is necessary to ensure that customers' rates are just and reasonable, and the public interest is protected.

**Q. Did the Commission make comments when it changed GPC's ratemaking capital structure to 56%?**

A. Yes. The Commission increased GPC's common equity ratio to 56%, from approximately 51% in an effort to strengthen GPC's financial integrity and credit standing. In a 2013 rate case, in Docket No. 36989, the Commission approved a

[19] *S&P Capital IQ*: "Georgia Power's Vogtle nuclear expansion costs rise; no new delays expected," September 2, 2022.

ratemaking capital structure with a 50.84% common equity ratio.[20] After this case, and after the Tax Cuts and Jobs Act went into effect in 2018, the Commission approved a settlement which allowed GPC to increase its common equity ratio to 55%.[21] In the Company's last rate case, in Docket No. 42516, the Commission approved a ratemaking capital structure with a 56% common equity ratio.

In approving a ratemaking capital structure with an increased common equity ratio, the Commission commented on the settlement in the case and the capital structure to be adequate to ensure GPC has access to capital whenever necessary, and reflected the impact on the Company's financial position as a result of the Tax Cuts and Jobs Act and settlement that was enacted after the Company's previous rate case in 2013.[22]

**Q. Does GPC's projected financial metrics indicate a significant improvement in its financial strength after the Vogtle Units are placed in-service?**

A. Yes. The Company's financial projections indicate significant improvement in the Company's financial standing after these units' construction is completed, and the facilities are placed in-service. The Company provided actual and projected financial statements and credit metrics in response to STF-NEC-1-5 in Attachment I Trade Secret. It was a 2022 rating agency meeting presentation. I summarize the results of that financial presentation and related core credit metric calculations as follows:

1. The Company's Funds From Operations ("FFO") as a percentage of capital expenditures improves significantly after the nuclear units are placed in-service, as expected, by 2024. During the period 2020 through 2023, the Company's FFO covered approximately 74% to 90% of its annual capital expenditures. After the units are expected to be placed in-service and included in rates in 2024, GPC's FFO to capital expenditures increases significantly to over [redacted]. This indicates that the Company is able to fund its planned capital expenditures in 2024 entirely with internally generated

[20]Docket No. 36989, Georgia Power 2013 Rate Case Settlement Agreement at 1.
[21]Order On The Tax Cuts And Jobs Act - 2018 TCJA Base Rates Settlement Exhibit 1, Docket No. 36989.
[22]*Id*.

cash. [redacted] As outlined on my Exhibit MPG-3, pages 7 and 15, GPC's projected internal cash flow to fund its capital expenditures makes it one of the strongest financial positions of the utilities in the *Value Line* regulated utility industry.

2. The Company's projected core credit metric financial ratios from both S&P, Moody's, and Fitch all improved significantly in 2024 relative to the preceding four-year period.
3. The Company's S&P core ratio of FFO to Debt improves considerably, [redacted]
4. The projected Moody's core credit ratios also improved significantly in 2024. [redacted]
5. Similarly, the projected Fitch credit ratios, like the other credit rating agencies, show very strong improvement in 2024 relative to the preceding four years.

**TABLE 5**

**Confidential - Financial Metrics**

| Line | Description | Company Presentation 2020A | 2021A | 2022E | 2023E | 2024E | Adjusted 2024 | Rating Agency Benchmarks "A" | "BBB" |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Equity Ratio | [redacted] | | | | | | | |
| 2 | Debt Ratio | | | | | | | | |
| 3 | FFO/Cap Exp | [redacted] | | | | | | | |
| | S&P Core[1] | | | | | | | "A" | "BBB" |
| 4 | FFO/Debt | [redacted] | | | | | | 23% - 35% | 13% - 23% |
| 5 | Debt/EBITDA | | | | | | | 2.5x - 3.5x | 3.5x - 4.5x |
| | Moody's Core[2] | | | | | | | | |
| 6 | CFO Pre-WC - Div / Debt | [redacted] | | | | | | 17% - 25% | 9% - 17% |
| 7 | Debt / Capitalization | | | | | | | 35% - 45% | 45% - 55% |
| 8 | CFO Pre-WC + Interest / Interest | | | | | | | 4.5x - 6.0x | 3.0x - 4.5x |
| | Fitch Core[3] | | | | | | | | |
| 9 | Debt/EBITDAR | [redacted] | | | | | | 3.25x - 3.75x | 3.75x - 4.75x |
| 10 | FFO Fixed Charge Coverage | | | | | | | 5.5x = > | 4.5x -5.5x |
| 11 | FFO Leverage | | | | | | | < = 3.5x | 5.0x - 3.5x |

Sources:
[1]Standard & Poor's: "Criteria: Corporate Methodology," November 19, 2013.
[2]Moody's: "Rating Methodology: Regulated Electric and Gas Utilities," June 23, 2017.
[3]FitchRatings: Sector Navigators Addendum to the Corporate Rating Criteria, October 15, 2021.

Also outlined in Table 5 above is a column titled "Adjusted 2024." In this column, I started with the Company's projected credit metrics in 2024, but I adjusted the metrics to reflect a 51% equity ratio and 49% debt ratio. As shown in this column, even with this capital structure adjustment and the related reduction in net income, and increase in interest expense, the Company's Debt to EBITDA credit metrics continue to support an improvement in the Company's current investment grade bond rating of BBB+, and continue to inch toward a stronger credit rating of "A" over time. Similarly, the FFO to Debt ratio is still in the A rating category range. This indicates that with the capital structure adjustment, GPC's credit rating metrics will [redacted].

As outlined later in my testimony, adjusting the ratemaking capital structure to reflect 51% common equity starting in 2024, after the Vogtle Units are placed in-service, the Company's projected credit metrics still support the expectation that its credit rating will be improved up to an "A" category.

**Q. Should the Commission be concerned about approving a ratemaking capital structure that is far more expensive than necessary to support the financial integrity of GPC?**

A. Yes. The Company will have an incentive to try to maintain the current capital structure after it is no longer needed not only to support GPC's financial integrity, but will continue to be needed to support the financial integrity of its parent company, Southern Company. I state this simply because GPC is one of the primary contributors of cash dividends to Southern Company, along with other regulated utility companies owned by Southern Company. Utility dividends cash flows are needed by Southern Company to service its own significant debt leverage.

Specifically, while GPC has a relatively modest level of leverage in its capital structure, its dividend payments to Southern Company are critical in supporting Southern Company's financial obligation, which is far more leveraged than that of its subsidiary GPC. Southern Company's actual capital structure mix of debt and equity is shown below in Table 6.

**TABLE 6**

**Southern Company Capital Structure**

| Line | Description | 2017 | 2018 | 2019 | 2020 | 2021 | June 30, 2022 |
|---|---|---|---|---|---|---|---|
| 1 | Long-Term Debt | 66.6% | 61.7% | 60.5% | 61.3% | 63.2% | 63.1% |
| 2 | Common Equity | 33.4% | 38.3% | 39.5% | 38.7% | 36.8% | 36.9% |
| 3 | **Total** | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

Sources:
S&P Market Intelligence, downloaded on September 28, 2022.

Because of the close affiliation and tie between Southern Company and GPC's credit rating, the Commission should be careful to ensure that the rates to customers are not inflated beyond what are necessary for Georgia Power's financial integrity and not to support the highly leveraged capital structure of its parent company, Southern Company.

Moreover, as shown on my Exhibit___(MPG-4), GPC's projected funding source for its capital improvement program indicates that GPC pays all of its earnings as

dividends up to its parent company, and in return, the parent company makes equity infusions in GPC to maintain its ratemaking capital structure. Because of the significant leverage at Southern Company, it may be funding equity infusions with a combination of debt and equity capital at the parent company level in exchange for GPC paying 100% of the equity it generates through retained earnings up to the parent company in the form of dividends. This exchange makes it clear that GPC's capital structure should be designed to support the financial integrity of GPC on a stand-alone basis, and Southern Company should finance the parent company structure in a manner that does not degrade or cause financial distress on GPC or any of its other regulated utility affiliates.

**Q. Would an adjustment to GPC's ratemaking capital structure to include a 51% equity ratio after the Vogtle Units are placed in-service produce a capital structure that reasonably aligns with industry normal regulatory capital structures?**

A. Yes. A 51% common equity ratio reasonably aligns with the industry average common equity ratio awarded to regulated utility companies over the 13-year period shown in Table 7 below. As shown in this table, the gas utility industry average and median common equity ratios have generally fallen to around 51% over the period 2010-2022. The industry medians generally support common equity ratios around of 50.00% - 51.00%.

**TABLE 7**

**Trends in State Authorized Common Equity Ratios**
**(Industry)**

| Line | Year | Electric[1] | | Natural Gas[1] | |
|---|---|---|---|---|---|
| | | Average | Median | Average | Median |
| | (1) | (2) | (3) | (4) | (5) |
| 1 | 2010 | 49.49% | 49.79% | 49.25% | 49.90% |
| 2 | 2011 | 49.09% | 49.10% | 52.49% | 52.45% |
| 3 | 2012 | 51.45% | 52.00% | 51.13% | 51.47% |
| 4 | 2013 | 50.12% | 51.03% | 51.16% | 50.43% |
| 5 | 2014 | 50.28% | 50.00% | 51.90% | 51.99% |
| 6 | 2015 | 50.24% | 50.48% | 49.79% | 50.33% |
| 7 | 2016 | 49.70% | 49.99% | 51.85% | 51.35% |
| 8 | 2017 | 50.02% | 49.85% | 51.13% | 51.76% |
| 9 | 2018 | 50.60% | 50.23% | 52.58% | 53.08% |
| 10 | 2019 | 51.55% | 51.37% | 52.72% | 52.22% |
| 11 | 2020 | 50.94% | 51.17% | 52.34% | 52.00% |
| 12 | 2021 | 51.01% | 52.00% | 51.63% | 52.00% |
| 13 | 2022 | 51.53% | 51.92% | 51.17% | 50.50% |
| 14 | Min | 49.09% | 49.10% | 49.25% | 49.90% |
| 15 | Max | 51.55% | 52.00% | 52.72% | 53.08% |
| 14 | Average | 50.46% | 50.69% | 51.47% | 51.50% |
| 16 | Median | 50.28% | 50.48% | 51.63% | 51.76% |

Source and Notes:
[1] S&P Global Market Intelligence; data through September 16, 2022.
- Excludes Arkansas, Florida, Indiana and Michigan because they include non-investor capital.

As shown above in Table 7, the industry average and median common equity ratios for electric utilities over the last several years have been consistently about 49.00% to 52.00%. GPC's proposed ratemaking capital structure of approximately 56.00% equity is significantly in excess of the electric utility industry average ratemaking capital structure.

**Q. Would a 51% ratemaking equity ratio align with the amount of leverage consistent with other regulated utility companies with bond ratings similar to that of GPC?**

A. Yes. In assessing its credit rating, S&P developed what it refers to as an "adjusted" debt ratio by deriving a utility's debt leverage reflecting all of its on-balance sheet debt, both short-term and long-term, and off-balance sheet contractual obligations. GPC indicated in data response STF-BAI-1-17, that it does not have any off-balance sheet debt obligations.

In calendar 2024, adjusted to reflect short-term debt not included in the ratemaking capital structure, and including all the off-balance sheet contractual obligations noted by GPC in response to STF-BAI-1-17 (zero), I developed an S&P adjusted debt ratio on my Exhibit____(MPG-5). As shown on this exhibit, at a 51% ratemaking common equity ratio, GPC's adjusted debt ratio would be approximately 50%.

I compared this 50% debt ratio to GPC's current bond rating of BBB+, and A-rated utility companies. As shown in Table 8 below, a ratemaking common equity ratio with around 50% debt is reasonably aligned with a majority of regulated utility companies with bond ratings in the range of BBB+ to A.

**TABLE 8**

**S&P Adjusted Debt Ratio**
**(Operating Subsidiaries of Value Line Electric, Gas and Water Utilities)**

| | | % Distribution of 3 Year Average | | | |
|---|---|---|---|---|---|
| **Rating** | **Average** | **<45** | **45 to 50** | **50 to 55** | **>55** |
| AA- | 43.6% | 67% | 33% | 0% | 0% |
| A+ | 52.7% | 18% | 36% | 0% | 45% |
| A | 48.5% | 26% | 41% | 15% | 19% |
| A- | 52.4% | 7% | 24% | 39% | 30% |
| BBB+ | 52.0% | 9% | 29% | 39% | 23% |
| BBB | 48.6% | 30% | 23% | 30% | 17% |

Source:
S&P Capital IQ, downloaded June 7, 2022.

Hence, adjusting GPC's ratemaking capital structure to reflect a 51% equity ratio in 2024 would be consistent with the normalized industry ratemaking capital structure and reflect a moderate amount of leverage in support of GPC's current investment grade bond rating, and even an improvement to the bond rating into the "A" category.

**Q. You stated that adjusting the common equity ratio in 2024 from 56% down to 51% will help to mitigate cost increases on customers. What is the potential reduction in GPC's cost of service through this adjustment to its 2024 and 2025 ratemaking capital structure?**

A. The impact on GPC's revenue requirement in 2024 by adjusting its ratemaking capital structure to include a 51% common equity ratio would lower its 2024 and 2025 revenue requirement by approximately $145.1 million and $153.7 million, respectively, which is developed on my Exhibit____(MPG-6). This offset to its cost of service reflects GPC's projected 2024 and 2025 rate base of $26.8 billion and $28.4 billion, respectively. Hence, this offset to its cost of service as of 2024 will support its customers' ability to be able to pay rates stated at GPC's cost of service, after the Vogtle Units are placed in-service and included in the development of base tariff rates.

**Q. What is your recommended ratemaking capital structure for GPC in the test year, and the proposed post-test year adjustments?**

A. As shown below in Table 9, I do not oppose the Company's proposed ratemaking capital structure in the test year, and for the calendar year 2023. However, in 2024, I recommend the Company's ratemaking capital structure be modified to reflect a common equity ratio of 51% and this capital structure would remain in place for 2025, and beyond.

**TABLE 9**

**GPC's Proposed Capital Structure**

| Description | Test Year 7/31/2023[1] | Year-End 2023[1] | Year-End 2024/2025[2] |
|---|---|---|---|
| Long-Term Debt | 44.18% | 44.00% | 49.00% |
| Common Equity | 55.82% | 56.00% | 51.00% |
| Total Regulatory Capital Structure | 100.00% | 100.00% | 100.00% |

Sources:
[1]Exhibit___(APA/SPA/ADH/MBR-3, Schedule 1, Workpapers 1).
[2]Exhibit___(MPG-2).

Adjusting the ratemaking capital structure in 2024 and 2025 to reflect 51% common equity is reasonable and appropriate, because it will reduce GPC's revenue requirement and offset the increase in the revenue requirement at the time Vogtle Units 3 and 4 are introduced due to its cost of service, and will maintain adequate credit metrics and financial integrity to support GPC's ability to access external capital after the development of Vogtle Units 3 and 4.

**Q. Will your proposed capital structure support credit metrics that will maintain GPC's investment grade bond rating?**

A. Yes. Later in the financial integrity section of my testimony, I show that my proposed overall rate of return supports GPC's current investment grade bond rating in the test year and 2023-2025.

**Q. Did GPC witness Steven Fetter comment on the appropriateness of maintaining a utility's financial integrity and strong credit standing?**

A. Yes. In summarizing his testimony, he recognized that GPC has a BBB+ bond rating from S&P, Baa1 from Moody's and BBB from Fitch with a "Stable" outlook from all three credit rating agencies.[23]

Mr. Fetter also points out that the credit rating agencies view the regulatory environment in GPC's service territory as supportive to credit ratings but they all express concerns regarding the delays with the Vogtle nuclear project.

Mr. Fetter also lists key credit metrics considered by S&P in assigning GPC's bond ratings. He states that two core financial ratios include Funds From Operations ("FFO") to Debt, which focuses on cash flow, and Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") which provides a comparative profitability measure. He further testified that it is S&P's long held belief that cash flow analysis is the single most critical aspect of credit rating decisions.[24]

**Q. Did Mr. Fetter demonstrate that the Company's proposed ratemaking capital structure, and the Company's requested return on equity are necessary to maintain adequate core credit metrics at a level that will maintain GPC's credit standing and financial integrity?**

A. No. I disagree with Mr. Fetter's assertion that GPC will maintain or improve its credit rating if the Commission adopts GPC witness Coyne's recommended return on equity of 11.0%. Importantly, Mr. Fetter provided no substance or evidence that supports his conclusion that GPC's credit rating and financial integrity are only achieved if the Company's return on equity and proposed ratemaking capital structure are adopted.

## II.F. Embedded Cost of Debt

**Q. What is GPC's embedded cost of long-term debt?**

A. GPC is proposing an embedded cost of long-term debt of 3.53% for the Test Period ending July 31, 2023 and is developed in the workpapers to

[23] Fetter Direct Testimony at 5.
[24] *Id*. at 15.

Exhibit___(APA/SPA/ADH/MBR-3, Schedule 3, Workpaper 3 and 4) of the Company's filing. GPC's embedded cost of debt is also 3.53% for December 31, 2023, 3.58% for December 31, 2024, and 3.66% for December 31, 2025.

## III. RETURN ON EQUITY

**Q. Please describe what is meant by a "utility's cost of common equity."**

A. A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

**Q. Please describe the framework for determining a regulated utility's cost of common equity.**

A. In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Electric Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Court found that a utility is entitled to such rates as are permitted to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Court continued that the utility has no constitutional rights to profits such as those realized or anticipated in highly profitable enterprises or speculative ventures, and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[25]

As such, a fair rate of return is based on the expectation that the utility's costs reflect efficient and economical management, and the return will support its credit

[25] *Bluefield,* 262 U.S. 679, 693 (1923), emphasis added.

standing and access to capital, without being in excess of this level. From these standards, rates to customers will be just and reasonable, and under economic management, compensation to the utility will be fair and support financial integrity and credit standing.

## III.A. Risk Proxy Group

**Q. Please describe how you identified proxy utility group that could be used to estimate GPC's current market cost of equity.**

A. I relied on the same proxy group developed by GPC witness Mr. Coyne with one exclusion. I excluded American Electric Power Company, Inc. because it entered into a definitive agreement to sell Kentucky Power Transmission, and the transaction has not been completed. I also included Southern Company, GPC's publicly traded parent company, which meets the proxy group risk selection criteria.

Companies that are involved in mergers and acquisitions ("M&A") or divestiture activities have market valuations that may not accurately reflect the stand-alone valuation of the company, but rather may anticipate enhanced valuation from the proposed M&A transaction. Therefore, removing them from the proxy group is necessary because the resulting market-based return analyses on these specific companies can be distorted and/or would simply be unreliable.

**Q. Please describe why you believe your proxy group is reasonably comparable in investment risk to GPC.**

A. My proxy group is shown in Exhibit___(MPG-7). The proxy group has an average credit rating from S&P of BBB+, which is identical to GPC's credit rating from S&P. The proxy group has an average Moody's credit rating of Baa2, which is one notch below GPC's credit rating of Baa1 from Moody's.

My proxy group has an average common equity ratio of 41.2% from S&P (including short-term debt) and a 44.7% equity ratio from *Value Line* (excluding short-term debt). GPC's requested common equity ratio of 56.0% is higher than the proxy group average of 44.7%. My proposed common equity ratio of 51.0% for forecasted years 2024 and 2025 is also higher than the group average common equity ratio.

## III.B. Discounted Cash Flow ("DCF") Model

**Q. Please describe the DCF model.**

A. The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} + \ldots + \frac{D_\infty}{(1+K)^\infty} \quad \text{(Equation 1)}$$

$P_0$ = Current stock price

D = Dividends in periods 1 - ∞

K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \quad \text{(Equation 2)}$$

K = Investor's required return

$D_1$ = Dividend in first year

$P_0$ = Current stock price

G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

## III.C. Constant Growth DCF

**Q. Please describe the inputs to your constant growth DCF model.**

A. As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

**Q. What stock price did you use in your constant growth DCF model?**

A. I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on September 16, 2022. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflects current market expectations, but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

**Q. What dividend did you use in your constant growth DCF model?**

A. I used the most recently paid quarterly dividend as reported in *Value Line*.[26] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the $D_1$ factor for use in Equation 2 above. In other words, I calculate $D_1$ by multiplying the annualized dividend ($D_0$) by (1+G).

**Q. What dividend growth rates did you use in your constant growth DCF model?**

A. There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, to determine the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend, or earnings growth rate, will be and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[27] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate

[26] *The Value Line Investment Survey*, July 22, August 12, and September 9, 2022.

[27] *See, e.g.*, David Gordon, Myron Gordon & Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

estimates from three sources: Zacks, MI, and Yahoo! Finance. All such projections were available on September 16, 2022, and all were reported online.

Each consensus growth rate projection is based on a survey of securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

**Q. What are the growth rates you used in your constant growth DCF model?**

A. The growth rates I used in my DCF analysis are shown in Exhibit___(MPG-8). The average growth rate for my proxy group is 5.45%.

**Q. What are the results of your constant growth DCF model?**

A. As shown in Exhibit___(MPG-9), the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 8.97% and 9.20%, respectively.

**Q. Do you have any comments on the results of your constant growth DCF analysis?**

A. Yes. The constant growth DCF analysis for my proxy group is based on an average long-term sustainable growth rate of 5.45%. The three- to five-year growth rate is higher than my estimate of a maximum long-term sustainable growth rate of 4.35%.

**Q. How did you estimate a maximum long-term sustainable growth rate?**

A. The long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is, accordingly, best proxied by the projected long-term GDP growth rate as that reflects the projected long-term growth rate of the economy as a whole. While growth rates on shorter periods can exceed the GDP growth rate, those short-term growth periods are likely followed by other periods where

the growth rate is below the GDP. On average, over long periods of time, the growth rate is most accurately approximated by the long-term growth rate outlooks of the U.S. GDP.

*Blue Chip Financial Forecasts* projects that over the next 5 to 10 years, the U.S. nominal GDP will grow at an annual rate of approximately 4.35%.[28] These GDP growth projections reflect a real growth outlook of around 2.05% and an inflation outlook of around 2.25% going forward. As such, the average nominal growth rate over the next 5 years is around 4.35%, which I believe is a reasonable proxy of long-term sustainable growth.[29]

**Q. Is there independent authoritative support for using long-term GDP growth as a maximum sustainable growth rate?**

A. Yes. In my multi-stage growth DCF analysis, I discuss academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Using the long-term GDP growth rate, however, as a conservative projection for the maximum sustainable growth rate is logical, and is generally consistent with academic and economic practitioner accepted practices.

## III.D. Sustainable Growth DCF

**Q. Please describe how you estimated a sustainable long-term growth rate for your sustainable growth DCF model.**

A. A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained by the utility and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases.

[28] *Blue Chip Financial Forecasts*, June 1, 2022, at 14.
[29] *Id*.

An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings.

The payout ratios of the proxy group are shown in my Exhibit___(MPG-10). These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate are based on GPC's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit___(MPG-11), the average sustainable growth rate using this internal growth rate model is 4.86% for my proxy group, which is in line with the long-term sustainable growth outlook as measured by the GDP growth.

**Q. What is the DCF estimate using these sustainable long-term growth rates?**

A. A DCF estimate based on these sustainable growth rates is developed in Exhibit___(MPG-12). As shown there, the sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.37% and 8.17%, respectively.

## III.E. Multi-Stage Growth DCF Model

**Q. Have you conducted any other DCF studies?**

A. Yes. My first constant growth DCF is based on consensus analysts' growth rate projections so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on this constant growth DCF model is that it cannot reflect a rational expectation that a period of high or low short-term growth can be followed by a change in growth to a rate that better reflects long-term sustainable growth. Therefore, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

**Q. Why do you believe growth rates can change over time?**

A. Analyst-projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which in turn accelerates earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows and its earnings growth slows from an abnormally high three- to five-year rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because the pace of rate base growth will slow and because the utility has limited human and capital resources available to expand its construction program. Therefore, the three- to five-year growth rate projection should only be used as a long-term sustainable growth rate in concert with a reasonable, informed judgment regarding the current market environment, the industry, and the three- to five-year growth outlook to be sustainable.

**Q. Please describe your multi-stage growth DCF model.**

A. The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections I used above in my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate, which is the projected long-term GDP growth rate.

**Q. Why is the GDP growth projection a reasonable proxy for the maximum sustainable long-term growth rate?**

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services.[30] Utilities' earnings/dividend growth are created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth. Sales growth, in turn, is tied to economic growth in their service areas.

The U.S. Department of Energy, Energy Information Administration ("EIA") has observed utility sales growth tracks U.S. GDP growth, albeit at a lower level, as shown in Exhibit___(MPG-13). Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative proxy for utility sales growth, rate base growth, and earnings growth. Therefore, the U.S. GDP nominal growth rate is a reasonable proxy for the highest sustainable long-term growth rate of a utility.

**Q. Is there research that supports your position that, over the long term, a company's earnings and dividends cannot grow at a rate greater than the growth of the U.S. GDP?**

A. Yes. This concept is supported in published analyst literature and academic work. Specifically, in "Fundamentals of Financial Management," a textbook published by Eugene Brigham and Joel F. Houston, the authors state:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[31]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

[30] A company cannot grow faster than the general economy indefinitely as it would become larger than the economy.

[31] "*Fundamentals of Financial Management*," Eugene F. Brigham & Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298, emphasis added.

**Estimating Growth Rates**

> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[32]

**Q. Are there actual investment results that support the theory that the growth on stock investments will not exceed the nominal growth of the U.S. GDP?**

A. Yes. This is evident by a comparison of the compound annual growth of the U.S. GDP to the geometric growth of the U.S. stock market. Kroll measures the historical geometric growth of the U.S. stock market over the period 1926-2021 to be approximately 6.4%.[33] During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.0%.[34]

As such, over the past 95 years, the geometric average growth of the U.S. nominal GDP has been slightly higher than, but comparable to, the geometric average growth of the U.S. stock market capital appreciation. This historical relationship indicates that the U.S. GDP growth outlook is a reasonable estimate of the long-term sustainable growth of U.S. stock investments.

[32]Morningstar, Inc., Ibbotson *SBBI 2013 Valuation Yearbook* at 51 and 52.
[33]Kroll, *2022 SBBI Yearbook* at 145.
[34]U.S. Bureau of Economic Analysis, Table 1.1.5 Gross Domestic Product, Revised May 26, 2022.

**Q. What is the geometric average and why is it appropriate to use this measure to compare GDP growth to capital appreciation in the stock market?**

A. The terms geometric average growth rate and compound annual growth rate are used interchangeably. The geometric annual growth rate is the calculated growth rate, or return, that measures the magnitude of growth from start to finish. The geometric average is best, and most often, used as a measurement of performance or growth over a long period of time.[35] Since I am comparing achieved growth in the stock market to achieved growth in U.S. GDP over a long period of time, the geometric average growth rate is most appropriate.

**Q. How did you determine a long-term growth rate that reflects the current consensus market participant outlook?**

A. I relied on the economic consensus of long-term GDP growth projections. *Blue Chip Financial Forecasts* publishes the consensus for GDP growth projections twice a year. These consensus GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth because the analysts' projections reflect all current outlooks for GDP. They are therefore likely the most influential on investors' expectations of future growth outlooks. The consensus projections published GDP growth rate outlook is 4.35% over the next 5 to 10 years.[36]

I propose to use the consensus for projected five-year average GDP growth rates of 4.35%, as published by *Blue Chip Financial Forecasts*, as an estimate of long-term sustainable growth. *Blue Chip Financial Forecasts* projections provide real GDP growth projections of approximately 2.05% and inflation of 2.25% over the ten-year (2024--2033) projected periods, resulting in an average five- to-ten-year nominal annual GDP growth projection of 4.35%.[37] These GDP growth forecasts represent the most likely views of market participants because they are based on published economic consensus projections.

[35] *New Regulatory Finance*, Roger Morin, PhD, at 133-134.
[36] *Blue Chip Financial Forecasts*, June 1, 2022, at 14.
[37] *Id*.

**Q. Do you consider other sources of projected long-term GDP growth?**

A. Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. Various, commonly relied upon analysts' projections are shown in Table 10 below.

**TABLE 10**

**GDP Forecasts**

| Source | Projected Period | Real GDP | Inflation | Nominal GDP |
|---|---|---|---|---|
| Blue Chip Financial Forecasts[1] | 5-10 Yrs | 2.05% | 2.25% | 4.35% |
| EIA - Annual Energy Outlook[2] | 29 Yrs | 2.21% | 2.28% | 4.55% |
| Congressional Budget Office[3] | 30 Yrs | 1.62% | 2.06% | 3.72% |
| Moody's Analytics[4] | 31 Yrs | 2.09% | 2.09% | 4.22% |
| Social Security Administration[5] | 74 Yrs | | | 4.12% |
| Economist Intelligence Unit[6] | 29 Yrs | 1.68% | 2.18% | 3.90% |

Sources:
[1]Blue Chip Financial Forecasts, June 1, 2022 at 14.
[2]U.S. EnergyInformation Administration (EIA), Annual Energy Outlook 2022, March 3, 2022.
[3]Congressional Budget Office, Long-Term Budget Outlook, July 2021.
[4]Moody's Analytics Forecast, downloaded June 29, 2022.
[5]Social Security Administration, "2021 OASDI Trustees Report," Table VI.G4, August 31, 2021.
[6]S&P MI, Economist Intelligence Unit, downloaded on March 9, 2022.

As shown in the table above, the real GDP and inflation fall in the range of 1.62% to 2.21% and 2.06% to 2.28%, respectively. This results in a nominal GDP in the range of 3.72% to 4.55%.

Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.35% as a reasonable estimate of market participants' expectations for long-term GDP growth.

**Q. What stock price, dividend, and growth rates did you use in your multi-stage growth DCF analysis?**

A. I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.35% long-term sustainable growth rate based on the consensus economists' long-term projected nominal GDP growth rate.

**Q. What are the results of your multi-stage growth DCF model?**

A. As shown in Exhibit___(MPG-14), the average and median multi-stage growth DCF returns on equity for my proxy group using the 13-week average stock price are 8.10% and 8.07%, respectively.

## III.F. DCF Summary Results

**Q. Please summarize the results from your DCF analyses.**

A. The results from my DCF analyses are summarized in Table 11 below:

**TABLE 11**

**Summary of DCF Results**

| Description | Average | Median |
|---|---|---|
| Constant Growth DCF Model (Analysts' Growth) | 8.97% | 9.20% |
| Constant Growth DCF Model (Sustainable Growth) | 8.37% | 8.17% |
| Multi-Stage Growth DCF Model | 8.10% | 8.07% |

Based on the current market conditions, my DCF studies indicate a fair return on equity for GPC in the range of 8.80% to 9.20%, with a midpoint of 9.0%.

## III.G. Risk Premium Model

**Q. Please describe your Bond Yield Plus Risk Premium model.**

A. This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds. The coupon (interest) payments on bonds represent contractual obligations that are paid on scheduled dates, and bondholders have more security of payment in bankruptcy proceedings than common equity shareholders. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year from 1986 through June 2022. The authorized returns on equity were based on regulatory commission-authorized returns for utility companies. Authorized return recommendations presented to commissions are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through June 2022 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit___(MPG-15), which shows the market-to-book ratio since 1986 for the electric utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized returns on equity were sufficient to support market prices that exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates utilities were able to access equity markets without detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit___(MPG-16), the average indicated equity risk premium over U.S. Treasury bond yields has been 5.72%. Since the risk

premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for the risk premium methodology.

I incorporated five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over at least one business cycle. As shown on my Exhibit___(MPG-16), the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 7.09%, with an average of 5.68%. The ten-year rolling average risk premium ranged from 4.38% to 6.91%, with an average of 5.68%.

As shown on my Exhibit___(MPG-17), the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.36%. The five-year rolling average risk premiums ranged from 2.88% to 5.90%, with an average of 4.33%. The ten-year rolling average risk premiums ranged from 3.20% to 5.73%, with an average of 4.32%.

**Q. Do you believe that the time period used to derive these equity risk premium estimates is appropriate to form accurate conclusions about contemporary market conditions?**

A. Yes. Contemporary market conditions can change during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Alternatively, some studies, such as Kroll, have recommended that the use of "actual achieved investment return data" in a risk premium study should be based on long

historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. Short-term, abnormal actual returns would be smoothed over time and the achieved actual investment returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on data that inherently relied on investor expectations, not actual investment returns, and, thus, need not encompass a very long historical time period.

**Q. What does current observable market data suggest about investor perceptions of utility investments?**

A. The equity risk premium should reflect the relative market perception of risk today in the utility industry. I have gauged investor perceptions in utility risk today in Exhibit___(MPG-18), where I show the yield spread between utility bonds and Treasury bonds over the last 43 years. As shown in this exhibit, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.48% and 1.91%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities through August 2022 were 1.54% and 1.85%, respectively.

The current 13-week average "A" rated utility bond yield of 4.87% when compared to the current 30-year Treasury bond yield of 3.21%, as shown in Exhibit___(MPG-19), implies a yield spread of 1.66%. This current utility bond yield spread is higher than the 43-year average spread for "A" rated utility bonds of 1.48%. The current spread for the "Baa" rated utility bond yield of 2.01% is also higher than the 43-year average spread of 1.91%.

**Q. Is there observable market evidence to help gauge market risk premiums?**

A. Yes. Market data illustrates how the market is pricing investment risk, and gauging the current demands for returns based on securities of varying levels of investment risk. This market evidence includes bond yield spreads for different bond return ratings as implied

by the yield spreads for Treasury, corporate and utility bonds. These spreads provide an indication of the market's return requirement for securities of different levels of investment risk and required risk premiums.

Table 12 below summarizes the utility and corporate bond spreads relative to Treasury bond yields.

**TABLE 12**

**Comparison of Yield Spreads Over Treasury Bond Yields**

| | Utility | | Corporate | |
|---|---|---|---|---|
| Year | A | Baa | A | Baa |
| Average Historical Spread | 1.48% | 1.91% | 0.84% | 1.91% |
| 2019 Spread | 1.18% | 1.61% | 0.81% | 1.79% |
| 2020 Spread | 1.49% | 1.87% | 0.96% | 2.10% |
| 2021 Spread | 1.05% | 1.30% | 0.65% | 1.34% |
| 2022 Spread* | 1.54% | 1.85% | 0.96% | 1.89% |

Source: Moody's Bond Yields
*2022 data through September 16, 2022.

As outlined above, the observable market evidence indicates that risk premiums are reasonably aligned with long-term historical averages. As such, in comparison to recent utility bond yields and Treasury bond yields, I believe the most reasonable estimate of the current market cost of equity should reflect an average historical yield spread.

In terms of utility stock yields over utility bond yields, the risk premium appears to be returning to more normal levels. As outlined on my Exhibit___(MPG-3), page 4, stock yield spreads over A-rated utility bond yields have expanded to around 1.0% from negative to very thin spreads extending back to 2016. The same is true for utility stock yield spreads over Baa-rated utility bonds. Observable stock yield spreads over utility bond yields indicate that risk premiums in the marketplace today more reasonably align with normal risk premiums that have been experienced over long historical periods.

**Q. What is your recommended return for GPC based on your risk premium study?**

A. Because yield spreads have reverted to the long-term historical average, I recommend applying a long-term historical average risk premium to current utility bond yield spreads.

For the Treasury bond yields, I relied on the five-year rolling average historical risk premium of approximately 5.68% in combination with a forecasted Treasury bond yield of 3.60%.[38] A forecasted Treasury bond yield of 3.60% reflects a substantial increase in the Treasury bond yield over a 13-week study period of 3.21%, as shown on my Exhibit___(MPG-19), page 1. Using a Treasury bond risk premium of 5.68% and a projected 30-year Treasury bond yield of 3.60% produces an indicated equity risk premium of 9.28% (5.68% + 3.60%).

A risk premium based on utility bond yields reflects current observable bond yields. Current observable bond yields may increase over time based on economists' projections of changes in interest rates. However, history indicates that economists typically overestimate increases in interest rates. Therefore, current observable rates should also be considered. With current observable rates, I recommend using the five-year rolling average risk premium estimate of 4.33%, which as shown on Exhibit___(MPG-17) with an A utility yield of 4.87% as shown on my Exhibit___(MPG-19), page 1, produces a risk premium return on equity of 9.21% (4.33% + 4.87%).

**TABLE 13**

**Summary of Risk Premium Results**

| | Treasury | Utility |
|---|---|---|
| Equity Risk Premium | 5.68% | 4.33% |
| Risk-Free Rate | 3.60% | 4.87% |
| Risk Premium | 9.28% | 9.21% |

[38] *Blue Chip Financial Forecasts*, August 1, 2022 at 2.

As shown in Table 13 above, based on this methodology, my 30-year Treasury bond risk premium and my utility bond risk premium rounded indicate a return on equity of 9.30% to 9.20%, or 9.30%.

## III.H. Capital Asset Pricing Model ("CAPM")

**Q. Please describe the CAPM.**

A. The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

$R_i$ = Required return for stock i

$R_f$ = Risk-free rate

$R_m$ = Expected return for the market portfolio

$B_i$ = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, stock-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

Risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market and referred to as systematic risks. Risks that can be eliminated by diversification are non-systematic risks. In a broad sense, systematic risks are market risks and non-systematic risks are business risks. The CAPM theory suggests the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk investors will be compensated for are systematic, or non-diversifiable, risks. The beta is a measure of the systematic, or non-diversifiable risks.

**Q. Please describe the inputs to your CAPM.**

A. The CAPM requires an estimate of the market risk-free rate, beta, and the market risk premium.

**Q. What did you use as an estimate of the market risk-free rate?**

A. As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 3.60%.[39] The current 30-year Treasury bond yield is 3.21%, as shown in Exhibit___(MPG-19).

**Q. Why did you use long-term Treasury bond yields as an estimate of the risk-free rate?**

A. Treasury securities are backed by the full faith and credit of the United States government. Therefore, long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. In this regard, a Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates reflect systematic market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

**Q. What beta did you use in your analysis?**

A. I reviewed the average utility beta of 0.89 for my proxy group as shown on my Exhibit___(MPG-20).

[39] *Id*.

I also reviewed the long-term trend of *Value Line* betas reported for the proxy group companies, and the *Value Line* regulated utility industries. The proxy group's betas have generally ranged between 0.65 and 0.75 prior to the elevated betas published after the COVID-19 pandemic commenced Exhibit___(MPG-20), page 2). The historical variability in the proxy group *Value Line* betas is similar to the historical variability in the entire regulated utility industry betas followed by *Value Line* (Exhibit___(MPG-20), page 3). On this schedule, similar to the proxy group companies, I show the *Value Line* electric industry historical beta estimates, which also indicate that the current beta is abnormally high, and the long-term historical average beta of the proxy group reasonably aligns with that of the entire industry.

The normalized historical beta estimates for the proxy group is 0.75. Thus, the current beta estimate of 0.89 is well above the normalized historical beta for my proxy group.

**Q. Have you performed any studies to prove that published *Value Line* betas are abnormally high and do not accurately reflect investment risk of GPC?**

A. Yes. Above, I outline a study based on *Value Line*'s methodology but using the S&P 500 utility index, relative to the New York Stock Exchange, and show that beta estimates are skewed due to two months of data within the 60-month time period used to measure beta. The two months that skew the betas are in March and April of 2020, a time period that coincides with the start of the worldwide COVID-19 pandemic. Removing these two months has the effect of reducing utility beta estimates from the very high levels right now of around 0.90, down to more normalized betas in the range of 0.65 to 0.75. This beta regression study is summarized in Table 14 below.

**TABLE 14**

**S&P 500 Utilities vs. NYSE**
**Regression Betas**

| Period | Raw Beta | Adjusted Beta | $R^2$ |
|---|---|---|---|
| 5 Yr Ending Feb '20 | 0.45 | 0.65 | 0.18 |
| May '20 - Current | 0.65 | 0.78 | 0.39 |
| Most Recent 5 Yr Period | 0.82 | 0.90 | 0.52 |

Note:
Calculated using Value Line's regression based beta methodology.
The current and most recent periods are through 9/16/22.

Based on this analysis, I reject placing significant weight on *Value Line* published betas and instead rely on more normalized historical betas to produce a fair risk-adjusted return in this proceeding.

**Q. Why is it not reasonable to estimate a CAPM return on a regulated utility based on beta estimates that are clearly outliers for historical average betas?**

A. Utility company betas have increased from around 0.65 to 0.75 up to a current level around 0.89 over the last two years. This increase in betas suggests that utility companies' investment risks are increasing relative to the overall general marketplace. But, the outlook of increasing utility investment risk is simply not supported by a review of other risk measures for utilities including: (a) current robust valuation metrics of utilities as described above; (b) risk spreads of utility stock yields relative to bond yields; (c) sustained investment grade bond ratings for utility companies, and (d) access to significant amount of capital. Again, as shown on Exhibit___(MPG-3), the historically strong valuation metrics of regulated utilities are particularly robust, indicating the market is paying a premium for utility stocks. The fact that utility stocks are trading at a premium is inconsistent with the notion that the market perceives the utility industry's investment risk to be increasing. It also shows that the market is not demanding a higher rate of return to invest in these securities. My conclusion is that the elevated betas for

utility stocks were skewed by the temporary effects of the market events during the onset of the pandemic but the beta impacts have returned to more normal levels as the market recovered.

For these reasons, in performing my CAPM, I used a more normalized beta of 0.75 and market risk premium factors in order to derive a CAPM return estimate in this proceeding.

**Q. How did you derive your market risk premium estimate?**

A. I derived two market risk premium estimates: a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Kroll's *2022 SBBI Yearbook* estimates the historical arithmetic average real market return over the period 1926 to 2021 to be 9.2%.[40] A current consensus for projected inflation, as measured by the Consumer Price Index, is 2.5%.[41] Using these estimates, the expected market return is 11.93%.[42] The market risk premium then is the difference between the 11.93% expected market return and my 3.60% risk-free rate estimate, or 8.33%, which I referred to as a normalized market risk premium.

I also developed a current market risk premium based on the difference between the expected return on the market of 11.93% as described above and the current 30-year Treasury yield of 3.21% as shown on my Exhibit___(MPG-19), which produced a current market risk premium of approximately 8.72%.

A historical estimate of the market risk premium was also calculated by using data provided by Kroll in its *2022 SBBI Yearbook*. Over the period 1926 through 2021, the Kroll study estimated that the arithmetic average of the achieved total return on the

[40] Kroll, *2022 SBBI Yearbook* at 146.
[41] *Blue Chip Financial Forecasts*, August 1, 2022 at 2.
[42] { (1 + 0.092) ∗ (1 + 0.025) – 1 } ∗ 100.

S&P 500 was 12.3%[43] and the total return on long-term Treasury bonds was 6.0%.[44] The indicated market risk premium is 6.3% (12.3% - 6.0% = 6.3%).

The long-term government bond yield of 6.0% occurred during a period of inflation of approximately 3.0%, thus implying a real return on long-term government bonds of 3.0%.

**Q. How does your estimated market risk premium range compare to that estimated by Kroll?**

A. Kroll makes several estimates of a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2021 as well as normalized data. Using this data, Kroll estimates a market risk premium derived from the total return on the securities that comprise the S&P 500, less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields.

Kroll's range is based on several methodologies. First, Kroll estimates a market risk premium of 7.46% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2021 period.[45]

Second, Kroll used the Ibbotson & Chen supply-side model which produced a market risk premium estimate of 6.22%.[46] Kroll explains that the historical market risk premium based on the S&P 500 was influenced by an abnormal expansion of price/earnings ("P/E") ratios relative to earnings and dividend growth during the period, primarily over the last 30 years. Kroll believes this abnormal P/E expansion is not sustainable. In order to control for the volatility of extraordinary events and their impacts

[43] Kroll, *2022 SBBI Yearbook* at 145.
[44] *Id*.
[45] *Id*. at 199.
[46] *Id.* at 207-208.

on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as well as the current P/E ratio.[47]

Finally, Kroll develops its own recommended equity, or market risk premium, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 3.5%, Kroll concludes the current expected, or forward-looking, market risk premium is 5.5%, implying an expected return on the market of 9.0%. However, when the current market risk-free rate exceeds the normalized risk-free rate, Kroll recommends applying the current 20-year Treasury yield. Currently, the 20-year Treasury yield is below the normalized risk-free rate.[48]

Importantly, Kroll's market risk premiums are measured over a 20-year Treasury bond. Because I am relying on a projected 30-year Treasury bond yield, the results of my CAPM analysis should be considered conservative estimates for the cost of equity.

**Q. What are the results of your CAPM analysis?**

A. As shown on my Exhibit___(MPG-21), using a current market risk-free rate of 3.21% and a projected market return of 11.93% produces a market risk premium of approximately 8.72%, combined with the beta of 0.89 indicates a CAPM return estimate of 10.93%.

Using a market return of 11.93%, with a projected risk-free rate of 3.60%, produces a market risk premium of 8.33%. This market risk premium and risk-free rate with a normalized utility beta of 0.75, indicates a CAPM return of about 9.88%.

As discussed above, the current elevated betas do not reflect the low industry risk for GPC or the utility industry as a whole. Therefore, I find a reasonable return on equity for GPC in this case using a CAPM study to be 9.90%.

[47] *Id*.

[48] Kroll, "Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher," June 16, 2022.

## III.I. Return on Equity Summary

**Q. Based on the results of your return on common equity analyses described above, what return on common equity do you recommend for GPC?**

A. Based on my analyses, I recommend GPC's current market cost of equity be in the range of 9.00% to 9.90%, with a midpoint of 9.45%.

**TABLE 15**

**Return on Common Equity Summary**

| Description | Results |
|---|---|
| DCF | 9.00% |
| Risk Premium | 9.25% |
| CAPM | 9.90% |

My recommended return on common equity of 9.45% falls at the midpoint of the range of 9.00% to 9.90%. The low-end of my range is based on my DCF studies, and the high-end is based on my CAPM. My risk premium study also falls in this range.

My return on equity estimates reflect observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the regulated utility industry and the market's demand for utility securities.

## III.J. Financial Integrity

**Q. Will your recommended overall rate of return support an investment grade bond rating for GPC?**

A. Yes. I have reached this conclusion by comparing the key credit rating financial ratios for GPC at my proposed return on equity and GPC's proposed capital structure to S&P's benchmark financial ratios using S&P's credit metric ranges.

**Q. Please describe the most recent S&P financial ratio credit metric methodology.**

A. S&P publishes a matrix of financial ratios corresponding to its assessment of the business risk of utility companies and related bond ratings. On May 27, 2009, S&P expanded its matrix criteria by including additional business and financial risk categories.[49]

Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities have a business risk profile of "Excellent" or "Strong."

The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the utilities have a financial risk profile of "Aggressive" or "Significant." Based on the most recent S&P report, GPC has an "Excellent" business risk profile and a "Significant" financial risk profile.

**Q. Please describe S&P's use of the financial benchmark ratios in its credit rating review.**

A. S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of GPC's total credit risk exposure. On November 19, 2013, S&P updated its methodology. In its update, S&P published a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for primary financial ratios that it uses as guidance in its credit review for utility companies. The two core financial ratio benchmarks it relies on in its credit rating process include: (1) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (2) Funds From Operations ("FFO") to Total Debt.[50]

[49]S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

[50]*Standard & Poor's RatingsDirect*: "Criteria: Corporate Methodology," November 19, 2013.

**Q. How did you apply S&P's financial ratios to test the reasonableness of your rate of return recommendations?**

A. I calculated each of S&P's financial ratios based on GPC's cost of service for its regulated utility operations in its Georgia service territory over the three-year period using Staff's projected cost of service for the test year (July 31, 2023) and projected years (December 31, 2024 and December 31, 2025). While S&P would normally look at total consolidated GPC financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in GPC's Georgia regulated utility operations. Hence, I am attempting to determine whether my proposed rate of return will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and GPC's financial integrity.

**Q. Did you include any off-balance sheet ("OBS") debt equivalents?**

A. No. In response to STF-BAI-1-17, GPC stated that it does not have any off-balance sheet debt equivalents. However, I included GPC's short-term debt obligations as provided in response to STF-BAI-1-11.

Hence, I developed my credit metrics using the same assumptions for projected total financial leverage which GPC included in developing current and projected credit metrics in its presentation to credit rating agencies material provided in STF-NEC-1-5 Attachment I Trade Secret.

**Q. How did you apply Staff's ratemaking adjustments?**

A. To calculate the credit metrics, based on my recommendations, I relied on the Company's ratemaking capital structure in the test year, and my recommended 9.45% return on equity. For 2024 and 2025, I used my recommended capital structure including a 51% common equity ratio and my recommended return on equity of 9.45%.

I also reflected several Staff adjustments to the depreciation and amortization expense and ratemaking rate base outlined in Staff witness Ralph Smith's testimony.

Further, as shown on my Exhibit___(MPG-22), pages 2 and 3, I included GPC's estimated rate base and associated depreciation expense for Vogtle Units 3 and 4 because both of these units are expected to be placed in-service in late 2023. I relied on the Company's projected cost of service for Vogtle Units 3 and 4 in 2024 and 2025 as included in GPC Exhibit___(APA/SPAADH/MBR-6, Schedule 3).

**Q. Please describe the results of this credit metric analysis as it relates to GPC for the test year ending July 31, 2023.**

A. The S&P financial metric calculations for GPC at a 9.45% return are developed on Exhibit___(MPG-22), page 1. The credit metrics produced below, with a financial risk profile from S&P of "Significant" and business risk profile of "Excellent," will be used to assess the strength of the credit metrics based on GPC's retail operations in the state of Georgia.

The adjusted debt ratio for credit metric purposes at GPC's capital structure is 44.6%, which is significantly lower than the average adjusted debt ratio for the industry as shown on Exhibit___(MPG-22), page 1 and calculated on Exhibit___(MPG-5).

Based on an equity return of 9.45% and GPC's common equity ratio of 56.0%, the Company will be provided an opportunity to produce a Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") ratio of 4.0x. This is within S&P's "Significant" guideline range of 3.5x to 4.5x.[51]

GPC's utility operations FFO to total debt coverage at a 9.45% equity return and 56% equity ratio is 19%, which is also within S&P's "Significant" guideline range of 13% to 23%.

I conclude that GPC's core credit metrics ratios based on my return on equity and its capital structure will support its investment grade credit rating. Importantly, my recommended overall rate of return will accomplish these objectives while minimizing GPC's cost of service and supporting the most competitive rates that remain just and reasonable from a rate-setting standpoint.

[51] *Standard & Poor's RatingsDirect®*: "Criteria: Corporate Methodology," November 19, 2013.

**Q. Please describe the results of this credit metric analysis as it relates to GPC for the projected year ending December 31, 2024.**

A. The S&P financial metric calculations for GPC at a 9.45% return are developed on Exhibit___(MPG-22), page 2. The credit metrics produced below, with a financial risk profile from S&P of "Significant" and business risk profile of "Excellent," will be used to assess the strength of the credit metrics based on GPC's retail operations in the state of Georgia.

The adjusted debt ratio for credit metric purposes at my proposed capital structure is 49.3%, which is lower but comparable to the average adjusted debt ratio for the industry as shown on Exhibit___(MPG-22), page 2 and calculated on Exhibit___(MPG-5).

Based on an equity return of 9.45% and my proposed common equity ratio of 51.0%, GPC will be provided an opportunity to produce a Debt to EBITDA ratio of 3.9x. This is within S&P's "Significant" guideline range of 3.5x to 4.5x.[52]

GPC's utility operations FFO to total debt coverage at a 9.45% equity return and 51% equity ratio is 20%, which is within S&P's "Significant" guideline range of 13% to 23%.

I conclude that GPC's core credit metrics ratios based on my return on equity and my proposed capital structure will support GPC's current investment grade credit rating in 2024, and start to reflect stronger credit metrics and a credit rating improvement. Importantly, my recommended overall rate of return will accomplish these objectives while minimizing GPC's cost of service and supporting the most competitive rates that remain just and reasonable from a rate-setting standpoint.

**Q. Please describe the results of this credit metric analysis as it relates to GPC for the projected year ending December 31, 2025.**

A. The S&P financial metric calculations for GPC at a 9.45% return are developed on Exhibit___(MPG-22), page 3. The credit metrics produced below, with a financial risk profile from S&P of "Significant" and business risk profile of "Excellent," will be used to

[52] *Standard & Poor's RatingsDirect®*: "Criteria: Corporate Methodology," November 19, 2013.

assess the strength of the credit metrics based on GPC's retail operations in the state of Georgia.

The adjusted debt ratio for credit metric purposes at GPC's capital structure is 49.6%, which is still lower but comparable to the average adjusted debt ratio for the industry as shown on Exhibit___(MPG-22), page 5 and calculated on Exhibit___(MPG-5).

Based on an equity return of 9.45% and my proposed common equity ratio of 51.0%, GPC will be provided an opportunity to produce a Debt to EBITDA ratio of 3.9x. This is within S&P's "Significant" guideline range of 3.5x to 4.5x.[53]

GPC's utility operations FFO to total debt coverage at a 9.45% equity return and 51% equity ratio is 19%, which is within S&P's "Significant" guideline range of 13% to 23%.

I conclude that GPC's core credit metrics ratios based on my return on equity and its capital structure will support GPC's current investment grade credit rating in 2025, and indicate stronger credit metrics and improved credit rating. Importantly, my recommended overall rate of return will accomplish these objectives while minimizing GPC's cost of service and supporting the most competitive rates that remain just and reasonable from a rate-setting standpoint.

**Q. Does this financial integrity assessment support your recommended overall rate of return for GPC?**

A. Yes. As noted above, I believe my return on equity and my proposed capital structure represent fair compensation in today's very low capital market costs, and as outlined above, my overall rate of return will provide GPC an opportunity to earn credit metrics that will support its bond rating.

## IV. RESPONSE TO GPC WITNESS MR. COYNE

**Q. What return on common equity is GPC proposing for this proceeding?**

A. Mr. Coyne recommends a return on equity produced by the DCF, CAPM, Risk Premium and Expected Earnings models in the range of 8.99% to 13.55%. The average of his four

[53] *Standard & Poor's RatingsDirect®*: "Criteria: Corporate Methodology," November 19, 2013.

models result is 10.92%. Adding 8 basis points for flotation costs, Mr. Coyne recommends a return on equity of 11.0% for GPC.[54]

**Q. Are Mr. Coyne's return on equity estimates reasonable?**

A. No. Mr. Coyne's estimated return on equity is overstated and should be rejected. Mr. Coyne's analyses produce excessive results for various reasons, including the following:

1. His constant growth DCF results are based on unsustainably high growth rates;
2. His CAPM is based on inflated market risk premiums;
3. His CAPM is based on beta estimates that do not reflect the low risk nature of utility investments;
4. His Bond Yield Plus Risk Premium studies are based on an overly simplistic inverse relationship between equity risk premiums and interest rates, which produces inflated equity risk premiums;
5. Both Mr. Coyne's CAPM and Risk Premium studies are based on projected interest rates that are highly uncertain, and
6. His Expected Earnings analysis is unreasonable because it measures the book accounting return, rather than the market required return.

**Q. Please summarize Mr. Coyne's return on equity estimates.**

A. Mr. Coyne's return on equity estimates are summarized in Table 16 below. In the "Adjusted" Column 2, I show the results with prudent and sound adjustments to correct the flaws referenced above. With such adjustments to Mr. Coyne's proxy group's DCF, CAPM, and Risk Premium return estimates, Mr. Coyne's studies show that my 9.45% recommended return on equity for GPC is more reasonable and consistent with the current capital market environment.

[54]Coyne Direct Testimony at 3 and 45.

**TABLE 16**

**Coyne's Adjusted Return on Equity Estimates**

| Description | Coyne Mean[1] (1) | Gorman Adjusted (2) |
|---|---|---|
| Constant Growth DCF | | |
| 30-Day Average | 8.88% | 8.79% |
| 90-Day Average | 9.01% | 8.82% |
| 180-Day Average | 9.09% | 8.83% |
| CAPM DCF-Derived Results at current (2.72%) | | |
| CAPM (*Value Line* Beta, Adjusted to 0.80) | 13.66% | 10.09% |
| CAPM (Bloomberg Beta, Adjusted to 0.75) | 13.34% | 9.44% |
| CAPM DCF-Derived Results at near projected (3.34%) | | |
| CAPM (*Value Line* Beta, Adjusted to 0.80) | 13.75% | 10.21% |
| CAPM (Bloomberg Beta, Adjusted to 0.75) | 13.44% | 9.78% |
| Risk Premium | | |
| Current 30-Yr Treasury (2.72%) | 9.83% | 8.82% |
| Near-Term Projected 30-Yr Treasury (3.34%) | 10.09% | 9.63% |
| Long-Term Projected 30-Yr Treasury (3.40%) | 10.12% | Reject |
| Expected Earnings Analysis | 11.03% | Reject |
| Recommended Return on Equity | 11.0% | 9.45% |

Sources: [1]Coyne Direct Testimony at 35, 34, 37, 39.

As shown in Table 16 above, corrections and improvements to the accuracy of Mr. Coyne's return on equity estimates support a return on equity for GPC of 9.45%.

While my adjustments are presented in Adjusted Column 2 of Table 16 above, a description of the bases for my adjustments to Mr. Coyne's return on equity estimates is presented below.

## IV.A. Reliability of DCF Return Estimates

**Q. Does Mr. Coyne comment on the reliability of market-based models to measure a fair return on equity for GPC?**

A. Yes, but Mr. Coyne's comments are flawed and without merit. Mr. Coyne opines that the traditional DCF analyses are not producing reasonable results at this time due to the current capital market conditions. He goes on to state that the DCF model, which relies on historical averages, is likely to understate the cost of equity for GPC.[55] He also opines that interest rates are expected to increase.[56]

**Q. Has Mr. Coyne identified anything different in this case to distinguish the projections that have been offered over the last five to ten years, but have yet to pan out?**

A. No. As explained in more detail later, economists have consistently been projecting increases in interest rates relative to current observable interest rates over approximately the last ten years. However, those projections for increased interest rates have turned out to be inaccurate. Instead, interest rates have remained relatively stable and at low levels for approximately the last five to ten years. Also, I show that projections for interest rates over the next five to ten years have been moderated by independent consensus economists. This is clear evidence that today's market is embracing the sustainability of relatively low capital market costs in the current market relative to what independent economists have projected in prior periods. A comparison of the components of the DCF return for utilities generally to other income return investment options and growth investment options shows that the results of DCF models are producing reliable and accurate estimates of the current market cost for utility companies.

[55] Coyne Direct Testimony at 20, 28-29.
[56] Coyne Direct Testimony at 5, 16, 20, 31.

**Q. Please explain why you believe the DCF model is producing reliable results for utility companies when the DCF return component is compared to alternative investments.**

A. The DCF model is producing an economically logical estimate of the current market cost of equity and a return that is comparable with observable returns in alternative investments of comparable risk. The DCF model sums the observable dividend yield on utility stocks and then adds to that an estimate of expected growth. These two components yield DCF returns that are comparable to alternative investments, and, thus, reasonably reflect the current market cost of capital for GPC.

Specifically, as shown on my Exhibit___(MPG-3) (pages 4 and 12), the 2022 dividend yield of electric (3.36%) and gas (3.22%) utility stock was competitive with the yield on "A" rated utility bonds in 2022 (4.38%). The current yield spread between stock and A-rated utility bond yields is reasonably comparable to that realized historically, and suggests that the stock yield component of the DCF model is robust and competitive with alternative income producing investments.

The growth component of the DCF return relates to earnings and stock growth over time. The growth outlook for utility stocks is not depressed generally, but rather provides a robust outlook for dividends and stock price growth. The DCF return is not understated due to the DCF growth rate component.

Additionally, the annual growth in dividends for utilities over the last 17 years has been approximately 4.08% for electric and 5.25% for gas as shown on my Exhibit___(MPG-3) (pages 5 and 13). In my constant growth DCF study presented above, the current three- to five-year forward projected growth rate for electric utilities is approximately 5.45%, which is considerably higher than the historical growth rate for the industry. Furthermore, utility earnings growth is expected to be considerably more robust than U.S. GDP growth, which generally is regarded as a reasonable proxy for the maximum sustainable rate of growth for investor capital markets. Going forward, long-term sustainable growth for equity investments is around 4.35%, as described above. Based on these factors, the growth rate component of a regulated utility DCF return is quite robust and produces a highly competitive DCF return estimate.

For these reasons, both dividend yield and growth components of a utility DCF indicate an economically logical return estimate that is competitive with comparably risky alternative investments.

## IV.B. Coyne's Constant Growth DCF Models

**Q. Please describe Mr. Coyne's constant growth DCF return estimates.**

A. Mr. Coyne's constant growth DCF returns are developed on his Exhibit JMC-4. Mr. Coyne's constant growth DCF models are based on consensus growth rates published by *Yahoo! Finance* and *Zacks* and individual growth rate projections made by *Value Line*.

He relied on dividend yield calculations based on average stock prices over three different time periods: 30-day, 90-day, and 180-day ending April 30, 2021 – all reflecting a half year of dividend growth adjustments.

Mr. Coyne's mean DCF results fall in the range of 8.88% to 9.09%.[57]

**Q. Are the constant growth DCF results produced by Mr. Coyne reasonable?**

A. Mr. Coyne's DCF study results are reasonable compared to the results of my own DCF analysis.

## IV.C. Coyne's CAPM Studies

**Q. Please describe Mr. Coyne's CAPM analysis.**

A. As indicated above, the CAPM analysis is based upon the theory that the market required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. The risk premium associated with the specific security is expressed mathematically as:

Bi x (Rm - Rf) where:

Bi = Beta - Measure of the risk for stock

Rm = Expected return for the market portfolio

Rf = Risk-free rate

Mr. Coyne's CAPM study is based on current and projected risk-free rates of 2.72% and 3.40%, respectively, a market return of 15.18%, and *Value Line* and

[57] Coyne Direct Testimony at 28.

Bloomberg beta estimates of 0.88 and 0.85, respectively.[58] His CAPM results fall in the range of 13.34% to 13.75%, with an average of 13.55.[59]

**Q. Please describe the issues you have with Mr. Coyne's CAPM study.**

A. I have two primary issues with Mr. Coyne's CAPM study. First, I believe the market risk premium he used in his CAPM studies is overstated because it does not reflect a reasonable estimate of the expected return on the market. Second, Mr. Coyne relies on a projected risk-free rate based on the 30-Year Treasury yield for 2023 to 2027. Mr. Coyne's consistent reliance on projected interest rates is unreasonable and should be rejected. Finally, Mr. Coyne's beta estimates do not reflect the low-risk nature of the rate regulated utilities.

**Q. Please describe Mr. Coyne's market risk premium.**

A. Mr. Coyne derived his market risk premium by conducting a DCF analysis for the market (S&P 500). Mr. Coyne market risk premium estimate is based on the total return on the market from 1) S&P Earnings and Estimates report of 15.87%, 2) Bloomberg of 14.03%, and 3) *Value Line* of 15.63%. The average of these market returns is 15.18%. Then, Mr. Coyne subtracts his current and projected risk-free rate of 2.72% and 3.40%, respectively, to produce a market risk premium of 12.46% and 11.78%, respectively.[60]

**Q. What issues do you have with Mr. Coyne's market risk premium estimates?**

A. Mr. Coyne's DCF-derived market risk premium is based on market returns in the range of 14.03% to 15.87% which consist of a growth rate component in the range of 12.38% to 14.22% and market-weighted expected dividend yield of approximately 1.54%.[61] As discussed above with respect to my own DCF model, the DCF model requires a long-term sustainable growth rate. Mr. Coyne's sustainable market growth rates in the range of 12.38% to 14.22% are far too high to be a rational outlook for sustainable long-term

[58]Coyne Direct Testimony, Exhibit JMC-5.2.
[59]Coyne Direct Testimony at 34.
[60]Coyne Direct Testimony at 33.
[61]Coyne Direct Testimony, Exhibit JMC-5.1.

market growth. These growth rates are more than three times the growth rate of the U.S. GDP long-term growth outlook of 4.35% as discussed above.

As a result of these unreasonable long-term market growth rate estimates, Mr. Coyne's market DCF returns (14.03% to 15.87%) used in his CAPM analyses are inflated and not reliable. Consequently, Mr. Coyne's market risk premiums should be given minimal weight in estimating GPC's CAPM-based return on equity.

**Q. Do historical actual returns on the market support Mr. Coyne's projected market returns?**

A. No. Historical data shows just how unreasonable Mr. Coyne's projected DCF return on the market is on a going-forward basis. Kroll estimates the actual capital appreciation for the S&P 500 over the period 1926 through 2021 to have been 6.4% to 8.2%.[62] Further, the historical geometric growth of the market of 6.4%[63] has reflected geometric growth of GDP over this same time period of approximately 6.0%.[64] This compares to Mr. Coyne's projected growth rate of the market in the range of 12.38% to 14.22%. Mr. Coyne's projected growth is not reasonable. The historical realized return on the S&P 500, reflecting growth rates between 6.4% and 8.2% resulted in arithmetic average growth of the S&P 500 of around 12.4%. This is far more rational and reasonable than Mr. Coyne's projected DCF return on the market in the range of 14.03% to 15.87%.

This review of historical data establishes two facts very clearly. First, historical, actual achieved growth has been substantially less than projected by Mr. Coyne. Second, historical growth of the market has tracked historical growth of the U.S. GDP. Projected growth of the U.S. GDP is now closer to the 4.0% to 4.5% range. All this information strongly supports the conclusion that Mr. Coyne's projected growth rate on the market in the range of 12.38% to 14.22% is substantially overstated. While I do not endorse the use of a historical growth rate to draw assessments of the market's forward-looking growth rate outlooks, this data can be used to show how unreasonable and inflated Mr. Coyne's market return estimate is.

[62] Kroll, *2022 SBBI Yearbook at 145.*
[63] *Id.*
[64] U.S. Bureau of Economic Analysis, May 26, 2022.

**Q. Why do you believe Mr. Coyne's reliance on a projected long-term risk-free rate is unreasonable?**

A. Mr. Coyne's reliance on long-term projected bond yield of 3.40% does not reflect market participants' outlooks for GPC's cost of capital during the period rates determined in this proceeding will be in effect. This bond yield is based on projections of Treasury bond yields five years out (2023-2027). Those projections are highly uncertain, and in any event, do not reflect the cost of capital in the test period or even the period over the next two to three years, the period in which rates determined in this proceeding will largely be in effect. As such, the market risk premium should be based on observable bond yields in the market today. Alternatively, the market risk premium should at most reflect bond yield projections through the rate-effective period in this case.

**Q. Please describe your concerns with Mr. Coyne's beta estimates.**

A. As discussed in regard to my own CAPM study, the current beta estimates have increased substantially during the COVID-19 pandemic. However, these elevated beta estimates do not represent an increase in utility risk or cost of equity. As discussed above, utility companies are well positioned to weather economic downturns and are considered defensive stocks. Their cash flows strength is consistent and supported by strong valuations. In fact, as shown in my Exhibit___(MPG-20), page 4 (industry beta) since 2014, 75% of the industry had an average beta estimate of 0.80. Importantly, prior to the COVID-19 pandemic there were no beta estimates close to 0.80. The highest average beta estimate prior to the pandemic was 0.74. Therefore, it is reasonable to consider a normalized beta estimate of approximately 0.75 , which is the average normalized beta estimate as discussed in regard to my CAPM studies.

**Q. Can Mr. Coyne's CAPM analysis be revised to reflect a more reasonable market risk premium and risk-free rates?**

A. Yes. Disregarding Mr. Coyne's long-term projected risk-free rate of 3.40% as described above and instead using his current and near-term projected risk-free rates of 2.72% and

3.34%[65], respectively, my calculated market return of 11.93%, and applying the average *Value Line* beta of 0.80 prior to the pandemic as discussed above, Mr. Coyne's CAPM study would yield a return of 10.09% and 10.21%, respectively.[66] Applying the current and near-term risk-free rates of 2.72% and 3.34%, my market return of 11.93%, and the average historical beta for regulated utilities of approximately 0.75, will result in a CAPM return of 9.63% and 9.78%, respectively.[67] Therefore, Mr. Coyne's CAPM study will produce a reasonable return in the range of 9.60% to 10.20%, with an approximate midpoint of 9.90%.

## IV.D. Risk Premium Analysis

**Q. Please describe Mr. Coyne's risk premium methodology.**

A. As shown on his Exhibit JMC-6, Mr. Coyne constructs a risk premium return on equity estimate based on the premise that equity risk premiums are inversely related to interest rates. He estimates an average equity risk premium of 6.06% for electric over the period January 1992 through April 30, 2022. He then applies a regression formula to the current, near-term, and long-term projected 30-year Treasury bond yields of 2.72%, 3.34%, and 3.40%, respectively, to produce electric equity risk premiums of 7.11%, 6.75%, and 6.72%, respectively. Thus, he calculates electric return on equity estimates of 9.83%, 10.09%, and 10.12%, respectively.[68]

**Q. Is Mr. Coyne's risk premium methodology reasonable?**

A. No. Mr. Coyne contends that there is a simplistic inverse relationship between equity risk premiums and interest rates without any regard to differences in investment risk. Academic studies are quite clear that interest rates are a relevant factor in assessing current market equity risk premiums, but the risk premium ties more specifically to the market's perception of investment risk of debt and equity securities, and not simply changes in interest rates.

[65]Coyne Direct Testimony, Exhibit JMC-6, page 3.
[66]2.72% + 0.80 x (11.93% - 2.72%) = 10.09% and 3.34% + 0.80 x (11.93% - 3.34%) = **10.21%**;
[67]2.72% + 0.75 x (11.93% - 2.72%) = **9.63%** and 3.34% + 0.75 x (11.93% - 3.34%) = 9.78%
[68]Coyne Direct Testimony at 37 and Exhibit JMC-6, page 3.

More specifically, while academic studies have shown that, in the past, there has been an inverse relationship among these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[69]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. As such, when interest rates were more volatile, perceptions of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[70] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates.

Importantly, Mr. Coyne's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology that does not produce accurate or reliable risk premium estimates.

[69]Robert S. Harris & Felicia C. Marston, "The Market Risk Premium: "Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance*, Volume 11, No. 1, 2001 at 10-13; Eugene F. Brigham, Dilip K. Shome, & Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Spring 1985, at 42-43.

[70]"The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Spring 1985, at 44.

**Q. Do you believe that the regression study used by Mr. Coyne in his risk premium demonstrates an accurate cause and effect between interest rates and equity risk premiums?**

A. No. Because the returns he uses are authorized by commissions, those returns are not directly adjusted by market forces. While I also use Commission-authorized returns as a proxy for market-required returns, Mr. Coyne unreasonably relies on a simple regression analysis that tries to describe and gauge equity risk premiums based on only changes in interest rates.

Equity risk premiums can move based on changes in market conditions that can impact both equity returns and bond returns in a like manner. This simple regression analysis of equity risk premiums and interest rates ignores these relevant market factors in describing the current market-required equity risk premium.

**Q. Do you have any other comments concerning Mr. Coyne's risk premium methodology?**

A. Yes. Similar to his CAPM analysis, in his risk premium, Mr. Coyne's use of a long-term projected bond yield of 3.40%,[71] does not reflect market participants' outlooks for GPC's cost of capital during the period rates determined in this proceeding will be in effect. Therefore, Mr. Coyne's use of projected bond yields five years out should be rejected.

**Q. Can Mr. Coyne's risk premium analysis be revised to reflect current projections of Treasury yields?**

A. Yes. Mr. Coyne's simplistic and incomplete notion that equity risk premiums change only with changes to nominal interest rates should be rejected. Adding his average electric and gas equity risk premiums over Treasury bonds of approximately 6.10% to his Treasury yields of 2.74% and 3.34%, produces an electric risk premium no higher than 9.40%.

[71] Coyne Direct Testimony, Exhibit JMC-6.

## IV.E. Coyne's Expected Earnings Analysis

**Q. Please describe Mr. Coyne's expected earnings analysis.**

A. Mr. Coyne's Expected Earnings analysis is based on the projected returns on book equity for the regulated utility companies followed by *Value Line* and included in his proxy group as developed on his Exhibit JMC-7. Based on this analysis, Mr. Coyne concludes that the average return on equity result for his proxy group is 11.03%, for the projected period 2025-2027.

**Q. What is problematic about Mr. Coyne's Expected Earnings analysis?**

A. Mr. Coyne's Expected Earnings analysis should be rejected because this approach does not measure the market-required return appropriate for the investment risk of GPC. Rather, it measures the book accounting return. The market required return is not the same as the accounting return, and the two can be – and in this instance are – vastly different.

The significant discrepancy between the level and meaning of a market-required return and a book return on equity can have significant implications to both investors and customers, when used to set a fair return on equity for ratemaking purposes. Simply stated, a market return provides a pure measure of fair compensation to investors, and allows for setting rates that provide no more than fair compensation. Conversely, using the earned return on book equity can cause compensation to be either too high or too low, and rates to be set either too low or too high, depending on the specific circumstances when the book return is measured.

For example, if the proxy group's earned return on book equity is lower than the market return, it could be an indication that the rates for the proxy group are too low and not providing fair compensation. As such, the measured return on book equity would be an indication rates need to be increased. However, if the earned return on book equity was used to estimate a fair return for ratemaking purposes, then this depressed earnings level could result in rates being set below a level that provides fair compensation to investors and may not support the utility's financial integrity. Conversely, if the earned return on book equity for the proxy companies is above a fair market return on equity, then that could be an indication that the rates for the proxy companies produce more

earnings than necessary to fairly compensate investors, and using this inflated return on equity would result in rates that are not just and reasonable for customers.

The market-required return is a long-standing practice in setting rates for utility companies. This is because the market sets the required rate of return for assuming the risk of an investment. To the extent the utility's earnings are adequate to allow it to attract investors, then it will be able to sell new equity shares to the market to secure capital needed to fund additional rate base investments. If this long-standing practice of setting authorized returns consistent with market returns is rejected, in favor of Mr. Coyne's proposal to look at returns on book equity, then the balance between estimating a return that is fair to both investors and customers will be turned upside down, and the rate-setting practice could be substantially impaired and rendered unreliable.

The earned return on book equity is simply not an accurate or legitimate basis upon which to determine a fair and reasonable return on equity for both investors and customers. A fair return on equity is a return that provides fair compensation to utility investors, but also results in customer rate impacts that are no more than necessary to produce that fair compensation – except to the extent greater earnings are necessary to maintain financial integrity or credit standing. For these reasons, the Expected Earnings analysis should simply be rejected.

## IV.F. Flotation Costs

**Q. Did Mr. Coyne include a flotation cost adjustment in his recommended return for GPC?**

A. Yes. Mr. Coyne calculated an upward adjustment of 8 basis points to his return results to compensate for flotation costs. He developed his flotation cost adjustment by observing the cost incurred by the proxy group companies in issuing equity securities. The costs incurred on these issuances averaged around 2.47% of the issuance amount.

Next, Mr. Coyne developed a constant growth DCF model for the proxy group with and without issuance costs to derive his flotation cost adjustment of 8 basis points.[72]

[72]Exhibit JMC-8.

**Q. Is Mr. Coyne's flotation cost adder reasonable?**

A. No. Mr. Coyne's flotation cost adder is not reasonable nor justified because it is not based on the recovery of prudent and verifiable actual flotation costs incurred by GPC. Southern Company, GPC's parent company, receives dividend payments from its various subsidiaries and can do whatever it wants with that capital, including redistributing it to another subsidiary. Paid-in capital at GPC can also be derived from debt capital issued by Southern Company. Mr. Coyne has failed to show that the GPC's paid-in capital portion of its common equity balance was derived from common equity issuances at its parent.

Because he does not show that his adjustment is based on GPC's actual and verifiable flotation expenses, there are no means of verifying whether Mr. Coyne's proposal is reasonable or appropriate. Stated differently, Mr. Coyne's flotation cost return on equity adder is not based on known and measurable GPC costs. Therefore, the Commission should reject a flotation cost return on equity adder for GPC.

## IV.G. Mr. Coyne's Consideration of Additional Risks

**Q. Did Mr. Coyne discuss consideration of additional business risks to justify his return on equity?**

A. Yes. In addition to GPC's capital expenditure program, Mr. Coyne compared the following factors that affect regulatory risk: (1) test year convention; (2) rate base convention; (3) revenue decoupling; and (4) construction work in progress ("CWIP") in rate base to the proxy group.[73] Mr. Coyne concluded that these additional risk factors are comparable to the proxy group and there is no additional return on equity adjustment needed. I would also point out that these additional risks are already incorporated in GPC's credit rating relative to the proxy group companies.

**Q. Please explain.**

A. The major business risks identified by Mr. Coyne are already considered in the assigning of a credit rating by the various credit rating agencies.

[73] Coyne Direct Testimony at 42-43, Exhibit JMC-9.

As shown on my Exhibit___(MPG-7), the average S&P credit rating for my proxy group of BBB+ is identical to GPC's credit rating from S&P. The relative risks discussed by Mr. Coyne are already incorporated in the credit ratings of the proxy group companies. Indeed, S&P and other credit rating agencies go to great lengths and detail in assessing a utility's business risk and financial risk in order to evaluate total investment risk. This total investment risk assessment of GPC, in comparison to a proxy group, is fully absorbed into the market's perception of GPC's risk. The use of a proxy group fully captures the investment risk of GPC and is, in fact, conservative, given that the proxy group has an identical credit rating to GPC and a significantly lower common equity ratio than GPC.

**Q. How does S&P assign corporate credit ratings for regulated utilities?**

A. In assigning corporate credit ratings, the credit rating agency considers both business and financial risks. Business risks, among others, include a company's size, competitive position, generation portfolio, and capital expenditure programs, as well as consideration of the regulatory environment, current state of the industry, and the economy as whole. Specifically, S&P states:

> To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. Cash flow/leverage analysis determines a company's financial risk profile assessment. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.[74]

[74] *Standard & Poor's RatingsDirect®:* "Criteria/Corporates/General: Corporate Methodology," November 19, 2013.

## IV.H. Capital Market Conditions

**Q. Did Mr. Coyne also offer an assessment of current capital market conditions in support of his recommended return on equity range?**

A. Yes. Mr. Coyne also offered an assessment of the current capital market conditions in support of his recommended return on equity range. He observes a few factors that he believes gauge the current capital market environment and investor sentiment, including the volatility levels as measured by the Chicago Board of Exchange ("CBOE"), Implied Volatility Index ("VIX'), the Federal Reserve's monetary policy, the inflationary pressure, and the expected interest rate environment.[75]

**Q. Do you believe that Mr. Coyne's use of these market sentiments supports his findings that GPC's market cost of equity is currently 11.0%?**

A. No. In many instances, Mr. Coyne's analysis simply ignores market sentiments favorable toward utility companies and instead lumps utility investments in with general corporate investments. A fair analysis of utility securities shows the market generally regards utility securities as low-risk investment instruments and supports the finding that utilities' cost of capital is low in today's marketplace.

**Q. What is the market sentiment for utility investments?**

A. Again, the current market sentiment toward utility investments, rather than just general corporate investments, is that the market is placing high value on utility securities, recognizing their low risk and stable characteristics. Total expected returns on utility stock is very heavily weighted by dividend yields and by expected stock price appreciation. The utility industry's ability to pay dividends has proven to be very stable and predictable and a large portion of the expected return on utility stocks has very low risk and uncertainty. In comparison, the expected returns on non-utility investments place minimal to no weight on dividend yields and are primarily produced by stock price appreciation. Stock price appreciation is far less predictable than stock yields, and thus utility stock investments are considered low investment risk options.

[75]Coyne Direct Testimony at 7-20.

This is illustrated by current utility bond yield spreads as discussed at length previously. The current strong utility bond valuation is an indication of the market's sentiment that utility bonds are lower risk and are generally regarded as defensive stocks.

Further, other measures of utility stock valuations also support the conclusion that there is a robust market for utility stocks. As shown on my Exhibit___(MPG-3), financial valuation measures (*e.g.*, P/E ratio and market price to cash flow ratio) show that utility stock valuation measures are robust.

For all these reasons, direct assessments of valuation measures and market sentiment toward utility securities support the credit rating agencies' findings, as quoted above, that the utility industry is largely regarded as a low-risk investment.

**Q. Did Mr. Coyne also opine that market volatility has increased, which has caused an increase in cost of equity for GPC and other utility companies?**

A. Yes. Mr. Coyne also talks about increased volatility as measured by the CBOE VIX. Mr. Coyne states that the VIX index, which generally tracks broader market equity security values, indicates volatility levels not seen since the Great Recession in 2008/2009 in the index.[76]

**Q. Is the VIX index adequate to support the notion that the market perception of the investment risk of GPC or utilities generally is increasing?**

A. No. The VIX is a broader-based market index of stock price volatility, and not that of subgroups within the market generally, and certainly not applicable to the utility subsector. Utility securities are generally regarded as low-risk investments, and the market generally flocks to low-risk sectors during periods of broader economic distress. The VIX index may indicate greater risk in the overall market but that does not indicate a similar change in investment risk for lower-risk regulated utility companies.

Further, the VIX measures investors' expectations of market volatility over the next 30 days and can change significantly over a short period of time. As Mr. Coyne correctly observes, recently it has declined. These drastic fluctuations of the VIX index

[76] *Id*. at 13.

emphasize the fact that the index should not be used to measure investors' perception of utility operating risk.

**Q. Do you have any comments concerning Mr. Coyne's contention that relying on projected market data is currently very important?**

A. Yes. Mr. Coyne develops his CAPM and risk premium studies mainly relying on near-term and long-term projected interest rates. Mr. Coyne's primary reliance on forecasted Treasury bond yields is unreasonable because he is not considering the highly likely outcome that current observable interest rates will prevail during the period in which rates determined in this proceeding will be in effect. This is important because, while current observable interest rates are actual market data that provide a measure of the current cost of capital, the accuracy of forecasted interest rates is highly problematic.

**Q. Why do you believe that the accuracy of forecasted interest rates is highly problematic?**

A. Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit___(MPG-23) illustrates this point. Specifically, on Exhibit___(MPG-23), under Columns 1 and 2, I show the actual market yield for Treasury bonds at the time a projection is made, and the corresponding projection for Treasury bond yields two years in the future, respectively.

As shown in Columns 1 and 2 of Exhibit___(MPG-23), over the last several years, Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. Column 3 shows the time period the projection is made to represent. In Column 4, I show the actual Treasury yield two years after the forecast. In Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in Exhibit___(MPG-23), economists have consistently projected that interest rates will increase over the near term. However, as shown in Column 5, those yield projections turned out to be overstated in almost every case. Indeed, actual Treasury yields have decreased or remained flat over the last several years rather than increasing as the economists' projections indicated. As such, current observable interest rates are just as likely to accurately predict future interest rates as are economists' projections.

**Q. Does this conclude your testimony?**

A. Yes.

BY MR. WALSH:

Q Mr. Gorman, did you also prefile or cause to be prefiled 23 public disclosure exhibits which were marked as MG-1 through MG-23?

A (Witness Gorman) Yes.

Q Do you have any changes or corrections to make to those exhibits?

A (Witness Gorman) I do not.

MR. WALSH: Madam Chair, I ask that the Exhibits MG-1 through MG-23 be marked for identification with the next 23 Staff exhibit numbers, which I believe goes from Exhibit 84 through Exhibit 106.

MADAM CHAIR PRIDEMORE: So marked.

MR. WALSH: Thank you.

(The documents referred to were marked for identification as Staff Exhibits 84 through 106.)

BY MR. WALSH:

Q Mr. Gorman, did you also prefile or cause to be prefiled 84 pages of trade secret testimony with exhibits on October 20th, 2022?

A (Witness Gorman) Yes.

Q Do you have any changes to that trade secret testimony?

A (Witness Gorman) I do not.

Q And if I asked you the questions that are in that trade secret testimony, would your answers be the same?

A (Witness Gorman) They would.

MR. WALSH: Thank you.

Madam Chair, I ask that the trade secret version of Mr. Gorman's testimony be marked for identification as Staff Exhibit No. 107.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 107.)

BY MR. WALSH:

Q Mr. O'Donnell, I'm going to take you through the same set of questions. Did you prefile or cause to be prefiled 28 pages of public disclosure testimony in question-and-answer form on October 20th?

A (Witness O'Donnell) Yes, I did.

Q Do you have any changes or correction to that testimony?

A (Witness O'Donnell) No, I don't.

Q If I ask you those questions today, would your answers be the same as in the testimony?

A (Witness O'Donnell) Yes.

MR. WALSH: Madam Chair, I ask that Mr. O'Donnell's prefiled public disclosure testimony be copied into the record as if read from the witness

**stand.**

**MADAM CHAIR PRIDEMORE: So marked. So moved.**

**MR. WALSH: Thank you.**

**(Whereupon, the prefiled direct testimony of Kevin O'Donnell follows:)**

**Before the**

**Georgia Public Service Commission**

| | | |
|---|---|---|
| **In the Matter of** | **)** | |
| | **)** | |
| **Georgia Power Company's 2022** | **)** | **Docket No. 44280** |
| **Rate Case** | **)** | |

# Testimony

# of

# Kevin O'Donnell

# On Behalf of

# Georgia Public Service Commission Staff

**PUBLIC DISCLOSURE**

**October 20, 2022**

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# DIRECT TESTIMONY OF KEVIN W. O'DONNELL, CFA

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 Maynard Rd., Suite 101, Cary, North Carolina 27511.

**Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?**

A. I am testifying on behalf of the Georgia Public Service Commission Public Interest Advocacy Staff ("PIA Staff" or "Staff").

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.**

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from Florida State University. I earned the designation of Chartered Financial Analyst (CFA) in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission (NCUC). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm.

I have been accepted as an expert witness on the subjects of rate of return, cost of capital, capital structure, credit matters, cost of service, and other regulatory issues, in general rate cases, fuel cost proceedings, and other proceedings before the NCUC, the South Carolina Public Service Commission, the Wisconsin Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Utilities Commission, the District of Columbia Public Service Commission,

the California Public Utilities Commission, the New Mexico Public Regulation Commission, the Maryland Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in Appendix A to my direct testimony.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to review credit ratings and the associated impact on Georgia Power investors and customers.

**Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING.**

A. My findings in this proceeding are as follows:

1. Georgia Power's bond rating is stable and is currently under no threat of a downgrade;
2. While Georgia Power's credit rating has been downgraded over the past several years, the primary reasons for the downgrade are the construction delays and cost overruns at the Vogtle Units 3&4;
3. With the completion of Vogtle Units 3&4 Georgia Power's cash flows and credit metrics will improve significantly and provide additional support to Georgia Power's credit rating.
4. The Commission has awarded returns on equity (ROE) and equity ratio higher than the national average in the past. However, the higher returns awarded by the Commission have not prevented Georgia Power's bond rating from being downgraded. The continuous delays and cost overruns on Vogtle Units 3&4 have been the primary cause for the bond rating downgrades;

5. Mr. Fetter's testimony in this proceeding is incomplete because it does not compare the cost to consumers of paying an unnecessarily high allowed rate of return to the much smaller increase from higher interest costs associated with a *potential* negative credit action;
6. Staff Witness Mike Gorman's recommended ROE and capital structure will provide Georgia Power the necessary revenues and cash flows to support investment grade credit rating. I recommend the Commission award an ROE and capital structure consistent with Mr. Gorman testimony.

## II. CURRENT GEORGIA POWER CREDIT RATING

**Q. WHAT ARE THE CURRENT BOND RATINGS OF GEORGIA POWER FROM S&P AND MOODY'S?**

A. At the present time, the credit ratings and associated outlooks are as follows:

Table 1: Georgia Power Credit Ratings

| | S&P | Moody's |
|---|---|---|
| Current Ratings | BBB+ | Baa1 |
| Outlook | Stable | Stable |

As can be seen in Table 1, Moody's and S&P have Georgia Power at the equivalent credit rating. However, as noted in the testimony of Company Witness Fetter, Fitch, which is a third credit rating agency, has Georgia Power at a BBB level.[1] All of these ratings are at investment grade rates and all are currently "stable" ratings.[2]

**Q. HOW DO THESE BOND RATINGS COMPARE TO OTHER RATINGS AVAILABLE FROM MOODY'S AND S&P?**

[1] Fetter Prefiled Direct Testimony, p. 4, l. 26 to p. 5, l. 3.

[2] Id

A. In Table 2 below, I have provided the list of available investment grade credit ratings from Moody's and S&P.

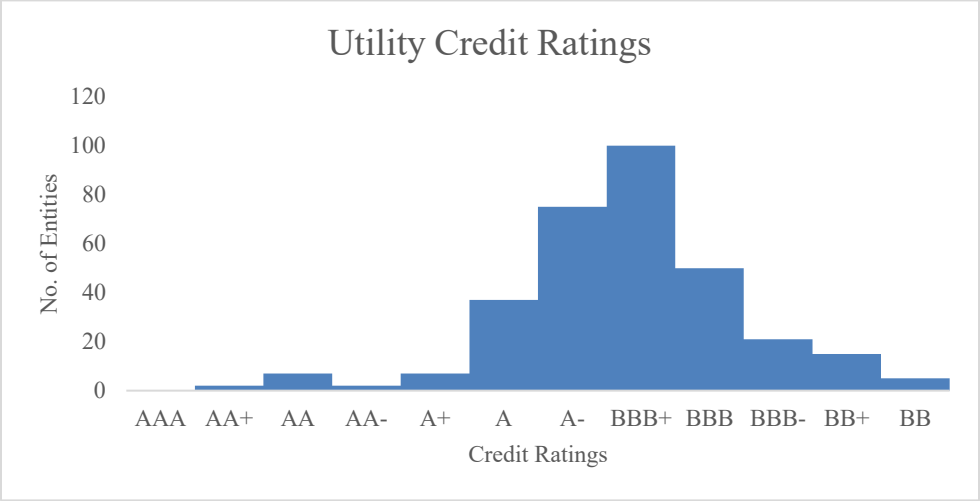
***Table 2: Moody's and S&P Ratings for Long-Term Debt***[3]

| Moody's | S&P and Fitch |
|---|---|
| **Long term** | **Long term** |
| Aaa | AAA |
| Aa1 | AA+ |
| Aa2 | AA |
| Aa3 | AA− |
| A1 | A+ |
| A2 | A |
| A3 | A− |
| Baa1 | BBB+ |
| Baa2 | BBB |
| Baa3 | BBB− |

Georgia Power's credit rating is well within the bounds of investment grade status. Georgia Power's credit rating is similar to most investor owned utilities across the country. Very few investor-owned utilities have AA or AAA credit rating. Chart 1 below provides the utility credit ratings by the number of utilities per rating.

[3]Fetter prefiled direct testimony, p. 12.

Chart 1: Utility Credit Ratings




Source: Data estimated from S&P Ratings Direct Chart sent to Nova Energy Consultants on on Sept. 28, 2022

As can be seen in the above chart, most utilities are in the A-, BBB+, and BBB range.

Table 3 below provides a comparison of the credit ratings of nearby utility operating companies:

Table 3: Georgia Power Comparison to Southeast Electric Utilities

| Utility | Moodys | S&P |
|---|---|---|
| Duke Energy Carolinas | A2 | BBB+ |
| Florida Power & Light | A1 | A |
| Georgia Power | Baa1 | BBB+ |
| Alabama Power | A1 | A- |
| Mississippi Power | Baa1 | BBB+ |

As can be seen in Table 3 Georgia Power's credit rating is similar to other southeast electric utilities.

## III. CREDIT RATING METHODOLOGY

**Q. HOW ARE CREDIT RATINGS USED IN THE CAPITAL MARKETS?**

A. Credit ratings reflect the rating agency's *opinion* of a utility's financial strength and ability to service its debt under different market conditions over time. Fixed income (bond) investors include credit ratings along with many other factors in their assessment of whether to buy, continue to hold or sell bonds issued by utilities. As such, depending on the credit rating determined appropriate by the credit rating agencies, bond investors may require higher or lower rates of interest to compensate for the level of risk implied by a given credit rating all else equal.

**Q. PLEASE EXPLAIN THE IMPLICATION OF A CHANGE IN THE CREDIT RATING OF A PUBLIC UTILITY.**

A. Companies are downgraded and upgraded by the credit agencies as the financial condition of a company changes and to take into account economic and financial markets changes as well. Being downgraded does not imply a company cannot access the capital markets. A downgrade implies that the bond rating agency has determined the risk of owning debt securities of the affected company has risen. All else equal, investors would require a higher return for purchasing a company's debt. Conversely, being upgraded implies that the affected company's financial condition has improved and therefore investors would require a lower rate of interest on a company's debt securities.

**Q. PLEASE DESCRIBE THE FACTORS THAT A CREDIT RATING AGENCY CONSIDERS WHEN ASSESSING THE CREDITWORTHINESS OF A COMPANY.**

A. Moody's uses four criteria as the bases for its rating methodology. This criteria and associated weightings are in Table 4 below.

Table 4: Moody's Credit Ratings Factors

| Rating Factors | Weighting of Rating Factors |
|---|---|
| Regulatory Framework | 25% |
| Ability to Recover Costs and Earn Return | 25% |
| Diversification | 10% |
| Financial Metrics | 40% |
| Total | 100% |

As can be seen in the above rating factors, Moody's takes a holistic approach to analyzing a utility credit rating. It should be noted that Georgia Power's regulatory framework and ability to recover its costs and earn a return are quite favorable and have been for many years.

### A. Regulatory Framework

**Q. PLEASE EXPLAIN "REGULATORY FRAMEWORK" AND HOW MOODY'S ASSESSES THIS FACTOR IN ITS CREDIT RATING METHODOLOGY.**

A. For a rate regulated utility, "regulatory framework" is the regulatory environment in which the utility operates and how the utility reacts to that environment. Moody's summarizes "Regulatory Framework" as:

> The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the

laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. [4]

**Q. HAS THE GEORGIA COMMISSION BEEN RECOGNIZED BY THE CREDIT RATING AGENCIES AS SUPPORTIVE OF GEORGIA POWER?**

A. Yes. The final order in Georgia Power's 2019 rate case was issued on December 17, 2019. In that final order, the Commission granted a ROE of 10.50% and an equity ratio of 56.0%. Both, the allowed ROE and the allowed equity ratio was significantly above the national average of allowed ROEs for that year. Specifically, the national average allowed ROE for electric utilities was 9.66% in 2019 and the national allowed equity ratio was 49.94%.

On December 18, 2019, Moody's wrote a report that stated:

[redacted] [5]

As outlined above, Moody's concluded that the Georgia Commission provided a supportive regulatory environment based on the Commission's decision in the 2019 rate case to awarded Georgia Power 10.5% ROE and 56% equity ratio, unsymmetrical earnings band and annual step increases.

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[4] Moody's Rating Methodology for Regulated Electric and Gas Utilities, June 23, 2017, page 7

[5] Georgia Power Response to STF-NEC-1-1, Attachment V, Moody's Report entitled *Georgia Power Company: Georgia regulator's final rate case order is credit positive*

### B. Ability to Recovery Costs and Earn Return

**Q. PLEASE EXPLAIN THE RATING FACTOR "ABILITY TO RECOVER COSTS AND EARN RETURN" COMPONENT OF THE CREDIT RATING PROCESS.**

A. This rating factor examines the adequacy of a utility's cash flow and the utility's ability to service its debt over time. This factor evaluates the regulatory elements that are crucial to utility operating cash flows and, as such, is a more direct causation than is the regulatory framework that may come from more of a policy standpoint. As noted in Table 1 above, the "ability to recover costs and earn return" factor accounts for 25% of the Moody's credit rating score.

However, as noted above, this Commission has awarded Georgia Power a very high ROE and common equity ratio in its last rate case, thereby enhancing the Company's ability to recover its costs and earn a fair return. In addition, the Commission has set rates that have enabled Georgia Power to earn well above its awarded ROE for the last several years. In this proceeding Mr. Gorman demonstrates in his testimony that a lower ROE and equity ratio would provide Georgia Power the ability to recover costs and earn a fair return under efficient and economic management.

### C. Diversification

**Q. HOW IS DIVERSIFICATION CONSIDERED BY MOODY'S IN THE CREDIT RATING PROCESS?**

A. Moody's considers both business and geographic diversification of utility operations. As a result, diversification of customer load is critical to the credit analysis of any utility. Georgia Power has a diverse set of customers with

residential, commercial and industrial customer sales of 34 percent, 38 percent and 28 percent, respectively.[6]

Fuel diversity is also, in general, viewed favorably by credit agencies. Georgia Power has a very diverse fuel mix of coal, natural gas, nuclear, hydro and solar.

### D. Financial Metrics

**Q. PLEASE DESCRIBE HOW MOODY'S ASSESSES FINANCIAL STRENGTH IN ITS CREDIT RATING METHODOLOGY.**

A. Financial strength represents 40% of the Moody's credit rating analysis and is defined as the ability of a utility to make its debt interest and principle payments consistently in a timely manner and to provide a return for shareholders sufficient to attract capital for investment purposes. The Moody's analysis is not only a historical analysis but is also a forecasted analysis of various financial metrics primarily focused on cash flow generated by operations relative to annual interest expense and amount of debt. The specific Moody's metrics are listed below:

- Cash flow interest coverage, which is defined as the sum of cash flow from operations pre-working capital plus interest divided by interest;
- Cash flow pre-working capital divided by debt; and
- The sum of cash flow from operations pre-working capital less dividends divided by outstanding debt.

[6] Southern Company 2021 10-K filing to the SEC. Page II-24. Values are calculated from kWhs of sales in 2021.

Georgia Power has produced ample operating cash flow from operations of $2.8 billion annually to cover cash interest expense of $380 million annually over the past three years.[7]

**Q. HOW HAS THE FINANCIAL RISK OF GEORGIA POWER CHANGED SINCE THE COMPANY'S LAST RATE CASE IN 2019?**

A. The Company's financial risk has increased due to delays and cost overruns on Vogtle Units 3 and 4. For example, the total debt on the balance sheet of Georgia Power has definitely risen since 2019 as shown in Table 5 below.

Table 5: Georgia Power Long-Term Debt

| Year | Long-Term[8] Debt ($ 1000s) |
|---|---|
| 2018 | $ 9,364,000 |
| 2019 | $12,073,000 |
| 2020 | $13,584,000 |
| 2021 | $14,108,000 |
| 6-30-22 | $15,400,000 |

However, Georgia Power's financial metrics have remained relatively stable. The stability of financial metrics is supported by the Commission's "constructive" regulation including setting of base rates and the collection of Vogtle financing cost as incurred through the Nuclear Construction Cost Recovery ("NCCR") tariff. The addition of $6 billion in debt since 2018 is significant, but the Company has been able to service the debt due in part to the constructive regulation provide by the Georgia Commission.

**Q. WHAT IS THE BASIS OF YOUR OBSERVATION THAT THE INCREASE IN DEBT BY GEORGIA POWER HAS NOT RESULTED IN**

[7] Southern Company 2021 10-K filing to the SEC. Page II-97. Statement of Cash Flows.

[8] Regulatory Research Associates, accessed Sept. 19, 2022

**SUBSTANTIAL CHANGES TO THE FINANCIAL POSITION OF GEORGIA POWER?**

A. I base this position on my review of Georgia Power's financial credit metrics/ratios relative to standard metrics followed by Moody's for electric and natural gas utilities.

**Q. PLEASE EXPLAIN THE FINANCIAL METRICS/RATIOS THAT YOU EXAMINED IN YOUR ANALYSIS OF GEORGIA POWER.**

A. I examined four financial ratios that are considered by Moody's when making a financial credit decision on a specific entity. These rates measure the ability of a company to service its debt requirements. Specifically, I studied four financial ratios and compared Georgia Power metrics to the criteria as outlined by Moody's.

The first ratio I studied was debt leverage. Table 1 below shows the Moody's financial ratio for debt leverage associated with the various credit ratings.

Table 1: Moody's Debt to Total Capital Ratio per Credit Rating[9]

| | Aaa | Aa | A | Baa | Ba | B | Ca |
|---|---|---|---|---|---|---|---|
| Debt/Capitalization | <29% | 25% - 35% | 35% - 45% | 45% - 55% | 55% - 65% | 65% - 75% | >=75% |

Table 2: Georgia Power Debt/Total Capital[10]

| Date | Debt/Cap |
|---|---|
| 12-31-18 | [redacted]% |
| 12-31-19 | [redacted]% |
| 12-31-20 | [redacted]% |
| 12-31-21 | [redacted]% |
| 6-30-22 | [redacted]% |

[9] Moody's "Rating Methodology Regulated Electric and Gas Utilities", June 23, 2017

[10] Moody's Credit Opinion "Georgia Power Company Update to Credit Analysis, dated October 13, 2021.

As shown above in Table 2 this metric indicates Georgia Power's debt to total capital ratio is consistent with a "Baa" rating for the last few years.

The next ratio I examined was the strength of a utility's cash flow relative to its debt. This ratio compared the Cash Flow from Operations pre-Working Capital to Debt.

Table 3 provides the Moody's pre-WC/Debt ratio for the various credit ratings.

Table 3: (CFO pre-WC)/Debt[11]

| | Aaa | Aa | A | Baa | Ba | B | Ca |
|---|---|---|---|---|---|---|---|
| CFO pre-WC/Debt | >+40% | 30% - 40% | 22% - 30% | 13% - 22% | 5% - 13% | 1% - 5% | <1% |

The corresponding ratio for Georgia Power is as follows:

Table 4: Georgia Power (CFO pre-WC)/Debt[12]

| Date | (CFO pre-WC /Debt |
|---|---|
| 12/31/2017 | [redacted]% |
| 12/31/2018 | [redacted]% |
| 12/31/2019 | [redacted]% |
| 12/31/2020 | [redacted]% |
| 6/30/2021 | [redacted]% |

As shown in Table 4, this metric indicates Georgia Power's cash flow pre operating capital to debt ratio is between "A" and "Baa" rating for the last few years.

[11] Moody's "Rating Methodology Regulated Electric and Gas Utilities", June 23, 2017

[12] Moody's Credit Opinion "Georgia Power Company Update to Credit Analysis, dated October 13, 2021.

The next financial metric examines the ability of a company to pay its interest expenses. This metric measures a company's cash flow generated by the business relative to interest expense. The specific metric is cash flow pre-working capital plus interest divided by interest expense "(CFO pre-WC+Int)/Int." The Moody's standards are below.

Table 5: (CFO pre-WC + Int)/Int[13]

| | Aaa | Aa | A | Baa | Ba | B | Ca |
|---|---|---|---|---|---|---|---|
| CFO pre-WC+Int/Int | >=8.0x | 6.0x - 8.0x | 4.5x - 6.0x | 3.0x - 4.5x | 2.0x - 3.0x | 1.0x - 2.0x | <1.0x |

Table 6 below provides the interest coverage ratio dating from 2017 through June, 2021.

Table 6: Georgia Power (CFO pre-WC + Int)/Int[14]

| Date | (CFP pre-WC +Int)/Int |
|---|---|
| 12/31/2017 | [redacted]X |
| 12/31/2018 | [redacted]X |
| 12/31/2019 | [redacted]X |
| 12/31/2020 | [redacted]X |
| 6/30/2021 | [redacted]X |

This financial ratio indicates Georgia Power is "Aa" rating for the last few years.

[13] Moody's "Rating Methodology Regulated Electric and Gas Utilities", June 23, 2017

[14] Moody's Credit Opinion "Georgia Power Company Update to Credit Analysis, dated October 13, 2021., p. 3

Another financial credit risk compares cash flow generated by the business relative to the amount of debt issued by a company. The specific metric is cash flow from operations plus working capital less dividends divided by debt outstanding "(CFO Pre-WC less Dividends)/Debt." This ratio is an indicator of a utility's cash flow after dividend payments relative to the amount of debt outstanding.[15]

Table7: Moody's Standards for CFO Pre-WC less Dividends/Debt[16]

| | Aaa | Aa | A | Baa | Ba | B | Ca |
|---|---|---|---|---|---|---|---|
| (CFO pre-WC-Div)/Debt | >=35% | 25% - 35% | 17% - 25% | 9% - 17% | 0% - 9% | (5^ - 0% | <(5%) |

Georgia Power's CFO Pre-WC less Dividend/Debt ratio is as follows:

Table 8: Georgia Power CFO Pre-WC less Dividends/Debt[17]

| Date | (CFO pre-WC -Div)/Debt |
|---|---|
| 12/31/2017 | [redacted]% |
| 12/31/2018 | [redacted]% |
| 12/31/2019 | [redacted]% |
| 12/31/2020 | [redacted]% |
| 6/30/2021 | [redacted]% |

For this ratio, Georgia Power is in the Baa range of the Moody's standards.

The four financial ratios noted above, Georgia Power is in the "Aa" rating for one metric, between "A" and "Baa" rating for one metric ; and in the "Baa" range for two metrics.

---

[15] Moody's "Rating Methodology Regulated Electric and Gas Utilities", June 23, 2017

[16] Id

[17] Moody's Credit Opinion "Georgia Power Company Update to Credit Analysis, dated October 13, 2021., p. 3

These four financial metrics indicate Georgia Power is between A and Baa. Given Georgia Power's elevated business risk due to the construction of Vogtle Units 3 and 4, it is not surprising to see the Company rated the lower "Baa" instead of "A".

Q. **IS THE RATING PROCESS FOR STANDARD AND POORS (S&P) SIMILAR TO THE RATING PROCESS OF MOODY'S?**

A. Yes. S&P separates the rating process into business risk and financial risk and then combines the two into a single "anchor" rating. [18] The anchor rating can be subjected to other factors such as financial policy, liquidity, diversification, and management.

## IV. MOST RECENT CHANGES IN GEORGIA POWER CREDIT RATINGS

**Q. WHEN IS THE LAST TIME THE CREDIT RATINGS OF GEORGIA POWER WERE CHANGED?**

A. On Oct. 27, 2021, S&P downgraded Georgia Power from A- to BBB+.[19]

On August 8, 2019, Moody's downgraded Georgia Power from A3 to Baa1.[20]

Fitch downgraded Georgia Power's rating from BBB+ to BBB on February 22, 2022.[21]

[18] S&P Ratings Direct, November 19, 2013, page 3

[19] Georgia Power Response to STF-NEC-1-9

[20] Id

[21] Id

**Q. WHAT WAS THE PRIMARY REASON FOR THE CREDIT DOWNGRADES AS NOTED ABOVE?**

A. Without a doubt, the focus of the credit agencies has been the problems associated with the completion of the Vogtle nuclear plants. Below are what the credit agencies stated in regard to the downgrades.

**Moody's Report of August 8, 2018**

[redacted][22]

On Oct. 16, 2020, S&P issued a report in which it stated the following:

Downside scenario

[redacted][23]

[22] Georgia Power Response to STF-NEC-1-1, Attachment H, Moody's Report of August 8, 2018 entitled *Rating Action: Moody's downgrades Georgia Power to Baa1, ratings on review; affirms Southern at Baa2, negative outlook; affirms Alabama Power at A1, negative outlook; upgrades Mississippi Power to Baa3, positive outlook*

[23] Georgia Power Response to STF-NEC-1-1, Attachment AA, S&P report on Georgia Power dated Oct. 16, 2020.

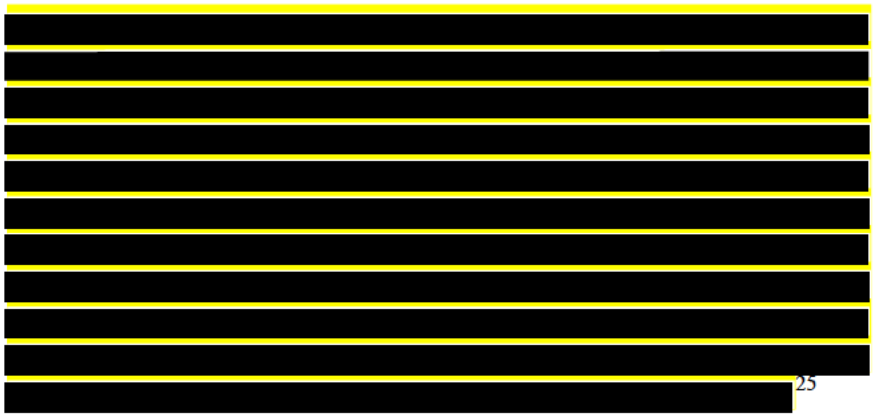
S&P gave warning of a potential downgrade on Oct. 16, 2020 and then, on Oct. 27, 2021, the credit agency did, indeed, lower the credit rating of Georgia Power.

On February 21, 2022, Fitch lowered the credit rating of Georgia Power to BBB and stated the reasoning as:

[24]

**Q. ARE THE CREDIT AGENCIES STILL CONCERNED ABOUT THE COMPLETION OF VOGTLE UNITS 3 AND 4?**

A. Yes, very much so. On January 25, 2022, Moody's wrote an article that stated:

 [25]

[24] Georgia Power Response to STF-NEC-1-1, Attachment AK, Fitch Ratings Report entitled *Fitch Downgrades Georgia Power to 'BBB'; Outlook Stable; Revises Southern's Outlook to Negative*

[25] Georgia Power Response to STF-NEC-1-1, Attachment AJ, Moody's Report entitled *Georgia Power Company: As Vogtle nears completion, achieving final milestones will be critical for both credit quality and stakeholder support*

Based on the above statement from Moody's, the pressure is on Georgia Power to complete the Vogtle units in a timely manner.

## V. COST OF CAPITAL TO CONSUMERS IS NOT LIMITED TO HIGHER INTEREST COSTS FROM CREDIT RATING CHANGES

**Q. DID COMPANY WITNESS FETTER TESTIFY IN THE 2019 RATE CASE?**

A. Yes, he did.

**Q. IN THE 2019 RATE CASE, DID WITNESS FETTER ADDRESS THE POSSIBLE DOWNGRADE OF THE GEORGIA POWER CREDIT RATINGS?**

A. Yes, he did. Below is what Mr. Fetter stated in his prefiled testimony from the 2019 rate case:

> Accordingly, I encourage the Commission to continue its supportive regulatory policies and procedures to solidify the Company's current credit ratings – with the potential that the ratings from Moody's and Fitch will be able to strengthen over time. Alternatively, a downgrade of S&P's 'A-' rating to 'BBB+', joining the other two agencies, would be financially injurious to both customers and investors, especially amidst the Company's effort to regain momentum with regard to bringing the Vogtle project to completion. [26] (underline added)

**Q. DID S&P LOWER GEORGIA POWER'S CREDIT RATING AFTER THE 2019 RATE CASE?**

A. Yes. Despite the Commission granting the Company a ROE 84 basis points (0.84 percent) higher than the national average of 9.66 percent and an equity ratio of 56 percent versus the national average of 49.94 percent, Georgia Power's credit rating was still downgraded by S&P on Oct. 27, 2021 from A- to BBB+.

[26] Prefiled Testimony of Fetter, Docket No. 42516, p. 19

**Q. DID YOU CALCULATE THE REVENUE REQUIREMENT IMPACT FROM THE HIGHER ALLOWED ROE AND EQUITY RATIO THAT WAS ALLOWED BY THE COMMISSION IN THE 2019 RATE CASE?**

A. Yes. Based on schedules filed by Georgia Power in the 2019 rate case, I was able to calculate that the higher revenue requirement associated with the 10.5% ROE and 56.0% equity ratio, as compared to the national averages in 2019, cost Georgia Power consumers an extra $683 million in higher rates over the three-year period 2020 - 2022.[27] The calculations for this estimate can be seen in Exhibit KWO-1.

In the Company's most recent rate case, the Commission granted Georgia Power a ROE and equity ratio considerable above national averages at that time that now, three years later, has cost consumers an extra $683 million. Unfortunately, the higher awarded ROE and equity ratio did not prevent the S&P bond downgrade.

**Q. WHEN DID MOODYS DOWNGRADE GEORGIA POWER'S CREDIT RATING?**

A. Moody's downgraded the Georgia Power credit rating on August 8, 2019, just prior to the final order being issued in the last Company rate case in December, 2019.

**Q. CAN YOU CALCULATE THE APPROXIMATE AMOUNT OF HIGHER INTEREST EXPENSES PAID TO-DATE BY GEORGIA POWER DUE TO THE CREDIT DOWNGRADE BY MOODYS IN AUGUST, 2019?**

A. Yes, since the downgrade that occurred in August, 2019, Georgia Power has made the following debt placements:

[27] DPP-SPA-MBR-1, Schedule 1 Total Company and DPP-SPA-MBR-3, Schedule 2, Workpapers 1-4.

Table 9: Debt Placements Since Moody's Downgrade[28]

| Coupon Rate | Maturity Date | Date of Issue | New Issues (a) |
|---|---|---|---|
| (2) | (3) | (4) | (5) |
| 3.25% | 3/15/1951 | 2/22/2021 | $ 750,000,000 |
| 2.20% | 9/10/2024 | 9/10/2019 | $ 400,000,000 |
| 2.65% | 9/10/2029 | 9/10/2019 | $ 650,000,000 |
| 2.10% | 7/30/2023 | 1/8/2020 | $ 700,000,000 |
| 3.70% | 1/30/1950 | 1/8/2020 | $ 500,000,000 |
| | | | $ 3,000,000,000 |

This debt of $3 billion has been subjected to higher interest rates due to the downgrade of Moody's and the higher interest costs are now in the embedded cost calculations in this case.

**Q. CAN YOU PROVIDE THIS COMMISSION WITH AN ESTIMATE OF THE HIGHER INTEREST EXPENSE PAID BY GEORGIA POWER CONSUMERS AS A RESULT OF THE DOWNGRADE BY MOODY'S IN AUGUST, 2019?**

A. Yes. In Exhibit KWO-2, pages 1-6, I provided a study to analyze the revenue requirement impact to consumers from the interest cost increase associated with the Georgia Power credit downgrade.

**Q. PLEASE EXPLAIN HOW YOU CALCULATED THE HIGHER REVENUE REQUIREMENT ASSOCIATED WITH HIGHER INTEREST COSTS FROM THE CREDIT DOWNGRADE THAT OCCURRED IN AUGUST, 2019.**

A. First, it is important to note that, from the Company's standpoint, higher interest costs associated with a downgrade apply only to debt issued prospectively. Hence, interest rates on bonds already issued prior to the downgrade cannot be changed to adjust for the credit downgrade.

[28] Supplemental Item MFR S-9

To determine the higher interest rate costs associated with a possible downgrade, I examined yield spreads to determine the increase in interest costs associated with the one-notch downgrade that has already occurred in the Georgia Power credit rating. The period I examined was from January 2019 through December, 2021 to align with the above-stated bond issuances. The bond yield spread information came from the Mergent Bond Record and listed the average yields on Public Utility "A" rated bonds and Public Utility "Baa" bonds. The data for this range can be seen in Exhibit KWO-2, p. 1-4.

To isolate the credit spreads to the time the bonds in-question were issued, I examined the calendar year average spread as well as the spread in the month in which the bonds were issued. Given that the Mergent spreads were for one full credit rating and there are three notches within a full rating, I divided the annual and monthly spreads by 3 to arrive at a representative spread that occurred at the time of the debt issuance. I then averaged the annual and monthly one-notch spread and applied it to the debt issuance for the three debt issuances that have occurred since the Moody's downgrade of August, 2019. I also summed up the interest cost for each issuance through the life of the issuance. The end result of these calculations can be seen in Exhibit KWO-2, p. 5 and show a total interest cost increase of approximately $45.3 million that has already occurred and will continue to occur over the life of the debt issuances dating back to just after the Moody's downgrade in August, 2019.

The higher ROE and equity ratio awarded in the last rate case cost consumers $683 million over the past three years. However, even with these actions approved by the Commission to shore up the financial position of Georgia Power, Moody's kept the bond rating at "Baa1". The downgrade that occurred in August, 2019, and the lack of any upward movement in the credit rating from Moody's has caused five Georgia Power bond issuances to be issued at interest rates higher than they would be had the downgrade not occurred. The end result is that consumers have paid

$683 million to help with the Georgia Power credit rating but, even with the above-average ROE and equity ratio granted in the last rate case, consumers have paid an additional $45.3 million in higher interest expenses over the life of the bonds due to the August, 2019 downgrade by Moody's.

**Q. IS MR. FETTER'S TESTIMONY IN THIS PROCEEDING SIMILAR TO HIS POSITION IN THE 2019 CASE?**

A. Yes, it is.

**Q. PLEASE EXPLAIN MR. FETTER'S TESTIMONY IN THE CURRENT PROCEEDING.**

A. In much the same manner as he testified in the 2019 rate case, Mr. Fetter is advocating for an outsized ROE and common equity ratio to prevent a *possible* downgrade in the credit rating of Georgia Power. Below is Mr. Fetter's position in this case:

> In order for Georgia Power to be able to, at a minimum, maintain, and potentially improve its current ratings range across all three agencies, I encourage the Commission to set the ROE and capital structure at levels consistent with Mr. Coyne's recommendations. Such a Commission determination would show a continuation of the strong regulatory support that Georgia Power has long experienced, which should avoid further weakening the Company's credit profile. On the other hand, a less than constructive decision by the Commission in this case could lead to further negative credit rating actions, potentially continuing the Company movement below the 'BBB+' / 'Baa1' rating level that I have long testified represents the lowest appropriate credit rating level for a U.S. regulated utility. Such negative ratings actions would increase the Company's cost of capital and its normal day-to-day capital investment for reliability during a time of increasing inflationary pressure, ultimately leading to higher rates for customers. [29]

[29] Prefiled Direct Testimony of Fetter, p. 5.

**Q. DO YOU AGREE WITH MR. FETTER THAT THE COMMISSION SHOULD AWARD THE COMPANY AN 11.0% ROE AND A 56% COMMON EQUITY RATIO?**

A. No. First, Mr. Fetter's testimony is speculative, at best, in that he cannot assure this Commission that its actions, no matter how much it awards Georgia Power in this case, will prevent a credit downgrade such as the recent Fitch downgrade that occurred earlier this year and the S&P downgrade that occurred late last year. The high ROE and equity ratio in the last rate case did not, contrary to Mr. Fetter's statements in the 2019 case, prevent a credit downgrade. Instead, the delay in completing Vogtle appears to be the primary reason for the credit downgrade. This construction delay was the responsibility of corporate management and not regulation, as cited by Mr. Fetter.

Second, as noted above, Georgia Power's financial metrics are stable, and the Company is on the final stretch for the completion of the Vogtle plants. Georgia Power should find itself flush with cash in less than two years as the Vogtle plants come online and the associated proceedings come to an end, all of which may very well result in a credit upgrade by the credit agencies.

Third, Mr. Fetter did not even attempt to provide this Commission with any evidence to support his contention that an excessively high ROE and equity ratio was needed by the Company for its credit rating. While I understand that Mr. Fetter is an advocate for his client in this proceeding, I believe he could have, and indeed should have, provided the Commission with a complete understanding of the costs to consumers of his recommendation versus the cost of a potential downgrade in credit costs.

**Q. CAN YOU PROVIDE THIS COMMISSION WITH A REVIEW OF THE COSTS SOUGHT BY GEORGIA POWER IN THIS CASE RELATIVE TO THE PROSPECT OF HIGHER INTEREST COSTS ASSOCIATED WITH A CREDIT DOWNGRADE AS FEARED BY MR. FETTER?**

A. Yes. In Exhibit KWO-3, I provided a study to analyze the revenue requirement impact to consumers from the prospective interest cost increase associated with a possible downgrade versus the significantly higher revenue requirement due to the higher ROE and equity ratio as requested by Georgia Power in this case.

**Q. HOW DID YOU CALCULATE THE HIGHER REVENUE REQUIREMENT ASSOCIATED WITH THE COMPANY'S REQUEST IN THIS CASE?**

A. I made this calculation in the same manner in which I calculated the revenue from the 2019 rate case that is shown in Exhibit KWO-1. Specifically, I calculated the pre-tax cost of capital for Georgia Power using its requested 11.0% ROE and 56% equity ratio in this case and compared that value to the pre-tax cost of capital that would Georgia Power receive if it had sought a ROE and common equity ratio equivalent to the national average provided by regulators across the country in 2021. I applied this difference in pre-tax cost of capitals to the requested rate base in this case and found that Georgia Power's request in this case increases the annual revenue requirement by an additional $421.1 million as compared to the national average allowed ROE and equity ratio. Over the three year plan period of 2023 – 2025 the increase to customers would be approximately $1.26 billion. The calculation details can be found in Exhibit KWO-3.

To determine the higher interest rate costs associated with a possible downgrade, I examined yield spreads to determine the possible increase in interest costs associated with the one-notch downgrade that has already occurred in the Georgia Power credit rating. The period I examined was from January 2012 through August, 2022. The bond yield spread information came from the Mergent Bond Record and listed the average yields on Public Utility "A" rated bonds and Public Utility "Baa" bonds. The data for this range can be seen in Exhibit KWO-4, p. 1-4. From January 2012, through August 2022 the average yield spread between these bonds was 51 basis points (0.51%). In August 2022, the spread was 33 (0.33%) basis point. I averaged the two points to arrive at an estimated future yield spread of 42 (0.42%) basis points. However, this spread represents a 3-notch

difference, whereas the credit downgrade for Georgia Power would be, in my opinion, a maximum downgrade of only one notch (Baa1 to Baa2). As a result, for the purposes of this analysis, I assumed the yield spread change would be 14 basis points (42 basis points divided by 3). The details of this analysis can be seen in Exhibit KWO-4, p. 5 attached to my testimony.

According to material filed in this case by Georgia Power Witnesses Abramovitz, Adams, Houston, and Robinson, the Company anticipates issuing $3.45 billion of new debt in 2023.[30] This analysis conservatively assumes that the significant increase cash flows from Unit 3 coming online would not prevent a hypothetical downgrade. Multiplying the 14 basis points (0.14) by the anticipated debt offerings of $3.45 billion results in a total cost of $4.8 million in annual additional interest expenses. Over a 20-year time period (life of the bond), the total increase in interest expense would be $96 million. The details of this analysis can be seen in Exhibit KWO-4 attached to my testimony.

So, in summary, Mr. Fetter and Georgia Power is asking this Commission to increase rates by $1.26 billion to POSSIBLY save $96 million in higher interest costs. I use the word "possibly" because, again, a higher ROE and equity ratio does not guarantee Georgia Power's credit rating will not be downgraded. The timely completion of Vogtle is clearly the most important factor affecting the current credit rating of Georgia Power.

**Q. WHAT IS YOUR RECOMMENDATION TO THIS COMMISSION IN REGARD TO SETTING AN APPROPRIATE ROE AND CAPITAL STRUCTURE IN THIS PROCEEDING?**

A. I will agree with Mr. Fetter that the credit rating of a utility has a significant impact on the interest expense paid by consumers. However, financial market conditions, general economic conditions, utility industry outlook and corporate management

[30] Exhibit APG-SPA-ADH-MBR, Schedule 3, Workpapers 1-6.xlsx

operating in an efficient and economic manner also impact interest expense incurred by a utility and recovered from ratepayers. However, Mr. Fetter's testimony is a classic case of "the tail wagging the dog". As noted above, it makes no sense whatsoever for the Commission to grant the Company's requested ROE and equity ratio in this case that would drive up rates $1.26 billion just to avoid possible higher interest costs of $96 million. My recommendation to this Commission is to give Mr. Fetter's testimony little weight and to recognize the potential risk is very small relative to the cost to ratepayers given that Vogtle units will be placed in service in the next year according to Georgia Power. The Commission should accept the well-reasoned recommendation of Staff Witness Gorman in this case.

## VI. SUMMARY OF RECOMMENDATIONS

**Q. PLEASE SUMMARIZE YOUR FINDINGS IN THIS CASE.**

A. My findings are as follows:

- The credit rating process examines business risk and financial risk;
- Georgia Power's business risk is elevated due to its ongoing struggles in completing Vogtle Units 3 and 4;
- Company Witness Fetter's testimony is incomplete because it does not address in a comprehensive manner the tradeoffs for customers of higher capital cost for Georgia Power versus interest expense savings and should therefore be given little weight;
- The Company's requested ROE and equity ratio requests in this case will amount to over $1.26 billion in higher annual revenue requirements to Georgia consumers as opposed to a possible $96 million in higher interest expenses should its bonds be downgraded;
- I recommend the Commission accept the recommended ROE and capital structure of Staff Witness Gorman.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes, it does.

BY MR. WALSH:

Q Mr. O'Donnell, did you also prefile or cause to be prefiled an Appendix A and four exhibits marked as KWO-1 through 4?

A (Witness O'Donnell) Yes, I did.

Q Do you have any changes or corrections to that; to any of those exhibits or appendix?

A (Witness O'Donnell) No, I do not.

MR. WALSH: Madam Chair, I ask that the appendix and exhibits KWO-1 through 4 be marked for identification with the next five Staff exhibit numbers, which are now Exhibit 108 through 112.

MADAM CHAIR PRIDEMORE: So marked.

MR. WALSH: Thank you.

(The document referred to were marked for identification as Staff Exhibits 108 through 112.)

BY MR. WALSH:

Q And, Mr. O'Donnell, did you also prefile or cause to be 128 pages of trade secret testimony in question-and-answer form, along with exhibits on October 20th?

A (Witness O'Donnell) Yes, I did.

Q Do you have any changes or corrections to those?

A (Witness O'Donnell) No.

Q No? And if I ask you the questions that are in the trade secret testimony, would your answers be the same?

A (Witness O'Donnell) Yes, they would.

MR. WALSH: Madam Chair, I ask that the trade secret version of Mr. O'Donnell's testimony with exhibits be marked for identification as Staff Exhibit 113.

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Staff Exhibit 113.)

BY MR. WALSH:

Q Gentlemen, did you prepare summaries of your testimony?

A (Witness Gorman) Yes.

A (Witness O'Donnell) Yes.

MR. WALSH: Madam Chair, may the panel present its summary?

MADAM CHAIR PRIDEMORE: Please go ahead.

MR. WALSH: Thank you.

MR. GORMAN: Good morning, Madam Chairman and Commissioners. My name is Mike Gorman. I'm representing Staff in addressing Georgia Power Company's overall rate of return in this rate case.

My recommendation is for Georgia Power to be

authorized an overall rate of return of approximately 6.83 percent in the test year, rising slightly to 6.84 percent through the multi-year rate review.

My overall rate of return is based on a return of equity recommendation of 9.45 percent, which is the midpoint of my estimated market-based return on range for Georgia Power Company in this case of 9 percent to 9.8 percent.

Within the test year, I recommended the company's ratemaking capital structure be approved for ratemaking purposes. However, after the Vogtle Units 3 and 4 construction period has been completed and those units are put back into service, I'm recommending that the company's ratemaking capital structure be adjusted at that point to -- for a lower common equity ratio.

My recommendation is at that point is that the company's ratemaking capital structure that existed prior to the start of the development of the Vogtle units, which included the 51 percent common equity ratio, again be used to set rates for this company.

In my testimony I outline the evidence why I believe that this is reasonable and fair to both the company and to the customers. After the development of the Vogtle units, the company's cash flows from

operations will be very strong. That supports its ability to reduce its cost to capital in setting rates and still maintain strong credit standing and access to capital.

A reduction in their rate of return at that point in time will benefit its customers because it will help offset an increase in rates necessary in order to fold in the rate base value of the Vogtle Units 3 and 4 into rates and will help mitigate the impact on its customers.

So that adjustment to the ratemaking capital structure at that point in time I think is fair to the company and will benefit customers by mitigating the increase in rates necessary to fully reflect the Vogtle units and cost of service, while still preserving the company's financial integrity, credit standing and access to capital.

In measuring the return on equity, I employed several market-based models, including the discounted cash flow analysis, the capital asset pricing model, and the risk premium model.

I performed several versions of the DCF model in arriving at my recommended return, as well as two different methods of the risk premium analysis. And I did a critical assessment of the current CAPM model

noting that current published betas are above normal for utility companies.

And my analysis of the current betas indicate that betas were skewed based on the statistical analysis used to measure betas based on a relatively short time period that coincided with the initial onset of the COVID-19 worldwide pandemic and the consequence it had to the capital markets during the months of March and April of 2020.

Those capital markets recovered very quickly after the -- after the market participants were confident that the economy was going to be able to cope with the limitations of the COVID-19 pandemic. And the market actually performed very well through most of the recovery from the COVID-19 pandemic up through current day.

I also responded to the company witness James Coyne's recommended return on equity. His range was 8.99 percent to 13.55 percent. Based on what I believe to be more reasonable inputs to his models, I believe his analysis would support a return on equity in the range of approximately 9 percent to 10.2 percent in this case.

I also responded to Mr. Coyne's concern about the reliability of the DCF results. Both his model

and my DCF models are supporting market-based return on equity using the DCF model of around 9 to 9.3 percent in this case.

He expressed concern about the reliability of those estimates. And I demonstrated in my testimony that I think the decomposition of that model in relationship to other alternative market-based investments demonstrate that the DCF return is producing economically logical results and is reasonably consistent with other investment opportunities in the market.

Specifically, the DCF is broken into a yield component and a growth component. For a stock investment, the yield component typically lags utility bond yields. But in the current market, utility stock yields are reasonably aligned with utility bond yields.

The growth component -- which is an indication that the yield component of the DCF model is not constrained enough or stressed. If anything, represents robust outlook for that component of the DCF return.

The growth component of the model also is robust, as it reflects growth rates going forward that are much higher than dividend growth rates have

been achieved in the past and reflect very strong capital investment programs for utility companies that are growing the rate base and growing the earnings and rewarding investors by growing dividend payments.

Based on that assessment, I think the DCF returns are economically logical, as well as the other aspects of my return on equity findings in this case.

Finally, I also looked at the credit metrics that would be realized based on my recommended overall rate of return in this case. And I found that my return on equity is both -- represents fair compensation to the utility, but it also will maintain credit metrics that are adequate to support its bond rating and preserve its financial integrity and access to capital.

That completes my summary.

MR. O'DONNELL: Madam Chair, Commissioners, my name is Kevin O'Donnell. I'm with Nova Energy. I'm representing the staff in this proceeding.

The purpose of my testimony in this proceeding is to review the current credit standing of Georgia Power and to comment on the testimony of Company Witness Fetter.

**Currently company's credit rating is BBB+ by Standard & Poor's and Baa1 for Moody's. Georgia Power's bond rating is stable and is currently under no threat of a downgrade. However, the company's credit rating has been downgraded over the past several years due primarily to construction delays and cost overruns at Vogtle.**

**Georgia Power's credit rating has been downgraded -- has been downgraded over the past several years with the primary reason being construction delays. With the conclusion of the Vogtle Units 3 and 4., Georgia Power's cash flows credit metrics will improve significantly and provide additional support to its crediting rating.**

**The Commission has awarded returns on equity and equity ratios higher than the national average in the past. Unfortunately, the higher returns awarded by the Commission have not prevented Georgia Power's bond rating from being downgraded due to the continuous delays and cost overruns at Vogtle Units 3 and 4.**

**Mr. Fetter's testimony is incomplete as it does not compare the cost to consumers of paying an unnecessarily high allowed rate of return to much smaller increase from interest -- from higher**

interest costs associated with a potential negative credit action.

Staff Witness Mike Gorman's recommended ROE and capital structure will provide Georgia Power with the necessary revenues and cash flows to support investment grade credit rating. I recommend the Commission award an ROE and cap structure consistent with Mr. Gorman's testimony.

MR. WALSH: Madam Chair, the panel is available for questions from the Commission and for cross-examination.

MADAM CHAIR PRIDEMORE: Okay. Very good.

Commissioners?

COMMISSONER MCDONALD: Did you say that -- that the staff's position on the ROE would not really affect because of the Vogtle situation?

It would affect the interest rates that the company is paying?

MR. GORMAN: The 9.45 percent return on equity, along with the company's capital structure during the development phase of the Vogtle units will provide adequate cash flows and earning strength to support its credit standing and continued access to capital, yes.

COMMISSONER MCDONALD: Will it support the

present earnings ratio and also support the ratings that presently exist?

Is that what you're saying?

MR. O'DONNELL: In my opinion, yes. What the staff is recommending, what amounts to $222 million rate increase on an annualized basis. Based upon my analyses, I would say that, yes, the credit rating is solid and I do not see it being downgraded from the staff's recommendation.

COMMISSONER MCDONALD: Thank you.

MADAM CHAIR PRIDEMORE: Any other questions from Commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. We're going to take this opportunity to recess for lunch. It is 11:49. We'll come back at 12:50. That's 12:50.

This is a popular panel, Mr. Gorman and Mr. O'Donnell. So we're going to make sure everybody has proper time to do their questions.

All right. With that, we stand adjourned for recess.

(A recess was held from 11:49 a.m. until 12:50 p.m.)

COMMISSIONER SHAW: We are going to get started in one minute.

We will go ahead and get started. I want to

remind the witnesses that you are still under oath, and we will call Georgia Public Service Commission and pick up where we left off.

MR. WALSH: Thank you, Mr. Commissioner. The panel is available for cross-examination and for questions from the Commission.

COMMISSIONER SHAW: Any questions from commissioners?

(No response.)

COMMISSIONER SHAW: All right. We will get started. Georgia Public Service Commission?

MR. WALSH: We are -- we are not going to be questioning them except on redirect.

COMMISSIONER SHAW: All right.

Americans for Affordable Clean Energy?

MS. LYNDALL: No questions.

COMMISSIONER SHAW: Georgia Coalition of Local Government?

MS. BROWN: Yes, sir.

COMMISSIONER SHAW: Ms. Brown.

CROSS-EXAMINATION

BY MS. BROWN:

Q Gentlemen, Alicia Brown on behalf of the Georgia Coalition of Local Governments.

This first question is going to be directed to

both of you, so, Mr. O'Donnell, if you can turn to page 8 of your testimony and, Mr. Gorman, page 21 of yours.

So, Mr. O'Donnell, on page 8 of your testimony in lines 25 and beyond, you reference this idea of a supportive regulatory environment or framework. And this is also including Mr. Gorman's testimony.

Mr. O'Donnell specifically cites a Moody's report which references ROE capital structure and unsymmetrical earnings bands as evidence of a supportive commission.

If the Commission were to accept your collective recommendations for ROE, capital structure, and things like that, would it lose its status as a supportive regulatory environment?

A (Witness O'Donnell) My opinion is, no. The fact is that the numbers given in the last rate case and in cases before that, you've had higher returns and higher equity ratios.

So coming back down to what is still Mr. Gorman's recommendation, is still higher than the national average. So, no, I -- I think it will continue to be very favorable regulatory treatment seen by the markets.

Q Okay.

A (Witness Gorman) And I agree. I think that the market understands that regulation is intended to

balance the interest between customers and investors. To the extent the utility's operated economically and efficiently, I am awarding a rate of return which reasonably aligns with the current market cost of equity, is fair compensation to the utility investors. And the overall rate of return recommendations and the resulting cash flows produced through this cost of service are adequate to support its bond rating and financial integrity, and I believe will provide continued access to capital under reasonable terms and prices.

Q All right. That's all I had. Thank you.

COMMISSIONER SHAW: Thank you, Ms. Brown. Georgia Interfaith Power and Light?

MS. KYSOR: No questions.

COMMISSIONER SHAW: Georgia SEIA?

MR. THOMASSON: No questions.

COMMISSIONER SHAW: Georgia Solar?

MR. MORELAND: No questions.

COMMISSIONER SHAW: Georgia Watch? Ms. Coyle.

MS. COYLE: Good afternoon, Commissioner Shaw. I have just a few questions.

CROSS-EXAMINATION

BY MS. COYLE:

Q Good afternoon, gentlemen, Liz Coyle with Georgia Watch.

A (Witness O'Donnell) Good afternoon.

A (Witness Gorman) Good afternoon.

Q And while certainly, Mr. Gorman, you are welcome to respond to any of these questions, I believe they are primarily directed to the testimony filed by Mr. O'Donnell.

So on page 5 of your testimony, Mr. O'Donnell, you included a table at the bottom of that page.

COMMISSIONER SHAW: What page was that?

MS. COYLE: It's page 5, the bottom of page 5, Table 3.

BY MS. COYLE:

Q Are you there?

A (Witness O'Donnell) Yes, I am here.

Q So I note that the two utilities on this chart, Georgia Power and Mississippi Power, the two that have lower ratings than their peers in the southeast, Georgia Power and Mississippi have the lower ratings, could -- in your testimony you have identified Vogtle as a driver in the rating for Georgia Power.

Would you say that Kemper was a driver in the Mississippi power rating?

A (Witness O'Donnell) Could very well be. I didn't follow Mississippi Power. I haven't gone through all their credit reports. But I am very well aware of Kemper,

so it's very possible that that was what was the driver there as well.

It's also a fact that Southern Company's equity ratio is somewhat lower than anticipated. It's about 40 percent. So a lot of the credit rating of -- between the parent and the subsidiary are interrelated.

A (Witness Gorman) I was in the Mississippi Power rate case, and Kemper was a factor --

Q And was a factor.

A -- in its bond ratings.

Q So that could show some consistency with the ratings agencies. They are looking for some -- maybe some trouble like Mississippi Power and Georgia Power have had with their major construction projects; whereas, Alabama Power, also a Southern Company subsidiary, is still on the higher ratings and no trouble with the construction projects?

A (Witness O'Donnell) That's one way to look at it.

Q And then I want to ask you to turn to page 11, in the O'Donnell testimony.

A (Witness O'Donnell) All right.

Q And as you are talking about -- well, when you talk about the ways throughout your testimony that you calculated the revenue requirement, that would be associated

were the Commission to authorize, for example, the higher ROE that the company is requesting.

Could you break out for me what portion of the revenue requirement, when you are doing your calculations, it -- by percentage -- is capital or other expense to be recovered, how much of it is interest on debt, how much of it is income tax, and how much of it is return on equity?

A (Witness O'Donnell) Yes, I could, but I can't do it now. You would have to take a look at what the revenue requirement is and then go down and calculate that as it's put in front of me.

The revenue requirement witness -- witnesses in this case would be better off handling that than I would.

Q But would you agree that you would have used that standard formula when you did your -- created your analysis?

A (Witness O'Donnell) It is one of the ways to do it, yes. I -- I did do that throughout this analysis, but I was looking more in terms of the pre-tax cost of capital applied to the rate base and then comparing that to interest cost. And there was quite a wide variance between developing the revenue requirement based upon what they are seeking in this case relative to national averages.

And what that revenue requirement is in the pre-tax basis in comparison to the cost of debt, I think it

was 1.26 billion as compared -- over three years as compared to 96 million interest cost over 20 years. So there was -- there was a wide gap right there.

Q Would you -- and I would make this subject to check, but would it surprise you that a significant -- nearly half of the revenue requirement is the return on equity?

A (Witness O'Donnell) Oh, no, no. I have been doing this for a long time. I understand that completely.

Q Thank you. And because you reference on page 5 your -- on page 11, excuse me -- you are referencing, as part of your analysis of the financial risk for Georgia Power, that the company has been pre-collecting Vogtle financing costs through the nuclear construction cost recovery tariff. Is that correct?

A (Witness O'Donnell) Yes.

Q And are you aware that residential customers have been paying the lion's share of that NCCR tariff since it began collecting in 2011?

MR. MARZO: Mr. Chair, this panel is here, my understanding, to talk about capital and the financial integrity cost of capital. These are questions that they are -- asking about what is the makeup of who pays for what, should have gone to witnesses earlier in the case. Plus, I would add the

NCCR is not a part of this case.

COMMISSIONER SHAW: Ms. Coyle, where are you going?

MS. COYLE: It is included in the witness testimony, and I have an exhibit I will pass out and hopefully that will help Mr. Marzo see where I am going.

COMMISSIONER SHAW: You may approach.

MS. COYLE: Thank you. Sorry. I am trying to learn the rules down here.

BY MS. COYLE:

Q So, Mr. O'Donnell's testimony is making the case, I believe, the policy case for the commissioners, that if the Commission were to approve the higher ROE the company is requesting, that's going to be an additional significant financial burden on ratepayers; is that correct?

A (Witness O'Donnell) Yes, that's correct. Any time you have a higher cost of equity, it's going to be higher rates. I mean, it's just a one-to-one ratio there.

Q And you also point out that one of the reasons that the company has the downgraded ratings is not the regulatory environment here at the Commission, but more likely what is happening at Plant Vogtle?

A (Witness O'Donnell) Absolutely.

Q So have you had a chance to take a look at the

document I just passed out to you?

A (Witness O'Donnell) Briefly.

Q Would you look at the chart prepared by staff in response to a data request I made in the last VCM 2006 hearings?

A (Witness O'Donnell) Okay.

Q Would you agree that the chart shows that the company will be earning an additional, per staff calculations, if the Commission authorizes recovery of the capital expenditures, would be an increase in profits for the company of over $9 billion tied to the delays at Plant Vogtle?

A (Witness O'Donnell) That's what this analysis says.

MR. MARZO: Mr. Chairman, I am going to object again. This is not an analysis that Mr. O'Donnell or Mr. Gorman has done. It's an analysis -- if she wants to ask questions about, there were staff witnesses that were actually on staff who participated in the VCM proceeding that were here earlier. Those questions would have been better directed to them. We are taking these two witnesses off the path of their testimony. Having him verify numbers that he didn't prepare --

MS. COYLE: Yeah. It's with respect to the

witness's recommendation that the staff not authorize a higher RO- --

COMMISSIONER SHAW: Ms. Coyle, just make sure your questions pertain to the testimony of this panel.

MS. COYLE: Okay. Thank you.

BY MS. COYLE:

Q And so now turning to page -- yeah, okay. Last question: On page 11 -- I mean, I am sorry, excuse me -- page 17.

You include in your testimony a couple of paragraphs of reports from Moody's and S&P on reasons for downgrading the company's rating; is that correct?

A (Witness O'Donnell) That's correct.

Q And are the Moody's and S&P reports public documents?

A (Witness O'Donnell) Not in this case. But they are otherwise. You can buy them on-line, and I bought one on-line. But they are not public in this particular proceeding.

Q Is that because Moody's would want people to pay to see the reports or because the company felt they should be redacted?

A (Witness O'Donnell) I -- that's a legal --

MR. MARZO: Yeah. Mr. Chair, that calls for

speculation. These witnesses don't know that. It's unfair to ask them that question.

MS. COYLE: Thank you. No further questions.

COMMISSIONER SHAW: All right. Thank you, Ms. Coyle.

MARTA?

MS. STURM: No questions.

COMMISSIONER SHAW: Resource Supply Management?

(No response.)

COMMISSIONER SHAW: Resource Supply Management?

(No response.)

COMMISSIONER SHAW: Sierra Club?

MS. ARIZA: No questions.

COMMISSIONER SHAW: SACE?

MR. DOWDY: No questions.

COMMISSIONER SHAW: United States Department of Defense? Ms. Medlyn?

(No response.)

COMMISSIONER SHAW: All right.

Georgia Power?

MR. MARZO: Thank you, Mr. Chair.

CROSS-EXAMINATION

BY MR. MARZO:

Q Good afternoon, gentlemen. Brandon Marzo on behalf of Georgia Power Company. It is good to see you

again, Mr. Gorman. It's nice to meet you for I think the first time, Mr. O'Donnell.

A (Witness O'Donnell) Yes, sir, first time here. Good afternoon.

Q And it seems that last -- yesterday I was talking depreciation after lunch, and now I get to talk about ROE and cost of capital after lunch, so we will try to make this as painless as possible.

Now, Mr. Gorman, just as -- some preliminary questions. I think most of my questions are going to be you, and so I will direct them to you. Obviously, Mr. O'Donnell, I may have some for you and I will direct them to you, but I think the bulk of my questions will be to Mr. Gorman.

Now, Mr. Gorman, would you agree with me that predicting the cost of capital for a company like Georgia Power involves some degree of judgment?

A (Witness Gorman) Well, estimating the cost of capital requires informed judgment that can be supported -- can be supported by observable market evidence.

Q Okay. And would you agree that in rate cases, experts can -- and I think as we have seen in the past, they often do -- disagree about the methods to use and the assumptions to make in trying to estimate the cost of capital for the company -- for a company like Georgia Power?

A (Witness Gorman) Yes. Typically the return on equity witnesses do not agree on a fair return on equity. That's true.

Q Okay. And you testified in Georgia Power's 2019 rate case on behalf of PIA staff; is that correct?

A (Witness Gorman) Yes.

Q And in that case, you recommended a 9.2 percent ROE and 51 percent equity ratio; is that correct?

A (Witness Gorman) I believe that's true, yes.

Q And are you aware that the Commission considered all the evidence presented in that case and ordered a 10.5 percent ROE and 56 percent capital structure for the company?

A (Witness Gorman) Yes, that's my understanding of the Commission's order, yes.

Q Okay. And that's just three years ago and that was roughly -- or I think precisely about 130 basis points above your recommendation and five basis points above your equity level; correct?

A (Witness Gorman) Yes.

Q Now, you criticize Mr. Coyne's expected earnings analysis in this case; correct?

A (Witness Gorman) I do.

Q You made a similar criticism of Dr. Vanderweide when he performed a comparable earnings analysis in the 2019

rate case; correct?

A (Witness Gorman) I would have to review my testimony, but if he recommended that methodology or used that methodology, I would have criticized it, yes.

Q Okay. And are you aware that the Commission had repeatedly considered or has repeatedly considered comparative earnings analysis in recent rate cases, including in 2010 and 2013 and 2019?

A (Witness Gorman) I know they have been offered in the -- by company witnesses in those cases. The Commission would have to opine on how much weight they gave to that evidence.

Q Okay. Have you reviewed the Commission's order from the 2019 rate case at all, the long order?

A (Witness Gorman) It's been a while, but yes.

Q Okay. And is it fair to say or do you recall that the Commission in fact in that order reported all of your assertions or restated all your assertions that challenged comparable earnings and still decided that 10.5 percent ROE was appropriate?

A (Witness Gorman) Well, I would hope they would consider my entire testimony. I presume they did and found that for the circumstances that existed at that time, 10.5 percent return on equity was what they found to be reasonable.

COMMISSIONER MCDONALD: Can you talk closer to that microphone, please.

MR. GORMAN: Yes. Sorry.

BY MR. MARZO:

Q And I agree, Mr. Gorman, that they should consider all the evidence, but I guess I was asking with more specificity if you were aware that your positions on comparable earnings were actually articulated in the Commission's order and they still decided to rule for a 10.5 percent ROE?

A (Witness Gorman) Again, I haven't reviewed that order in a while, but --

Q Fair enough.

A (Witness Gorman) -- the 10.5 percent return on equity is what they found to be appropriate.

Q Well, the order can speak for itself.

Now, you are aware that the Commission -- are you aware that after considering your criticisms -- well --

Can we agree that the 10.5 percent ordered by this Commission was significantly closer to Dr. Vanderweide's recommendation of 10.9 percent?

A (Witness Gorman) It was closer to his -- to a 10.9 percent ROE, yes.

Q Now, you also recommended a 5 percent reduction in the company's equity ratio in that case as well; correct?

A (Witness Gorman) I did, yes.

Q And would you agree with me that the current trend is increasing levels of equity and not decreasing levels?

A (Witness Gorman) Well, the increasing -- that is true, but the increasing trend typically is for an equity ratio right around 50 percent to something slightly over 50 percent.

Q Okay.

A (Witness Gorman) It's not up to around 56 percent.

Q And I guess my point was when I was looking at your testimony, I think you had a chart that was on page 32, Table 7, and I think to what you just said, Mr. Gorman, that chart showed an increasing level. It doesn't show 56 percent, but it did show the trend is to increase.

A (Witness Gorman) It is increasing slightly; that's true.

Q Okay. Now, you referred to national averages for ROE's for electric and gas utilities since 2020 in your testimony as an observable evidence in trends; is that correct?

A (Witness Gorman) Yes.

Q First, can we agree that similar information regarding national averages was provided to this Commission

by you and others in the 2019 rate case and the Commission still authorized the ROE it authorized in that case?

A (Witness Gorman) Yes.

Q Okay. And if the Commission wanted to consider observable evidence of a utility with a similar risk profile as Georgia Power Company, the Commission could consider the most recent decision in the Florida Power and Light case; correct?

A (Witness Gorman) The Commission can consider what evidence it feels to be relevant in measuring a fair return on equity. So I would agree it certainly can consider that.

Q And you presented testimony in that case; is that correct?

A (Witness Gorman) I did in support of its settlement, yes.

Q Okay. I believe you recommended a 9.4 percent return on equity?

A (Witness Gorman) Yes.

Q Okay. And 53 percent equity ratio?

A (Witness Gorman) I believe that's correct, yes.

Q And do you recall that Mr. Coyne also presented testimony on behalf of FP&L in that case applying a similar test as the ones he has used in this case in recommending

11 percent ROE?

A (Witness Gorman) I'd need to check my testimony in that case, but that seems accurate.

Q Okay. Do you recall, and tell me if you are aware, that in that case, you termed it, in your recommendation in responding to Mr. Coyne's recommendation, that his recommendation was excessive and unreasonable?

A (Witness Gorman) Yes.

Q And you have done that similarly, made those same statements in this case; is that correct?

A (Witness Gorman) I have.

Q And we know that the Florida Commission awarded FP&L a 10.6 percent ROE which, due to a treasury adjustment, is now at 10.8 percent; correct?

A (Witness Gorman) Well, that treasury adjustment could have gone either way. But the adjustment was based on other findings by the Commission. So the 10.6 percent was what the Commission found and it was subject to that adjustment, yes.

Q And is it fair to say that in that case, you had mentioned that you represented not the -- obviously not the company. I believe you represented the federal customers in that case. And are you aware that they actually signed the settlement?

A (Witness Gorman) Settlement in that case, yes.

Which was a complete settlement of the entire case. Not just the rate of return issue.

Q Fair enough.

On page 32, lines 10 through 17 of your testimony, you calculate the revenue impact and savings to customers of your proposed 51 percent equity ratio.

A (Witness Gorman) Just the capital structure value of that --

Q Yes.

A (Witness Gorman) -- adjustment, that's correct.

Q That's right. Now, isn't it true that your impact analysis assumes that the company's cost of debt remains constant with the reduction to 51 percent equity as opposed to the current 56 percent?

A (Witness Gorman) Well, that's -- yes, it does, and that's consistent with my testimony that there will be no negative impact on the company's credit rating.

Q And so you wouldn't expect a more highly leveraged company to pay more for its debt?

A (Witness Gorman) Not if its bond rating is not impacted by the adjustment in the rate-making capital structure, no.

Q So my next question was going to be, so you provided no analysis to support that. Is your S&P analysis the analysis that you're using to support that position?

A (Witness Gorman) I provided two analyses on the credit metrics. First the one I did based on the company's cost of service and staff's adjustments to cost of service in this case, but I also provided projections made by the company.

Q Okay.

A (Witness Gorman) Or credit metrics over the next three years, with and without a capital structure adjustment.

A (Witness O'Donnell) I'm the one who also gave credit metrics in his testimony and went through those and compared them relative to what Moody's seeks out in all of its factors in setting a credit rating.

Q Okay. And, gentlemen, would you agree with me that if we are going to present to the Commission testimony that suggests that a recommendation will not impact a credit rating, it's very important that the analysis done to prove that is done correctly; is that fair?

A (Witness Gorman) Yes.

A (Witness O'Donnell) And I think that's part of the reason why I went back and looked specifically at Moody's reports and looked at the credit parameters, looked at their last credit rating statement. So that those numbers you find on my testimony are from Moody's. I felt like that was important. Instead of me trying to

recalculate everything, I went directly to the Moody's source.

Q Okay. But you didn't -- did you speak to Moody's in terms of what your recommendation would do to the credit rating?

A (Witness O'Donnell) I didn't need to. I saw everything in writing that I needed to see.

Q Okay. And so let's talk about the S&P analysis first. Now, in your testimony, Mr. Gorman, you attempt to assess impacts of your recommendation on the company's ratings by attempting to replicate the analysis performed by S&P. Is that -- is that fair?

A (Witness Gorman) No, that's not -- in my testimony, I described the methodology I used is based on the rate-making cost of service in this case, which is different than what S&P would be looking at. They would focus on the entire company. Not just retail operations of the company.

So from that standpoint, it's different. But the calculation of the ratios based on test year cost of service is done based on the definitions S&P offers for the credit metric calculations.

Q Okay. So that was my -- I think you may have answered my question, but I just want to make sure that I understand for the purposes of understanding your testimony.

So when I turn to exhibits like Exhibit MPG-5 --

A (Witness Gorman) MPG-5? I am there.

Q Okay. So when I look at that particular analysis and I think, similarly MPG-22 --

A (Witness Gorman) Right.

Q Looking at 5 first, I mean, when you say Standard & Poor's credit metrics, I mean, it seems to be descriptive of what you would expect the output to be if Standard & Poor's ran this particular analysis; correct? Are you saying that it's not that, it is your -- it's your analysis?

A (Witness Gorman) Well, I mean, it's described at pages 62 and 63 of my testimony, what I did. And the significance of what I am doing and the reason it's not exactly done the same way that S&P does it is because I am doing it for a different purpose. What we are trying to do on a rate case is to measure retail rates which are fair and reasonable to utility and to its customers.

So the rate of return in setting those utility rates has to be Hope and Bluefield. That means customers pay rates that provide fair compensation that maintain the financial integrity of the utility based on the obligations the utility has to take on in order to provide regulated utility service.

So, I'm looking at the cash flows and the earnings on a regulated jurisdictional basis to determine whether or not the rate of return used to set rates is fair and reasonable to both the company and the customers.

Conversely, what S&P does is look at the total company irrespective of who's -- who is generating the revenues, and whether or not the financial obligation is for regulated retail operations or for some other operations in the company, and look at the overall financial strength of the total company in assessing the credit strength of that company.

They also look at affiliation risk and some other factors, which I did not look at in measuring the quantitative metrics for establishing whether or not the rate of return in this case is fair and reasonable.

Q Okay. And I think we're talking about two separate exercises here, Mr. Gorman -- and correct me if I'm just not -- if I'm misunderstanding.

I know one of the staff's positions in this case, and one of the questions I believe asked earlier by the Commission, related to whether or not the recommendation would result ultimately in some sort of adverse action by the credit rating agencies.

And what I understood you were doing in your testimony, in particular with these types of exhibits,

were -- was trying to replicate what S&P does so that we could better see what the outcome would be of your recommendation. Is that not what was going on?

A (Witness Gorman) Well, it is, yes.

Q Okay.

A (Witness Gorman) But it is more complicated than just replicating what the credit analysts are doing. Because in setting rates, customers can be asked to pay higher rates of return to support financial obligations the utility takes on to -- to support operations that are not included in retail operations.

Retail customers' rates should not be increased for financial obligations that are outside their jurisdictional umbrella of the utility. To the extent those non-retail jurisdictional operations need a rate increase, then the utility needs to go adjust rates to the other customers. The non-retail customers.

Q So let -- oh, go ahead, Mr. Gorman. You finish.

A (Witness Gorman) So in assessing whether or not the rate of return and the cash flow strength from setting retail rates in this case, that is what we focused on in determining whether or not what we are recommending the Commission approve will be adequate to support the utility's current bond rating financial integrity and access

to capital.

Q Okay. So let me get a better understanding of what you did. Now, as a precursor question -- now you have never worked for a credit rating agency; is that correct?

A (Witness Gorman) Correct.

Q And you have no hands-on experience in securing ratings for proposed securities issuance on behalf of a publicly-traded company; is that correct?

A (Witness Gorman) I have never worked for a credit rating agency, that's true. But I have been looking at credit rating reports and credit metric calculations for utility companies for several decades now.

Q Okay. And my second question was: And you've have had no hands-on experience in securing ratings for proposed securities issuance on behalf of publicly-traded companies?

A (Witness Gorman) That's correct.

Q And you are not an accountant, are you?

A (Witness Gorman) I am not an accountant, no.

Q Now let's turn to page 26 at line 11.

Now, you make -- you have a point there responding to questions about financial metrics, and you introduce a term that I want to ask you about. You use S&P's core ratio of FFO to debt. Do you see that?

A (Witness Gorman) Yes.

Q Now, first, am I correct that FFO refers to funds from operation? Is that correct?

A (Witness Gorman) Yes, it is correct.

Q Okay. Now, my second question is whether you call S&P's core ratio FFO to debt -- is that what's shown on page 27, Table 5 as S&P's core?

A (Witness Gorman) Yes.

Q And let's look at the footnote on that particular table. Do you see the footnote, which is -- it says 2013 S&P document?

A (Witness Gorman) Yes.

Q Now, you did not calculate what you call the S&P core FFO to debt ratio in accordance with Standard & Poor's April 2019 corporate methodology, did you?

A (Witness Gorman) Well, these ratios were calculated by the company, not by me.

Q Okay. And how is that? Explain that to me.

A (Witness Gorman) Well, the -- the ratios for 2020 actual through 2024 estimated are based on a response from the company in a data request. It is noted at page 25 at line 17. It's trade secret information provided by the company.

Q Did you -- do you recall the data response that you are referring to, because --

A (Witness Gorman) Yeah. STF-NEC-1-5,

attachment 1 -- or attachment I, Trade Secret.

Q So now are you aware -- well, let me ask you this: So you are -- are you aware that the S&P methodology that is included in the 2019 report, and also -- I believe is also in 2013 -- includes asset retirement obligations, leases, and certain power purchase agreements as things that are -- deferred compensation or are things that are treated as debt and adjusted out by S&P?

A (Witness Gorman) Well, we explored all of that with the company because I was aware that they did that. So we asked the company to provide us with information on off-balance-sheet debt equivalents considered by the credit rating agencies. And Georgia Power indicated they didn't have any.

When we looked at their calculations at these metrics outlined in Table 5, they didn't really detail specific off-balance-sheet debt adjustments to the debt numbers.

But, nevertheless, they did represent these credit metrics as being done consistent with S&P and Moody's methodologies.

Q So let's explore that for a minute. So the off-balance-sheet adjustments -- can we agree that's an accounting terminology? Accountants use off-balance-sheet approach. Isn't it true -- let me ask the question this

way --

A (Witness Gorman) More of an economic -- I would say it's more of an economic, because it looks at contractual obligations that the utility can default on if they don't meet their obligations effort.

Q But isn't it true -- or are you aware, Mr. Gorman, that the credit rating agencies, when they look to adjust debt, they also look at the balance sheet and they impute debt to certain categories on the balance sheet? Is that fair?

A (Witness Gorman) I am sorry. What did you say? Repeat that question.

Q Sure. When S&P, for example, if they were doing your analysis, my understanding is that S&P would look at the balance sheet and there are certain items that are treated as debt.

A (Witness Gorman) A balance sheet is a relatively straightforward identification of items that are debt equivalents, yes. They are explicitly debt.

Q Okay. In fact, you did -- I'm sorry. I didn't mean to cut you off, Mr. Gorman.

A (Witness Gorman) You know, off-balance-sheet debt equivalents are more things like operating leases, which aren't -- didn't used to be recorded on the balance sheet. They probably are going forward now.

Q Okay. So --

A (Witness Gorman) But since there's contractual obligations to meet the payment obligations under those leases, credit rating agencies create what they refer to as off-balance-sheet debt equivalents. That means if you don't pay your operating lease, you go in default of it, then there's financial and legal consequences to the utility. So they recognize those obligations as debt equivalents.

Q Okay. And I think we are saying -- I think you were answering my question for me, Mr. Gorman.

So asset retirement obligation, leases, purchase power agreements, pension benefit obligations, those are all the types of things that S&P would look at and would impute basically or treat as debt when they calculate their matrix; right?

A (Witness Gorman) They are, and that's why we went to great efforts to discover from the company all of those contractual obligations which may be regarded as off-balance-sheet debt obligations by the credit rating agencies. And Georgia Power informed us that they didn't have any of those.

Q And you understand that Georgia Power doesn't have any off-balance-sheet debt, but it does have things on its balance sheet that S&P would impute as debt?

A (Witness Gorman) Well, operating leases would

be one of those.

Q That's right. And so when we look at -- when we look at this calculation that you've done, it's our understanding that what you have not included is an imputation of those items, like asset retirement obligations, like leases, like pension benefits.

A (Witness Gorman) Yes. We were careful to include what the company was able to identify as those off-balance-sheet debt obligations in developing these credit metric calculations.

We asked that question explicitly in a discovery request, and the company informed us that they don't have any off-balance-sheet debt equivalents.

Q Now, you referred to Staff NEC 1-5, but do you understand that those -- my understanding of 1-5 is that those are reports that are put together by the company but the company doesn't run the analysis that S&P does. They don't do their own imputation for S&P. They provide information to S&P and S&P does the imputation, is my understanding. Is that different than your understandings?

A (Witness Gorman) Well, it's a little bit different. It's is my understanding that the -- there is an interaction between the company and the credit rating agencies in the development of those credit metric calculations. To the extent there's a disagreement, that

there is communication between the two parties. But ultimately the credit rating agencies are in control of the published credit metrics.

Q Now, in 2019, you ran a similar analysis as you did here in terms of what S&P's metrics would come out with. And my understanding is in that case, you did impute -- properly impute things like asset retirement obligations, pension benefits and otherwise.

A (Witness Gorman) In that case, I did the same analysis, but I did not have an explicit effort to identify from the company what their off-balance-sheet debt obligations are. So we issued discovery requests to identify what those obligations are to understand them to see whether or not it's short-term or long-term in nature and how they would impact the credit metrics going forward.

Based on responses to those discovery requests, the company informed us that they didn't have any off-balance-sheet debt obligations. That, in combination with the company's calculation of these credit metrics, which are listed in my table -- I am sorry. Turn the page -- my Table 5 at page 27 of the company, which are what the company shared with the investment community, as I understand it, the calculation without off-balance-sheet debt equivalents seemed to be reasonably consistent with what the company had done in that presentation to investors.

Q So let me ask you this: Did you ask the company whether or not there were items that are imputed by S&P that are on the balance sheet? It sounds like to me, and correct me if I am wrong, you asked the question at NC-1-5 that provides you information that is provided to the credit rating agencies. But what I'm trying to explain to you is that the company doesn't make the adjustments for the credit agencies.

A (Witness Gorman) No.

Q Is that your understanding?

A (Witness Gorman) No, that's not my understanding.

Q Okay.

A (Witness Gorman) Page 62 of my testimony, when I describe my credit metrics calculation, I ask the question: Did you include any off-balance-sheet debt equivalents? They said: No, in response to STL BAI 1-17 GP -- GPC stated it does not have any off-balance-sheet debt equivalents. However, I included short-term debt obligations provided in response to that because I knew that would be something that the credit rating agencies would include in measuring total financial leverage. The significance of short-term debt is not included in the rate-making capital structure.

Q Well, do you understand the company took that

as an accounting question, where they -- the answer is correct, they don't have off-balance-sheet debt. But what you didn't ask, and what the company would explain is that if you look at what can be imputed on the balance sheet by the rating agencies, is roughly $5 billion worth of items that don't show up in any of your tables.

MR. WALSH: I am going to object to the extent that that's testimony from counsel as to what the company has and didn't present in its case. If -- that's my objection.

MADAM CHAIR PRIDEMORE: Mr. Marzo, would you like to rephrase it?

MR. MARZO: Let me just approach.

BY MR. MARZO:

Q Mr. Gorman, did you review FERC Form 1? I think it's -- you cited to it in your testimony.

A (Witness Gorman) I did, yes.

Q Okay. Now, I tabbed a couple of pages there, and you are welcome to look at the whole FERC Form 1. I tried to include the entire item, but I am going to point you to the areas that I tabbed specifically.

MR. MARZO: And just for the record, Madam Chair, I would like to mark this as FERC Financial Report FERC Form 1, Number 1, with Georgia Power Exhibit 40, which this lays out in it the comparative balance sheet. And

that's what I am going to point Mr. Gorman to and ask questions on.

MADAM CHAIR PRIDEMORE: So marked.

(Document was marked for identification and admitted into evidence as GPC Exhibit 40.)

BY MR. MARZO:

Q So, Mr. Gorman, the two things I want to point you to is if you look on this particular document, particularly line 26 on the page that I showed you, that's where obligations under capital leases are picked up. That's over a billion dollars.

If you look at the next page, there is accumulated provisions for pension and benefits. That's almost 1.2, almost $1.3 billion. And then asset retirement obligations, which are the upwards of $6.8 billion. Do you see those?

A (Witness Gorman) I see those as, yes, being liabilities. What I don't see on this sheet, however, is the analysis the credit rating agency does in order to determine what the debt-like equivalents of these obligations are. And their analysis includes, essentially, an equivalency analysis to determine whether or not the company's obligation to make payments for these items is equivalent to issuing debt at the utility, as to the extent the pricing provisions or the payment provision under the

contracts is the equivalent of issuing debt.

Often the credit rating agencies, when they make that analysis, they will look at the obligation and the annual cash flows over time. They will provide a discounted calculation of that and then they do a debt equivalent or risk equivalent of it that indicates to the extent the utility does not make a timely payment on one of these obligations, then will that result in a default on the utility?

So simply looking at the balance sheet item does not tell me whether or not the credit rating agencies have determined that these accounting adjustments have a debt equivalent. That, in combination with the company's clear response to a discovery request that it does not have any off-balance-sheet debt equivalents by any of the credit rating agencies, supported my testimony to not include an off-balance-sheet debt equivalent in my credit metric calculations.

Q Do you understand it's a different question, whether or not the company has things on its balance sheet that are imputed debt? You keep referring back to the data response that refers to off-balance-sheet debt. That's correct. The company answered that correctly.

Wouldn't you agree with me, in light of the fact that you performed this same analysis in 2019, that the

question really is: Are there things on the balance sheet that would factor into S&P's analysis of imputing debt?

A (Witness Gorman) Well, there is, but there are -- there are offsets to that based on the company's ability to fully recover those obligations from their customers.

Specifically, for example, like an asset retirement obligation. To the extent the company is allowed to recover those costs through a specific tracking mechanism -- in this case it is -- then that reduces the debt-like nature of that obligation because it's being automatically recovered from customers.

For pension obligations, to the extent there is some recognition of the difference between recorded pension expense and pension contributions, and the underfunded status of the company's pension cost and the assurance of recovering that cost difference from customers, that impacts the debt-like nature of that obligation.

For capital lease obligations, depends on the term of the lease, and there are certain offsets that aren't listed here also, such as the amount of cash maintained on the utility's balance sheet, that may have the effect of minimizing or even canceling those as being off-balance sheet debt obligations.

Q Okay. So let's see how S&P does that analysis.

Are you familiar with STF-NEC-1-1 Attachment AI?

A (Witness Gorman) Can you give me that again?

Q Sure. STF-NEC-1-1 -- Attachment -- it's a mouthful -- Attachment AI.

A (Witness Gorman) Do I have that in front of me?

Q I can get it for you. I was just going to introduce it.

MR. MARZO: Madam Chair, could I approach?

MADAM CHAIR PRIDEMORE: You may approach.

MR. MARZO: Okay. I would like to have this marked as well, Madam Chair. It is STF-NEC-1-1 Attachment AI. I would like to mark it as Georgia Power Exhibit No. 41. It is "Ratings Direct S&P Global's Ratings."

And what I'm going to point the witness to is the calculation that he asked about, which is wanting to see how this was treated, how this level imputed --

MADAM CHAIR PRIDEMORE: So marked.

(The document referred to was marked for identification as Georgia Power Exhibit 41.)

BY MR. MARZO:

Q And you're welcome to look at the whole document, Mr. Gorman. I don't want to rush you, but I am

going to point you to page 8.

A (Witness Gorman) Okay. I am there.

Q Okay. So you had asked the question earlier that you weren't sure how these particular line items were being treated by S&P.

Would you agree with me that this is a depiction of the actual calculation S&P is doing? And as I stated earlier, there's over $5 billion worth of adjusted -- total adjusted items for debt by S&P.

A (Witness Gorman) For fiscal year 2020 is what you're referring to, and it does list total adjustments of about $5.7 billion, 5.8 billion, yes.

Q And is it -- are you aware through this conversation at this point that it's the company's position that the analysis that you've done has not adjusted for over $5 billion worth of debt that S&P would, in fact, impute to the company?

A (Witness Gorman) Well, I would encourage the company to give accurate responses to data requests if that's the -- if that's the determination here.

I would also note that the way I did the calculations, it was very similar to those in Table 5, which were done by the company and provided to the investment community.

Q And one last -- well, I think I have already

asked you this, so I won't ask you that question again.

But, Mr. Gorman, just to sum this line up, would you expect or -- now I just need you to agree -- would you expect the company disagrees with your position that somehow the requests you made in this particular case about off-balance-sheet debt was, in fact, a question that was elicited the response necessary to make your calculation?

A (Witness Gorman) I would be shocked if they misunderstood what the purpose of the data request was. First, it's stated specifically for off-balance-sheet debt equivalents with respect to the capital structure and rate of return discovery.

This company, Southern Company, is very familiar with my rate of return analyses. You know, I have testified here before. I have testified in Illinois with respect to your subsidiary for NiSource. We do credit metric calculations as part of our rate-of-return testimony. We have not gotten inaccurate off-balance-sheet debt numbers from Southern Company affiliates up apparently until this rate case, this instance. So I would be shocked if the company misunderstood what I was asking.

A (Witness O'Donnell) Could I --

Q So -- I'm sorry --

A (Witness O'Donnell) -- add something about this?

What Mr. Gorman did was -- would have been the same thing I would have done, and that is he asked the company for specific data and then you act upon what's provided to you. So the company may disagree with Mr. Gorman, but I think I would agree with him. I would have done the same kind of thing.

Q Well, we can both agree, at least, and maybe subject to -- well, let me see if you will agree with this. You have got to ask the right question to get the right data; correct?

A (Witness O'Donnell) And I think he did. I think he asked the right question. I don't see how it's been so misinterpreted.

Q And Mr. Gorman ran the exact same analysis in 2019 and got the same sort of responses that you got in this case so I am --

A (Witness Gorman) I didn't ask for the off-balance-sheet debt numbers in the last case. What I intended to do with them in this case was have greater detail what those off-balance-sheet debt obligations were. So I could have done a more detailed review of it to see whether or not the obligation is short term in nature or whether or not it is a long-term recurring issue.

Also, whether or not there are regulatory procedures which improve the likelihood of full recovery of

those obligations, which should be -- likely will be a factor, is a factor by the credit rating agencies in determining the debt equivalents of those obligations.

And also, it's relevant in establishing to the extent customers are paying for these financial obligations through some separate non-base-rate mechanism, but yet they are paying base rates, including a common equity ratio, in the rate-making capital structure that ignores what's going on in the non-base-rate regulatory mechanism.

It's inconsistent with the objective of my testimony to ensure that customer rates are no higher than necessary to provide fair compensation to the utility and to ensure the utility is able to maintain its credit standing and financial integrity.

Q Well, understand this, Mr. Gorman, the company's concern, based upon your testimony, is if I look at your exhibits and I see, for example, the ones we started off with, which was Number 5 and Number 22, they appear to represent that that's how S&P would have done its calculation.

And my point to you is, you've left out $5 million worth of debt. And so we don't agree that's how S&P would do its calculation.

A (Witness Gorman) Sir, I left out -- to the extent I left out debt it's because the company acknowledges

in discovery response that that debt was not considered by credit rating agencies, be the off-balance-sheet debt equivalents. That's the reason it was left out. It was based on information provided by the company.

Q Okay. So we will agree to disagree on that.

And, Mr. O'Donnell, to be clear, if I look at Mr. Smith and Mr. Trokey's demonstrative exhibits that Mr. Walsh handed out at the beginning of this proceeding, none of their proposed adjustments are attributed to your testimony; is that correct?

A (Witness O'Donnell) I don't believe that they are.

Q So your testimony is that the recommendation of Staff Witness Gorman in this case, to support that; correct?

A (Witness O'Donnell) Well, I'm here to discuss what the credit rating agencies would do and the cost of what the company is requesting relative to the interest expense. But I am here ultimately to support the recommendation of Mr. Gorman.

Q Now, Mr. O'Donnell, you state in page 6, line 20 of your testimony that a downgrade does not imply a company cannot access the capital markets?

A (Witness O'Donnell) That's correct.

Q Okay. Now, wouldn't you agree with me that a downgrade, depending upon where the rating has dropped,

could prevent a company from being able to access capital?

A (Witness O'Donnell) No. I mean, even if you were at the junk bond status, you can still access the market. It may not be favorable terms and it may be a private issuance, but you can still access the market. And right now they are at Baa1 on Moody's and they're nowhere close to being non-investment grade.

Q Okay. So it's your position that no matter what the credit rating is, you can always access the capital markets?

A (Witness O'Donnell) If you do -- you can do private issuances in some cases. You don't -- I mean, there are times, for example, a merchant plant where they are not -- they don't have a bond rating, but they can still issue debt and it's a private one-on-one issuance with whoever is financing their merchant plant operations.

So it definitely helps. Because if you don't have a bond rating, at least in merchant plants, you would have to have some kind of letter of credit and that's going to cost you something. And then you stand on the credit rating of the issuer of the letter of credit, but there are different ways to address that problem.

Q Is Georgia Power a merchant plant?

A (Witness O'Donnell) No. I am just giving you an example. It is good to have a credit rating, but you can

still do business without a credit rating.

Q Okay. And is -- it's not your recommendation that the company should do business without a good credit rating; correct?

A (Witness O'Donnell) No. No. I was here to talk about what their credit rating is and what -- where they currently are and the cost of what the company is requesting in this case relative to what may happen under a worst-case scenario of a bond downgrade.

And the numbers are staggering. What you are asking for is a tremendous amount of money for what may not happen. Even if it did happen, the ratio is more than 12 to 1 in terms of cost relative to savings.

Q And can we agree, Mr. O'Donnell, at least that if you're going to represent to the Commission what may or may not happen, the information needs to be accurate? Is that fair?

A (Witness O'Donnell) To the best of everyone's capabilities. And I would follow up that data request responses need to be accurate as well.

MR. MARZO: Madam Chair, thank you for your time.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Marzo. Redirect?

MR. WALSH: Thank you, Madam Chair.

**REDIRECT EXAMINATION**

**BY MR. WALSH:**

**Q I would like to follow up on the questions you -- Mr. O'Donnell, that you just received regarding a downgrade. You said the ratio is more than 12 to 1. You are talking about the ratio between the cost to consumers of a higher return on equity versus a potential for a downgrade.**

**Could you explain what type of dollar amounts we're talking about in that ratio?**

**A (Witness O'Donnell) Yes. It is actually more than 12 to 1. The reason is -- what I did was I compared the company's requested equity ratio and its requested return on equity relative to the national average. And what I found was that the cost was 1.26 billion over three years for the company's request in this case, relative to the national average. So, over three years, consumers in this state would pay 1.26 billion.**

**But if you look at what may happen, what may not happen, the credit rating may be impacted. It may not be impacted. But if it was impacted, the cost would be 96 million over the next 20 years. So it's actually a ratio of more than 12 to 1. It's probably closer to 20 to 1. But that's a lot of money for what may or may not happen going forward.**

Q Thank you, Mr. O'Donnell. And if there was a downgrade, is return on equity the only thing that is -- factors into a decision as to whether there is a downgrade?

A (Witness O'Donnell) No. Table 4 in my testimony has weighting of rating factors, regulatory framework is 25 percent. Ability to recover costs and earn a return is 25 percent. Diversification is 10 percent. And then, finally, metrics is 40 percent.

So 60 percent of what goes into a credit rating is not related to metrics. 60 percent.

Q And is it your position or -- what is your position as to whether the adoption of staff's recommendation on return on equity is likely to result in a downgrade for the company?

A (Witness O'Donnell) I do not believe it will impact the credit rating.

Q Mr. Gorman, I'm going to turn to you now. Could I get you to turn to page 30 of your testimony.

You were asked about state-authorized common equity ratios. Do you recall those questions?

A (Witness Gorman) I do.

Q And I believe you were asked as to whether your recommendation on -- comment on the capital structure and the common equity ratio is out of step with a trend to increase the equity component. Do you recall those

questions?

A (Witness Gorman) I do.

Q Okay. And just to be clear, your recommendation on the capital structure, would that -- for calendar year 2023, you are not recommending a change to the company's proposed common equity ratio, but you would recommend a change from 56 percent to 51 beyond that?

Is that correct?

A (Witness Gorman) In 2024 and beyond, yes. That's after the Vogtle Units 3 and 4 developments is expected to be completed, the units placed in service, be placed in commercial operations, and the cost of which would be included in development of rates. After that point, the utility's cash flows will increase dramatically relative to the period where those -- those nuclear units are under construction.

Q If I could get you to take a look at Table 7. Do you believe that the 51 percent common equity ratio that you are recommending for 2024 and beyond is in line with the trends in state-authorized common equity ratios as shown on this table?

A (Witness Gorman) That's precisely why I offered this table, to show that it's fairly standard rate-making treatment for establishing a regulated regulatory capital structure.

The 51 percent equity ratio is roughly equivalent to the average electric ratio from 2018 through second quarter of 2022.

You know, they are moving up and down a little bit, but that -- these are recorded regulatory-commission-approved capital structures. And in some instance, those capital structures have outlier utilities which drive the average up or down.

But, generally speaking, a 51 percent rate-making capital structure common equity ratio is in line with the majority or the average and -- of high frequency of rate-making capital structures approved for an electric utility companies.

Q Is the common equity ratio that is recommended by the company in this case in line with the state-authorized common equity trend?

A (Witness Gorman) No. It's considerably higher than that. And at the point where the Commission decided to approve a rate-making capital structure with a 56 percent equity ratio rather than the 51 percent was right at the time where the Vogtle units developments were creating financial strain on the company.

So that is why I am tying that rate-making capital structure approval for the Vogtle unit development after which, when rates will be adjusted to reflect the

cost -- the prudent and reasonable cost of the Vogtle units, that the rate-making capital structure be adjusted back down to where it had been prior to the Commission's decision to change its rate-making equity ratio position.

Q Thank you, Mr. Gorman.

Now, I just want to ask a couple questions about the cross dealing with the off-balance-sheet debt obligations.

Did you take into consideration, in developing your recommendation, everything that the company provided in support of its rate case?

A (Witness Gorman) I did. I went through extensive evidence trying to understand why the company was telling you that they didn't have any off-balance-sheet debt equivalents. Both in direct response to that discovery request and in reviewing their methodology for calculating these credit metrics that they included the document that I relied on to report the company's projected credit metrics in my Table 5 at page 27.

As my understanding of this utility and the dozens of utilities I work with on an annual basis for the last several decades, there's communication between the utility and the credit rating agencies about how these credit metrics are calculated. So I am assuming that the credit metrics that were included in Table 5, which were

calculated by the utility, with the exception of the adjusted 2024 column, reflected the utilities' understanding of what the credit rating agencies were looking at in calculating these credit metrics.

So I relied on that information, and I also relied on a direct data response from the company asking for what off-balance-sheet debt equivalents were considered by credit rating agencies. And that response indicated that there was no off-balance-sheet debt numbers.

Q In your experience, would you have expected to receive the type of information the company was asking about today in response to that discovery request?

A (Witness Gorman) I have been asking that question to the utility to come to a common understanding of off-balance-sheet debt numbers, because they're not clean. You don't look at a balance sheet and point at numbers on it, say there it is, because it's not developed like that.

An off-balance-sheet debt obligation is an assessment of the credit rating agencies of future obligations of the utility. Like making debt service payments, principal and interest, under a contractual obligation.

And what happens if you don't make the full contractual payment to the third party? Do they have the legal recourse to cause a default and cause some financial

consequence to the utility?

The utility goes -- or the credit rating agency goes through that assessment of those contractual obligations, comes up with a net present value number. It's not a number they take directly off the balance sheet. And then apply a risk factor to it to determine what is the debt equivalent of that contractual obligation. And that number, then, is what the credit rating agencies use in assessing the overall financial risk of the utility, which includes all recorded on-balance-sheet financial obligations, plus all contractual financial obligations which are not recorded on the balance sheet.

And that goes into what the credit rating agencies refer to as their adjusted debt ratio calculation.

So the default of the utilities' obligation is a major issue in that determination of off-balance-sheet debt equivalents, and I would note that on -- I don't know -- this STF-NEC-1-1 Attachment 1I to the S&P credit report, it identifies one of the largest off-balance-sheet obligations for this utility is asset retirement obligations.

Well, currently, the company is recovering those coal combustion residual asset retirement obligations through its environmental cost compliance rider.

So if it's passing these obligations that it

has to remediate coal ash ponds directly to its customers, then its ability to recover that liability from customers reduces the risk of -- the risk to the utility of having to do that environmental remediation, and that cost recovery assurance is considered by credit rating agencies in determining how much debt equivalent should be assigned to that environmental remediation obligation.

That's precisely why I asked this utility for off-balance-sheet debt obligations. It's a commonly understood factor in assessing bond ratings, looking at capital structures, that I know for certain that the Southern Company subsidiaries are well aware of that, because I have argued -- made this same argument with other affiliates of this company around the country, and this is the first instance where I found a utility subsidiary that didn't understand what off-balance-sheet debt equivalents were.

MR. MARZO: Madam Chair, I have let the redirect go on. It's a mischaracterization of what I crossed him on. We understand what the question was. It was the wrong question to elicit the response he wanted. And it wasn't any sort of trap by us; we answered the question the way accountants would have answered that type of question. And so the mischaracterization is my objection.

Mischaracterization of what I said on my cross.

MR. WALSH: Madam Chair, it is not a mischaracterization. It is a difference of opinion. Georgia Power Company stated what their opinion was, and the witness is stating his opinion.

MADAM CHAIR PRIDEMORE: Mr. Walsh, isn't this entire case a difference in opinion?

MR. WALSH: Exactly. And I think that's why the witness gets to state his opinion, and I think that -- you know, I think we've said it. I'm not asking for -- that was my last question on my redirect. But I don't think it's a mischaracterization. It's his honest opinion, and if the company has a different opinion, that's ultimately before the Commission to render a decision.

MADAM CHAIR PRIDEMORE: I just want to make sure that Mr. Gorman isn't implying that the company is not hastily doing the work the federal government is requiring them to do for a coal ash remediation, they are not doing that because they are earning a rate of return. Are you implying that?

MR. GORMAN: No, they are not earning a rate of return. It's an out -- it's a cash obligation of the utility to remediate environmental compliance sites.

But they fully recover the cash obligation they're incurring for remediating those sites.

So that the question is, is are credit rating agencies recognizing the significant liability for the company, but to the extent there is a regulatory mechanism in place that explicitly allows them to recover the cost of that liability from the customers, does that impact the credit rating agency's assessment of what the financial risk is to the utility for that environmental remediation obligation?

It's a financial risk issue. It's not a -- it's not a question of whether or not this improves their profitability. It's a question of whether or not their capital structure does need to be adjusted to reflect this environmental liability.

And that's what I'm taking issue with, because customers are paying the cost of that environmental remediation through the ECCM rider mechanism. So they shouldn't also be asked to pay a higher rate of return after the Vogtle units are fully developed. Because over time, the utility will have to expend those funds to remediate those coal ash pond sites.

MADAM CHAIR PRIDEMORE: I see your difference of opinion, and it's up to commissioners to decide

whether or not they agree with you or not.

MR. GORMAN: Yes. Thank you.

MR. WALSH: Madam Chair, that concludes my redirect. I would ask that Staff Exhibits 84 through 113 be admitted into record.

MADAM CHAIR PRIDEMORE: Yes. So moved.

(Staff Exhibits 84 through 113 were admitted into evidence.)

MR. WALSH: And I would ask that the panel be excused.

MADAM CHAIR PRIDEMORE: The panel is excused.

MR. WALSH: Thank you very much.

Thank you, panel.

MR. MARZO: Madam Chair, I would just ask any exhibits that have not been moved in by Georgia Power be moved into the record.

MADAM CHAIR PRIDEMORE: So moved.

We're down to our final two.

On, come on, that elicited a cheer. There we go. All right.

I believe that we have one housekeeping measure that SACE has that they would like to address before we move on to the -- to Georgia Power panels.

Yes, hello, Mr. Dowdy.

MR. DOWDY: Thank you, Madam Chairman. I

previewed this a little bit earlier in the hearing, and just wanted to move the direct testimony of Ronald L. Lehr on behalf of Southern Alliance for Clean Energy and Southface Energy Institute, Inc. Mr. Lehr could not travel, and, therefore, be here today. The parties have agreed to stipulate the testimony in.

Mr. Lehr did want to make two corrections to the testimony. The first at page 13, line 10, where the word "third" should be "fourth." And the second at page 14, line 17, where it references Exhibit RLL-Exhibit 5. It should say Exhibit 6.

And with those two corrections, we would ask that the testimony be copied into the record.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimony of Mr. Ronald L. Lehr follows:)

**STATE OF GEORGIA**
**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:**

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|---|---|---|
| | ) | |
| **Georgia Power Company's** | ) | **DOCKET NO. 44280** |
| **2022 Rate Case** | ) | |

# DIRECT TESTIMONY OF RONALD L. LEHR
# ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY AND SOUTHFACE ENERGY INSTITUTE, INC.

# I. INTRODUCTION

**Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A: My name is Ronald L. Lehr. I am a consultant and the Board Chair for New Energy Economics. My business address is 4950 Sanford Circle West, Englewood, Colorado 80113.

**Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A: I am testifying on behalf of Southern Alliance for Clean Energy ("SACE") and Southface Energy Institute, Inc. ("Southface").

**Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS AND WORK EXPERIENCE.**

A: I consult clients about energy regulation and business matters. Current assignments include work for Western Grid Group on the western grid-level system, operations integration, and transmission planning and for a consortium of foundations interested in application of new financial approaches to address stranded utility assets resulting from retiring uneconomic generation plants. I have worked for the largest privately owned Swiss utility, private firms, trade and business associations, non-profit advocacy groups, national energy laboratories, and foundations on energy acquisitions, renewable energy policies, and commercialization strategies. I represented the wind industry in the Western U.S. on regional transmission and related issues for over a decade and have appeared as an expert witness, sponsoring testimony in administrative venues on utility planning and mergers, and in antitrust, employment, and government claim litigation. I am currently board chair of New Energy Economics, which supports competitive acquisition of new utility generation and demand resource portfolios to manage risks, based on rapidly changing economic fundamentals. I served for seven years, from 1984 to 1991, as Chairman and Commissioner of the Colorado Public Utilities Commission. I have served on corporate and foundation boards of directors and boards of advisors. I also completed terms as an appointed member of panels charged to make recommendations on electric industry restructuring, renewable energy resources, and transmission needs to the Colorado General Assembly, and as President and Commissioner of the Denver Board of Water Commissioners, the water utility for Denver and surrounding suburban areas. I hold a B.A. in history from Dartmouth College, University of Sheffield, and a J.D. from University of Colorado College of Law.

**Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION ("GPSC" OR "THE COMMISSION")?**

A: No.

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A: We ask consideration of consumer benefits to put downward pressure on rates, proposing conditions within the ARP related to recent changes in federal law. Specifically, we recommend that the Commission require inquiry into economic impacts, given new laws, that can lower consumer costs. We outline two examples without exhausting potential for consumer benefits from broader use of other provisions of the new laws, of which there are many.

**Q: ARE YOU SUBMITTING EXHIBITS ALONG WITH YOUR TESTIMONY?**

A: Yes, I am submitting six exhibits along with my testimony, itemized below:
RLL-Exhibit-1: Resume
RLL-Exhibit-2: Georgia Power's Currently Identified IRA benefits 2022-2025
RLL-Exhibit-3: Examples of Policies Now Available to Georgia Power
RLL-Exhibit-4: Summary of Electricity Tax Credit Provisions in the IRA
RLL-Exhibit-5: IRA Section 20144 Text
RLL-Exhibit-6: Georgia Power's Generation Assets in U.S. Dollars ($) and Percent (%)

## II. SUMMARY

**Q: PLEASE SUMMARIZE THE RESULTS OF YOUR REVIEW OF GEORGIA POWER'S 2022 RATE CASE AND THE ANALYSIS YOU HAVE CONDUCTED.**

A: The results of my review and analysis of Georgia Power's filings, informed by my experience as a former Commissioner and utility regulator, are summarized as follows:

1. The Commission must assure just and reasonable rates and charges for customers.
2. Commissioners should place Georgia Power's current revenue request in context of three additional bill increases that I understand are pending or expected over the next three years, including a fuel cost recovery filing anticipated within the next six months.

3. The Commission should reduce cumulative amounts of these rate increases by ordering Georgia Power to identify and use all newly available financial resources to lower costs *during* the proposed 3-year ARP.
4. The Commission should order the company to aggressively pursue federal and state resources as soon as possible, identify benefits to both customers and company, evaluate impacts on investment costs, and adjust the revenue requirement accordingly.
5. The company has a once-in-a-legislative-lifetime opportunity to offset some costs to reduce consumer impacts in their $2.9 billion revenue request – a cumulative amount confirmed by Mr. Abramovitz during the previous hearing (Tr. 293, Lines 1-6) – with sizable new investments in energy technologies and transitions.
6. A variety of existing regulatory mechanisms, at the Commission's disposal, are available for Georgia Power to utilize newly available federal financial resources within the context of their proposed ARP.
7. Significant potential financial opportunities and savings have been newly created, including, but not limited to, the 2021 Infrastructure Investment and Jobs Act ("IIJA")[1] and the 2022 Inflation Reduction Act ("IRA")[2].

Consumers deserve rates that reflect thorough assessment and aggressive use of all potential lower-cost funding alternatives.

**Q: BASED ON THIS REVIEW, WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION TAKE IN THIS PROCEEDING?**

A: The Commission should take the following steps to assure consumer benefits are captured as Georgia Power implements provisions of new federal laws that substantially change industry economics:

1. Reject the proposed levelized rate increase and adopt an annual step increase.
2. Require the company to identify available funding through IRA, IIJA, and present findings to the Commission.
3. Encourage the company to apply for, receive approvals, and use available funding to best provide timely consumer and community benefits.
4. Encourage Commission staff and company to develop agreed upon federal funding tracking processes, including actual and anticipated funding, and actual and estimated costs and benefits to customers and communities.

[1] H.R.3684 - 117th Congress (2021-2022): Infrastructure Investment and Jobs Act, H.R.3684, 117th Cong. (2021), http://www.congress.gov/.
[2] H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022, H.R.5376, 117th Cong. (2022), http://www.congress.gov/.

5. Order annual reports detailing results and define true ups resulting in updated revenue requests for 2024 and 2025 within the 3-year ARP.
6. Provide for tax and other savings to benefit customers, including to offset rate increases during 2022-2025.

## III. A COMMISSIONER'S PERSPECTIVE OF A RATE CASE

**Q: AS A FORMER COMMISSIONER, HOW WOULD YOU APPROACH THIS RATE CASE?**

A: Essential duties for a commissioner in a rate case include assuring due process, finding facts based on the case record, applying relevant utility law to those facts, while finding a just balance between competing claims, particularly as between consumers and shareholders. Events may have resulted in that balance falling too severely on consumers, requiring rates that could be lower, or investors taking risks for which they are not adequately paid. If so, commissioners have the duty to rebalance so utility operations and investments are as efficient as possible and rate case results achieve just and reasonable rates. Another challenge for commissioners is to strike the right relationship between current consumers and shareholders and those who will be involved across decades ahead. Rate cases are not filed in a vacuum, instead they are chapters in longer running narratives. Commissioners need to understand both the case before them and the circumstances in which it has been filed. For example, financial cycles including rising and falling interest rates provide relevant background for consideration when considering rate cases. Rapidly changing technologies can result in new economic relationships among investment choices. Utility management changes, and management approaches and choices change and evolve over time. State and federal policies that impact utilities and regulation are in continuous development. Commissioners can bring the best of their understanding of all these developments, changes, and considerations to their rate case decision making.

Commissioners owe all parties, and themselves, a duty to learn as much as they can across a range of regulated industry issues and developments as well as gathering insights that can be gained from a range of professional perspectives. These include law, economics, engineering, finance, accounting, management, and policy. No other party or participant has a commissioner's responsibilities. They bear ultimate responsibility for all the issues in all the commission's dockets. No other participant or party, including commission staff, bear these responsibilities.

If we consider the "regulatory compact," utilities enjoy state mandated franchise monopoly in exchange for being economically regulated. But regulators face an information asymmetry wherein utilities have all the information regulators need to do their jobs. In these challenging circumstances, commissioners are thought to have responsibilities to

protect consumers from results that would differ from those obtained in workably competitive markets.

## IV. PUTTING NEW FINANCIAL TOOLS INTO ACTION

**Q: WHAT DO YOU UNDERSTAND TO BE THE BENEFITS OF GEORGIA POWER'S THREE-YEAR ARP PERIOD?**

A: It is clear that Georgia Power views the three-year ARP structure as a successful framework for the Commission, the company, and its customers. In addition to its authorized earnings band, they suggest that the ARP provides longer financial and operational time horizons for planning, continuity with Integrated Resource Plans (IRPs), and more consistent information about anticipated rate or billing adjustments. The currently proposed ARP for this case, they say, "is similar to the ARP's that have benefited both our customers and our Company since 1995" (Tr. 255, Lines 15-16). But, as Mr. Abramovitz attested at the previous hearing, in addition to the ARP framework itself, "the inputs do matter, as they always do." (Tr. 291, Lines 24-25). As Mr. Abramovitz also noted during his testimony, the three-year ARP structure is not a given, and it can be adopted, modified, or rejected at the Commission's discretion.

**Q: DO YOU KNOW IF THE COMMISSION HAS PREVIOUSLY ORDERED GEORGIA POWER TO IDENTIFY COST REDUCTION OPPORTUNITIES DURING AN ARP PERIOD?**

A: Yes, it is my understanding that the Commission has previously ordered the company to *identify* possible savings for customers *during* an ARP period. I'll provide two examples, among others.

First, a 2009 Stipulation (Document 122306) as a part of Georgia Power's 2007 Rate Case (Docket No. 25060), for an accounting order request stated, "The Company will use its best efforts to continue to reduce costs and will identify those cost reductions in its 2009 and 2010 Annual Surveillance Reports ("ASRs")." This shows that the company, GPSC staff, and the Commission have successfully worked together to identify cost reductions within a previous rate case period.

Second, the 2013 Rate Case (Docket No. 36989) provides several examples. In addition to orders emerging from ASRs in 2018 (Document 180405) and 2019 (Document 182469) that resulted in refunds to customers, in 2015, the Commission ordered the company to file updated tariffs (Document 157212). My understanding is that it occurred two years following the previous rate case and four years prior to the next one.

**Q: DO YOU KNOW IF THE COMMISSION HAS PREVIOUSLY ORDERED GEORGIA POWER TO IMPLEMENT COST REDUCTION OPPORTUNITIES DURING AN ARP PERIOD?**

A: Similarly**,** yes, the Commission has ordered the company to *implement* additional cost savings mechanisms *during* an ARP period, again, on more than one occasion. In 2018, the Commission and Georgia Power worked together to ensure emerging benefits from the Tax Cuts and Jobs Act ("TCJA")[3] would *immediately* flow to customers. I think the specifics, especially the timing, of that Order and the company's response are worth revisiting.

The TCJA was signed into law on December 22, 2017. Despite the holiday season, the Commission responded to that historic opportunity within one month of it being signed into law. On January 19, 2018, the Order on the TCJA (Document 170797) was filed – an impressive response by this Commission – as a part of Georgia Power's 2013 Rate Case (Docket No. 36989). Equally commendable, the company filed a response (Document 171428) within two months, on March 6, 2018. After meetings between GPSC staff and Georgia Power, a Stipulation Agreement was reached and an order (Document 171901) was filed on April 5, 2018. As I reviewed the order, I found the following quote especially pertinent:

> "The proposed Settlement provided ratemaking treatment to address the effects of the TCJA on the Company's cost of service in several areas" (Page 1).

**Q: HOW DID THE 2018 TCJA SETTLEMENT BENEFIT CUSTOMERS?**

A: As former Georgia Power Chairman, President, and CEO, Mr. W. Paul Bowers, confirmed in his testimony (Document 177523) during Georgia Power's 2019 Rate Case (Docket No. 42516), much of the benefit was refunded directly to customers through direct bill credits, with the remaining benefits applied to mitigate costs in its 2019 revenue request. In total, Mr. Bowers testified that GPC worked to return more than $1.1 billion to customers by leveraging the available tools in the TCJA. $330 million was issued across three refunds, one in 2018, 2019, and 2020. An additional $670 million was apparently assessed in the 2019 Rate Case, of which $660 million in benefits were used during the previous three-year ARP, as indicated in the company's filings for the current proceeding (Document 190559).

The impacts of these swift and decisive actions by the Commission and Georgia Power were not limited to previous rate cases and their respective ARPs. The company's responses to data requests (Document 19910, STF-LA-2-115) indicate that some of these

[3] S.2254 - 115th Congress (2017-2018): Tax Cuts and Jobs Act, S.2254, 115th Cong. (2017), http://www.congress.gov/.

savings continue through 2025. As we saw with the TCJA in 2018, the immediate use of newly available federal funds has meaningful benefits for customers that carry well into the future.

**Q: WHAT FACTORS MIGHT AFFECT WHETHER A LEVELIZED RATE INCREASE OR ANNUAL STEP INCREASE PROVIDES THE LOWEST COSTS AND MOST BENEFITS TO THE UTILITY AND CUSTOMERS?**

A: It is my understanding that Georgia Power proposes to over collect in the first year's traditional base rate request. In their filings, they claim this will save customers money, overall, and provide clearer information about anticipated bill increases during the three-year ARP. Mr. Womack said as much during the previous hearing, in his oral summary, stating:

> "...we are proposing to levelize most of the requested rate adjustment over the three-year ARP because it provides customers with more stable and predictable rates and will result in customers paying $40 million less over the three-year ARP" (Tr. 099, Lines 17-19).

Consumer economics change, quite drastically, however, as new sources of federal funding have and will continue to become available since the company's initial rate case filing in this docket, and these changes are likely to increase potential for consumer benefits during the ARP period.

According to Georgia Power's supplemental filing based on results of the 2022 IRP (Document 191294), the actual revenue deficiency applicable to traditional base rate tariffs is just above $477 million in 2023, $746 million in 2024, and $1.1 billion in 2025. If the levelized rate request is approved, and Georgia Power would be authorized to collect approximately $762 million in traditional base rate in 2023 – more than $284 million above the actual revenue deficiency – the company, and its customers, would be locked into a pathway in which they cannot maximize the benefits of newly available federal funding over the next three years. Alternatively, if only the $477 million revenue requirement for 2023 is collected now, the company, the Commission, and GPSC staff have more opportunity and flexibility to use these new funds.

As I will discuss further, sizable cost savings that can put downward pressure on rates will be lost if available benefits of new legislation are not considered until the next rate case in 2025. The Commissioners should also note that the frontloaded, levelized request was not used in the settlement approved by the Commission for the 2019 Rate Case, for reasons, as I understand them, similar to those I describe below.

**Q: DO YOU THINK THE ANNUAL STEP RATE INCREASE COULD BENEFIT CUSTOMERS?**

A: Even before the IRA, IIJA, and other financial opportunities changed economics of this proceeding, the company's assumptions about customer preferences are worth revisiting. GPSC staff asked Mr. Abramovitz if the company included the net present value of money – which involves understanding economic pressures facing individual customers – in their conclusion that the levelized request is for the benefit of customers. Mr. Abramovitz first nodded in the affirmative and then said "Correct" (Tr. 286-287. Lines 13; 6). As I understand it, Georgia Power has provided no further details about how the net present value of money for, say, individual residential customers was incorporated into any of their calculations or filings in this proceeding.

If the Commission rejects the levelized request and orders the company to collect the $477 million revenue request in 2023, in addition to the substantial benefits customers will receive through reduced costs as the company identifies and uses funds from the IRA and IIJA, those customers will also have more money in their pockets in 2023. In the current economic and inflationary environment, this approach will allow the company to increase the economic resilience of their customers, for whom the company makes clear in their filings and testimony, and as Mr. Womack said well, "are at the center of everything [they] do" (Tr. 071, Lines 7-8).

**Q: DO YOU THINK THE ANNUAL STEP RATE INCREASE COULD BENEFIT THE COMPANY?**

A: When the company filed their case, the levelized rate increase may indeed have been the lowest cost plan that provided the most benefits to the utility. But, as I've said, the economics have changed, and now the company has the new opportunities to take advantage of hundreds of millions, if not billions, to reduce costs. This is advantageous to the company not only for the obvious reasons, like saving money, but also for more qualitative, but equally important reasons: their relationships with their customers.

It will be to the advantage of Georgia Power to aggressively pursue every dollar available to reduce their customers' bills, increase reliability and resilience, and proactively reduce the cumulative bill impacts of the next three years. The cost saving opportunities in the IRA and IIJA, over immediate and long term, are clear financial incentives for the company to act, as is their ability to pass along savings to their customers through defined true-ups resulting in updated revenue requests for 2024 and 2025 and potential refunds for customers.

## V. EMERGING FINANCIAL OPPORTUNITIES

**Q: DOES GEORGIA POWER PLAN TO USE ANY FUNDS FROM THE IRA OR IIJA DURING THE THREE-YEAR ARP COVERED BY THIS REQUEST?**

A: Yes, they do, and I commend them for their initial commitment. In a response to a GPSC staff data request (Document 191627, STF-LA-5-14), Georgia Power states that it has currently identified $33 million in potential IRA benefits. The company provides the estimated tax savings, reproduced in RLL-Exhibit-2, in their discovery response.

In this response, Georgia Power explicitly states it "expects the IRA will provide tax benefits that, over time, can help reduce costs for customers" (Document 191627, Page 1). Commendably, we also learn that they are already on the case:

> "The Company is actively reviewing the wide range of flexible tax credits and other benefits from the IRA and, as such, the Company is still working on the analysis to be able to quantify further potential customer savings" (Document 191627, Page 2).

Similarly, in a discovery response about the potential use of the IIJA (Document 191627, STF-LA-5-17), the company is actively reviewing availability and opportunities. This proactive approach by Georgia Power reflects the constructive regulatory environment nurtured and maintained by the Commission. I suggest, to the benefit of both customers and the company, that the Commission should play its role, providing certainty to the company by requiring Georgia Power to bring these analyses before the Commission in as timely a manner as possible.

In the previous hearing, Mr. Womack also signaled the company's desire to use IRA's benefits. Responding to a question about re-evaluating company's incentives, Mr Womack said:

> "That's something we'll engage with the Commission… and, yeah, the Inflation Reduction Act, we continue to evaluate what it means for us going forward… we'll take a look at that and work with the Commission to decide what we do going forward" (Tr. 143, Lines 12-23).

I applaud Mr. Womack, and I believe this proceeding is the perfect opportunity to formally begin this process with the Commission before being locked into a three-year plan.

**Q: ARE THERE ANY ADDITIONAL BENEFITS OF THE IRA THAT THE COMPANY HAS IDENTIFIED IN ITS FILINGS?**

A: Based on their discovery responses (Document 191627, STF-LA-5-14), I believe the company is also currently evaluating potential IRA savings as they relate to employee

benefits, income tax expenses, and electric vehicle purchases. Additionally, Georgia Power has already identified at least two projects approved by the Commission in the 2022 IRP – the Hydro Modernization and Integrated Hydrogen Microgrid projects. I, again, applaud the company's swiftness in evaluating these opportunities, especially those related to IRP and procurement processes.

**Q: WHAT ARE SOME KEY POLICIES FOR UTILITIES TO CONSIDER?**

A: In RLL-Exhibit-3, I provide a non-comprehensive list of provisions in the IRA and IIJA that could be used by Georgia Power with estimated funding amounts.

**Q: WHAT IS THE POTENTIAL MAGNITUDE OF THE BENEFITS FROM IRA AND IIJA?**

A: It's hard to overstate IRA and IIJA benefits applied to the U.S. electricity sector, investor-owned utilities, public utility commissions, and the public. The IRA is one of the largest federal energy investments in U.S. history. This legislation has fundamentally changed energy economics for states and utilities, making available billions of dollars for energy investments that benefit economic growth, public health, grid reliability and resilience, and energy affordability.

The IRA provides more than $413 billion in new funding for climate and energy, with approximately $221 billion for the electricity sector alone. The IIJA includes more than $168 billion in funding, the largest categories funding transportation, climate, and electricity, respectively. The Congressional Budget Office estimates that enacting the IRA alone results in a net decrease in the deficit totaling $90 billion over the 2022-2031 period. These benefits will flow to utilities as well as their customers. Although there are thousands of provisions, we here focus on two examples, which we suspect might be the main benefits to Georgia Power, energy tax credits and infrastructure financing.

**Q: WHAT ARE RELEVANT COSTS AND CHALLENGES OF RESPONDING TO IRA AND IIJA OPPORTUNITIES?**

A: Because these opportunities are substantial and new, information providers like consultants, law firms, policy analysts, and trade press are all working to understand the new provisions and summarize and explain them. We see daily contributions to this flow of information now and expect that improved analysis and output from these sources will continue. Less information is available concerning actual early examples of use of new

provisions, and as those early examples emerge, we will learn a lot about what the changes mean and how to use them.

However, not all the provisions are shrouded in mystery. For example, tax credits are relatively straightforward and since they have existed previously in more modest forms, quite a lot of analysis and experience is available to help Georgia Power understand their impacts on investment choices and potential for consumer benefits. Other provisions of the new laws require implementing agencies to develop criteria and regulations that will explain a lot about how to apply for, receive, use, and report on newer provisions, like loan guarantees for energy transition purposes. Each provision that offers potential benefits for Georgia Power consumers will need to be investigated, analyzed as it develops, and assessed for application to Georgia Power's circumstances. These challenges demonstrate all the more clearly why being locked into a levelized rate adjustment, which results in a greater than 35% overcollection in the first year, might limit the company's ability to take advantage of the vast new financial opportunities at their disposal.

While that's not the work of an hour or a day, in the immediately following weeks and months, we hope active participation with implementation of the most relevant provisions will equip Georgia Power sufficiently to make early use of as many of these provisions as possible. That will require staffing, management engagement, and possibly use of expert advisors from outside the company. But we think the chances of benefits for consumers are better than an even bet and worth the effort. The Commission and its staff should prepare to travel on the same journey with the company, so they are fully advised in all the premises to take maximum advantage of new funds to put downward pressure on rates.

**Q: WHAT IS THE POTENTIAL MAGNITUDE OF THE OPPORTUNITY FOR GEORGIA POWER?**

A: Potential benefits for Georgia Power and its customers are substantial. As I discuss below, I think several items from the recent Georgia Power IRP deserve immediate attention. Expanding renewables, building a standalone storage facility, and investment in transmission and distribution upgrades all emerge from the 2022 IRP and can potentially benefit from these new funding opportunities. There are also opportunities to use any immediately available tax credits or other savings as refunds – similar to the 2018 TCJA tax cuts – to help customers weather the six bill increases expected over the next three years.

**Q: WHAT IS THE POTENTIAL MAGNITUDE OF OPPORTUNITIES FOR TAX CREDITS IN THE IRA?**

A: The IRA makes four key changes to the production tax credit (PTC) and investment tax credit (ITC). I have summarized some of their key components in RLL-Exhibit-4. First, the IRA restored the PTC and the ITC to full values and extended the timeline to 2022-2032. Credits are then reduced through a phase-out mechanism. Second, solar projects in service in 2022 or later can elect for the PTC, which could soon be more lucrative. Third, as RLL-Exhibit-4 shows, there are bonuses to incentivize states, Commissions, and utilities to focus on the human impacts of the ongoing energy transition. Third, the IRA improves effectiveness for investor-owned utilities by making tax credits transferable.

There are significant opportunities to 'stack' PTC and ITC benefits. Projects can receive an ITC ranging in value from 6 to 50% for utility scale projects and up to 70% for projects under 5 MW. For both the PTC and ITC, there is an additional 10% incentive to develop projects in locales critical to an equitable energy transition, defined as 'energy communities'.

As one example of how this may apply for Georgia Power, we can look at energy storage. The company says the 65 MW Mossy Branch battery storage project will qualify for the 30% full ITC, resulting in $31.7 million in tax credits (Document 191627, STF-LA-5-14). The Commission recently "provisionally approved" a standalone battery storage facility in Georgia Power's 2022 IRP (Docket No. 44160), the McGrau Ford Battery Facility. In the 2022 IRP, the company's cost-benefit analysis for the McGrau Ford Battery Facility, submitted in their main filing (Document 188519) showed it to be in the best interest of all customers. If we take their analysis at face value, then the facility will be even *more* beneficial for customers now that it qualifies for the ITC with a 30% full credit reduction in capital costs. Improved economics, given federal tax changes, might be an opportunity for the commission to revisit their "provisional" approval to encourage the company to make the investment.

The IRA also includes a zero-emission nuclear PTC that could provide tremendous cost reduction opportunities for the Vogtle Nuclear Power Plant.

**Q: WHAT IS AN 'ENERGY COMMUNITY'?**

A: The IRA provides a variety of incentives tied to labor, manufacturing, and geography. One mechanism is the newly defined 'energy community', a location especially impacted by the ongoing energy transition. The IRA identifies three independent eligibility criteria: (i) brownfields, (ii) census tracts with closed coal plants or mines, and (iii) census tracts with certain fossil fuel employment and overall unemployment characteristics. These incentives

may influence commissions to reevaluate when certain fossil fuel assets should be retired and transitioned, and where new energy and grid assets might be located now that financial benefits exist specifically to support economic vitality in highly impacted communities.

**Q: WHAT IS THE POTENTIAL MAGNITUDE OF OPPORTUNITIES FOR REFINANCING IN THE IRA?**

A: IRA's section 50144, text provided as RLL-Exhibit-5, gives the Department of Energy's Loan Program Office $5 billion in appropriated funds to handle $250 billion in authorized loan guarantee funding for a broad set of purposes related to energy transition. The loan guarantees may be applied to loans supporting projects that retool, repower, repurpose, or replace retired energy infrastructure. Among these broad purposes, reinvestment financing for fossil infrastructure aims at potentially stranded electric utility generation assets allowing loan guarantees to decrease cost of capital used to pay off outstanding, unpaid investments. The provision requires electric utility loan applicants to provide assurances of both community and consumer benefits.

One assessment, provided as RLL-Exhibit-5, suggests that Georgia Power might have about $10 billion in fossil assets that could require refinancing for which Section 50144 loan guarantees would apply.

The U.S. Department of Energy's Loan Program Office (LPO) will support loan-making authority. In addition to handling the energy transition applications, LPO provides a non-exhaustive list of qualifying projects that also include (i) refinancing, upgrading, uprating existing nuclear or hydropower facilities and (ii) transmission upgrades. The company would be wise to evaluate these tools to reduce costs associated with their transmission and distribution request in this case.

The IRA builds upon grid investments made in the IIJA. Many available federal and state funds can potentially complement one another. Utilities that proactively work with commissions and staff to leverage these additive effects will position themselves as leaders in ongoing energy transitions and likely win admiration in capital and credit markets.

**Q: ARE THERE EARLY INDICATIONS OF INTEREST IN THESE OPPORTUNITIES TO ACHIEVE CONSUMER BENEFITS IN OTHER STATES?**

A: There are some very preliminary assessments starting to become available from other jurisdictions. We anticipate that more of this kind of information will emerge as these new opportunities continue to attract serious attention. Here are a few examples:

In a September 23, 2022, petition to approve refund and rate reduction resulting from the IRA (Document 07675-2022) filed by Florida Power and Light (Docket No. 20220165),

the company has already identified approximately $234 million in customer savings for 2022-2025.

On October 12, 2022, Ameren Missouri filed supplemental testimony (File No. ER-2022-0037) on the currently known impacts of the IRA for their annual rate review. They estimate PTC savings for wind and solar totaling $1.3 billion from 2023-2032. They also detail the potential for savings associated with PTCs for nuclear facilities, although they await guidance. One unique feature of Ameren Missouri's recent filing is that they formally request an IRA guidance tracker. To demonstrate the need for this tracker, they show how the PTCs for a specific nuclear facility "could be zero one year and more than $100 million in the next" (File No. ER-2022-0037, Page 9, Lines 12-13). Worth noting, they conclude,

> "We estimate that the net IRA benefits will result in customer rates that are on average approximately *four and a half percent lower* per year under the IRA than they would have been had the IRA not been enacted" (File No. ER-2022-0037, Page 9-10, Lines 20-21; 1) (emphasis added).

**Q: WHAT ARE OPPORTUNITIES FOR THIS COMMISSION IN THIS PROCESS?**

A: The Commission must play a central role in implementing these new federal funding incentives. IRA and IIJA dramatically reduce the cost of certain energy technologies. A recently published guide for states summarizes the new opportunity facing the Commission:

> "[PSCs] should prioritize re-examining now-outdated cost assumptions in planning and procurement, enabling competition to drive new investment and retirement, and taking a proactive role in community transition…"[4]

I know that planning and procurement are beyond the scope of this proceeding; but, as I've discussed above, waiting until the next IRP and Rate Case in 2025 will be far too late to take advantage of the full potential of new legislation.

## VI. SIX BILL INCREASES IN THREE YEARS

**Q: WHAT IS THE SIGNIFICANCE OF THE OTHER KNOWN BILL INCREASES ANTICIPATED DURING THIS THREE-YEAR PERIOD?**

A: As a Commissioner, I was concerned about just and reasonable rates for customers, reducing costs for both customers and the utility, promoting competition, reducing risk, and fostering a constructive regulatory environment. I think it's difficult to do those things

[4] O'Boyle, M., Esposito, D. and Solomon, M., October 2022, "Implementing the Inflation Reduction Act: A Roadmap for State Electric Policy," Energy Innovation Policy and Technology, LLC. Page 3.

in this case without placing it in context of the other rate adjustments and bill increases anticipated over the next three years. It is my understanding, based on the company's testimony and responses to data requests, that customers will experience three bill increases – two associated with the deployment Vogtle Units 3 & 4 and one with an upcoming fuel cost adjustment (FCA) – in addition to the three rate increases requested in this case during the next ARP. If I am correct, combined, Georgia Power's customers will likely experience six bill increases over the next three years. This necessitates that commissioners consider overall and cumulative impacts of these increases on customers and how the company can, as aggressively as possible, reduce costs during this period.

At the same time, I see the magnitude of available funds through new legislation as an incredibly serendipitous moment if the company carries through on its apparent commitment to use these newly available resources to offset consumer cost increases. To keep rates as reasonable as possible, the company does have a strong incentive to apply newly available funds to put downward pressure on rates whenever possible.

**Q: WHAT'S YOUR UNDERSTANDING OF THE FCA YOU MENTION ABOVE?**

A: Because increasing natural gas exports have exposed domestic gas markets to world prices, and natural disasters and other factors have challenged price stability, particularly in gas markets in the "gas shed" served by facilities impacted by storm Uri, it is not unexpected that gas prices have surged. So, one of the broader circumstances that impact commissioners' decisions in this rate case must be impacts of volatile and rising prices for gas, both for consumers' consumption and for producing the electricity that consumers need.

In Georgia Power's 2022 IRP, SACE and Southface presented testimony by Ron Binz (Document 189984, Docket No. 44160), my colleague on the New Energy Economics board, suggesting that natural gas risks to consumers could be ameliorated by choosing among higher, but still reasonable, estimates for gas costs going forward, arguing that future gas cost estimates, likely to be wrong, need to be wrong too high, rather than wrong too low. He also noted that the company's incentives to give full consideration to risk-managing resource portfolios are impacted by fuel cost adjustment practices that insulate shareholders from gas costs, and gas cost estimates that are wrong and too low, by placing all gas cost risks on consumers. He argued that sharing gas cost risks between consumers and shareholders would help to correct this inappropriate risk allocation.

Because an upcoming fuel cost review is part of the context that will likely result in additional consumer bill increases, the Commission should keep these arguments in mind. They help to support the notion that offsetting consumer fuel costs with savings achieved

by using newly available federal funding opportunities is a policy the Commission should pursue in this rate case.

Mr. Womack made this case as well during the previous hearing. When asked about the cumulative impact of six bill increases in three years, he said:

> "We take seriously any rate changes. And we don't do this in a vacuum… we don't operate in isolation" (Tr. 117, Lines 3-7).

**Q: WHAT'S YOUR UNDERSTANDING OF GEORGIA POWER'S LEADERSHIP IN HELPING CUSTOMERS?**

A: In Mr. Womack's pre-filed testimony, he acknowledges not only Georgia Power's commitment to their customers, but also the need of the company's desire

> "to manage our business in a way that minimizes costs to our customers over the long term" (Tr. 073, Lines 10-11).

He added:

> "We are unwavering in championing the energy needs of our customers and communities across the state" (Tr. 070, Lines 21-22).

And he built on the company's commitment to customers, saying:

> "...one thing remains constant for Georgia Power: our customers are at the center of everything we do" (Tr. 071, Lines 7-8).

We applaud Mr. Womack's concern for consumers:

> "I mean, we take this stuff very seriously at the power company. I mean, that's what we do. We know our customers. We know our communities. And we're committed to helping any way that we can" (Tr. 158, Lines 19-22).

One way we think the company could help consumers would be to make maximum use of emerging funding to offset rate increases that the company has proposed. The Commission can act to make sure this happens by not being locked into a three-year plan. Based on the above, I hope Mr. Womack will support the Commission.

## VII. CONCLUSIONS

**Q: HOW DO YOU THINK A COMMISSION ORDER TO IDENTIFY AND USE NEWLY AVAILABLE FEDERAL FUNDS COULD BENEFIT STAKEHOLDERS?**

A: Georgia Power is fortunate they are proposing a substantial revenue request while billions in new federal and state financial resources simultaneously become available for the

company and the Commission. Ordering Georgia Power to seek, identify, and use these newly available financial resources will benefit:

1. The company. These funds can save the company considerable costs, achieve customer savings, and help to acquire more diverse and cost-effective generation and demand side resources to manage costs and risks.
2. The customers. Tax credits, rebates, and refunds are just a few examples of how additional federal funds can provide a critical buffer against the significant bill increases customers face between 2023-2025.
3. The Commission. The Commission has the authority to facilitate these processes, building upon and expanding its legacy as a regulatory body that benefits all stakeholders even in difficult proceedings with myriad competing priorities.

**Q: WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?**

A: The Commission need only leverage a few existing mechanisms, well within their authority, to provide significant savings detailed above:

1. Reject the proposed levelized rate increase and adopt an annual step increase.
2. Require the company to identify available funding through IRA, IIJA, and present findings to the Commission.
3. Encourage the company to apply for, receive approvals, and use available funding to best provide timely consumer and community benefits.
4. Encourage Commission staff and company to develop agreed upon federal funding tracking processes, including actual and anticipated funding, and actual and estimated costs and benefits to customers and communities.
5. Order annual reports detailing results and define true ups resulting in updated revenue requests for 2024 and 2025 within the 3-year ARP.
6. Provide for tax and other savings to benefit customers, including to offset rate increases during 2022-2025.
7. Determine whether savings achieved through federal funds could also be used to offset some of the expected fuel cost increases in the upcoming FCA proceeding.

**Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

A: Yes, it does.

MR. MOODY: And then secondly, we would ask that the exhibits, which in the prefiled are RLL-1 through 6, be numbered SS-1 through 6.

MADAM CHAIR PRIDEMORE: So marked.

(The documents referred to were admitted into evidence as SACE Exhibits 1 through 6.)

MR. MOODY: Thank you.

MADAM CHAIR PRIDEMORE: Very good. Last call for housekeeping.

(No response.)

MADAM CHAIR PRIDEMORE: Okay.

All right. Georgia Power Company?

MR. HEWITSON: Thank you, Madam Chair. At this time, Georgia Power calls its witnesses Mr. Lee Evans and Mr. Larry Legg as Georgia Power Company's witnesses on the supplemental direct testimony regarding the renewable and non-renewable resources tariff as required by the second amended procedure on the scheduling order.

Gentlemen, would you please raise your right hands.

Thereupon,

LEE EVANS,
LARRY LEGG,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HEWITSON:

Q Mr. Evans, would you please state your full name and your business address for the record, please.

A (Witness Evans) Lee Evans. 241 Ralph McGill Boulevard, Atlanta, Georgia.

Q Okay. And, Mr. Legg, would you do the same.

A (Witness Legg) Larry Legg, 241 Ralph McGill Boulevard, Atlanta, Georgia.

Q Gentlemen, on October 20th of this year, did you prefile or cause to be prefiled 17 pages of supplemental direct testimony in question-and-answer format in this docket?

A (Witness Legg) Yes.

A (Witness Evans) Yes.

Q Did you also at that time prefile one exhibit?

A (Witness Legg) Yes.

Q Was that exhibit prepared under your supervision and direction?

A (Witness Evans) Yes.

A (Witness Legg) Yes.

Q Do you have any corrections which you need to make to your prefiled testimony or exhibit?

A (Witness Legg) I do have one to the testimony at the top of page 16, the second line. Where it says in fact behind -- "BTM project applications in 2022 are on pace

to equal or exceed the volume experienced in 2020 and 2021," change "equal or exceed" to "on pace to see slightly less than the volume experienced in 2020 and 2021."

Q Okay, Mr. Legg. And with that correction, if I were to ask you the same questions today under oath, would your answers be the same as they are in the prefiled direct supplemental testimony?

A (Witness Legg) Yes.

MR. HEWITSON: Madam Chair, the court reporter has been previously been given a copy of the prefiled supplemental direct testimony, and I now ask that the testimony of Mr. Evans and Mr. Legg be copied into the record as if it were given here today.

MADAM CHAIR PRIDEMORE: So moved.

(Whereupon, the prefiled direct testimonies of Lee Evans and Larry Legg follows:)

**SUPPLEMENTAL DIRECT TESTIMONY OF**

**LEE EVANS AND LARRY LEGG**

**ON BEHALF OF**

**GEORGIA POWER COMPANY**

**DOCKET NO. 44280**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.**

A. Lee Evans, Director of Demand Planning & Analysis for Southern Company Services, Inc. ("SCS"). My business address is 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

A. Larry T. Legg, Director of Pricing and Rates for Georgia Power Company ("Georgia Power" or the "Company"), 241 Ralph McGill Boulevard N.E., Atlanta, Georgia 30308.

**Q. MR. LEGG AND MR. EVANS, DID YOU PRESENT DIRECT TESTIMONY AND EXHIBITS ON BEHALF OF GEORGIA POWER IN THIS PROCEEDING?**

A. Yes.

**Q. ARE YOU PROVIDING ANY EXHIBITS TO YOUR TESTIMONY?**

A. Yes. Exhibit___(LPE/LTL-1) provides a comparison of the cost shift for customers participating in the monthly netting pilot on a primarily volumetric base rate (for example, the Residential Service or "R" rate) versus a three-part base rate such as the Time of Use-Residential Demand rate ("TOU-RD," otherwise known as "Smart Usage").

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. Our testimony provides Georgia Power's response to the August 5, 2022, Second Amended Procedural and Scheduling Order ("PSO") issued in this proceeding by the Georgia Public Service Commission ("Commission"). The PSO is based on Commissioner Shaw's motion in Georgia Power's 2022 Integrated Resource Plan ("IRP"), ordering the Company to "address the appropriate structure and pricing of [the Company's Renewable and Nonrenewable Resources ("RNR") tariff] in the current rate case so that the Commission can move towards a fair and long-term way of addressing the issue."

Our testimony demonstrates that based on the analysis of data from the monthly netting pilot, monthly netting excessively compensates monthly netting customers for the energy they push back onto the electric grid and in so doing, disproportionately shifts costs from participating to non-participating customers. Considering this analysis, the Company recommends that the Commission not expand the monthly netting pilot that it first authorized in the 2019 base rate case. Additionally, because a cost shift also occurs from instantaneous netting customers taking service under the R rate to non-participating customers, the Company recommends that the Commission require all customers who enroll in the RNR tariff on or after January 1, 2023 take service under a three-part rate,[1] such as the Company's TOU-RD or Smart Usage rate or an equivalent Commercial or Industrial rate. Finally, to protect customers from dishonest and misleading business practices in the marketplace for behind the meter ("BTM") generation resources, the Company recommends that the Commission establish a formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office.

[1] As explained in more detail in our testimony, a three-part rate is a rate that separately prices the three primary cost components that comprise a customer's bill; specifically, the customer, demand, and energy charges, and in so doing, better reflects and aligns cost recovery from customers using BTM resources.

**Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S RNR TARIFF.**

A. The Company designed the RNR tariff in 2002 in response to the Georgia Cogeneration and Distributed Generation Act of 2001 ("Cogen Act"), and the Commission approved the tariff in August 2002 (Order in Docket No. 15363). The RNR tariff, which is currently in its tenth version ("RNR-10"), establishes the terms and conditions by which the Company compensates customers with qualifying BTM generation resources for the energy they provide to the electric grid. Residential, commercial, and industrial customers take electric service under any of the Company's rate plans for which they qualify, and additionally, enroll in the RNR tariff to be compensated for the energy they provide to the electric grid.[2] The types of generation resources installed under the RNR tariff predominantly consist of rooftop solar generation installed behind the customer's meter.

In the Company's 2019 base rate case, the Commission ordered Georgia Power to implement a new payment methodology – monthly netting – under the RNR tariff and directed the Company to offer monthly netting on a pilot basis for the first 5,000 subscribers or until newly installed capacity reached 32 MW, whichever came first. The monthly netting pilot reached 5,000 participant applications and is now closed to new applicants. The Company's longstanding instantaneous netting program remains open to new customer enrollments.

**Q. PLEASE DESCRIBE INSTANTANEOUS NETTING.**

A. Prior to the start of the monthly netting pilot in the 2019 base rate case, the Company exclusively offered instantaneous netting to customers under the RNR tariff. Under instantaneous netting, the Company credits the excess energy that a participating customer generates and pushes back to the grid at a value equal to the Company's Solar Avoided Energy Cost, which is established under the Company's Commission-approved Renewable Cost Benefit ("RCB") Framework and filed annually with the Commission. With instantaneous netting, a BTM generation system first offsets the customer's electricity use.

[2] The RNR monthly netting pilot is not available to customers receiving service under the Company's FlatBill, Pre-Pay, Community Solar, or Real Time Pricing tariffs.

Then, for each instant that a customer produces electricity in excess of its demand, the customer receives a bill credit for the energy pushed back to the grid valued at the Solar Avoided Energy Cost rate. These bill credits for excess generation are summed on a monthly basis and an aggregate credit is reflected on the customer's monthly electric bill, thereby lowering the customer's overall bill.

By way of example, a customer participating in instantaneous netting with a rooftop solar generation system that delivers 400 kWh of energy back to the grid during the month would receive a bill credit in the amount of $10.71. This credit represents the amount of excess energy delivered to the system – 400 kWh – multiplied by the current Solar Avoided Energy Cost rate of just under 3 cents per kWh.[3] Again, the monthly credit to the customer's bill is in addition to the benefit the customer receives from reducing their energy purchases by supplying some of their energy needs from their BTM generation system.

**Q. PLEASE DESCRIBE MONTHLY NETTING.**

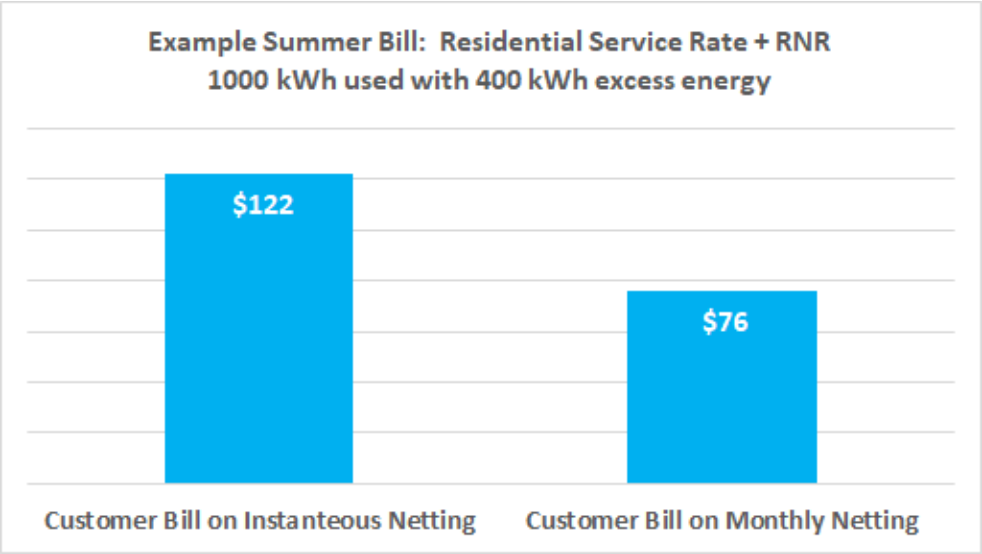
A. Under monthly netting, the Company *subtracts* the total amount of energy a participating customer delivers to the grid from the total amount of energy the customer purchased from Georgia Power during a bill period. Monthly netting compensates the customer for the excess energy they deliver to the grid at the full volumetric portion of the retail electric rate the customer pays to Georgia Power, which substantially overpays the customer for the energy it delivers to the grid. This substantial overpayment disproportionately shifts costs from participating to non-participating customers.

For example, assume a customer on the R rate, who averages 1,000 kWh of monthly consumption, has a rooftop solar generation system delivering 400 kWh of energy back to the grid. Unlike the instantaneous netting customer in the previous example, the monthly

[3] The Company's current Solar Avoided Energy Cost rate is $0.026763/kWh. This compensation to BTM customers is designed to comply with the Cogen Act's mandates that customers be credited "at an agreed to rate as filed with the commission" that is not "above avoided energy cost." O.C.G.A. §§ 46-3-55(1)(C)(ii), -56(a).

netting customer does not pay for the full 1,000 kWh of energy that the Company delivers to that customer during the billing period. Instead, the monthly netting customer's excess energy (400 kWh) reduces what the customer pays for their actual monthly consumption from 1,000 kWh to 600 kWh (1,000 kWh – 400 kWh). The Company would then bill the monthly netting customer for only 600 kWh on the retail rate. Figure 1 below further illustrates the difference in how the monthly and instantaneous netting methodologies compensate customers for the excess energy they provide to the grid.

**FIGURE 1**




As the example above demonstrates, a customer participating in the monthly netting pilot pays *substantially less* for the same electric service than a customer participating in instantaneous netting, despite that both scenarios assume the same monthly usage (1000 kWh) and provide the same amount of excess energy (400 kWh) back to the grid. Because Georgia Power recovers its full cost of service through established revenue requirements, monthly netting shifts the costs that are not recovered from the monthly netting customer to non-participating customers. This cost shift creates an unjustified and disproportionate subsidy that only benefits the customer participating in the monthly netting pilot.

**Q. IN LIGHT OF THE ABOVE, WHAT ARE THE COMPANY'S RECOMMENDATIONS?**

A. This case represents the first opportunity for the Commission to evaluate the results of the monthly netting pilot since its adoption in the 2019 base rate case. The Company recognizes the benefits that BTM renewable energy resources provide to the Company's system. However, the Company requests the Commission balance these benefits with the costs shifted to all other non-participating customers under the predominant volumetric rate structure. The Company does not recommend continuing to subsidize BTM solar customers at the expense of other customers by using the monthly netting methodology combined with volumetric rate structures.

Independent of the monthly netting pilot, Georgia Power has seen a rapid increase in renewable energy development. This growth stems from this Commission's measured and deliberate approach to procuring and incentivizing renewable energy resources in Georgia. This rapid growth demonstrates that the Commission's existing programs are working as intended, particularly as renewable resources become even more cost competitive as a result of further technological maturation and the generous incentives that the recent federal Inflation Reduction Act ("IRA") provides.

In developing a holistic approach to Georgia Power's other renewable energy programs under the IRP process, the Company has identified several core principles that equally apply to the RNR tariff, which include ensuring customer fairness by minimizing cross subsidization and appropriately valuing the costs and benefits of renewable energy. This holistic approach, together with the continued refinement of the Company's RCB Framework, will appropriately and fairly compensate customer generation in a way that encourages the development of BTM resources while also protecting non-participating customers from cost-shifting.

In response to the Commission's PSO, the Company:

- Opposes expansion of the RNR monthly netting pilot because it results in significant subsidization to customers participating in the pilot while disproportionately shifting costs to non-participating customers;

- Recommends requiring all customers who enroll in RNR on or after January 1, 2023, to take service under a three-part rate, such as the Company's TOU-RD rate or an equivalent Commercial or Industrial rate, to mitigate the disproportionate cost shift to non-participating customers; and

- Recommends the development of a formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office to help protect customers from dishonest and misleading business practices in the marketplace for BTM generation resources, which appear to have increased in frequency since the start of the monthly netting pilot.

As we explain in this testimony, given the sustained growth of BTM solar resources in Georgia under the existing RNR tariff structure and the expected effect of new incentives resulting from the federal IRA, the Commission does not need to further expand BTM incentives at this time, particularly at the expense of homeowners and businesses that are unable or unwilling to install BTM resources. The compensation rate paid to RNR monthly netting customers—almost the Company's full retail rate of electricity—worsens a cost shift already present under instantaneous netting. The compensation rate paid to RNR monthly netting customers significantly exceeds the rate the Company otherwise pays for renewable energy and instead compensates participants for utility services they are not providing—such as the costs incurred for delivering that electricity, which includes capital costs and reasonable and necessary operating expenses. The Company is then left to recover these unrecovered costs from non-participating customers.

## II. RNR TARIFF AND RATE DESIGN

**Q. PLEASE DESCRIBE THE HISTORY OF THE RNR TARIFF.**

A. Georgia Power designed and implemented the RNR tariff as its customer offering to comply with the requirements of the Cogen Act and the federal Public Utility Regulatory Policies Act ("PURPA"). Georgia Power introduced the RNR tariff in 2002 and the Commission originally approved it in its August 22, 2002 Order in Docket No. 15363.

**Q. CAN YOU PLEASE DESCRIBE THE COMPANY'S APPROACH TO INTEGRATING BTM RESOURCES?**

A. The Company's longstanding approach to successfully integrating BTM resources under the RNR tariff has been to develop an equitable rate design that encourages the development of BTM resources while ensuring that the costs associated with operating the Company's electric system continue to be fairly recovered among its customers based upon appropriate cost causation principles. Following the enactment of the Cogen Act in 2001, the Company's approach has relied upon the instantaneous netting approach currently reflected in the Company's RNR tariff. Under instantaneous netting, participating customers can offset their own consumption of electricity while also receiving compensation for excess energy they deliver to the Company's electric system at a rate that reflects the Commission-approved value of solar energy—a value derived from the Company's RCB Framework. Conversely, under the monthly netting pilot approved in the 2019 base rate case, the Company must compensate monthly netting customers for the energy generated by the customer's BTM generation system at the full volumetric portion of the Company's retail electric service rate.

The current monthly netting methodology significantly overpays customers for the energy they deliver, whereas instantaneous netting better follows established cost causation principles that more appropriately compensate participating customers for the excess generation they provide to the grid. For this reason, the Company's consistent and appropriate solution to integrating BTM resources has been to pay for this excess

generation pushed to the grid under an instantaneous rather than monthly netting methodology. As compared to monthly netting, this approach strikes a better balance between incentivizing BTM resources and protecting non-participating customers from the additional cost shift associated with monthly netting. However, as we discuss in the remainder of our testimony, even the instantaneous netting approach can cause disproportionate cost shifts that require appropriate rate design to mitigate.

**Q. DOES THE COMPANY'S RETAIL BASE RATE INCLUDE COST COMPONENTS BEYOND JUST THE VALUE OF THE ENERGY DELIVERED?**

A. Yes. The Company's retail rates are designed to recover various costs that the Company must incur to serve customers, such as generation, transmission, and distribution capacity, as well as other costs, like metering, billing, and customer service support. Although some tariffs include individual pricing components for customer-, energy-, and demand-related costs, for other tariffs the demand-related costs are recovered through the energy price. For example, under any rate that primarily relies upon volumetric energy charges, such as the R rate, the actual cost of energy is only a small percentage of the overall retail base rate. As Mr. Evans explained in his Direct Testimony filed in this proceeding, the Company's cost allocation methodology seeks to apportion respective costs into three primary classifications – demand-related, energy-related and customer-related. These cost classifications can be descried as follows:

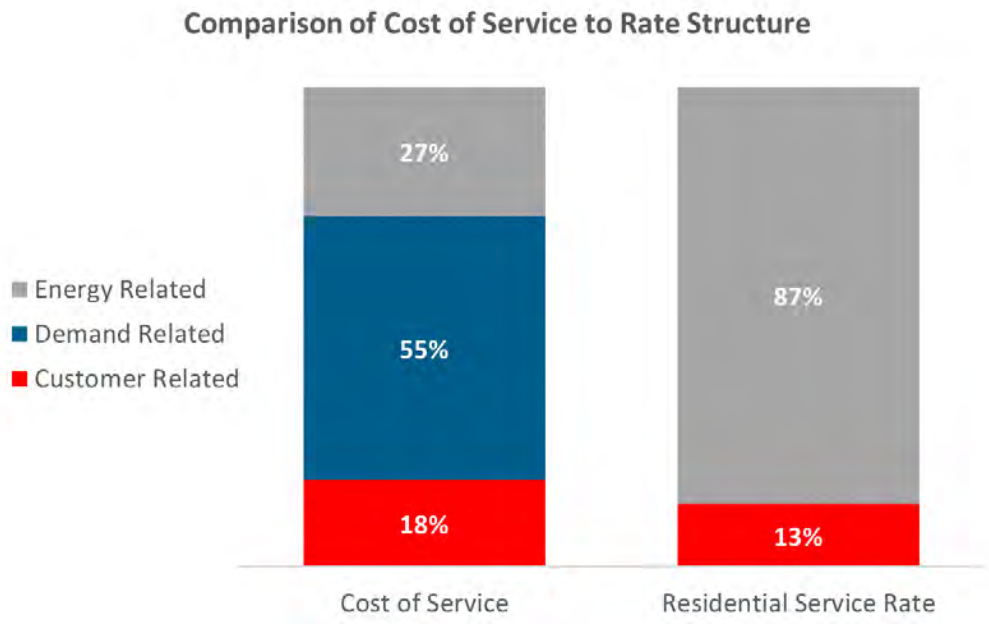
(1) ***Demand-related*** costs are incurred to serve customers' peak requirements for electricity. This generally refers to costs incurred by the Company to provide the capacity necessary to serve the customers' peak kilowatt loads (demands) throughout the year. Examples of demand-related costs include costs associated with generation, transmission, and portions of distribution investments and associated expenses.

(2) ***Energy-related*** costs vary with the amount of energy the customer consumes. These costs comprise primarily production fuel and variable operations and maintenance ("VO&M") expenses, which vary with the kilowatt-hours consumed by the customer.

(3) ***Customer-related*** costs are associated with establishing service to customers but are independent of customers' kW and kWh consumption. This classification generally refers to the costs the Company incurs to attach a customer to the distribution system and be ready to serve that customer, and for customer metering, customer billing, and certain administrative costs.

As the chart below demonstrates, the bill for customers taking service on the R rate is overwhelmingly made up of volumetric energy charges. Because this rate does not include a large enough monthly customer charge and has no demand charge, all or portions of demand-related costs are collected through the energy charge. Therefore, when monthly netting compensates customers at the volumetric energy rate for the excess energy pushed back to the grid, the Company is crediting them for fixed customer and demand related services they are still using. See Figure 2 below.

**FIGURE 2**




Notably, a customer participating under the RNR tariff is likely not providing *any* immediate demand- or customer-related services when they deliver energy back onto the grid. Instead, they are only providing and offsetting the cost of the energy. The amount the

Company pays to BTM customers should reflect the value of the energy being pushed back onto the grid and nothing more. Without this change, the Company is overcompensating participating customers and other customers are shouldering the additional cost.

**Q. WHAT OCCURS WHEN THE COMPANY COMPENSATES A CUSTOMER AT THE RETAIL RATE UNDER MONTHLY NETTING?**

A. When a customer enrolls in monthly netting and is compensated at the prevailing retail rate, that customer sheds or "shifts" cost recovery to all other customers. Compensating a customer for intermittent energy they deliver to the grid at the retail rate allows these customers to avoid paying their proportional share of the costs to build, operate, and maintain the system. In certain situations where fixed costs are recovered entirely through variable volumetric charges, monthly netting can result in a customer paying less than the actual fixed costs the Company incurs to serve that customer. For a monthly netting customer on the R rate, the Company has calculated the resulting shift in cost to be approximately $1,356 per year for the average monthly netting participant.

**Q. WHAT IS THE ANNUAL COST SHIFT RESULTING FROM THE MONTHLY NET METERING PILOT?**

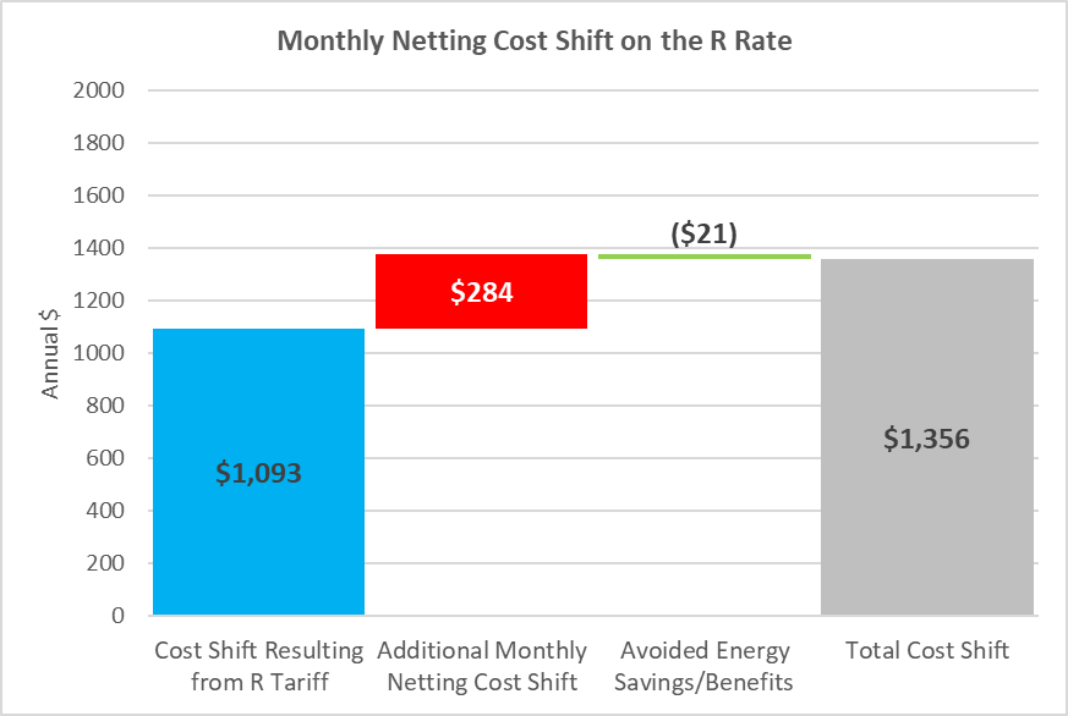
A. In addition to the cost shift resulting generally from BTM solar, the monthly netting pilot results in an annual cost shift of $1.4 million. As Mr. Legg identified in his Direct Testimony filed in this proceeding, to address this cost shift, the Company has made an adjustment of approximately $1.4 million to rates related to the projected cost shift from the monthly netting pilot. All customers will pay for this adjustment, including customers who do not have BTM generation.

**Q. DOES THE COMPANY HAVE DATA BASED ON THE MONTHLY NETTING PILOT TO DEMONSTRATE THIS COST SHIFT?**

A. Yes. The Company has reviewed the load profiles of residential customers enrolled in the monthly netting pilot with at least twelve months of participation and accounted for the installed behind the meter solar capacity. Using this data, the Company formed before-solar and after-solar loadshapes for participants in order to calculate the cost shift that

occurs with monthly netting. The Company utilized these same inputs to calculate the instantaneous netting cost shift. Figure 3 below illustrates the incremental levels of cost shift associated with an average pilot participant receiving service under the R rate who is enrolled in instantaneous netting and a residential customer on the R rate who is enrolled in monthly netting.

**FIGURE 3**




As shown in Figure 3 above, although a significant cost shift already exists when customers install BTM solar due to the volumetric design of the R rate, the monthly netting pilot exacerbates this cost shift.

**Q. DOES THE COMPANY'S ANALYSIS FOCUS PRIMARILY ON RESIDENTIAL CUSTOMERS?**

A. Yes. The Company's analysis to date has focused on residential customers primarily on the R rate. 74% of Georgia Power's residential customers are on the R rate, and 84% of the RNR monthly netting pilot customers are on the R rate. Although commercial and

industrial customers are also eligible for the RNR tariff, the Company has not reviewed the cost shifts presented by those customer classes and prevailing rates due to the relatively small population of non-residential customers currently enrolled in RNR monthly netting. Although the residential R rate provides the best "apples to apples" comparison by providing the Company with the largest data set, the principles and trends identified in the residential analysis are likely to carry over to commercial and industrial customers receiving service under volumetric energy rates.

**Q. THE COMPANY HAS IDENTIFIED A DISPROPORTIONATE COST SHIFT ASSOCIATED WITH MONTHLY NETTING, BUT HAS IT ATTEMPTED TO QUANTIFY THE BENEFITS?**

A. Yes. Under monthly netting, as with instantaneous netting, the Company avoids the incremental costs of fuel and generation variable operations and maintenance expenses. Currently, RNR customers do not offset any existing transmission and distribution costs.

**Q. DOES A MONTHLY NETTING CUSTOMER STILL UTILIZE THE COMPANY'S ELECTRIC SYSTEM?**

A. Yes. Monthly netting customers rely on the full capacity of the electric system in two critical ways: first, to receive energy from the electric system when their BTM system is not fully offsetting their energy usage, and second, to export energy generated by their BTM system to the grid. With this in mind, the practice of monthly netting is merely an accounting construct that allows the customer to bank its excess generation for future use. The reality, however, is the grid does not physically store the excess electricity produced and supplied to the grid by the customer. When the monthly netting customer exports power in excess of its onsite load, the energy must be immediately utilized elsewhere on the system and cannot be banked for later use. This happens even though monthly netting pays for this delivered power as if this banking were physically possible.

**Q. IS THE COMPANY RECOMMENDING THAT THE COMMISSION CONSIDER OTHER POLICY OPTIONS?**

A. Yes. The Company recommends the Commission consider three-part rates as a solution to the disproportionate cost shift occurring today by requiring all customers who enroll in RNR on or after January 1, 2023 to take service under a three-part rate. Such rates better align with the Company's underlying costs, and further mitigate the cost shift between participating and non-participating customers. As shown in Exhibit___(LPE/LTL-1), broader adoption of three-part rates, such as the Company's TOU-RD rate, would significantly reduce the cost shift currently associated with the misalignment of BTM customer generators on primarily volumetric rates, such as the residential R rate.

**Q. HAS THE COMPANY PREVIOUSLY RECOMMENDED ADOPTION OF A RESIDENTIAL DEMAND RATE TO MITIGATE DISPROPORTIONATE COST SHIFTS FROM BTM CUSTOMER INSTALLATIONS?**

A. Yes. When the Company introduced the TOU-RD tariff in the 2013 rate case, it was presented as a complement to the then-proposed Supplemental Power Service ("SPS") tariff. At that time, to avoid cost shifts between customers with BTM generation and those without, the Company proposed that a residential BTM customer generator either participate on a demand rate like TOU-RD or remain on the residential R rate and pay an additional flat monthly capacity charge. As stated in Witness Roberts' testimony from the 2013 base rate case, the TOU-RD tariff was designed to be (i) revenue neutral to the standard residential tariff, (ii) provide "residential customers with a demand rate option to satisfy the requirement of SPS," and (iii) approximate energy credits at the Company's avoided cost and provide capacity credits for reductions in peak demands provided by the customers' BTM generation. Since the inception of TOU-RD, the Company has supported the use of demand rates with time of use components to mitigate cost shifts from customers with BTM generation to those customers without. As the Company, this Commission, and the market embraces the growth in BTM customer generation, Georgia Power recommends the Commission again consider the Company's arguments in support of transitioning customers with BTM generation to three-part rates.

**Q. IF THE COMMISSION ADOPTS THE COMPANY'S RECOMMENDATION TO ENROLL NEW RNR CUSTOMERS IN A THREE-PART RATE, WHAT WILL HAPPEN TO EXISTING RNR CUSTOMERS WHO ARE NOT CURRENTLY ON A THREE-PART RATE?**

A. Assuming the monthly netting pilot remains capped at 5,000 customers, the Company's proposal is to move all *future* RNR customers to a three-part rate, such as the TOU-RD/Smart Usage rate or an equivalent Commercial or Industrial rate. If adopted, this change would apply to all customers who enroll in RNR on or after January 1, 2023. Additional policy questions for the Commission are:

1. Whether and for how long existing RNR customers, including the 5,000 monthly netting pilot customers, should be allowed to remain on a rate other than a three-part rate (i.e., TOU-RD/Smart Usage) or an equivalent Commercial or Industrial rate.

2. Whether and for how long the 5,000 monthly netting pilot customers should continue to be compensated under monthly as opposed to instantaneous netting. For example, the Commission could consider allowing the 5,000 monthly netting pilot customers to continue monthly netting for a time period sufficient to recover their investment in their BTM generation system.

The purpose of the Company's proposal is to help ensure that, going forward, the disproportionate cost shift between customers with BTM generation and non-participating customers is minimized to the greatest extent possible. With this in mind, the Company and the Commission can also continue to address the appropriate rate structures for BTM customers in future regulatory cycles.

## III. BTM SOLAR MARKETPLACE AND CONSUMER PROTECTIONS

**Q. HOW WOULD YOU DESCRIBE THE CURRENT BTM SOLAR MARKET IN THE COMPANY'S SERVICE TERRITORY?**

A. The Company has experienced robust and continued growth in the BTM market, as demonstrated by increasing enrollments in the Company's RNR tariff. This steady growth

has continued notwithstanding the full subscription of the monthly netting pilot. In fact, BTM project applications in 2022 are on pace to equal or exceed the volume experienced in 2020 and 2021. This steady and consistent growth shows that BTM development in Georgia remains strong and that monthly netting is not necessary to encourage rooftop solar adoption in Georgia.

Considering the recent passage of the federal IRA, demand for BTM generation is likely to continue and we will likely see a further increase in the number of applications received under the RNR tariff regardless of any further extension of the monthly netting pilot. With this expected increase in demand, there is no need to further incentivize the BTM transition through additional rate design programs such as an expanded monthly netting program.

**Q. DO YOU HAVE ANY ADDITIONAL CONCERNS ABOUT THE ROOFTOP SOLAR MARKET IN GEORGIA?**

A. Yes. The Company is aware of unethical business practices employed by some solar marketers, lead generators, solar installers, and solar loan providers offering services to Georgia Power's BTM customers. Unlike some other states dealing with this issue, the state of Georgia does not yet have a certification requirement to ensure that BTM service providers have the expertise and financial capability to serve customers. Increasing the incentives for BTM resources without additional oversight of BTM service providers invites potentially more unqualified actors and additional customer complaints. Therefore, the Company supports the development of a more formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office. Georgia Power's customers are at the center of everything we do, and it would be a disservice to our customers and the continued growth of rooftop solar in Georgia for customers to be taken advantage of through unfair and deceptive business practices.

## IV. CONCLUSION

**Q. PLEASE SUMMARIZE THE COMPANY'S RECOMMENDATIONS.**

A. As the Company's analysis of the monthly netting pilot demonstrates, monthly netting disproportionately shifts costs from RNR monthly netting customers to non-participating customers. The Company recommends that the monthly netting pilot remain capped at 5,000 customers. Additionally, given the cost shifts also inherent in the Company's instantaneous netting program, the Company recommends that the Commission require all customers who enroll in the RNR tariff on or after January 1, 2023, to take service under a three-part rate, such as the Company's TOU-RD rate, to mitigate the disproportionate cost shift to non-participating customers. These recommendations appropriately balance the need to protect non-participating customers while continuing to support the rapid adoption and growth of BTM resources. Finally, to protect customers from dishonest and misleading business practices in the BTM marketplace, the Company requests that the Commission establish a more formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

MR. HEWITSON: For the record, I would also like to identify the prefiled exhibit as Georgia Power's Company Exhibit No. GPC 41 (sic) and have it admitted into the record subject to cross-examination.

MADAM CHAIR PRIDEMORE: So marked, so moved.

(The document was identified as GPC Exhibit Number 42.)

MR. HEWITSON: Madam Chair, with your permission, I would like to ask Mr. Legg to summarize the testimony of the panel.

MADAM CHAIR PRIDEMORE: Please go ahead, Mr. Legg.

MR. LEGG: Good afternoon, Madam Chair and commissioners. Thank you for the opportunity to be here today. The purpose of our testimony is to explain Georgia Power's position on the appropriate structure and pricing of the company's renewable and nonrenewable resources or RNR tariff and support the company's recommendations for how the Commission can move towards a fair and long-term solution for addressing this matter.

As such, our testimony addresses three key issues: First, we recommend that the Commission not expand the monthly netting pilot approved in the 2019

rate case because monthly netting overcompensates RNR participants for the energy they push back onto the electric grid, and in doing so, disproportionately shifts costs from participating to nonparticipating customers.

Second, we address the cost shift that occurs from instantaneous netting customers taking service under the R rate. To reduce this cost shift, we recommend that all customers who enroll in the RNR tariff on or after January 1st, 2023, take service under a three-part rate such as the company's TOU-RD or an equivalent commercial or industrial rate.

Finally, we address the company's recommendation that the Commission establish a formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's office to protect customers from dishonest and misleading business practices in the marketplace for behind-the-meter generation resources.

The company's longstanding approach to successfully integrating behind-the-meter resources under the RNR tariff has been to develop an equitable rate design that encourages the development of behind-the-meter resources while ensuring that the

costs associated with operating the company's electric system continue to be fairly recovered among its customers based upon appropriate cost causation principles.

The company's consistent and appropriate solution to integrating behind-the-meter resources has been to pay for the excess generation pushed to the grid under an instantaneous rather than monthly netting methodology.

Under the -- using the instantaneous methodology, the company compensates RNR customers at the solar avoided energy cost using the Commission-approved renewable cost-benefit framework. This compensation is consistent with the company's broader approach to renewable resources which aims to ensure customer fairness by minimizing cross-subsidization and appropriately valuing the costs and benefits of renewable energy.

Monthly netting, however, compensates the customer for the excess energy they deliver to the grid at the full volumetric portion of the retail electric rate the customer pays to Georgia Power, which substantially overpays the customer for the energy it delivers to the grid. This substantial overpayment disproportionately shifts costs from

participating to nonparticipating customers.

To evaluate the cost shift caused by monthly netting, the company performed an analysis of customers enrolled in the monthly netting pilot with 12 months of participation. The company's analysis indicates that, for the average monthly netting customer on the R rate, the cost they shift to other customers without solar is approximately $1,356 per year.

Based on the monthly netting pilot analysis, our testimony demonstrates that monthly netting excessively compensates customers for the energy they push back onto the electric grid and disproportionately shifts these costs from participating to nonparticipating customers.

The compensation rate paid to RNR monthly netting customers significantly exceeds the rate the company otherwise pays for energy they push back onto the electric grid

RNR monthly netting customers not only provide and offset the cost of the energy they use, but are compensated as if they provide utility services they don't actually provide, such as the costs incurred for delivering that electricity, which includes capital costs and reasonable and necessary operating

expenses.

Compensating a customer for intermittent energy they deliver to the grid at the full volumetric portion of the retail rate shifts the cost to build, operate, and maintain the system onto nonparticipants. The company is then left to recover these unrecovered costs from nonparticipating customers, which creates the cost shift the company proposes to correct.

In addition to the cost shift for monthly netting, the company also quantified the cost shift to nonparticipating customers due to the misalignment of cost recovery from residential customers on the R rate. This misalignment stems from the fact that 87 percent of the cost to serve a customer on the R rate, including customer demand and energy costs, is recovered through energy charges.

When a residential customer on the R rate installs behind-the-meter solar, they are offsetting more than just the energy costs associated with their retail electric service and are shifting the cost to build, operate, and maintain the system. This cost shift is only exacerbated by the shift caused from RNR monthly netting customers.

For context, 74 percent of Georgia Power's

customers are on the R rate and 84 percent of the RNR monthly netting pilot customers were on the R rate. As a result of this inherent cost shift, the company proposes that all RNR customers enrolled on -- after January 1st, 2023, be placed on a three-part rate like TOU-RD or the equivalent commercial or industrial rate as appropriate.

Unlike the R rate, rates like TOU-RD better align with the company's actual cost to serve and mitigate the shifting of cost to nonparticipating customers.

Independent of the monthly netting pilot, the company has experienced rapid, robust, and continued growth in the behind-the-meter solar market.

Notwithstanding the full subscription of the monthly netting pilot in 2021, the company continues to see increasing enrollments in the company's RNR tariff. This steady and consistent growth shows that behind-the-meter development in Georgia remains strong and that monthly netting is not necessary to encourage rooftop solar adoption in Georgia.

In addition, considering the recent passage of the Federal Inflation Reduction Act, demand for behind-the-meter generation is expected to continue, and we will likely see a further increase in the

number of applications received under the RNR tariff regardless of any further extension of the monthly netting pilot.

With this expected increase in demand, there is no need to further incentivize behind-the-meter transition by expanding the monthly netting program at the expense of homeowners and businesses that don't install behind-the-meter resources.

The rapid expansion of the behind-the-meter solar market has been accompanied by an increase in solar marketers, lead generators, solar installers, and solar loan providers, some of which have engaged in unethical business practices when offering services to Georgia Power's customers.

Our customers are at the center of everything we do, and it would be a disservice to them and the continued growth of rooftop solar in Georgia for customers to be taken advantage of through unfair and deceptive business practices.

As such, Georgia Power recommends that the process for addressing consumer complaints between the Commission and the Consumer Protection Division of the Georgia Attorney General's Office be formalized.

Within this context and as a result of the

customers -- of the company's analysis, we recommend the following: First, the Commission should not expand the monthly netting pilot beyond the existing 5,000 customers, because of the demonstrated cost shift between participating and nonparticipating customers and because it overpays participating customers for the energy they provide.

Second, because a cost shift also occurs from instantaneous netting customers taking their service under the R rate to nonparticipating customers, the company recommends that the Commission require all customers who enroll in RNR on or after January 1st, 2023, take service under a three-part rate such as the company's TOU-RD rate or an equivalent commercial or industrial rate to mitigate the disproportionate cost shift to nonparticipating customers

Third, to protect customers from dishonest and misleading business practices in the marketplace for behind-the-meter generation resources, the company recommends that the Commission establish a formal framework for the Commission's referral of consumer complaints to the Consumer Protection Division of the Georgia Attorney General's Office.

The company's proposal will minimize the disproportionate cost shift between customers with

behind-the-meter generation and nonparticipating customers and avoid paying behind-the-meter customers for services they don't provide.

These recommendations appropriately balance the need to protect nonparticipating customers while continuing to support the growth of behind-the-meter resources.

Thank you for your time and consideration.

MR. HEWITSON: Madam Chair, before questions or cross-examination begins, I do need to amend my number. Instead of GPC Exhibit No. 41, it should be 42.

MADAM CHAIR PRIDEMORE: So moved.

MR. HEWITSON: Now they're available for questions and for cross-examination.

MADAM CHAIR PRIDEMORE: Questions from commissioners for the panel?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Georgia Public Service Commission?

MR. THOMAS: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. THOMAS:

Q Panel, Preston Thomas on behalf of Public Service -- PIA staff. I just want to start, has the company

conducted a cost-of-service study that distinguishes RNR customers from non-RNR customers?

A (Witness Evans) No, we have not. A cost of service study designed for such a small population would be unreliable. To borrow a phrase from Mr. Watkins yesterday, staff's witness Mr. Watkins, the cost of service study does not have the surgical precision to determine costs for such a small population of residential customers. So breaking them out separately would not produce reliable results.

Q Okay. And so in your testimony, you state, I believe, 38 times that solar generators on the RNR tariff shift cost.

Can you substantiate what costs are not being paid for simply based on analysis of the amount of revenue received from the rooftop solar customer?

A (Witness Legg) Yes. In fact, that's what our analysis here shows. If you turn to page 12 of our testimony, it actually has a chart that shows the amount of cost shift resulting from the analysis from the -- the first bar in blue is from the R tariff, $1,093. The second bar in red is the additional monthly netting cost shift of $284. That's offset by avoided energy savings in the green bar of $21. So that's a total cost shift, when you add those, of $1,356 that I mentioned.

And when you say the -- I'm sorry. How did you

refer it to in your question? Could you ask that again -- the revenue?

Q Sure. So are you able to actually substantiate these costs that are not being paid since you haven't done a cost of service study for this category?

A (Witness Legg) Yes. What we're saying here is, you know, by definition, each time the company redesigns its rates, for instance, when this Commission makes a decision at the end of this rate case process, whatever the Commission decides, that will be incorporated in the Georgia Power's rates in January.

Any time the company -- and so the company will have to redesign all its rate to hit that target. Any time the company redesigns its rates as the result of a change to rates, implicitly what falls out of that is you've got the cost to serve your customers. You have got the kilowatt hours that you're going to collect -- that you're going to sell to your customers. And you divide the cost to serve your customers into -- which makes up the revenue requirement -- into those kilowatt hours.

And so when you have customers who are using less energy, that changes the energy part of the equation. The cost goes down a little bit in this case, but the energy goes down more than that. And so that's ultimately what happens is the costs are spread among fewer kilowatt hours,

and the result is everyone else's rates are higher as a result.

So that's where the cost shift comes in, regardless of whether you performed a class cost to service study on this small group of customers. That's just what's implicit in the math. It's going to be spread to everybody because it's part of the cost to serve.

A (Witness Evans) Yes. And to add to that, an embedded cost of service study is not designed or meant to reflect a change in cost. The embedded cost of service study simply takes the company's total costs and allocates those primarily to rate groups, large populations of customers, based on load. So it does not reflect a cost change or a change in load. So to derive meaningful results from an embedded cost of service study for a cost shift analysis would yield unreliable results.

Q And the cost shifting that the company is concerned about here is around $1.4 million, and that is roughly four one-hundredths of one percent of the current residential revenues of 3.77 billion; correct?

A (Witness Legg) Well, yeah. I would say that's what we've put in this case, because right now we're only talking about a pilot of 5,000 customers. So the 1.4 million is actually -- of the two bars that I mentioned, the blue bar and the red bar on page 12, it's only a

representation of the red bar just for the monthly netting pilot of 5,000 customers.

What the company is really concerned about is over the long term, if you were to continue to allow that cost shifting both for monthly netting and from customers remaining on a volumetric rate and avoiding some of the cost to serve them that gets shifted to other customers, that that number could get much bigger with a much -- with -- as we grow the behind-the-meter solar population in Georgia Power's service territory.

So the 1.4 million is just for the monthly netting portion of this small pilot of 5,000 customers.

Q Okay. And am I correct that, for the $1,356 cost shift number provided in your testimony, around 1,093 of that is self-consuming energy generated from the solar system?

A (Witness Legg) That's right. That's what gets shifted to other customers by the fact that a customer generates their own electricity and then the result from that on the -- again, on the R rate versus another rate that would do a better job of collecting those costs.

COMMISSIONER MCDONALD: When you say, "other customers," who -- who all does that include?

MR. LEGG: It really would be all other -- all other residential customers. If you were to spread

it within the class. Yes, Commissioner, it would be, for instance, all other residential customers. If you spread the residential cost shifting just to that class or the commercial to the commercial class, et cetera.

BY MR. THOMAS:

Q But that $1,093 is just from self-consuming energy. It's not the -- the remainder between the difference between paid to the customer for retail rate instead of the avoided cost, that's only 200 -- roughly $260; correct?

A (Witness Legg) You're talking about the red bar minus the green bar?

Q Um-hum.

A (Witness Legg) Right. And again, this is per customer. So when you say, "only $260," that's per customer per year. So when you multiply that out, again, you know, the 5,000-customer pilot is $1.4 million. As you expand the program significantly, that number could get large fairly quickly.

Q Right. But I guess my question was more of, of that $1,356, only 260 of the 1,300 you're pointing to is the difference between the different -- the different tariffs and not related to the self-consuming energy; right?

A (Witness Legg) Well, no. The difference

between the two tariffs is the blue bar, the 1,093. The red bar is the difference between customers being compensated for energy pushed back to the grid at monthly netting versus instantaneous netting. That's what the red bar represents.

So the red bar really is the impact of monthly netting versus instantaneous for pushed back energy. The blue bar represents the difference between customers on -- or because of the rate that they are on.

And to illustrate this, if you switch over to page 10 in my testimony, or our testimony, there's another chart there. The bar on the left shows what it costs to serve a typical residential customer. So if you think about your home, the company puts in place a lot of infrastructure to serve your home. We have, you know, generators, transmission system, distribution system. We have metering that goes to your home. We have a, you know, customer service function that answers the phone call. We have folks who respond when there are power outages, storms, things like that, different operations and maintenance functions.

And so this divides those different functions. And then we have the actual energy that we burn in our plants, right, the energy-related costs.

So that left bar shows the cost to serve a customer. The red piece is the customer-related piece. That's generally, again, your -- the cost to serve -- to

serve a customer just for being there, whether they use the energy or not. And that's mainly their meter, their service drop, billing services, customer service, a portion of the distribution system that has to be there for minimal usage.

The blue piece of that is the demand-related pieces of serving them. Again, whether they use any energy or not, we have to have a transmission system, a distribution system, a generator, a portfolio to be in place to serve them for when they do decide to use energy.

The gray bar at the top is the portion that's related to just the energy that they actually use. When we actually burn fuel in a plant or sell them energy from a solar facility or something like that. So that's the cost.

On the right, is the residential service rate that we're talking about and how it actually collects the revenue from these customers. The way it's designed, about 13 percent of the rate is customer-related. So it doesn't even really collect the full customer-related costs. And then the remaining 87 percent is energy-related, cents per kilowatt hour.

So we're collecting the rest of the red bar -- or the red portion of the bar, all of the blue portion of the bar, and the gray energy portion of the bar through energy-related charges. That's where the cost shift occurs, is in a rate where you collect those fixed costs that are

red and blue through variable charges in the gray part of the bar, on the right. So that's how the shift occurs.

Q Okay. And in regards to those fixed costs, it is true, isn't it, that the residential customer that uses zero kilowatt hours in a month still has a base bill of almost $19; right?

A (Witness Legg) I -- that's probably about right. Subject to check, that's probably about right. But, again, you're talking about just the red portion then would be the only thing that's collected there.

And I would say, one thing I would say with monthly netting, that's particularly a problem. So I started thinking about that concept as we were going through this process of preparing for the hearings. And looking at -- with monthly netting, you know, whatever a customer with solar panels pushes back to the system, is credited against their kilowatt hour use before we actually calculate their bill on the R rate or on whatever rate they're on.

So I wondered how many customers there were and, you know, if you look at a customer that generates and pushes back, they use some of the energy they generate, but when they're pushing back, they actually push back onto the system more than they buy from Georgia Power that month.

So let's say you push -- you bought 500-kilowatt hours from Georgia Power, you used some of your

own behind the meter, but then you pushed back 600-kilowatt hours for the month total. These would be happening at different times. If your solar panels aren't producing, you're buying from Georgia Power. If you're producing more than you need, you push back.

So on monthly netting, that customer actually pays for zero kilowatt hours of usage because they pushed back more than they -- than they used from Georgia Power during the month, and it's netted out. So they actually only pay the 13 percent that you were just talking about, in spite of the fact that they may have used 500-kilowatt hours from Georgia Power that month. They don't pay for any of that energy, nor of any of the associated cost with the riders that are added to that energy charge.

And then, in fact, for the extra 100 above what they used from Georgia Power, they are compensated at the avoided cost for that. So that's one of the dangers of the cost shift is, all of those costs that it cost to send them 500-kilowatt hours when they were buying from Georgia Power that month, those have to be paid by somebody, so they shift to other customers eventually.

Q But they did supply electricity back to the grid; right?

A (Witness Legg) They did, and they were compensated for that.

A (Witness Evans) Oh, I would correct that. They supplied energy back to the grid. They did not provide electric service.

Q Okay. And you're not saying that they are not paying the fixed cost; right? You agree that they pay 19, roughly $19 a month towards those fixed costs?

A (Witness Evans) Towards fixed costs, correct. But, again, as Mr. Legg said, looking back at Figure 2, the blue bar, whenever we talk about demand-related cost, that is for a large part our infrastructure. That's the transmission system, the generation system that they relied on to supply them in Mr. Legg's example, the 500-kilowatt hours that they did consume from the grid.

A (Witness Legg) That's right. And those are fixed costs also. Whether a customer uses those -- you know, any energy or not, those, the transmission distribution, generation facilities are out there ready to be used, those are costs that have already been spent, that aren't going anywhere if the customer doesn't choose to use them.

Q And looking at those calculations, the company approximated each RNR customer's usage before they installed the solar at their premises by using the RNR customer's current usage with solar, an estimation of how much energy their system produces and a presolar usage amount based on

generic load profile; right?

A (Witness Legg) Well, we used PVWatts, which is, you know, NREL tool. It's industry standard for this type of activity. So, right, we had -- for all the RNR -- for the population of RNR customers that we performed our analysis on, a little over 1,100 customers that had 12 months of history on the pilot, we took a look at what their -- obviously, their usage is after solar, right, because they have solar panels for the past year.

So we took that. We needed to know what their before-solar-panel profile would look like. We knew what size system they have on their house. When they fill out the application, they tell us what size system they have, the size of the panels. So we used PVWatts, which is the new industry standard software, to estimate what their before-solar would look like. And that's what we used in the analysis.

There really is no other way to do that other than to actually individually meter the output behind the customer's meter for every single solar customer, which would involve, you know, the company signing agreements with every customer to see the output of their -- what they're doing behind their meter. And that's not the normal company's practice. So we don't have -- we don't have that data, so we had to estimate it using the methodology.

Q Okay. But you didn't use actual AMI data; right?

A (Witness Evans) Well, AMI data measures the consumption from the grid. AMI data doesn't measure the production behind the customer's meter from the solar facility.

A (Witness Legg) Right. So to perform the analysis, we needed both of those pieces of information. We had the customer's actual meter usage. We actually divided that into four different quartiles to get four different kind of, you know, if you will, small, medium, medium/large, large groups of customers. And then performed the analysis based on those four -- we found load sample research, customers that matched that profile for each of the quartiles, and that's what we performed the analysis on to represent what that group of customers would look like.

Q On page 6 of your testimony, you talk about the independent monthly netting pilot, and you talk about seeing a rapid increase in renewable energy development. Is that talking about behind-the-meter renewable solar for the rapid increase?

A (Witness Legg) Are you referring to page -- line 11?

Q I'm sorry. Yes. Yes, that's right.

A (Witness Legg) Yeah, I would say I'm talking

about all of the above. We have obviously seen a tremendous amount of growth in renewable energy development in the state. Some of that has been behind-the-meter. And that growth continues behind the meter. We've added, as the Commission knows, upwards of -- I'm not sure of the current number. Maybe around over -- somewhere over 3,000 megawatts may be renewable with several thousand more to come based on what came out of this last IRP. So it's just talking about, really, all of the above.

Q And do you know where the company stands or where Georgia stands among other states in adoption of behind-the-meter solar?

A (Witness Legg) I do not on behind-the-meter.

Q Okay.

A (Witness Legg) I know that overall, I think we are maybe seventh in renewable growth in the nation, somewhere around there. That's off the top of my head. I may be off a little on that. But it's top ten, I believe.

Q You believe it is top ten for behind-the-meter generation?

A (Witness Legg) Not for behind-the-meter. For overall renewable, yeah.

Q Would you agree that behind-the-meter is probably more in the top 40?

A (Witness Legg) I don't know.

Q And on page 16 of your testimony, you talk about the company's supporting a formal framework for referrals of consumer complaints to the consumer protection division?

A (Witness Legg) Yes.

Q Can you explain what this framework would look like and what kind of gaps you think need to be filled that currently exist?

A (Witness Legg) Well, we don't have any particular idea of what exactly that would look like. We just -- we would be open to meeting with the Commission and Commission staff to discuss any type of formalization of that, if needed, and just exchange ideas. We just want to, I think, make sure that there is a formal process in place.

As we've seen, you know, as Georgia Power talks to its customers, we talk to thousands of customers a year about the potential of adding solar to their rooftop. We hear complaints from customers as well. We -- customers call us back sometimes and -- and are angry at Georgia Power because of maybe the way they were treated by a solar developer.

Not to say that that's widespread. There are certainly lots of -- lots of very good developers in the state that do a lot of good work.

But since we are aware that that's out there, I know that we've made the Commission aware of when we've gotten those complaints. We want to make sure that a robust process is in place for those complaints to be followed up on.

COMMISSIONER MCDONALD: When you were asked about more formal -- what's in your tool box that would make that behind-the-meter more protective and distanced from the bad folks?

MR. LEGG: Yes. Commissioner, it -- you know, there are a number of things we could do, formalize from the standpoint of keeping a tracked list and following up to see what happens with those. It could be something -- I think we mentioned at one point in our testimony about some states have a certification process for solar developers within the state so that they make sure that everyone who is in that -- in that line of work is following all the required or -- you know, following all the required pieces and parts of a certification program, things like that.

COMMISSIONER MCDONALD: Well, like on line 20 of that page, you know, you suggest the company supports the development of a more formal framework for the Commission. Have you -- have you given us

that information?

MR. LEGG: I don't believe we have, Commissioner.

COMMISSIONER MCDONALD: I don't think so either.

MR. LEGG: I think we're just talking about starting the process of talking about what that would look like at this point.

COMMISSIONER MCDONALD: Don't you think we should have some of that information as we go forward to look whether we want to continue with behind-the-meter or what we're going to do?

MR. LEGG: Are you talking about -- when you said "giving you the information," do you mean about some of the complaints that we have received?

COMMISSIONER MCDONALD: Well, not necessarily the complaints, but how to fix it.

MR. LEGG: Yes. I do think the company would love to share ideas with the Commission staff and the commissioners on that, yes.

COMMISSIONER MCDONALD: The door is open.

MR. LEGG: Yes, sir.

MR. THOMAS: Thank you, panel. That's all I have.

MADAM CHAIR PRIDEMORE: Americans for

Affordable Clean Energy?

MS. LYNDALL: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?

CROSS-EXAMINATION

BY MS. BROWN:

Q Good afternoon, panel. Alicia Brown on behalf of the Georgia Coalition of Local Governments.

A (Witness Evans) Good afternoon.

A (Witness Legg) Good afternoon.

Q So a lot of the last cross was around Figure 3 on page 12, if you want to turn there.

A (Witness Legg) Yes.

Q Just picking up on that, to be clear, this is an argument that even the customer's self-consumption is a cost shift?

A (Witness Legg) Yes. And that's consistent, really, with what we've said in the broader case. We've been talking about cost shifts in general from the R rate for at least the last three rate cases, I think. So, yes.

Q So when a customer is consuming the energy that he or she generated, are they using Georgia Power's system in any way?

A (Witness Legg) It depends on if they're consuming the energy -- if they are producing enough to

supply all of their own energy or just part of their own energy. Certainly, if a customer produces energy from behind-the-meter solar, there are hours in the day when they may produce enough for all of their energy needs, if the solar panels are big enough and their energy usage is low enough.

There probably are hours in the day, and if you look at a typical load profile, where they produce some of the energy they need and they still buy some from Georgia Power. And then there are plenty of hours in the day when their solar panels aren't functioning and they require Georgia Power's system for all of their energy needs. So, yes, I think the customer would be using Georgia Power's system.

Q But in the moment, since we're talking about instantaneous netting?

A (Witness Legg) I'm sorry?

Q In the moment, since we're talking about instantaneous netting?

A (Witness Legg) Right.

Q Are they using --

A From moment to moment, they may not be, but the company can't, you know, remove the system from moment to moment. It's there. It's ready to be used; and for the times they are using the system, it has to be at the ready

and ready to provide energy to them.

Q Why should a customer have to make the same contribution to fixed cost if they use less of a commodity?

A (Witness Legg) Well, on the TOU-RD rate -- when you say the same contribution to fixed cost, are you talking about as other customers?

Q Yes.

A (Witness Legg) Well, I would say they wouldn't. They would make a contribution to fixed cost for the customer portion the same as other customers; but for the demand portion, it is a per KW charge. So to the extent that their demand is lower than their next-door neighbor, they would contribute less to that because they're using less of the system. To the extent that their demand during the month is higher than their neighbor's, they would pay more of that charge because, again, they're causing those costs by using more of the system than their neighbor is.

Q But even on the R tariff, why should a customer who uses less have to make the same contribution as someone who's using more?

A (Witness Legg) I'm not following when you say why should they have to make the same contribution. I don't believe they do. I believe what we are advocating for is moving customers to a rate that does a better job of recovering what they're causing and then just charging them

for whatever they use.

Q All right. Let me ask this differently. If Georgia Power was another kind of company, like an auto manufacturer or a restaurant, how would they recover their fixed costs?

A (Witness Legg) You mean if -- they would spread that across whoever they sold their product to, I would imagine.

Q Right. Would they not recover that on a volumetric basis?

A (Witness Legg) It depends. If you are a rental car company, you would have a reservation charge per day for the rental car, and the rental car could be used -- a lot of them are, you know, regardless of how many miles you drive. Some of them have a plan where you can pay by the mile, I suppose. But it depends on what the type of business is.

In the case of Georgia Power, we are a large electric utility. We have to put billions of dollars of facilities in the ground to be ready for all of our customers and each of our customers to use, whether they use it or not. So it's out there, and that's where we say, it's appropriate for customers who cause those fixed costs to be there and ready, they should pay for those through fixed charges.

Q But to be clear, I don't pay for the rental car to exist until I reserve it. Would that be correct?

A (Witness Legg) Say that again.

Q So with your rental car analogy, I don't pay for the rental car to just be sitting on the lot unless I choose to reserve it; is that correct?

A (Witness Legg) Yeah, that may be true. But what I would also say is --

COMMISSIONER MCDONALD: No, that's not true. You pay for that car sitting there when you rent. There's a certain amount of capital outlay that you put to have that car available to you. You may not -- it may not be a line item of what you're paying, but I promise you you're paying for that rental car to be there.

MS. BROWN: But, Commissioner, what if I don't use a rental car?

COMMISSIONER MCDONALD: Well, then you're not paying for it.

A (Witness Legg) So -- yeah. So the rental car company has the option, if you don't rent a car, they have the option of not having enough cars -- not having enough cars for you to rent one because they know you're not going to rent one.

Georgia Power doesn't have that option. We

have 2.6, 2.7 million customers. We have to have all the facilities in place to serve all of those customers. A rental car company doesn't have the obligation to serve people who want to rent a car. When they run out of cars, they can stop renting cars. We can't run out. We have to serve all of our customers because we have an obligation to serve. That's the difference.

A (Witness Evans) And while you use less energy, we recognize that and provide energy benefits for that. But whenever that solar is intermittent and not providing service, the capacity that we have to have on the ground to serve you is what we're talking about from demand-related costs. And that is the fixed costs that are required.

BY MS. BROWN:

Q Okay. So let's talk about what the proposal is. You are proposing to put all of the customers on behind-the-meter tariffs on a three-part rate.

Can you name another regulated IOU that is requiring DG customers to be on a three-part rate?

A (Witness Legg) I don't know -- we just answered a data request. I believe Alabama Power has three different options for customers behind the meter to choose one of those as a demand-related rate. One is like a fixed charge to account for the fixed costs. I know that there are some utilities in the past that have done that. There

may be some others that are looking at filing something like that.

A (Witness Evans) Also, utilities that have non-bypassable charges or fixed cost-type charges as part of it.

Q But to be clear, you cannot name one that has it as a mandatory requirement that cannot be abated?

A (Witness Legg) Other than the Alabama Power example I mentioned.

Q But did you not just say that that was an option and not a requirement?

A (Witness Legg) Well, I think it is one of three options that require some kind of fixed cost contribution.

I would also say that what Mr. Evans mentioned, that's also a type of fixed cost contribution, whether it's done through a demand charge or done through a non-bypassable charge. I know there are some utilities that have implemented those. I haven't studied which ones. I don't have a list of them.

Q Okay.

A (Witness Evans) Lots of utilities also have higher minimum bills that serve as a function to recover fixed costs should behind-the-meter solar customer's usage drop so low that they cannot recover it. So there's

different pricing mechanisms which accomplish the same effort of fixed cost recovery.

Q Now, there's plenty of other ways that a customer can purchase less energy from Georgia Power. I mean, one example being that you quit using electric heating so you can use natural gas heating. Is the company planning to charge those who leave electric heating for natural gas heating a three-part rate?

A (Witness Evans) No. And let me address this quickly. You know, customers absolutely have the right to use less energy. The company has a number of energy efficiency and DSM programs that promote conservation energy usage, but none of these programs have the magnitude and impact that behind-the-meter solar can have.

There is no energy efficiency goal that can reduce your usage to zero. The largest energy efficiency measure for residential customers only reduces energy by 20 percent. There is no program that can reduce energy to zero and then in the next minute bring your load back to 100 percent.

It is a very different type of issue that we are dealing with behind-the-meter solar.

MADAM CHAIR PRIDEMORE: Mr. Evans, though, to that point, a net metered solar customer is looking to get compensated for something that they're putting

back into the system. If I move away from electric heating, or if I implement LED light bulbs in my home, I'm just looking to save money. I'm not looking for the utility or a subsidy to try to come in and step up for something that I'm trying to sell back; correct?

MR. EVANS: Absolutely. And they're very different, additionally, in that, to your point, one is a reduction of consumption. The other one is having the same consumption but sometimes meeting it with behind-the-meter production. Right? Again, customers, absolutely -- and we encourage it -- can conserve energy; but having the intermittent behind-the-meter generation that meets that load sometimes but then relies on the capacity of the system at other times, is the issue we are talking about in this proceeding.

BY MS. BROWN:

Q So in Figure 2 in the surrounding areas, you mentioned that largely volumetric rates like the R tariff recover demand-related costs through the energy price.

To clarify, is any of the company's infrastructure sized for an individual customer's peak?

A (Witness Evans) There -- there is an -- individual customer's, we size equipment to serve the load

that the equipment serves in total, so transformers often serve more than one customer. Obviously, feeders and circuits serve, you know, a group of customers on that.

But it's also a representation of how you can price those elements.

Q But just to be clear, an individual non-coincident peak does not drive the sizing of transformers and generation and transmission lines?

A (Witness Evans) Well, demand does. And this is -- and a non-coincident peak is a representation of a customer's demand.

Q But it has to be coincident with other people's to affect the size of the infrastructure, does it not?

A (Witness Evans) Can you repeat your question?

Q Is it the system peak or the peak on a piece of infrastructure that drives the size, or is it each individual customer's peak regardless of when it happens?

A (Witness Evans) Yes, there's -- and Mr. Legg can speak to this. There's an interpretation of cost drivers to pricing elements. You know, to have the actual cost drivers of when actual -- each actual independent piece of equipment that serves a group of customer's peaks, would be enormously complex and have -- be almost un- -- unable to interpret.

A (Witness Legg) Yeah. And so I think -- I

don't know if this gets at what you're asking, but I mean, obviously, the utility serves hundreds of thousands or millions of customers and gets to take advantage of economies of scale which keeps prices low for customers. Obviously, we size our equipment in the field to serve our customers in aggregate in the most efficient way possible. So -- you know, so that's how the system is planned by the company.

Q Okay. On page 9, looking at lines 20 and 24, you assert that most generation and transmission costs as well as some distribution costs are driven by demand; is that correct?

A (Witness Evans) Can you point me to a line?

Q 20 through 24.

A (Witness Evans) Yes.

Q So in the latest IRP, we saw a lot of different kinds of models and ultimately came up with a plan that the company brought to the Commission and had approval for. Did the company only look at demand in selecting the portfolio that it brought to the Commission, or did it also try to optimize energy costs?

A (Witness Evans) What -- there was a lot in the IRP. Can you be more specific of what plans you're referring to?

Q Sure. So you used capacity expansion models,

production cost models. Are you telling me that the only thing that affected the generation you selected was the need to meet peak demand?

A (Witness Evans) No. A big part of that is also fuel costs, which are handled separately outside of base rate proceedings, which are 100 percent energy-related. Solar customers, whether it is behind-the-meter or push-back, are recognized for those fuel-related energy benefits; and fuel costs absolutely go into Lickley's cost planning.

A (Witness Legg) Yes. And I don't think that's what we're saying here. I mean, we've talked about the three different types of costs. You said, is only demand important? No, we recommend recovering customer-related costs through a customer charge. We recommend recovering demand-related costs through a demand charge, and energy-related costs through an energy charge. And that's what the TOU-RD rate does. So that's what we're advocating for.

Q But -- yes. But aren't some fixed generation costs influenced by a desire to optimize or reduce energy costs?

A (Witness Legg) You'd have to ask the folks who do that planning in the IRP. I didn't testify in the IRP to the -- to the generation plan.

Q Okay. Fair enough.

On page 13 -- I think it's just three pages over -- you describe monthly netting as an accounting construct that allows customers to bank their excess generation for future use, presumably at night. Generally speaking, is electricity more expensive during the day or at night?

A (Witness Legg) It depends on the season, but generally more expensive during the day, and particularly during the hot summer afternoons. It also can get very expensive to produce on a very cold winter morning as we've seen in recent years with some spikes in electricity consumption. So it could be either one.

Q Now, to be clear, the monthly netting pilot, as opposed to full net metering, does not allow you to roll excess credits from month to month or season to season?

A (Witness Legg) That's right.

Q That's right. Okay.

So you said that typically it is more expensive during the day. So if a customer is banking their energy to be used at night when it's cheaper, aren't they essentially trading more expensive energy for less?

A (Witness Legg) Yeah. We're not saying that they're -- that they are banking the energy. We're saying it's an accounting construct that makes it appear as if they

could bank the energy. The energy actually has to be used right then. We're talking -- and this is talking about energy that's pushed back to the grid; okay? So instantaneously it's pushed back onto the grid. It has to be used by someone somewhere down the line instantaneously, just because of the physics of electricity.

But we're saying, at the end of the month, Georgia Power for the monthly netting customers adds all of that pushed back energy up and subtracts it from what the customer bought from Georgia Power that month before we bill them. So it is effectively acting as if they could bank all of that so that we could go act like they didn't use some of the electricity they used. That's the concept.

Q But even as an accounting construct, if the electron used in the daytime is worth more and the electron at night is worth less, are you not trading something of less value for something of more value or vice versa?

A (Witness Legg) Well, in the -- we're talking, again, about an accounting contract that doesn't exist. There is no kilowatt hour at night. We're saying you can't bank those kilowatt hours. I mean, if you have a battery, sure, you could charge the battery and then discharge it at night and then what you say may be true. But this -- what we're saying is, it's acting as if that can happen when it really can't happen.

A (Witness Evans) And also, it's important to understand under monthly netting, using your example, the energy produced and pushed back onto the grid is more expensive during the day. But then by it being monthly netted and offsetting consumption at night, we're paying full retail for that. So it is certainly not cheaper.

Q So if we can look at page 17, line 20.

A (Witness Legg) Mine only goes to line 17.

Q Oh, whoops. Did you file an errata by any chance? I may have the old sheet.

A (Witness Legg) No.

A (Witness Evans) No.

Q Okay. Well, you write that the compensation rate paid to RNR monthly netting customers significantly exceeds the rate the company otherwise pays for renewable energy.

I assume you're talking about utility scale resources?

A (Witness Legg) Can you point me -- do you know what page you are talking about?

Q It was page 17.

MR. HEWITSON: It only goes to 17.

MS. BROWN: I may have the page number wrong.

MR. HEWITSON: What line?

MS. BROWN: I had it as 20, but I think I was

wrong.

MADAM CHAIR PRIDEMORE: Yes.

BY MS. BROWN:

Q Okay. But if you -- just to quote the statement that you made, that the compensation rate paid to RNR monthly netting customers significantly exceeds the rate the company otherwise pays for renewable energy. That's referring to utility scale?

A (Witness Evans) I believe it refers to RNR instantaneous netting.

Q Okay. Well, I wanted to clarify that.

A (Witness Legg) But it does -- I believe it would also be true that it exceeds the price of utility scale.

Q Okay. And one last question, just talking about the customer perspective on all of this. You mentioned in your summary that the behind-the-meter solar market is still going pretty strong after the monthly netting pilot ended.

Do you think that this will continue if you -- if the Commission approves what you are proposing to put everyone on a three-part rate?

A (Witness Legg) Nobody can tell the future, but I do believe that it will continue to be strong, and really a couple of reasons behind that. One is, we have continued

to see an increase in the number of applicants since the monthly netting pilot started. Even though we reached the five thousandth applicant back in 2021, we continue to see almost as many applicants every single month as we were seeing while the pilot was open. So the interest continues to be strong and almost at the same level as when the pilot was opened.

Second, we mentioned the Inflation Reduction Act. There are -- you know, that has changed things here in the last few months, because all of a sudden there are a lot more incentives for customers to put solar generation behind their meter and a lot more certainty with ten years of certainty around those incentives. So we believe those two things will continue to drive interest in behind-the-meter solar.

Q To that point about the continued strong interest even after the pilot closed, is it possible that some of those unscrupulous solar installers that you're talking about might be driving that continued interest by telling people that they can get monthly netting when they actually can't?

Q All right. Thank you.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power & Light?

CROSS-EXAMINATION

BY MS. KYSOR:

Q Good afternoon, gentlemen.

A (Witness Legg) Good afternoon.

A (Witness Evans) Good afternoon.

Q I'm going to start by referring you to page 3 of your testimony, lines 17 through 18.

A (Witness Legg) I am sorry. Page 3?

Q Correct. Page 3, lines 17 and 18, you note that the instantaneous netting option still remains open.

Do you see that?

A (Witness Legg) Yes.

Q And is the instantaneous netting option under the RNR tariff, is that open without any cap?

I can rephrase. Is that an uncapped program?

A (Witness Legg) To my knowledge, there is no cap on that. I know that actually in the RNR tariff, there is a reference to .2 percent of the company's annual peak demand. I don't know where we stand in reference to that.

Q Okay. So you -- you're not sure of the company's position?

A (Witness Legg) I'm not sure. I don't actually run the application, you know, and process for these, so I'm not sure. But to my knowledge, there's no cap on it.

Q Okay. And just to make sure I understand it clearly for the record, the .2 percent cap referenced in the

RNR tariff, do either of you know which program that applies to? Which solar customers that applies to?

A (Witness Legg) As I read it on the bottom of the RNR 10 tariff, it's in the RNR instantaneous netting section of the tariff. I just don't know how that's being implemented or enforced because I don't actually run the application process. There are people at Georgia Power who can answer that.

Q People that are testifying in this hearing?

A (Witness Legg) No.

Q If there is no cap on the RNR instantaneous netting program, do you agree that it might make sense to remove language alluding to a cap from the RNR tariff?

A (Witness Legg) It's possible. That's not something the company has recommended. Again, we would -- it would be subject to check how that's actually being enforced or implemented.

Q Would you agree it might be confusing if there is language about a cap but it may or may not be enforced?

A (Witness Legg) It could be. In my experience, generally customers call the company to ask about that, or solar installers. So they wouldn't necessarily be getting their -- our customers wouldn't necessarily be getting their information off the tariff sheet, but certainly someone reading that could be confused if that were the case.

Again, I'm not saying it is or it isn't. I don't -- I don't actually run that program, so we'd have to check with the folks who do.

Q And today you have no expectation of the company stopping offering the instantaneous netting option?

MR. HEWITSON: I have a clarification objection. I want to know if Ms. Kysor is talking about the RNR tariff or the cap that's in the cogeneration act.

MR. KYSOR: There is a reference to the .2 percent cap from the cogeneration act inside the RNR tariff.

MR. HEWITSON: Right.

MS. KYSOR: In the language.

MR. HEWITSON: So are you asking them whether they are going to change the statute or the RNR tariff?

MS. KYSOR: I am asking not for an interpretation of the Cogen Act and nothing about the statute. Only about the RNR tariff and its availability to Georgia Power customers.

MR. HEWITSON: Okay. And that would be limited by the Cogen Act; right?

MS. KYSOR: I think that the tariff itself is available based on the language that's contained

within it.

MR. HEWITSON: Fair enough. Thank you.

A (Witness Legg) I am sorry. What was the question again?

BY MS. KYSOR:

Q I think we've covered it.

A (Witness Legg) Okay. We all agree I don't know.

Q I had a nice talk with Mr. Hewitson and we can move on.

Okay. In response to Mr. Thomas, you were giving an example about when -- under monthly netting, if a customer basically netted out their kilowatt hour of usage in a given month and was only paying their base bill.

Do you recall that conversation?

A (Witness Legg) Yes.

Q Now, based on your knowledge, would you agree that, on average, monthly netting customers aren't zeroing out their usage? They're average or above-average electric users?

A (Witness Legg) So, yes. While they are average or above average users, actually was curious about the same thing as we were preparing for these hearings. So I went back to look at what customers had used and what had been pushed back and what had been netted so far in 2022

through October billing.

Out of about -- just for monthly netting customers. Out of about 36,000 thousand -- nearly 36,000 bills on monthly netting so far this year, about 7,400 of them had netted to zero. In other words, they pushed back enough energy such that they did not get billed for any kilowatt hours even though they used -- almost all of them used some kilowatt hours from Georgia Power that month.

So that's about 20 percent -- a little over 20 percent of the bills for monthly netting customers were for zero kilowatt hours so far this year.

Some of those customers, I sorted them by size. To your point, some are very large customers. But some of those customers actually who were billed for zero kilowatt hours for a given month were using over 1,000 kilowatt hours for that month from Georgia Power, but since they pushed back more than 1,000, we actually billed them for zero kilowatt hours.

So while, yes, the majority of customers pushed back less than their total energy used for the month, 20 percent of the customers are pushing back enough so that they are billed for zero kilowatt hours.

And if we go back to -- just to illustrate the point the company is trying to make, if we go back to Figure 2 on page 10, that means all of those customers who

netted out to zero in those months, including some who used over 1,000 kilowatt hours from Georgia Power in that same month, only paid that little red part, the bar on the right.

Q Well, quick clarification. That's true only of the ones -- there might be customers that aren't on the R tariff in that group that you are talking about; right?

A (Witness Legg) That's true. There are a few. But the vast -- again, I think we said 84 percent of the customers on the monthly netting pilot are on the R rate, so that the vast majority of them -- certainly not only the ones on R, but the vast majority are on the R rate.

MS. KYSOR: Madam Chair, could I make a hearing request for the analysis that Mr. Legg did on the 20 percent or so of customers that are zeroing out their usage?

MADAM CHAIR PRIDEMORE: Will we have time based upon the schedule to get it back, is my question? Because this was the added-on portion to the PSL.

MS. KYSOR: So for my -- for my use, you know, we have briefing due in mid December. We definitely have time for me to see the information --

MADAM CHAIR PRIDEMORE: Okay.

MS. KYSOR: -- and put it in the record, at least, if it's an analysis that Mr. Legg did that's not in the record.

MADAM CHAIR PRIDEMORE: So moved.

MS. KYSOR: Thank you.

BY MS. KYSOR:

Q And I think from data requests and responses that are in the record, on average, monthly netting customers are using about the same as the average residential customer; right?

A (Witness Legg) I don't know if I agree with that. As you just mentioned a minute ago, the typical customer with solar panels is larger than average. So I haven't looked at that. But I would anticipate that they may be using more than average. But I haven't performed an analysis of that in particular.

Q Could you turn to page 5 of your testimony, figure one.

A (Witness Legg) Yes.

Q And this figure shows a monthly netting customer basically. Is the take-away that this -- that a monthly netting customer pays less in a given month than an instantaneous netting customer?

A (Witness Legg) That's right. It's an example of two customers with the same usage and the same pushback and how they are billed differs on monthly versus instantaneous.

Q So it's showing the company would collect less

revenue from a monthly netting customer than a non-monthly netting customer?

A (Witness Legg) Yes, for the exact same usage.

Q But's it's not showing what the actual cost to serve that customer is; correct?

A (Witness Legg) No, it's not. This is a bill representation. An example of a bill calculation.

I mean, that being said, the reason that we bill our customers is to recover the cost to serve them. That's why we are so concerned about the cost shift and about how the R rate doesn't do a good job of recovering those costs and the TOU-RD rate does a better job of recovering those costs.

Q I think we have had a good bit of TOU-RD rate testimony in this case, so I'm going to keep mine very brief. Turning to page 13 of your testimony at the top.

So at the top of page 13, lines 1 through 4, your -- I will just summarize -- you are testifying about how the company hasn't reviewed cost shifts presented by nonresidential customer classes because of the relatively small population.

But it's true that the company is still recommending that those customers be required to go onto demand tariff rates moving forward?

A (Witness Legg) Right. For the same reason.

And the truth is, most of the customers on the monthly netting pilot that are commercial or industrial are already on a rate that has a demand component to it, so they would already be covered.

What we have said in here several times, TOU-RD for residential or the equivalent commercial or industrial tariff, we just mean one with a demand rate. When most of them are on that already -- Power and Light Medium, for instance. Most of our commercial and industrial rates have a demand component. There are few that don't that are energy only. But it would only be those that that were on an energy only rate that we would want to be on a demand rate.

Q But you are proposing that that be a requirement for those customers absent doing the actual analysis; right?

A (Witness Legg) That's right. Just from the principle standpoint. This is the same recommendation we made, as a matter of fact, though, back in the 2013 rate case for the same reason. It is the same exact recommendation that we made back then when we introduced the TOU-RD rate. And back then, something that was called a supplemental power service tariff. But it's the same concept.

Q And I am still on page 13 of your testimony,

but I am now on lines 8 through 13, where you talk about the benefits associated with monthly netting.

A (Witness Legg) Yes.

Q Where in your testimony or in the record can I find support for that response?

A (Witness Evans) I think it's demonstrated on figure 3.

MADAM CHAIR PRIDEMORE: Mr. Evans, what pages?

MR. EVANS: Page 12. I'm sorry.

MADAM CHAIR PRIDEMORE: Thank you.

BY MS. KYSOR:

Q Sorry. Where in figure 3 have you detailed that analysis?

A (Witness Evans) So on figure 3, we see the avoided energy benefits, which this is looking at non-fuel costs. So we showed the avoided generation variable operation and maintenance expenses of $21 in figure 3. And then RNR customers not offsetting any distribution or transmission investment.

Q And where in your testimony or supporting documents can I find support for that statement, about how customers currently aren't offsetting any transmission or distribution?

A (Witness Evans) Well, RNR customers not offsetting any distribution investment has been litigated in

PURPA and going back for several IRPs, has been approved to not recognize any distribution deferral costs. As a result of -- I believe it is IEEE Standard 1547, and the company's compliance with that.

Transmission costs -- again, we are looking at current costs and cost shifts of current investment. And that capacity is in the ground ready to serve customers today. And by installing solar, that capacity, nothing has changed with it. It has not been deferred. It still has to be -- it still has to be ready to serve customers, and the recovery of those costs is still required.

A (Witness Legg) Yes. And I would say that the -- what's in the record regarding this is a long history of the RCB process here at the Commission. In fact, the -- you know, the company has just filed its latest version of solar-avoided costs, which outlines the costs and benefits for behind-the-meter solar in the IRP just this year, and the Commission approved that. So there's a long history of that here at the Commission.

Q Sure. And I appreciate the long history. I guess I was looking for -- in this rate case record in response to the Commission's IRP order, I was looking for any additional documentation.

A (Witness Evans) Well, we built our analysis on the final order of the IRP and many IRPs before that and the

PURPA docket of what costs are or are not deferred.

Q Okay.

Mr. Legg, I believe you referenced the mandatory demand charge for Alabama Power customers. Do you recall that?

A (Witness Legg) Right.

Q Harkening back to Mr. Thomas's ranking question, do you have any idea where Alabama Power ranks on rooftop solar installed?

A (Witness Legg) I do not.

Q Subject to check, would you take my word for it that it is very low?

A (Witness Legg) I don't know.

Q Okay.

A (Witness Legg) I have never studied Alabama Power's rooftop solar installation.

MADAM CHAIR PRIDEMORE: That's fair, Ms. Kysor. If he doesn't know, he doesn't know.

MS. KYSOR: Madam Chair, I'm not going to push him on it. I am done with my questions. Thank you.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Kysor.

GASEIA?

CROSS-EXAMINATION

BY MR. THOMASSON:

Q All right. A lot of my questions have been

asked already, so I am going to keep things moving.

On this 20 percent of customers that you talked about sort of netting out all of their usage in a month, I accept that analysis in your -- well, I don't know about the 20 percent, but I was just hoping you might help me clarify some terminology that we're using in this docket about monthly netting, because -- and I think Ms. Brown started to ask you a similar question about other states that allow for a carryover beyond the current month and even a full calendar year so that you might be generating kilowatt hours in June and July in the summer and not using those credits until December. Is that -- are you familiar with that?

A (Witness Legg) I am vaguely familiar with that. I know I used to have a cell phone plan where you could carry over minutes from month to month.

Q No, that's very similar.

A (Witness Legg) So it's a similar concept.

Q Yeah, I think that's right. And would you agree that when folks talk about net metering policy in other states and the efforts to roll back from some of the net metering programs, that what they are referring to in those other -- the starting point for those other states is actually that annual net metering type construct and not monthly netting that we're talking about in this proceeding?

A (Witness Legg) It's possible. I am sure that

there are states that have all different types of different flavors of monthly netting.

Q But just -- and final question on this. No one in this proceeding is proposing full annual-style netting.

A (Witness Legg) Well, in this part of the proceeding, the company is not. No one else has filed testimony on the net metering portion of the case yet, so, yes. Yeah. But the company has not.

Q You got a couple questions about the growth of rooftop solar and the RNR program.

Have you filed any year-over-year numbers on participation or applications in this proceeding for RNR?

A (Witness Legg) We actually just filed a data request that we received that was due, I believe, yesterday. So we did file some information on that.

Q We have that information. I just haven't had a chance to look through it.

A (Witness Legg) Yes. Like I say, I think it just got filed yesterday.

Q It saves me from asking for it, so thanks.

A (Witness Legg) Yes.

Q And then as a follow-up on the growth conversation, or questions, you also mentioned that the new incentives in the federal IRA for behind-the-meter solar; correct?

A (Witness Legg) Right.

Q I am curious which incentives in the IRA specific to rooftop solar are new that you think are going to boost the Georgia market?

A (Witness Legg) I am not an expert in the IRA. I understand, though, that it has extended some incentives out to ten years. I know that there are some portions of that related to, you know, domestic production to different -- different qualifiers that can increase some of the incentives, but I am by no means an expert in the IRA.

Q Granting that you are not an expert, are you familiar, though, when we talk about federal incentives to rooftop, we are usually primarily talking about the investment tax credit?

A (Witness Legg) Yes. And I understand that was extended ten years as well.

Q Are you also aware that that investment tax credit was established in 2005 under President Bush and has been mostly extended since that time?

A (Witness Legg) I understand it has. I understand, again, that this is -- you know, extended it ten years. I also understand from talking to folks who know more about this at the company, there's a component there to allow nonprofit companies to take advantage of some of the incentives where they may not have been able to before. So

that would be a new qualification, I think.

Q But that's not going to be a typical residential customer, though?

A (Witness Legg) I know, but certainly we offer, you know, RNR to commercial and industrial customers as well.

Q But aside from that direct pay for nonprofits, the 30 percent ITC is something that's been around in the Georgia market for a while?

A (Witness Legg) To my knowledge, and now it's been extended ten years.

Q Okay. I have one set of specific questions about the language you use for the value of energy that behind-the-meter solar is putting on the grid. And the first is on page 10, line 17. And now I am looking at the wrong testimony. Sorry about that.

You say a customer participating under RNR tariff is not likely providing any immediate demand or customer-related services when they deliver energy back to the grid. Do you see that?

A (Witness Evans) Yes.

Q I'm not trying to play "gotcha" here, but does that immediate -- that use of "immediate," does that allow for the possibility that there may be longer-term demand benefits from that energy being pushed back to the grid but

that aren't being accounted for in the immediate term?

A (Witness Evans) So whenever we are talking about RNR, there's two portions of RNR. There's the energy produced and consumed behind the meter and then there's what's pushed back to the grid.

Is your question -- which one is your question related to?

Q Well, the sentence is about what's being pushed back to the grid, I believe. So I'm really just asking not about the mechanics of what goes to the grid and what doesn't, but the value that you're accounting for for that energy that is delivered to the grid. And I am really just asking, and it is nitpicky, I know --

A (Witness Evans) Sure.

Q -- but just this word "immediate" and whether that's meant to distinguish from the fact that there may be longer-term benefits that aren't baked into this or might be baked in somewhere else, like RCB.

A (Witness Evans) Yes. Let me clear that up. The value of the energy pushed back to the grid was determined in the RCB framework in the IRP. It did not recognize any of those benefits.

The use of "immediate" in this sentence was only to recognize that we were taking cost information from the cost of service study of current costs.

**Q I am -- and I basically have the same question about a different use on page 13 -- or sorry -- yeah -- page 13, line 13.**

**You also say, "RNR customers do not offset any existing transmission or distribution costs."**

**I am trying to reconcile this with some other testimony that we are hearing in this proceeding about the value of this energy perhaps offsetting future distribution costs, deferred investments or whatever it may be. Is there similar -- is there wiggle room in that sentence with the word "existing" that does not necessarily preclude future investment costs?**

**A (Witness Evans) Yes, and this sentence is talking about RNR customers in total. So it is talking about both that energy pushed back onto the grid and consumed behind the meter.**

**So those two different kind of buckets of energy, if you will, show up in the planning process in very different ways. Right? What's pushed back onto the grid and has been litigated and discussed in RCB framework and IRPs for -- going back several proceedings now -- and extensively in PURPA, that is not viewed as a resource. We cannot and do not plan around it. So it does not defer any investment.**

**What is consumed behind the meter, meaning it**

was produced by the generator behind the meter and all -- and consumed, that shows up in the planning process as a reduction of load served through the meter. And it shows up in the forecast; right? So right now we have such small amounts of behind-the-meter solar, it does not have an impact on the forecast; right?

Q Is it conceivable that as that number gets larger that it could be incorporated as -- either as a resource or some adjustment for the sort of future cost plan?

A (Witness Evans) Yes. We -- right now, number one -- we can't -- we don't have a line of sight, because it is so small, of the impact to the forecast.

If it grows to scale, we would have to understand how that forecast impacts the rest of the planning process and ensure that we are still building infrastructure to reliably serve our customers in accordance with NERC requirements and IEEE standards.

Q All right. And I had some cost of service study questions that I think were mostly asked, and I did hear your answer about cost of service not providing the surgical precision for solar customers. But are you aware of the neighboring utilities or neighboring commissions that have performed or required cost of service studies specifically for solar customers?

A (Witness Evans) I have seen it. And my recollection -- and subject to check, I certainly have not studied this extensively nationwide.

My recollection is that four -- the cost of service studies that I have seen, those are in states that have very large populations of behind-the-meter solar and sometimes they're on specific rates.

For Georgia Power, we have just -- you know, it's in the thousands of residential customers. And, again, the purpose of the cost of service study, we assign and allocate costs to rates and rate groups to aid the Commission in making parity adjustments to rates; right?

Solar customers are not a specific rate or rate group. So it would be a very different intent and use of the cost of service study even if it grew to a population. Because what you would essentially be doing is carving out customers -- sorry -- carving out customers from an existing rate, separating them to the side, determining a parity for them, but then any adjustments to rates would still be done to a rate that did include both solar producers and nonsolar producers.

So it's a very different intent of the tool and the study, even if it grew to a size that you could accurately and reliably do it.

Q But it has been at least attempted and

including possibly neighboring Duke in South Carolina? Are you familiar with that?

A (Witness Evans) I have not reviewed their cost of service study.

Q Are you aware that they have done one specifically for solar customers?

MADAM CHAIR PRIDEMORE: Mr. Thomasson, if the witness knows or not, just if you've got a question about their study, just ask the question.

A (Witness Evans) There is different --

MR. THOMASSON: I think he made clear that he doesn't know the conclusions from them. I just wanted to know if he was aware of them in sort of putting this analysis together. We will talk about the study in our testimony. That's fine.

A (Witness Evans) There's certainly different ways that you can look at this and professionals can use different analyses. We have relied on a couple. We have done one here and additional one since our filing to look at this in different ways to determine the cost shift of behind-the-meter solar customers.

MR. THOMASSON: That's fine.

Madam Chair, that's all.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Thomasson.

GA Solar? Hello, Mr. Moreland.

MR. MORELAND: Hello, hello. How are you? Almost there; right?

CROSS-EXAMINATION

BY MR. MORELAND:

Q Hey, gentlemen, how are you doing today?

A (Witness Legg) Good.

A (Witness Evans) Good afternoon.

Q Good. I would like to direct you to the bottom of page 8 and top of page 9. Start there. And some of this is a little bit overlapping.

If the commissioners could be just a little patient, I promise you I'm not going to ask the same questions, but there's some similar subject matter with only 17 pages to work with here. Okay? So I will -- I will do my best.

COMMISSIONER MCDONALD: We will help you.

MR. MORELAND: Thank you. I know you will.

BY MR. MORELAND:

Q Where it says, "As compared to monthly netting, this approach" -- and we are speaking of instantaneous netting.

A (Witness Legg) Sorry, which line are you on?

Q We are on the bottom of page 8 and top of page 9.

MADAM CHAIR PRIDEMORE: Yes. But what is the line?

A (Witness Legg) Yes. Which line?

COMMISSIONER MCDONALD: Line 23, if you need some help.

BY MR. MORELAND:

Q Yes. Let's see here. Where did I copy this? Okay. I'm sorry. It is at the top of page 9, line 2, saying, "As compared to monthly netting," and we are -- again, we are talking about instantaneous netting. "This approach strikes a better balance between incentivizing BTM resources and protecting nonparticipating customers from the additional cost shift associated with monthly netting."

Are you saying here that instantaneous netting incentivizes behind-the-meter resources in Georgia?

A (Witness Legg) We said it strikes a better balance between -- than monthly netting -- between incentivizing those and protecting nonparticipating customers. So, yeah, we do believe it provides some incentive for that as we've talked about earlier here today. We are still seeing significant interest even though the pilot's been closed out for over -- or we've reached the 5,000 participants over a year ago. We are still seeing almost the same level of applications that we saw while the pilot was open.

Q So would you be surprised to learn that since the beginning of time, since Georgia Power was -- first came into existence, and even with the 30 percent federal tax credit that took effect in 2006, just 9 megawatts of behind-the-meter solar was installed prior to the monthly netting pilot?

A (Witness Legg) I don't know that behind-the-meter solar was probably cost effective when the company started. I would say that, yeah, we are aware of the growth that we have seen just in the last few years.

It did take off with monthly netting with the pilot, but now it's continuing without the pilot, without monthly netting. So that's what we based that on. You asked whether we believe there were -- it incentivizes customers. Obviously it does incentivize some customers in almost the same number that we were seeing in the pilot because they continue to apply.

Q We'll get to that in just a second.

Would it also surprise you to learn that -- well, you just mentioned that since the monthly netting program took effect, 13 megawatts have been installed. So we are -- we have seen a -- you know, for decades and decades and decades, even with the 30 percent federal tax credit, we've got 9 megawatts prior to monthly netting and then suddenly in the flash of a pan, in a year-and-a-half,

we have and additional 13 megawatts.

So my question is: Is instantaneous metering incentivizing people to go solar?

A (Witness Legg) That's the answer I just gave a minute ago. Yes, I believe it is. And you are going back decades and decades. Again, I don't think it would have been cost effective for anyone decades ago to put solar on their rooftop.

The payback would have been very long. The cost of PV panels has come down, as we all know, significantly just in the last ten years or so. That, I think, is one of the biggest drivers behind the interest in solar panels.

We also mentioned earlier the new IRA that was just passed a few months ago. I believe that will be another driver with those incentives being out there of future increases in behind-the-meter solar.

Q How has the company, in general, performed since the monthly netting pilot took effect?

A (Witness Legg) What do you mean, "how has the company in general performed"?

Q Yeah, I mean, has the company gone broke since the pilot program took effect?

A (Witness Evans) Can you repeat your question? It broke up a little bit.

Q I said: Has the company lost money since the pilot program took effect?

A (Witness Legg) All right. When you say "has the company lost money," no. I mean, we didn't -- we didn't file anything in our testimony here about the company's profitability or loss or anything like that. That's -- I don't know that that's within the scope of this testimony.

A (Witness Evans) I think we have demonstrated that a cost shift has occurred and will continue to occur with the monthly netting pilot.

Q Well, then Evans Exhibit 1 on page 2, line 35, we are showing total revenues of 8.4 billion last year, 2021.

A (Witness Legg) Are you talking about something other than this filing?

Q No.

A (Witness Legg) You said Evans Exhibit 2?

Q Exhibit 1, page 2.

MR. HEWITSON: There is only one.

A (Witness Legg) Are you talking about the net metering filing?

MADAM CHAIR PRIDEMORE: There is just testimony, Mr. Moreland.

MR. MORELAND: Okay.

MADAM CHAIR PRIDEMORE: If you have a title of

a document you would like to state...

MR. MORELAND: No, I will skip over that part.

BY MR. MORELAND:

Q Okay. Would you say that pilot program was successful?

A (Witness Legg) Yes, I would say it was successful in that we signed up the 5,000 applicants, if that's a def- -- that's one definition of success.

Q Do you think that the -- it sold out faster than originally anticipated?

A (Witness Legg) I don't -- I didn't have any anticipation as to how quickly it would fill up. I mean, we assumed once it was put in place that it would -- that it would draw some interest, and it did.

Q Isn't it true that the pilot program also included an option for customers who had solar prior to the pilot program to opt into the program?

A (Witness Legg) I don't know if that's true or not. I didn't run the pilot. So I am not sure what the option was for -- are you talking about for existing customers who already had rooftop solar to opt in? That may be possible. Again, I didn't run the program; so I am not sure.

Q Subject to check, would you agree?

A (Witness Legg) Subject to check. I don't

know.

Q From what -- would you be surprised to learn that around 1,000 customers that already had solar prior to the pilot program coming into existence opted into the program?

A (Witness Legg) Again, I said I don't know. So subject to check, it is possible.

Q Is it true that the company is keeping a waiting list for customers who have applied after the cap was met?

A (Witness Legg) To my knowledge, the company had to keep a waiting list because a number of the applicants --

COMMISSIONER MCDONALD: I believe you said that it has been coming in every month since then; right?

MR. LEGG: That's right, and we do keep a list.

COMMISSIONER MCDONALD: That was mentioned several hours ago.

MR. LEGG: That's right.

BY MR. MORELAND:

Q The waiting list, that we are keeping a waiting list?

A (Witness Legg) Well, we did have to keep a waiting list because a number of the applications that were submitted actually never materialized. Either those

customers decided not to -- not to put solar on their roof, or in some cases, we believe there were multiple applications that may have been submitted before customers actually showed interest just to kind of put a place in line.

But -- so as a result, we had to move some off the list that never materialized, and we had to keep a list past 5,000 to make sure that we filled them back in in the right order because it was first come, first served.

Q Are you still keeping a list?

A (Witness Legg) I don't know. I don't run that pilot program.

Q On --

A (Witness Legg) But I would say we have a list of customers who have applied, and certainly the software that they applied through online has a date stamp. So, I mean, it wouldn't be hard to create a list, I would imagine.

Q All right. On page 16, you state that, "In fact behind-the-meter project applications in 2022 are on pace to equal or exceed" -- and I understand you did amend that at the beginning to say "slightly less than."

A (Witness Legg) Right.

Q -- "the volume experienced in 2020 and 2021. This steady and consistent growth shows that behind-the-meter development in Georgia remains strong and

that monthly netting is not necessary to encourage rooftop solar adoption in Georgia."

But given that existing customers before the pilot program were allowed to opt in to the program before, and given that you are keeping a waiting list, is it reasonable to assume that customers who are applying now would be able to opt in should the monthly netting pilot be expanded later?

A (Witness Legg) I don't know. Those are details that are not related to anything the company has recommended --

Q Is it reasonable to assume customers --

MR. HEWITSON: Madam Chair, can we let him answer the questions.

MADAM CHAIR PRIDEMORE: Mr. Moreland, let the witness answer the question.

A (Witness Legg) Yes. So -- and also I would say I didn't say that we are keeping a waiting list. I said we did keep a waiting list at one point to make sure that we filled out the full 5,000, because the number of applications dropped off. I don't know if we are still keep a waiting list because the 5,000 customers are already on there. But from this standpoint --

I am sorry. What was the rest of your question?

BY MR. MORELAND:

Q Well, my question was, is it reasonable to assume that customers are still applying for rooftop solar because prior to the pilot program, existing customers were able to opt in.

So if the pilot program is expanded, is it reasonable to assume that those new customers that missed the 5,000 cutoff would be able to opt in to future capacity?

A (Witness Legg) It is possible.

MADAM CHAIR PRIDEMORE: Can I ask something first?

MR. MORELAND: Sure.

MADAM CHAIR PRIDEMORE: Because -- so we are getting things confused here, and I realize this is a -- this is a detailed issue. But if a customer calls Georgia Power and wants to have rooftop solar, you have an option for them and it is instantaneous netting.

MR. LEGG: Correct.

MADAM CHAIR PRIDEMORE: And so people could call the company to try to get rooftop solar and be directed that -- that way. Putting them on a waiting list for monthly netting is not the only option.

So I just want to make sure that we are being true to the record and the actual facts for anybody

who might be spending their Thursday afternoon watching this on YouTube.

MR. MORELAND: All right. Thank you.

BY MR. MORELAND:

Q Do interconnection applications automatically translate into installations?

MR. HEWITSON: Madam Chair, I don't think that's part of their testimony.

MR. MORELAND: No, they go into detail talking about how there is an increase of or slightly less applications this year than there was last year. And what they are saying -- what the conclusion there is, is that there is still a healthy interest in rooftop solar.

But just an application doesn't necessarily mean that it was -- they passed and that it turns into an installation. An application is just an application.

MR. HEWITSON: Yeah.

MADAM CHAIR PRIDEMORE: Do you object?

MR. HEWITSON: I do.

MADAM CHAIR PRIDEMORE: Okay.

MR. HEWITSON: I also think Mr. Legg has already testified that he doesn't run that part of the program.

**MR. MORELAND: Well, he is testifying to an increase in applications.**

**MR. HEWITSON: Right. Which he --**

**MR. MORELAND: And drawing a conclusion --**

**MADAM CHAIR PRIDEMORE: Can I help you with your question, Mr. Moreland?**

**MR. MORELAND: Sure.**

**MADAM CHAIR PRIDEMORE: Okay. So an application could come in to the company, but there can be a variety of factors that would keep that application from going into interconnection; right?**

**MR. MORELAND: Exactly my point, yes.**

**MADAM CHAIR PRIDEMORE: Okay. So maybe ask your question about the factor or factors that Georgia Power and this witness has control over, and then he can then -- the witness panel can answer it.**

**I mean, because think about it. I can apply for rooftop solar, and then I could move, or I could just change my mind, or I could lose my job and have a financial hardship.**

**So there is all these factors that could come in to keep me from the application process to the interconnection process. Maybe ask the panel questions about those things that directly relate to Georgia Power moving them from application to**

interconnection.

MR. MORELAND: I understand what you are saying. But we just learned that these gentlemen don't work in that department. So I don't know that they would be able to answer that question.

MADAM CHAIR PRIDEMORE: Okay. Well, then they can't. Ask him another one.

BY MR. MORELAND:

Q Would the number of approved applications be a better indicator as to the level of people getting solar in Georgia?

A (Witness Legg) It is -- yes, it is possible that it could. As I mentioned earlier, we certainly have had experience with applications put into the process that don't result in going to the program because for whatever reason the customer decides not to participate.

We have also seen plenty of applications put into the process that did result in customers participating in RNR. Regardless of that, the number of applications that we continue to receive is very close to what we saw during the pilot. So that's the only point we are trying to make.

And we are saying since we are still seeing a similar number of applications -- and, again, as you read in the next paragraph, we talk again about the federal IRA that we believe will continue to increase demand in

behind-the-meter solar. We don't believe that the additional incentive of monthly netting is justified when you compare that to the cost shift that other customers have to bear if it is continued.

Q Yes, we will talk about the IRA in the next panel.

You mentioned earlier -- I am sorry. I forgot the person who was asking the question. But it was generally agreed to earlier that energy is generally more expensive during the day than it is at night?

A (Witness Legg) Right. We were asked that question.

Q And what was your answer?

A (Witness Legg) The answer was yes, generally.

Q Do you know how much more?

A (Witness Legg) I don't have a number, no.

Q Okay.

A (Witness Evans) I think it is shown in the IRP docket the difference between standard avoided cost and the solar weighted avoided cost, though.

Q Okay. Mr. Legg, you referred earlier to a data request as TAI-4-1 where lines F through G indicated the amount -- do you remember the 30,000 different lines on this spreadsheet? 30,424 to be exact. Where you were asked to supply the amount of energy sold to the customer? The

amount of --

A (Witness Legg) Are you -- I am sorry. Go ahead.

Q The amount of electricity pushed back and the net between the two?

A (Witness Legg) I am not sure what data request you are talking about. I think TAI, set four, was from the direct hearings in this, not this supplemental filing.

What I was referring to earlier was out of curiosity, as we moved through preparations for this case, and there was a hearing request made, looking at how many customers out of all the customers that had been billed on monthly netting this year so far through October, how many of those had netting to zero. That's not a data request. It's a hearing request that's coming -- forthcoming.

Q Since you referred to that data request before, do you mind if I ask questions about it here?

A (Witness Legg) Are you talking about one in the direct testimony?

MADAM CHAIR PRIDEMORE: Yes, do we have a data request that you could show them?

MR. HEWITSON: You would have to put it in front of the witnesses to ask. As Mr. Moreland said, I mean, there's lines F through G we are talking about here and a lot of data involved in that data

request.

A (Witness Legg) And we answered hundreds and hundreds of data requests. So I would not know anything off the top of my head about that.

BY MR. MORELAND:

Q Okay. All right. Well, thank you, gentlemen. No further questions.

A (Witness Legg) Thanks.

MADAM CHAIR PRIDEMORE: Thank you, Mr. Moreland.

Georgia Watch?

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Watch?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management?

(No response.)

MADAM CHAIR PRIDEMORE: Resource Supply Management?

(No response.)

MADAM CHAIR PRIDEMORE: Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. DOWDY: Thank you, Madam Chairman, Commission.

CROSS-EXAMINATION

BY MR. DOWDY:

Q Good afternoon, panel. This will just be brief.

A (Witness Legg) Good afternoon.

A (Witness Evans) Good afternoon.

Q A few clarifications. One, in your testimony, you referenced net metering, instantaneous netting, and monthly netting.

What is your definition of net metering?

A (Witness Legg) Yeah, when we reference net metering, we are really talking about monthly netting. And the definition actually is in the RNR-10 tariff, which is the current version of the tariff.

On page 2 of the tariff, there is a section called "Renewable Energy Resources" that actually defines RNR monthly netting and RNR instantaneous netting. So that's what we are referring to.

Q All right. And then in 2021, did you have any net metering customers?

A (Witness Legg) Yes, we did. I mean, the pilot -- the monthly netting or net metering pilot started in as a result of the 2019 rate case, I believe, yes,

because the pilot actually was fully subscribed by the middle of 2021, and there were already a number of customers on that.

Q It is true, is it not, that Georgia Power reported to the Energy Information Administration that they had zero net metering customers on Form EIA-861 for calendar year 2021?

A (Witness Legg) I do not know. And I don't know what that definition of net metering is versus the RNR monthly netting definition, which is what we are referring to here.

Q And that's what I am trying to make sure that we understand and clarify what your definition is.

A (Witness Legg) Right.

Q But on that same form, do you know that -- or on the same form, do you know that the company did report 4,146 customers as non-net meter distributed?

A (Witness Legg) I do not know. I didn't prepare the data for the EIA-861 form.

Q All right. And then we talked about earlier, several people have mentioned now the ITC and the 3 percent. One of your witnesses talks about that being profound. But it has been around since 2006.

So you agree, do you not, that the success of behind-the-meter solar would depend not just on a tax credit

that's been in effect for -- primarily for a long time, but also the regulatory rate treatment by the utility in their jurisdiction?

A (Witness Legg) Are you asking, would that -- would the regulatory treatment additionally influence that? Certainly. Certainly it would, and I believe it has and -- yeah.

Q And related to that, as you started to look at how you would change this tariff, did you look at which utilities were having the most success with behind-the-meter solar?

A (Witness Legg) We did not. We weren't looking at necessarily which -- when you say, "success," I assume which ones have the most customers. Is that what you are asking?

Q Yes.

A (Witness Legg) Yes. We did not look at that. I wouldn't necessarily equate having the most behind-the-meter customers with success, because in some instances it may be because there was a law or a mandate that they reach a certain percentage. I know that's what has driven some states to get to the point where they have great -- or very, very large cost shifts. We have seen this in industry reports and things like that.

So I wouldn't necessarily equate having more

customers with behind-the-meter solar with success. I would say what we are -- what we are putting forth here is, we think the Commission should consider balancing, continuing to support the behind-the-meter solar activity with how much cost it shifts to other customers. So that's what I would define as a successful program.

Q And I understand that. What I am really looking for, since success also depends on the rate structure and how it is structured, you didn't do any research of the other major utilities throughout the country that were having success with it to see if they had -- if part of that was a tariff that they were using, the regulatory treatment they were giving was attractive and was also covering all of the costs that the utility thought should be covered.

You did not do research to determine what else is being tried and working?

A (Witness Legg) I have read quite a bit of industry information about this around the country. I am generally aware that lots of utilities that have had a lot of growth on primarily volumetric rates like our R rate are now concerned because there is a lot of cost shifting going on.

That was one point of -- one point of research that I -- that I am familiar with it. I am also familiar

with some activities of states that are trying to put fixes in place for that, are trying to back away from what they have done for a lot of years and implement some rates that -- and/or a structure that works better and does not shift as much cost.

So while I am generally aware of that, I didn't put a -- do a significant amount of research to see specifically what those rates were doing.

Q All right. And the only company that has been mentioned while you were sitting there in questions about tariffs was Alabama Power, your sister company?

A (Witness Legg) Right. Yes. The only specific one I mentioned, yes.

Q So your sister company on that.

Does Georgia Power believe that having an effective program and promoting behind-the-meter solar helps the system grid resiliency, deferral of investment -- generation investment? Are there any benefits that the company sees to that?

A (Witness Evans) Yes. And the company has recognized those. And I think they are represented in the RCB framework that the Commission has approved. Solar has energy benefits to the grid and to the system. And then they are compensated for those benefits through the framework that the Commission has approved.

Q Thank you. Thank you, panel. Thank you Commission.

A (Witness Legg) Thank you.

MADAM CHAIR PRIDEMORE: United States Department of Defense?

(No response.)

MADAM CHAIR PRIDEMORE: United States Department of Defense?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. There you go. Redirect?

MR. HEWITSON: Madam Chair, let's move this along. No redirect for this panel. I ask that Exhibit 42 be moved into evidence and the panel be excused.

(GPC Exhibit 42 was admitted into evidence.)

MADAM CHAIR PRIDEMORE: You are excused. Next panel, final panel, Dr. David Gattie.

Thereupon,

DAVID GATTIE,

having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HEWITSON:

Q Dr. Gattie, for the benefit of the record, would you please state your full name and business address.

A My name is David Gattie. I work at the University of Georgia. I would like to point out that this is my testimony, reflects only my opinions and not the University of Georgia.

Q Okay. And I understand you are appearing here individually and not in your professional capacity.

But just for the benefit of the record, would you please tell us what you do for a living?

A I am an associate professor of engineering at the University of Georgia and a senior fellow with the Center for International Trade Security.

Q Okay. On October 20th of this year, did you prefile or cause to be prefiled 25 pages of supplemental direct testimony in question-and-answer format in this docket?

A I did.

Q Dr. Gattie, are there any corrections which you need to make to your prefiled testimony?

A No.

Q If I were to ask you the same questions today as under oath, would your testimony be the same as if set forth in that prefiled testimony?

A Yes.

MR. HEWITSON: Madam Chair --

MADAM CHAIR PRIDEMORE: Dr. Gattie?

**MR. GATTIE: Yes, ma'am.**

**MADAM CHAIR PRIDEMORE: Could I ask you to speak into your mic.**

**MR. GATTIE: Am I not close enough?**

**MADAM CHAIR PRIDEMORE: Thank you.**

**MR. GATTIE: Let me move me it closer.**

**COMMISSIONER MCDONALD: My hearing aids' battery left me a while ago.**

**MR. GATTIE: Yes, sir. My apologies.**

**MR. HEWITSON: Madam Chair, the court reporter has been given a copy of Dr. Gattie's prefiled supplemental direct testimony. I would now ask that it be copied into the record as if given here today.**

**MADAM CHAIR PRIDEMORE: So moved.**

**(Whereupon, the prefiled direct testimony of David Gattie follows:)**

**SUPPLEMENTAL DIRECT TESTIMONY**

**OF DR. DAVID GATTIE**

**ON BEHALF OF**

**GEORGIA POWER COMPANY**

**DOCKET NO. 44280**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS**

A. My name is Dr. David Gattie. I am an Associate Professor of Engineering in the School of Environmental, Civil, Agricultural, and Mechanical Engineering at the University of Georgia. My business address is Driftmier Engineering Center, Room 1211, 597 D. W. Brooks Drive, Athens, Georgia 30602.

**Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?**

A. I am testifying on behalf of Georgia Power Company ("Georgia Power" or the "Company").

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?**

A. Yes. I previously submitted testimony on behalf of Georgia Power in Georgia Public Service Commission ("Commission") Docket No. 29849.

**Q. DR. GATTIE, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.**

A. I am an Associate Professor of Engineering in the University of Georgia's ("UGA") College of Engineering, and a Senior Fellow in UGA's Center for International Trade and Security, which is in UGA's School of Public and International Affairs. I have fourteen years of private industry experience as an energy services engineer and environmental engineer. Currently, my research is in the area of energy policy and integrated energy

resource planning for the power sector and the security implications of transitioning the U.S. economy to low- or zero-carbon energy resources. A particular focus of mine is the national security implications of U.S. nuclear power. I established UGA's first environmental engineering undergraduate program in 2009, which I ushered through full accreditation in 2012, and I teach graduate and undergraduate courses in energy systems and energy security for both the College of Engineering and the Center for International Trade and Security. I serve on the Advisory Board for the Energy Policy Institute at Boise State University and as an uncompensated member on the Advocacy Council for Nuclear Matters.

I've conducted research in natural resources engineering and in material and energy flows in ecosystems as a basis for understanding the limitations of energy flows in ecological and coupled human-natural systems, and the importance of stored energy for sustaining growth in ecological systems and industrialized economies. Based on my extensive international experiences and firsthand involvement around the challenges of meeting electricity needs in developing and recently developed countries, my current research focus is energy policy for the electric power sector. Part of my current research efforts have included research with the 1 MW solar demonstration project in Athens, GA and a solar plus storage project as a resource for renewable generation intermittence (both in collaboration with Georgia Power)

With increased attention and national policy efforts directed at transitioning the U.S. away from conventional resources to low- or zero-carbon resources, I've dedicated my most recent research efforts toward evaluating the broader security implications of such an unprecedented shift in the world's largest industrialized economy and greatest military power. Over the past eight years, I have made over one hundred presentations at the local, state, national, and international levels and have authored or co-authored over thirty journal articles and commentaries on energy policy. One of these is a co-authored article with President Ronald Reagan's former National Security Advisor, Robert "Bud" McFarlane, entitled, "China and the Importance of Civil Nuclear Energy," which was published in *The*

*National Interest*. For the past five years, I've spent time in fourteen states, including Georgia, meeting with individuals associated with the electric power industry to discuss the energy transition issue, as well as my own research on the security implications of energy policy at the state and national levels. These meetings and discussions have included industry professionals, state legislators, academicians, and working-class citizens. Moreover, I have been, and continue to be, engaged in extended energy policy summits with practitioners, policymakers, and academics from South Korea and Japan (two key U.S. allies in global and national security) to discuss our respective countries' energy and nuclear power policy within the energy transition framework and the challenges confronting us in such a transition. I am particularly engaged with South Korea having recently participated as an invited participant for the Inaugural US-ROK Energy Security Dialogue held in Seoul, South Korea. This was followed up by a reciprocal Multilateral Nuclear Energy Dialogue that I organized and hosted on the University of Georgia campus. In all, these summits and deliberations focus on energy as a national, economic and climate security issue.

I am currently leading the development of the Applied Energy Studies (AES) initiative at UGA. This is a collaboration between UGA's College of Engineering and Center for International Trade and Security in the School of Public and International Affairs. Whereas energy is generally debated in the U.S. as either a market commodity or as a climate change issue, the mission of the AES initiative is to elevate the security implications of energy policy within the energy policy debate. To this end, I have led the development of the Energy Security track within the School of Public and International Affairs' Master of International Policy degree program. This has included the development of three graduate courses: INTL 8278 Energy Statecraft, INTL 8279 Energy Security and Policy and MCHE 8500 Technical Foundations of Energy for Policymakers.

I also have provided testimony before the U.S. House Energy and Commerce Committee on energy, climate, and nuclear power policy and the critical role of energy diversity.[1]

In summary, my research efforts are focused on elevating energy security, national security, economic security, and climate security as core issues around which our energy and climate policy debate, as well as any energy transition we pursue, should revolve. And, germane to these efforts, is the role of renewable energy resources such as solar.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to respond to the Commission's request for Georgia Power to address whether its monthly netting program is a fair and long-term way to compensate customers with behind the meter generation resources such as rooftop solar photovoltaic ("PV"). In this testimony I offer to the Commission my opinion on whether monthly netting, known in other states as monthly net metering, is the right policy choice for Georgia. Directly, my recommendation is that the Commission should not extend Georgia Power's monthly netting pilot whereby solar customer-generators are compensated at approximately the retail rate for excess energy exported onto the grid. In my testimony, I recommend that the Commission adopt a rate structure and compensation rate that ensures solar customer-generators pay their fair share of the costs to operate the Company's electric system while also fairly compensating customer-generators for the energy they export to the grid.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A. I recommend that the Commission reject expanding Georgia Power's monthly netting pilot as monthly netting represents a fundamentally flawed mechanism for compensating customers with behind the meter ("BTM") generation in Georgia. I make this recommendation for a variety of reasons, including the discrepancy in value placed on electricity exported by solar customer-generators onto the grid, the lack of consensus on

[1]Gattie, D. (2019). Testimony before the U.S. House Energy & Commerce Committee. December 5, 2019. https://energycommerce.house.gov/sites/democrats.energycommerce.house.gov/files/documents/Witness%20Testimony_12.05.19_Gattie.pdf

the use of monthly net metering as a policy tool in other states, and because disproportionately compensating customer-generators as a means to increase solar development does not align with Georgia's energy policy goals. I base this conclusion on the following key considerations:

- **Disparity in Value**: Under monthly netting, a customer-generator who exports electricity onto the grid is treated as providing *all* of the services, like transmission and distribution, traditionally associated with electric utility service. But the cost to provide electricity coming from the grid to the solar customer-generator is higher than the value of electricity exported from the solar customer-generator onto the grid. This is because the solar customer-generator is not providing the same transmission, distribution and other services required to transmit power across the Company's system and maintain reliable electric service for its customers. As I explain further below, any rate structure or compensation rate that does not appropriately account for this discrepancy unfairly shifts costs to other customers by compensating customer-generators for services they do not provide. This cost shift most egregiously occurs under monthly netting but can occur under any rate design or compensation mechanism that fails to align the compensation provided to customer-generators for the energy they export to the grid with the actual costs of providing them with electric service.

- **Excess Subsidization**: The Inflation Reduction Act ("IRA"), President Biden's signature climate change policy, includes a 30% tax credit specifically designed to spur investment and lower barriers for entry into rooftop solar. All estimates suggest the IRA's impact on the rooftop solar market will be profound and that it is likely to have a transformative effect on the rooftop solar industry. The Commission should, therefore, allow the financial impacts of this game-changing federal subsidy to unfold before committing additional ratepayer dollars in the form of expanded monthly net metering subsidies. This is especially the case when these additional ratepayer subsidies may not be needed for continued and stable solar

customer-generator deployment in Georgia. Federal dollars, not state ratepayer dollars, should be the first to support these resources. And federal IRA subsidies may be enough.

While I do not offer my opinion as to a specific rate structure and compensation rate for solar customer-generators, I do urge the Commission to only compensate these resources for the services they actually provide—and not provide a level of compensation that unfairly shifts costs to other customers. The right mechanism will ensure that solar customer-generators pay their fair share of the costs of electric service and fairly compensate them for the energy they export to the grid.

From a policy perspective, my testimony also provides a broader view of the implications associated with leveraging monthly net metering as a tool for regulators and policy makers to accelerate the transition away from conventional energy resources. In this regard, monthly net metering is a national issue, as the U.S. is in a sharply divided debate as to which energy resources will power its 21st century economy. States that have led the way in adopting aggressive net metering strategies as a means to achieve their energy policy goals are now walking back or reevaluating net metering policies, on account of significant negative externalities and issues of ratepayer fairness. My recommendation is that the Commission consider the lessons learned in other jurisdictions and that it avoids the expansion of monthly net metering in Georgia, which is a flawed policy with fading national support.

## II. NET METERING

**Q. PLEASE EXPLAIN THE HISTORY OF NET METERING POLICY.**

A. The origins of net metering are rooted in the Public Utility Regulatory Policies Act of 1978, which was enacted following the energy crisis of the 1970s and required utilities to

compensate solar customer-generators based on the utility's avoided cost.[2,3] The first actual application of net metering was in 1979 in Massachusetts.[4] Some of the original motivation for, and interest in, net metering is summarized in the National Renewable Energy Laboratory's (NREL) *Net Metering Programs Topical Issues Brief*, published in 1996:

> There has been a recent surge of interest from the renewable energy industry and environmental groups in net metering. The reason for this interest is that net metering is a simple, low-cost, and easily administered method to encourage direct customer investment in renewable energy technologies. The renewable energy industry supports net metering because it removes an economic disincentive for potential customers by increasing the value of the electricity generated by renewable energy technologies. Environmental groups support net metering because it promotes clean energy production.[5]

NREL defines net metering as "a metering and billing arrangement designed to compensate distributed energy generation (DG) system owners for any generation that is exported to the utility grid."[6] The Congressional Research Service, in 2019, defined net metering as "a policy that allows electricity customers with their own generation capacity to be financially compensated for the energy they produce."[7]

Net metering, then, is a policy that governs the billing arrangement and compensation structure between a solar customer-generator and the utility providing the grid and utility services to which the solar customer-generator is connected. In other words, this debate examines the appropriate compensation level paid by the utility to the solar customer-generator for the excess energy they deliver to the grid. The billing arrangement,

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[2] American Public Power Association. (2020). The Public Utility Regulatory Policies Act of 1978. https://www.publicpower.org/system/files/documents/PURPA%20-%20January%202020.pdf.
[3] Michigan Public Service Commission. (2019). Issue Brief: Public Utility Regulatory Policies Act (PURPA). https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/info/briefs/MPSC_Issue_Brief_--_PURPA.pdf?rev=cf1855f9f14c476dbfa86974a67206d0.
[4] Verzola, R. (2015). Net Metering History & Logic. https://cleantechnica.com/2015/09/06/net-metering-history-logic-part-1/.
[5] Wan, Y. H. (1996). *Net metering programs* (No. NREL/SP-460-21651). National Renewable Energy Lab.(NREL), Golden, CO (United States).
[6] National Renewable Energy Laboratory. Net Metering. https://www.nrel.gov/state-local-tribal/basics-net-metering.html.
[7] Lawson, A. J. (2019). Net metering: In brief. *Congressional Research Service*. Link: https://sgp.fas.org/crs/misc/R46010.pdf.

compensation structure, and the value assigned to this excess energy are the points of contention. Currently, there is no shortage of studies, papers, briefs, and reports on the issues of net metering, with myriad proposals for how solar PV customer-generators should be compensated.[8,9,10,11] One literature review in 2006 found twenty-two distinct definitions for the term "net metering" and proposed "a taxonomy that distinguishes between sixteen distinct compensation practices."[12] For the purpose of my testimony and my recommendation around the appropriate rate of compensation for solar customer-generators, I primarily address concerns associated with monthly netting, which provides compensation for excess generation at or near the retail rate of electricity.

**Q. HOW DO YOU DEFINE THE "RETAIL RATE OF ELECTRICITY"?**

A. The retail rate of electricity includes a utility's fuel costs, generation costs, transmission costs, distribution costs, grid infrastructure costs, and administrative support costs provided by the utility. All costs beyond fuel and marginal operations and maintenance costs incurred at the power plant represent added value provided solely by the utility to move electricity reliably and safely from the generating source to its customers—including moving electricity to those customers with distributed solar generation. Because of these delivery costs, the value of electricity generated at the power plant is much lower than the value of electricity delivered to the meter of a customer. This discrepancy in value reflects all the costs associated with transmission, distribution, grid infrastructure, and support services provided by the utility—costs that go unrecovered where a solar customer-

[8] Eid, C., Guillén, J. R., Marín, P. F., & Hakvoort, R. (2014). The economic effect of electricity net-metering with solar PV: Consequences for network cost recovery, cross subsidies and policy objectives. *Energy Policy*, *75*, 244-254. (From Eid, et. Al, 2014): *"Furthermore, the impact of net-metering on public and network utilities' income has been studied within numerous policy reports. Those reports argue differently regarding financial impacts of PV penetration, possibly due to the influence of main stakeholders involved (California Public Utilities Commission, 2013; Cohen, 2013; NREL, 1996). Consequently, different efforts have been made to deal with the issue of net-metering focused on financial stability of network utilities and preserving equity between ratepayers"*.

[9] California Public Utilities Commission, 2013. California Net Energy Metering (NEM) Draft Cost- Effectiveness Evaluation.

[10] Cohen, R., & Khermouch, G. (2013). The giant headache that is net energy metering. *The Electricity Journal*, *26* (6), 5-7.

[11] Wan, Y. H. (1996). *Net metering programs* (No. NREL/SP-460-21651). National Renewable Energy Lab. (NREL), Golden, CO (United States).

[12] Hughes, L., & Bell, J. (2006). Compensating customer-generators: a taxonomy describing methods of compensating customer-generators for electricity supplied to the grid. *Energy Policy*, *34*(13), 1532-1539.

generator fails to pay its fair cost of electric service or is overpaid for the excess energy it exports to the grid, as is the case under monthly net metering.

**Q. HOW DO YOU DEFINE MONTHLY NETTING?**

A. Under monthly netting, when a solar customer-generator generates sufficient electricity to meet its own demand, no electricity flows to the customer from the grid through the meter. When a solar customer-generator generates less than its own energy demand, the insufficiency is made up by consuming electricity from the grid, in which case, the meter spins forward and registers the customer's consumption of electricity. When the solar customer-generator generates electricity in excess of its own demand, the excess electricity is exported to the grid through the meter, which then essentially "spins backwards," reversing the customer's previously registered consumption of electricity from the grid. As I understand Georgia Power's monthly netting pilot, participating customers are billed based upon the lower netted usage, meaning that the customer-generated electricity that is exported to the grid is valued at close to the retail rate of electricity.[13]

**Q. CAN YOU PROVIDE AN EXAMPLE?**

A. Yes. The following hypothetical example illustrates how I interpret monthly netting. Consumption for an Oconee County, Georgia residence was compiled for the month of April 2022, during which time the residence consumed and paid for 1,343 kWh of electricity (Figure 1). PVWatts was then used to model electricity output from a 10 kW solar PV system installed at this location.[14] This output was estimated to be 1,333 kWh. This would then translate to a net difference of 10 kWh, which, under monthly netting would result in a bill to the customer-generator for 10 kWh of measured consumption. However, this is only measured consumption since electricity from the grid and electricity

[13] When I say "close" to the retail rate, I mean that certain charges are excluded from the retail rate when credited back under monthly netting. While this varies by jurisdiction, certain non-volumetric, non-bypassable and other fixed charges embedded in the retail rate are not compensated under monthly netting. While these charges are usually a small amount of the overall retail rate, they are nonetheless not included when compensating customer-owned generation, resulting in a rate that is close to—but not the full—retail rate.
[14] PVWatts Solar Calculator. https://pvwatts.nrel.gov/.

to the grid are considered equivalent under monthly netting arrangements that do not account for the difference between actual consumption and export. In reality, based on hourly data for both the residence and from PVWatts, the residence with a solar PV system would have consumed 826 kWh during times when the PV system either was not generating electricity or was not generating sufficient electricity to meet the solar customer-generator's demands. At the same time, the solar customer-generator would have exported 816 kWh of excess electricity to the grid during times when solar PV generation exceeded the solar customer-generator's demands. Monthly netting would report this as a 10 kWh consumption, even though the solar customer-generator was still dependent on the grid for providing its consumption of 826 kWh of electricity. Such is the difference between "measured consumption" under monthly netting, which in this case is 10 kWh, and "actual consumption" which in this case is 826 kWh.

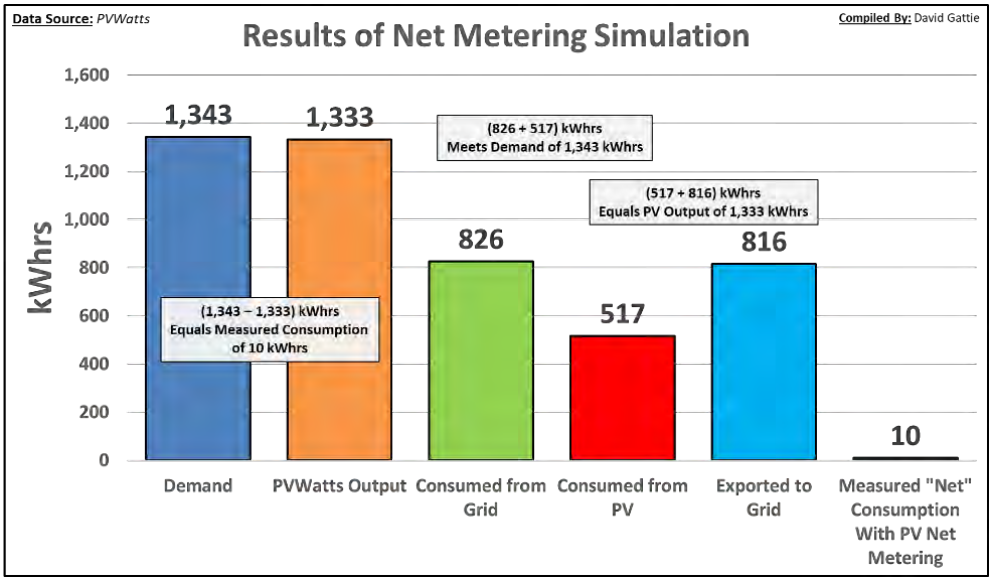


**Figure 1**. Net metering simulation profile of the grid and PV electricity consumption and export for a residence in Georgia.

Under monthly netting type arrangements, all electricity moving through the meter, in either direction, is treated equally at the retail rate, with no distinction in value. The question then comes down to the value of electricity coming from the grid to the solar customer-generator compared with the value of electricity exported from the solar

customer-generator onto the grid. And in my determination, this value of excess energy exported by the customer-generator is nearly always less than the value of the energy delivered to the customer.

**Q. WHY SHOULD THE COMPENSATION RATE OF ELECTRICITY EXPORTED FROM THE SOLAR CUSTOMER-GENERATOR BE LOWER THAN THE RETAIL RATE OF ELECTRICITY?**

A. Customers with solar resources are still dependent on the grid itself, including the generation, transmission, and distribution services a utility provides — but which the solar customer-generator avoids paying under a monthly netting arrangement. Under monthly netting arrangements, solar customer-generators are compensated at approximately the full retail rate and are thus significantly overpaid for the energy they export. As such, the solar customer-generator essentially avoids paying for the fixed operating costs of generation, transmission, and distribution, even though it uses them and, in fact, depends on access to them to export its own energy to the electric grid. As such, monthly netting represents a regressive policy that favors and rewards those who choose to participate at the expense of those who choose not to participate or who can't participate in behind-the-meter solar generation. This underscores the need for an appropriate rate structure that ensures solar customer-generators pay their fair share of the costs associated with electric service while also being fairly compensated for the energy they export to the grid.

## III. STATE-LEVEL POLICY CHOICES

**Q. PLEASE FRAME THE NET METERING DEBATE.**

A. States have adopted monthly net metering primarily as a means to achieve renewable energy and energy resiliency goals. In the nascent days of rooftop solar PV, excess compensation in the form of monthly netting was used by some state regulators and policymakers to encourage the growth of small-scale renewables. At the time of its adoption, monthly netting provided a simple but crude billing solution for the small subset of customer-generators participating on an electric utility's system. As solar PV technology has matured and solar PV costs have declined, participation rates in monthly net metering programs nationwide have rapidly expanded. This rapid expansion has forced state

policymakers and regulators to reexamine net metering policies more holistically, with an eye towards fairness, affordability, energy diversity, and reliability. As I describe in the balance of my testimony, monthly netting is not a recommended approach for Georgia, given the negative externalities these policies have produced in other parts of the U.S. and the other far more preferable ways Georgia can achieve these objectives.

**Q. HAVE YOU REVIEWED NATIONAL NET METERING PARTICIPATION RATES?**

A. Yes, I have. In 2021, there were 3,012,404 residential net metering customers in the U.S.[15] Since 2011, the number of residential solar PV net metering customers has increased 1,790% while net metering capacity increased over 2,350% (Figures 2 & 3).

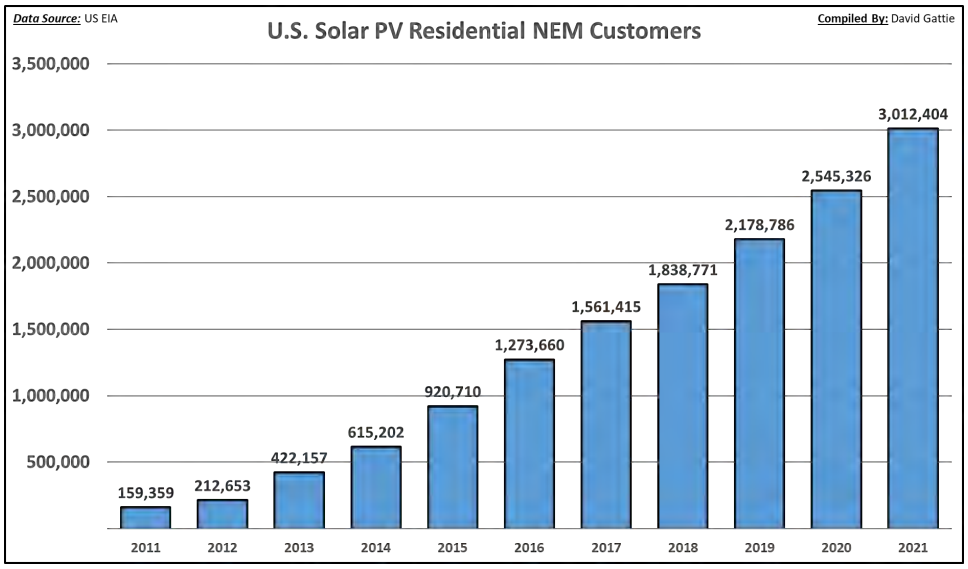


**Figure 2**. U.S. solar PV residential net metering customers, 2011-2021.

[15] U.S. Energy Information Administration. https://www.eia.gov/electricity/data/eia861m/#netmeter.

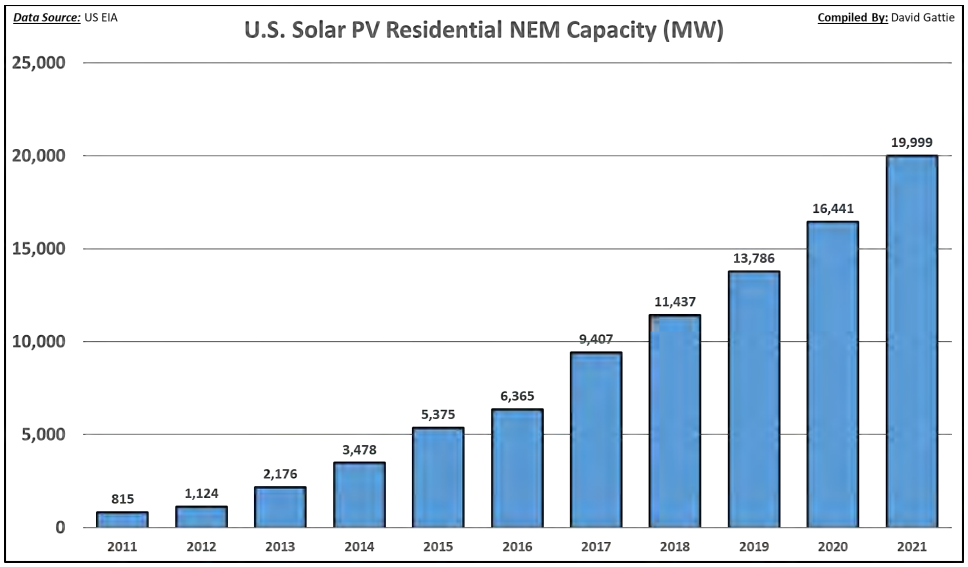


**Figure 3**. U.S. solar PV residential net metering capacity (MW) from 2011—2021.

A breakdown of 2021 shows that two-thirds (66.19%) of residential solar PV net metering customers were located in five states—California, Arizona, New York, New Jersey, and Massachusetts—with California alone accounting for almost half (45.56%) of the country's total residential solar PV net metering customers (Table 1).

| Solar PV Net-Metering: 2021 | | | | |
|---|---|---|---|---|
| | Capacity | | Number of NEM Customers | |
| State | Residential NEM (MW) | % Share of U.S. Residential NEM | Residential NEM | % Share of U.S. Residential NEM |
| CA | *7,952.4* | *39.76* | *1,372,586* | *45.56* |
| AZ | *1,465.3* | *7.33* | *211,133* | *7.01* |
| NY | *1,045.4* | *5.23* | *153,802* | *5.11* |
| NJ | *1,041.2* | *5.21* | *140,635* | *4.67* |
| MA | *801.5* | *4.01* | *115,705* | *3.84* |
| Rest of U.S. | *7,692.9* | *38.47* | *1,018,543* | *33.81* |
| *Data Source:* U.S. EIA-861M; https://www.eia.gov/electricity/data/eia861m/#netmeter | | | | |

**Table 1**. Breakdown of residential solar PV net metering customers.

As it is the dominant net metering state, California merits a closer look. In 2020, while about 1.86% of all U.S. residential grid customers were net metering customers, 8.62% of California's residential grid customers were net metering customers while in the remaining U.S. states, 1.1% of residential grid customers were net metering customers (Table 1). Meaning, while California constituted about 10.12% of U.S. residential grid customers in 2020, it also constituted about 40.93% of U.S. residential net metering capacity and 46.84% of U.S. net metering customers.

| 2020 Residential Solar PV | | | | | |
|---|---|---|---|---|---|
| | U.S. | CA[4] | | Rest of U.S. | |
| | | Value | % of U.S. | Value | % of U.S. |
| Net-Metering Capacity (MW) | 16,441 | 6,729.873 | 40.93 | 9,711 | 59.07 |
| Net-Metering Customers | 2,545,326 | 1,192,208 | 46.84 | 1,353,118 | 53.16 |
| Grand Total of U.S. Grid Customers | 136,682,001 | 13,834,719 | 10.12 | 122,847,282 | 89.88 |
| [1]1.86% of U.S. residential grid customers are U.S. NEM customers | | | | | |
| [2]8.62% of CA residential grid customers are NEM customers | | | | | |
| [3]For Rest of U.S., 1.10% of residential grid customers are NEM customers | | | | | |
| [4]CA constitutes 10.12% of U.S. residential grid customers, but 40.93% of U.S. residential NEM capacity and 46.84% of U.S. NEM residential customers | | | | | |
| Data Source: U.S. EIA-861M; https://www.eia.gov/electricity/data/eia861m/#netmeter | | | | | |

**Table 2**. Comparison of net metering customers for the U.S., California and the rest of U.S. states.

Trends of California's share of solar PV net metering customers and capacity show that while the state's share of the U.S. total is trending down for both number of customers and capacity, it remains the dominant state, therefore a dominant voice in the net metering policy debate (Figures 4 & 5).

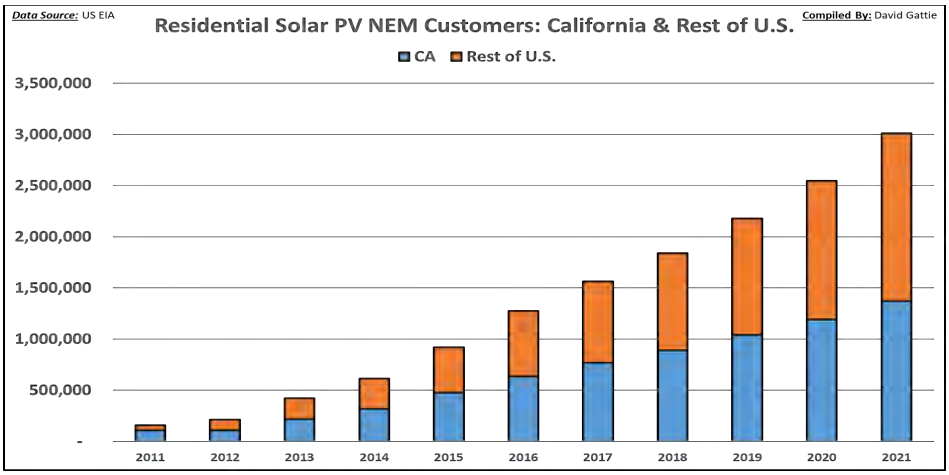


**Figure 4.** Residential solar PV net metering customers for California and the rest of the U.S.

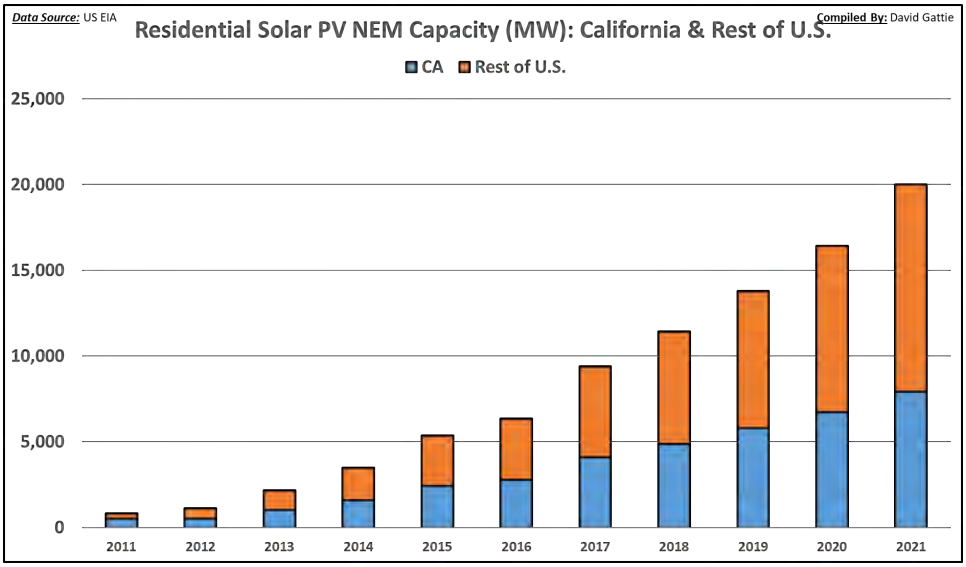


**Figure 5.** Residential solar PV net metering capacity (MW) for California and the rest of the U.S.

**Q. YOU HIGHLIGHT STATES SUCH AS CALIFORNIA AND OTHERS; WHAT APPROACHES HAVE THESE STATES TAKEN WITH RESPECT TO NET METERING?**

A. Unlike Georgia's measured approach towards net metering, many states, including California, have implemented net metering in a manner that compensates the solar customer-generator for exported electricity on a monthly basis at the retail rate (i.e.,

monthly net metering), similar to the monthly netting approach piloted here in Georgia. Policymakers in these states made a policy choice to use monthly net metering as a tool to deliver rapid rooftop solar development as part of an overall decarbonization and energy transition strategy, and these policies have indeed delivered on this goal. However, this rapid development of rooftop solar has come at a cost, not only in the form of increased electric rates, but also as a result of additional stresses on these state's electric grids and unhealthy cross-subsidies that negatively impact customers who either cannot or chose not to adopt rooftop solar.

I contend there is a better way to achieve decarbonization and energy transition goals, without relying on methodologies that increase costs, penalize existing ratepayers, and skew the efficient development of renewable energy resources. In fact, in many jurisdictions, monthly net metering has become a victim of its own success, delivering too high of a subsidy resulting in too much growth, too fast, at too high a cost, causing many state regulators and policymakers to reevaluate net metering policies in their respective jurisdictions. Despite the prevalence of monthly net metering in other jurisdictions, in my view this methodology is rapidly becoming a disfavored approach, given the negative externalities it is apt to cause when adopted at scale. No state exemplifies this more than California.

**Q. WOULD YOU CONCLUDE THEN THAT STATES ARE MOVING AWAY FROM MONTHLY NET METERING AS A PREFERRED POLICY OPTION?**

A. I would conclude it is near universally accepted that monthly net metering at the retail rate is no longer the preferred policy option, even in states with aggressive decarbonization and energy transition targets. Many states have adopted, or are in the process of adopting, so-called net metering "successor tariffs" intended to replace monthly net metering at close to the retail rate with new methodologies to compensate excess generation delivered to the grid. While I disagree with many of these "value of solar" studies that apply unrealistic and ethereal valuations to supposed grid benefits from distributed solar generation, my main point is to underscore that most states with aggressive net metering policies have begun to

acknowledge the inadequacy of monthly net metering at close to the retail rate as a fair and sensible method for compensating distributed generation.

California's ongoing NEM 3.0 proceeding, for example, is poised to dramatically scale back monthly net metering for distributed energy resources. While the details are still under debate, the ultimate result is very likely to be a compensation mechanism that is less lucrative to customer-generators than the prior net metering practice present in California, and results in less of a cost shift to all other customers. Other states such as Arizona, Indiana, Kentucky, Utah, and others have moved away from net metering entirely, or implemented compensation rates that are significantly less than the retail rate, fixed customer charges, time of use rates, or any combination of these measures to reduce the overall unfair cost shifts associated with monthly net metering. My objective is for the Commission to be aware that many state policy makers and regulators are moving away from—and not towards—monthly net metering at approximately the retail rate. The decision before the Commission then is to consider whether to adopt or expand the monthly netting policy at a time when the national trend is moving away from compensating behind-the-meter generation resources at approximately the retail rate. The Commission has an opportunity to avoid the problems encountered in these other jurisdictions by incorporating the lessons learned in other states and avoid adopting a disfavored methodology (i.e., monthly netting) as other states are moving away from this approach.

## IV. GEORGIA'S APPROACH TO ENERGY POLICY

**Q. WITH THIS NATIONAL CONTEXT, WHAT DO YOU RECOMMEND FOR GEORGIA?**

A. Georgia has always taken a measured and practical approach to the integration of renewable resources, and this wisdom has paid dividends for all stakeholders in this ongoing debate. Solar is Georgia's most promising renewable energy resource, and integrating it into Georgia's energy portfolio, in the responsible manner the Commission has done for the past several years, has improved the resource and technology diversity of the state's power sector without sacrificing reliability or putting upward pressure on retail

rates. I am in favor of the most economic and cost-effective ways of deploying renewable energy. As such, I'm a proponent of utility-scale solar as it directly benefits all ratepayers in Georgia, and I am agnostic on residential rooftop solar PV as it is a customer-choice issue. However, monthly net metering (or monthly netting here in Georgia) is a separate policy issue that involves shifting costs to ratepayers who do not participate as solar customer-generators. Significantly, my testimony on monthly netting should not be misconstrued as opposition to residential rooftop solar PV nor should it be misinterpreted as opposition to compensating solar customer-generators for electricity exported onto the grid. Quite the opposite, customer-generators should be compensated for the energy they export to the grid, and at a rate that is fair and equitable for all Georgia ratepayers and that does not shift costs to ratepayers who do not participate in distributed solar PV.

**Q. HOW DO GEORGIA'S ENERGY POLICY OBJECTIVES DIFFER FROM OTHER STATES?**

A. California is prioritizing carbon reduction, which has resulted in one of the lowest carbon footprints in the country, but also some of the highest electricity rates with regular threats of blackouts and power shortages. This can be contrasted with Texas, which is optimizing its power sector for lowest rates—and indeed has affordable rates—but has experienced severe reliability issues the past two years. States in other deregulated markets are dealing with premature closure of nuclear power plants due to deregulated markets structured around lowest marginal costs, oftentimes meaning low-cost natural gas and subsidized renewables.[16]

As states discuss how best to organize their respective electric power sectors within what would be an unprecedented energy paradigm for an industrial economy, some states are having heated debates and taking aggressive policy actions around renewable energy—

[16] Gattie, D., Darnell, J., Massey, J., 2018. The Role of U.S. Nuclear Power in the 21st Century. *The Electricity Journal, 31(10):1-5*.

particularly solar. And monthly net metering at approximately the retail rate is embedded in many of these policy debates.[17,18,19]

Georgia has taken a different approach than that of states such as California and Texas as it has prioritized reliability, affordability, and resource diversity within its long-term integrated resource planning process and regulated market structure (Figure 6).[20,21] I argue Georgia has struck the right balance between these competing objectives. Some data points that support Georgia's approach towards these issues are:

- Among regulated and deregulated market states, residential rates for Georgia's total electric power sector remain below the national average and below those in most deregulated market states (Figures 7 & 8).[22]
- Georgia has reduced carbon emissions from its electric power sector by 58% from 2007-2020.[23]
- Among the top eight states with the highest GDPs in the U.S., Georgia residential rates are third lowest (Figure 9).[24]
- Georgia ranks seventh in the country for utility-scale solar PV generation (Figure 10).[25]

[17] National Renewable Energy Laboratory. Net Metering. https://www.nrel.gov/state-local-tribal/basics-net-metering.html.
[18] Murphy, P. (2022). As contentious net metering debates persist across the US, Connecticut and Hawaii show a way forward. *Utility Dive*. June 3, 2022. https://www.utilitydive.com/news/as-contentious-net-metering-debates-persist-across-the-us-connecticut-and/624658/.
[19] Energy Fairness. (2020). Net Metering: Costs, Customers, and a Smarter Way Forward for Florida. Energy Fairness. January 2020.
[20] Energy Information Administration. https://www.eia.gov/electricity/data.php.
[21] Gattie, D. (2022). Georgia's Future of Prioritizing Energy Security and Reliability. James Magazine. September/October, 2022. https://www.paperturn-view.com/insideradvantage/james-septemberoctober-2022-web?pid=MjY269511&p=27&fbclid=IwAR3UEiARUamH069gDamIYuUKITtYNdA1dKQP2yo1e3fUNUcERanK-TDLgDQ.
[22] Ibid.
[23] Ibid.
[24] Ibid.
[25] Ibid.

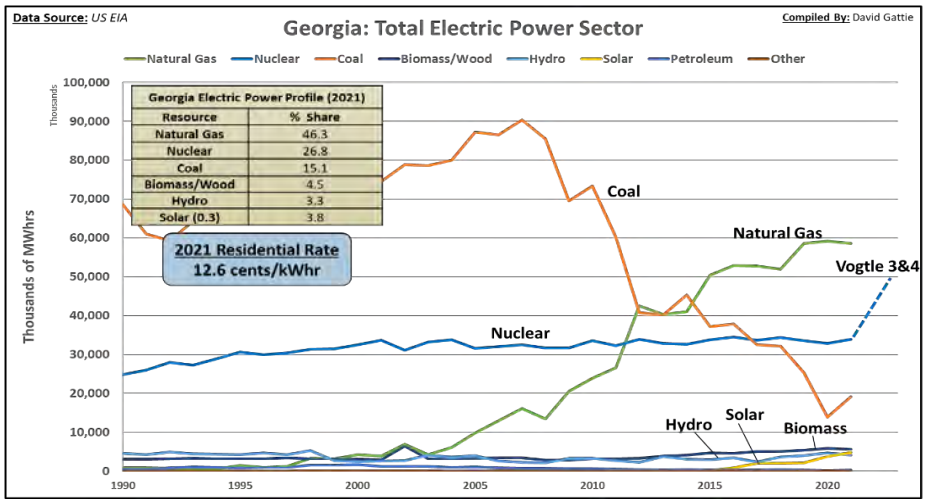


**Figure 6**. Energy resource trend for Georgia's total electric power sector, 1990-2021.

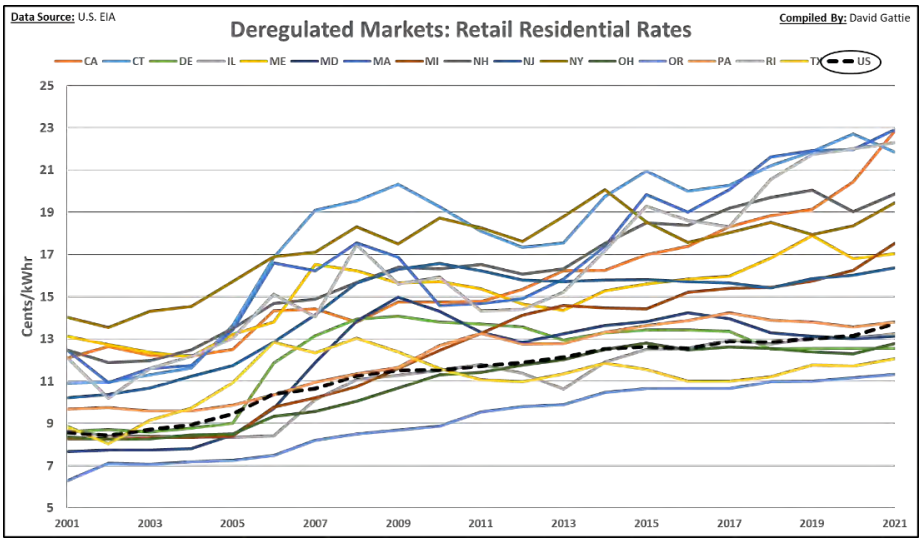


**Figure 7**. Retail residential rate trends for states operating under deregulated electricity market structures, 1990-2021.

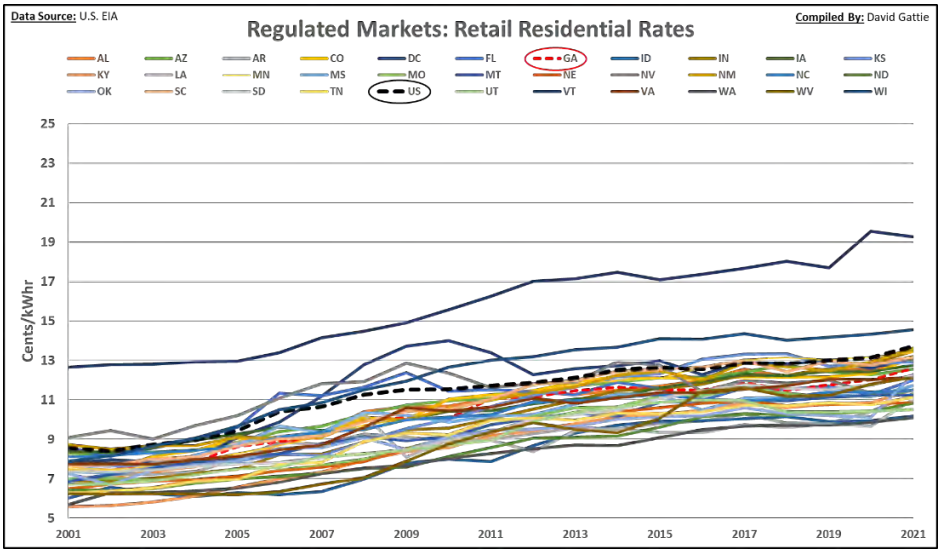


**Figure 8**. Retail residential rate trends for states operating regulated electricity market structures, 1990-2021. Georgia is below the national average and competitive with other states.

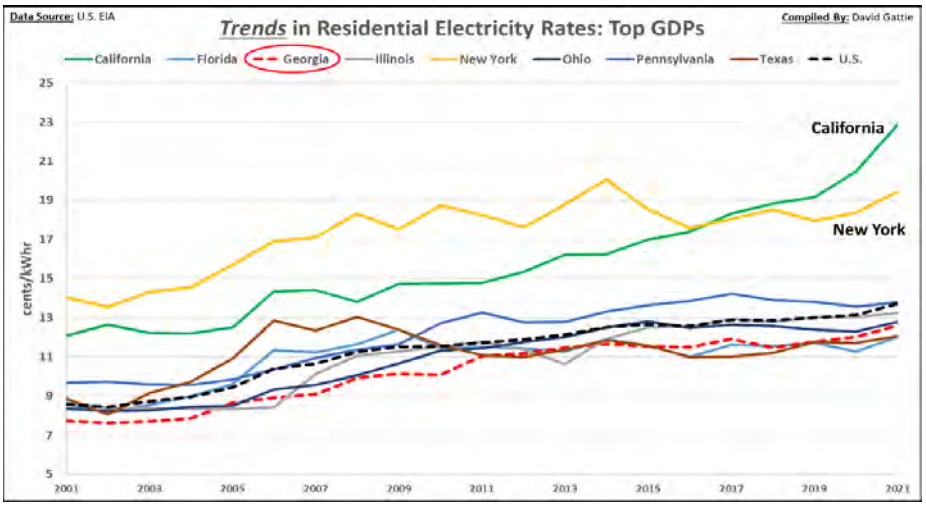


**Figure 9**. Trends for residential electricity rates among the top eight states with highest GDPs in the U.S.

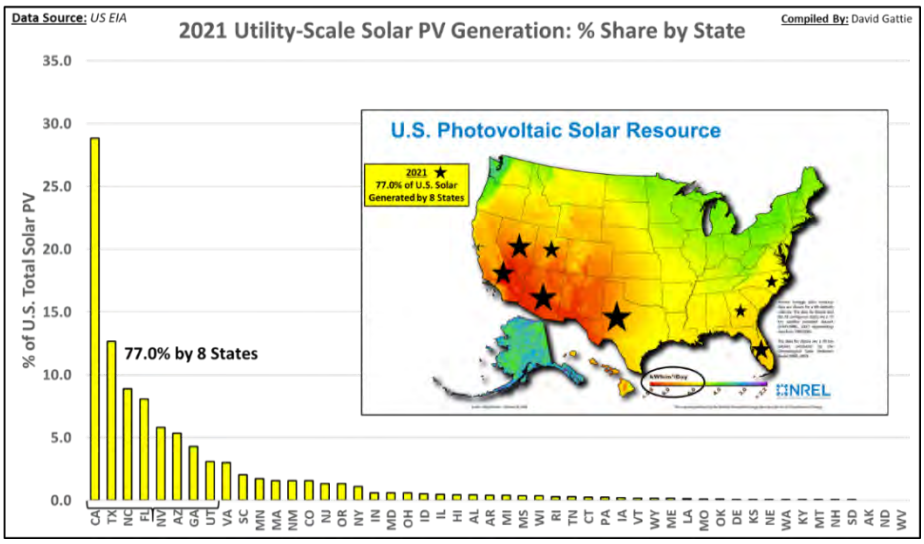


**Figure 10**. Percent share, by state, of utility-scale solar in the U.S. for 2021.

Georgia's approach to its electric power sector has been calculated, deliberative and pragmatic, particularly with respect to solar PV.

**Q. HOW WILL THE RECENTLY PASSED FEDERAL IRA IMPACT GEORGIA'S ROOFTOP SOLAR MARKET?**

A. The IRA[26], signed into law on August 16, 2022, provides historic federal support to the solar industry. From tax incentives for both businesses and individuals to direct investments, the significance of the IRA to the solar industry is difficult to overstate. According to a recent study, the IRA will be a massive growth catalyst for the solar industry and will triple solar installations by 2027.[27] Other studies suggest investment in the solar industry will increase solar manufacturing capacity by 25 GW[28] or a fivefold annual increase from 10 GW in 2020 to 49 GW in 2024.[29]

In addition to many supply-side subsidies for solar that will drive down overall equipment costs for customers choosing to install solar, the IRA also provides direct incentives to

[26] Pub. Law No. 117-169.
[27] Wood Mackenzie and Solar Energy Industry Association, US Solar Market Insight, September 2022.
[28] Roth Capital Partners: The Solar Snapshot - IRA on its Way; NEM3, UFLPA Updates (Aug. 5, 2022).
[29] Princeton University Rapid Energy Policy Evaluation and Analysis Toolkit, Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022 (Aug. 2022)

individual taxpayers and families to further encourage rooftop solar development. For example, the IRA's Residential Clean Energy Credit aims to further subsidize the cost of solar by providing a 30% tax credit to homeowners choosing to install solar through 2032. Under the Residential Clean Energy Credit, a taxpayer that spends $10,000 on solar PV panels installed at their residence in 2022 may claim a 30% ($3,000) tax credit—further reducing the overall system cost and encouraging additional deployments of rooftop solar in Georgia. Nationally, it is estimated that this credit will allow 7.5 million more residential customers to install solar, reducing the cost to install these systems at an estimated $9,000 over the life of the system, or at least $300 per year.[30]

The IRA represents a first-of-its-kind expansion of federal subsidies for rooftop solar, and the Commission should consider the magnitude of these historic federal investments before significantly altering Georgia's longstanding net metering policy. As I have explained in my testimony, Georgia has struck the right balance by encouraging renewable energy development without significantly increasing electric rates or negatively impacting the reliability of the electric system. As a result of the IRA, Georgia is likely to see considerable growth in the rooftop solar market in the coming years—without any modification to Georgia's existing compensation structures for customer-owned generation. As stated previously, I strongly disagree with compensating customer-generators at a rate that exceeds the value such resources provide to the grid. As such, I recommend that the Commission carefully consider not only whether additional ratepayer dollars are actually needed to encourage rooftop solar investment in the first place, but whether it is appropriate to subsidize rooftop solar at the expense of other customers. Given the generous benefits provided by the IRA and Georgia's proven track record in developing these resources, I conclude that further ratepayer investments are not needed to encourage this growth, and additional subsidies would likely result in nothing more than additional windfall payments to solar installers and developers on the backs of other ratepayers.

[30] By the Numbers: The Inflation Reduction Act, The White House Briefing Room (August 15, 2022), https://www.whitehouse.gov/briefing-room/statements-releases/2022/08/15/by-the-numbers-the-inflation-reduction-act/

**Q. HOW SHOULD GEORGIA COMPENSATE CUSTOMER-OWNED GENERATION?**

A. The Commission has been calculated, measured, and conservative as to the integration of utility-scale solar PV into the grid. It now has a policy choice with respect to distributed solar PV. Based on the aforementioned discussion of issues and impacts associated with compensating net metering solar customer-generators at approximately the retail rate, as is done with monthly netting, I recommend that the Commission not extend the monthly netting pilot or methodology in Georgia. As mentioned upfront in my testimony, I do not offer a recommendation for a specific rate for solar customer-generators. However, I do recommend that, moving forward, the Commission guard against enacting any program that over-subsidizes solar customer-generators, particularly given the robust set of incentives to be delivered by the federal IRA. Any net metering policy should therefore align with the broader energy legacy objectives of Georgia as pertains to fairness, affordability, energy diversity and reliability. Specifically, any policy objectives for compensating solar customer-generators, as first principles, should:

- Provide equitable credit to those who choose to be solar customer-generators;
- Retain energy diversity as Georgia determines its own long-term energy transition priorities, irrespective of the direction taken by some states with more aggressive net metering policies; and
- Avoid shifting any costs to ratepayers who elect not to or are unable to participate in distributed solar PV.

Electricity from the grid is more than a resource or commodity—it is a service from a utility that comes with a 24/7 commitment that if service is ever disrupted, the utility responds and restores service. The value of this service and commitment is calculated into the retail rate. This value is something solar customer-generators do not, and cannot, provide. They are therefore not entitled to receive equal compensation at or near the retail rate for their excess energy. This is not intended to discourage distributed solar PV, but is only intended to keep the value prospect of electricity from a solar customer-generator in the proper

comparative context with the value prospect of the electrical service supplied from the utility. They are not equivalent. Therefore, state energy policy should not artificially equate these resources through a policy such as monthly net metering.

## V. CONCLUSION

**Q. DO YOU HAVE ANY FINAL RECOMMENDATIONS?**

A. Yes. Rather than extend the monthly netting pilot first approved in the 2019 base rate case, I recommend the Commission adopt compensation rates for rooftop solar customers that ensure these customers pay their fair share of the Company's cost of service while receiving appropriate compensation for the excess energy they provide to the grid. When adopting such a compensation rate, the Commission should avoid disproportionately shifting costs to customers who are not participating in distributed solar generation. By compensating customers with BTM generation at close to the retail rate, monthly netting worsens this cost shift. Ultimately, the goal of the Commission should be twofold—to protect customers from these cost shifts while simultaneously enabling the development of rooftop solar in Georgia. I contend that with revised compensation rates that more accurately and fairly compensate these resources, coupled with the generous incentives provided by the IRA, the Commission can strike the right balance between these two objectives.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

**MR. HEWITSON: There are no exhibits. So with your permission, I would like to ask Dr. Gattie to summarize his testimony.**

**MADAM CHAIR PRIDEMORE: Please go ahead with your summary.**

**MR. GATTIE: Madam Chair, members of the Georgia Public Service Commission, thanks for the opportunity to testify today on the issue of monthly net metering as a policy issue for Georgia.**

**Georgia has always taken a measured and practical approach to the integration of renewable resources which has paid dividends for all stakeholders.**

**Solar is Georgia's most promising renewable energy resource and integrating it into Georgia's energy portfolio in the responsible manner the Commission has done for the past several years has improved the resource and technology diversity of the state's power sector without sacrificing reliability or putting upward pressure on retail rates.**

**I am in favor of the most economic and cost-effective ways of deploying renewable energy. As such, I am a proponent of utility-scale solar as it directly benefits all ratepayers in Georgia. And I am agnostic on residential rooftop solar.**

Customer -- as it is a customer choice issue, provided it doesn't impact ratepayers who do not participate as solar customer generators.

Importantly, my testimony on monthly netting should not be misconstrued as opposition to residential rooftop solar, nor should it be misinterpreted as opposition to compensating solar customer generators for electricity exported onto the grid.

Quite opposite: Customer generators should be compensated for the energy they export to the grid and at a rate that is fair and equitable for all Georgia ratepayers.

While I do not offer my opinion as to a specific rate structure and compensation rate for solar customer generators, I do recommend that the Commission reject expanding Georgia Power's monthly netting pilot based on two key considerations.

First, under monthly netting a customer generator who exports electricity onto the grid is treated as providing all of the services provided by a utility, which they aren't.

The cost to provide electricity coming from the grid to the solar customer generator is higher than the value of electricity exported from the solar

customer generator onto the grid because the solar customer generator is not providing the same transmission, distribution, and other services required to transmit power across the electric system and maintain reliable electric service for all customers.

Any rate structure or compensation rate that does not appropriately account for this discrepancy unfairly shifts costs to other customers by compensating customer generators for services they do not provide.

Second, the Inflation Reduction Act, President Biden's signature climate change policy, includes a 30 percent tax credit specifically designed to spur investment and lower barriers for entry into rooftop solar.

This is likely to have a transformative effect on the rooftop solar industry as it provides historic federal support to the solar industry through tax incentives for businesses and to individual taxpayers and families to further encourage rooftop solar development.

The significance of the IRA to the solar industry is difficult to overstate as it represents first of its kind expansion of federal subsidies for

rooftop solar.

This being the case, the Commission should consider the magnitude of these historic federal investments before significantly altering Georgia's longstanding net metering policy since Georgia is likely to see considerable growth in the rooftop solar market in the coming years without any modification to Georgia's existing compensation structures for customer-owned generation.

As such, the Commission should allow the financial impacts of this game-changing federal subsidy to unfold before committing additional ratepayer dollars in the form of expanded monthly net metering subsidies.

More broadly, I am sure it isn't lost on the Commission that our country is in the middle of a politically charged debate over which energy resources will power the U.S. economy in the 21st century. It is being characterized as an energy transition, and there is no shortage of top-down policy proposals to enforce it.

The Clean Power Plan, the Green New Deal, 100 Percent Renewable Energy, and most recently the Inflation Reduction Act touted as the biggest climate bill that any country has ever passed.

**Unfortunately, this national debate has pitted fossil fuels, nuclear power, and renewables against one another in a last-resource-standing competitive match rather than an all-resources-on-deck energy portfolio that ensures reliable and affordable electricity for our state.**

**Consequently, opposition to a policy such as monthly net metering will be distorted by some as opposition to solar energy.**

**But opposition to a compensation policy, especially one such as monthly net metering, that overpays customer generators and disproportionately shifts costs to other customers, is not opposition to a resource, particularly a resource such as solar which is Georgia's most promising and fastest-growing renewable resource.**

**Therefore, from a policy perspective, my testimony provides a much broader view of the implications associated with leveraging monthly net metering as a tool for regulators and policymakers to subsidize the adoption of behind-the-meter solar generation and accelerate the transition away from conventional energy resources, a transition that if overly incentivized and pursued on too aggressive of a timeline could very well jeopardize grid**

reliability, placing the needs of all customers who rely on electric energy at risk.

We can look to states such as California and Texas for examples. In the middle of America's debate over the energy resources that will power its economy, Georgia has prioritized reliability, affordability, and resource diversity within its long-term, integrated resource planning process and regulated market structure.

In fact, Georgia is the only state in the country offsetting base-load coal with dispatchable natural gas, base-load nuclear, and calculated pragmatic integration of solar resources.

This said, I contend that the Commission has struck the right balance in addressing reliability, affordability, and carbon reduction, thus ensuring that the state of Georgia remains on a pragmatic glide path to a lower carbon future, although not necessarily zero carbon, rather than forcing an abrupt top-down shift on the state's power sector that could compromise energy security and grid reliability.

In closing, my recommendation is that the Commission reject expanding Georgia Power's monthly netting pilot. This will continue the Commission's

pragmatic, measured, and strategic approach to the integration of solar resources.

It will avoid shifting cost to ratepayers who do not participate in rooftop solar. And it will allow the financial impacts of the Inflation Reduction Act to unfold over the next ten years without additional ratepayer subsidies.

That ends my summation. Thank you.

MR. HEWITSON: Dr. Gattie is available for questions from the Commission as well as cross-examination.

MADAM CHAIR PRIDEMORE: Questions from commissioners?

COMMISSIONER SHAW: I do.

MADAM CHAIR PRIDEMORE: Commissioner Shaw.

COMMISSIONER SHAW: Dr. Gattie, I thank you for being here. I always enjoy your perspective. You're a DGD.

MR. GATTIE: Thank you, Commissioner. I appreciate that. It's easy to say that right now.

COMMISSIONER SHAW: That's right. I am thankful for that.

But, you know, you just mentioned that, you know, in your conclusion and in your final recommendations that you are not in favor of

extending the monthly netting pilot, but you did recommend that the Commission adopt compensation rates for rooftop solar customers that ensure these customers pay their fair share of the company's cost of service while receiving appropriate compensation for the excess energy they provide to the grid.

That really, you know, hits home with me because it follows really the intent of my motion that put us where we are today in having -- still having this conversation about this issue.

MR. GATTIE: Yes, sir.

COMMISSIONER SHAW: Because in my motion, that was what I was trying to get to was, let's set a fair rate. But what I am really missing is suggestions or recommendations on what that cost of service is and what that rate should be.

Do you have any perspective on that?

MR. GATTIE: No, sir. I am only here to recommend to not pursue the monthly net metering.

COMMISSIONER SHAW: Well, I'm --

MR. GATTIE: There is a lot of weeds to go through, Commissioner, to get to that compensation rate that's fair. I think you just heard from Georgia Power what their proposal is. I have read and studied lots of papers and reports on this, and

they are all over the map.

COMMISSIONER SHAW: Well, you can look at what other states have done --

MR. GATTIE: Right.

COMMISSIONER SHAW: -- and that's all over the map, too.

MR. GATTIE: Right. So in that sense, if you talk about fair compensation rate, it is -- it is very subjective at that point. My contention is just simply not to pursue the monthly net metering and not -- not set that rate at the retail rate.

COMMISSIONER SHAW: I understand that. But I'm going to keep asking that question because I still think that we have done this before in Georgia, and we have come up with solutions that everybody else turns around and looks and says: I think they got it right. And we are running out of time, but I am not going to quit.

MR. GATTIE: Yes, sir.

COMMISSIONER SHAW: It's --

MR. GATTIE: Well, that's the dog in you. It is probably not going to quit.

COMMISSIONER SHAW: I am going to move on. I've got one follow-up question. I don't want to get too much in the weeds on the IRA because we have all

read a lot of it and know a lot about it.

But in your opinion, you know, there is a lot of things in that that are not new. There is some things that are new.

But in your opinion, what do you think is the biggest thing that sets that apart from prior tax credits? Mainly I want to ask your perspective on the change in terms of the tax credits available based on the cost per kilowatt, and it is tied to -- it is tied -- what I want to know more about is, it is tied to the -- that meeting of certain labor conditions. What is that?

MR. GATTIE: Right. From what I understand, Commissioner, the objective there is to incentivize American-made products.

COMMISSIONER SHAW: Uh-huh.

MR. GATTIE: If you have kept up with solar panel manufacturing over the past several years, particularly because of rare earths and metals and minerals, the U.S. has not done a good job over the past 15 or 20 years in those markets.

Right now, I think -- I don't have the numbers right off the top of my head, but just to summarize it, China owns that market globally in key rare earths and metals and also the solar PV industry

itself.

So I think President Biden -- and I think it was -- I think it was a well-intended point there -- is to domesticate the production of solar panels and incentivize people to purchase U.S.-made products there.

COMMISSIONER SHAW: So -- I understand that. That -- I get it.

MR. GATTIE: Was that anything new, Commissioner?

COMMISSIONER SHAW: That credit can be as high as -- from what I have read, as high as one-and-a-half cents per kilowatt hour, I guess, if you had the right panels and they were American made. And I love that.

But if we were paying full retail value on a true net metering and then you are getting another 30 percent credit and a one-and-a-half cents per kilowatt hour, that's a pretty good deal, isn't it?

MR. GATTIE: And not to -- not to belabor it, but somebody still has to pay for that.

COMMISSIONER SHAW: That's right.

MR. GATTIE: Here in the state, it's a smaller number of people that have to pay for monthly netting cross-subsidies. It tends to sometimes seem to get

washed away when it is at the federal level because we have so many more people. But -- but the bottom line is somebody has to pay for that.

COMMISSIONER SHAW: That's right. All right. Thank you, Madam Chair.

MADAM CHAIR PRIDEMORE: Commissioner McDonald?

COMMISSIONER MCDONALD: Dr. Gattie, I have not read the Residential Clean Energy Credit Act myself. But you in your statement you say that the -- a PV panel installed at their residence.

Does that mean somewhere on their property, or does that have to be on their house or -- at their residence, what does that mean?

MR. GATTIE: Well, I am leaving it broadly. I won't -- I won't discount someone having a standard panel attached like we would utility scale if they have got the space for it. But for the most part, it is to incentivize rooftop for residential.

Commissioner, did I answer your question?

COMMISSIONER MCDONALD: No.

MR. GATTIE: What -- I am being -- I am being paid by the hour, so let's just -- I don't want to not answer your question.

COMMISSIONER MCDONALD: I am houseless.

MR. GATTIE: Sir?

COMMISSIONER MCDONALD: I am houseless.

MR. GATTIE: Houseless. Oh --

COMMISSIONER MCDONALD: I am not homeless.

MR. GATTIE: Yes, sir. I under- -- yes, sir. I understand.

COMMISSIONER MCDONALD: I am houseless. I live in an RV. If I have an array attached to my RV, is that qualifying me for the 30 percent tax credit?

MR. GATTIE: I -- my -- the prediction out of the White House was that there are going to be 950,000,000 solar panels incentivized by this act. My guess is you can have one of them.

MADAM CHAIR PRIDEMORE: Any other questions from commissioners?

(No response.)

MADAM CHAIR PRIDEMORE: Okay. Before we start cross, I'm going to ask Mr. Dowdy and Ms. Lyndall, take it out in the hallway or stay in here. Okay? Thank you.

All right. Georgia Public Service Commission?

CROSS-EXAMINATION

BY MR. THOMAS:

Q Good afternoon, Dr. Gattie.

A Hey.

Q Preston Thomas on behalf of the PIA staff. In

your testimony, on page 4, starting around line 13, you state that, "Georgia Power's net metering customers are being compensated at approximately the retail rate such that certain fixed costs are not being credited back to such customers."

Are those fixed costs you are talking about like the base cost, ECCR, DSM, NCCR, franchise fee?

A I am referring to customer charges that are fixed in there that they can't bypass.

Q Okay.

A So that's at -- nearly at the retail rate.

Q Okay. And what is the retail rate in cents per kilowatt hour?

A For Georgia Power? I am not sure. I think for the State of Georgia the average is about 12.6, 12.9 cents a kilowatt hour.

Q Okay. So you are saying they are being paid nearly that, but you are not sure exactly what that amount is?

A I am saying that if they are -- if it is under a monthly netting program, they will be compensated at nearly that retail rate.

Q Okay. And you have said in your conversation with commissioners here that you believe that what a fair rate is is subjective.

So do you think that's a policy decision for commissioners?

A I think it is a policy decision for commissioners. And my point about it being subjective is there are probably as many rates set as you can find studies. The part where I settle in without -- without shifting here is that it should not be the retail rate and that it should not be under monthly netting.

Q Okay. But whatever the appropriate rate is, it sounds like you are just saying the commissioners have to weigh policy considerations and make a subjective decision on that?

A I -- this is a policy decision.

Q Okay. And so you have said your only recommendation is that it is not retail rate?

A That is the recommendation of this testimony.

Q Yes. So anything under that would be fair game?

A I am recommending that it not be the monthly netting. That we -- that you not extend the monthly netting program. That's my recommendation.

Q Okay. How do we ensure that there is a fair rate for those customers?

A Again, that's -- I did not do a cost analysis and wasn't going to do a cost analysis. That's a study

beyond what my testimony is about. I am not suggesting a rate.

Q Okay. I have no further questions. Thank you, Dr. Gattie.

MADAM CHAIR PRIDEMORE: Americans for Affordable Clean Energy?

MR. GALLOWAY: No questions.

MADAM CHAIR PRIDEMORE: Georgia Coalition of Local Governments?

CROSS-EXAMINATION

BY MS. BROWN:

Q Good afternoon, Dr. Gattie, Alicia Brown on behalf of the Georgia Coalition of Local Governments.

If we can start on page 5 of your testimony beginning on line 5.

A Okay.

Q Do you --

A Okay. Excuse me.

Q You argue against treating exported solar as providing all of the services like transmission and distribution that are traditionally associated with electric utility service?

A That's right.

Q Does exported solar need transmission services to be used by their customers?

A Yes.

Q So if I have solar on my rooftop, is that electron flowing to the transmission system?

A The person that's exporting solar is still nonetheless using all services on that grid, all infrastructure on that grid.

Q But specifically talking about the exported solar, does that use the transmission system?

A They are utilizing all the services on that grid when they export solar.

Q All right. If we move down to line 20, on the same page, you talk extensively about the Inflation Reduction Act and say that it is sufficient to support the continued growth of distributed solar.

Are these tax credits available to all customers?

A Under certain conditions under the IRA.

Q Let's talk about lower-income customers. If you were a lower-income individual with a lower adjusted gross income, can you take the ITC? Is it refundable?

A Under this plan, the 30 percent tax credit?

Q Under this IRA.

A Yeah, there are certain restrictions on that. I am not going to be able to go into all the details. I know that for the most part what the -- there are some

lower-income issues associated with it.

Q But just a very basic question, is the solar investment tax credit refundable?

A Is it refundable?

Q Yes.

A I am not sure.

Q Okay. And what about customers who participate in third-party ownership, say, under a lease model or a solar energy procurement agreement here in Georgia, in those cases, do they realize the full benefit of the tax credit?

A I am not sure.

Q Not sure.

All right. Let's shift to some other states. On page 16 of your testimony, looking at lines 4 and 5.

A Okay.

Q You invoke the state that everyone talks about in the context of net metering, and you mention California, saying that it has --

A What -- is this page 16?

Q That's what I have written here.

A What line?

Q 4 and 5.

A I don't see the word "California."

Q Oh, my goodness. Did I write the wrong page again? All right.

Do you remember where in your testimony you talked about California?

I am sorry. I am off by a page. It is 15.

A It's page 15?

COMMISSIONER MCDONALD: On line 17 of that page is --

COMMISSIONER JOHNSON: Yes. It's on page 17, lines 5 and 6.

MS. BROWN: I apologize. I can't count.

MADAM CHAIR PRIDEMORE: What about California is my next question?

MS. BROWN: Oh, you'll love this.

A Okay. I am on page 17. I didn't hear that.

MADAM CHAIR PRIDEMORE: I am asking her what her question is about California.

BY MS. BROWN:

Q So you say that, "California's net metering policy has delivered on its climate goals but at the cost of increased electric rates and additional stresses on the state's electric grid"?

A Right.

Q So I just wanted to start with that, that point that you made about the stress on the grid. There has been concerns with blackouts in California.

But is rooftop solar part of their Resource

Adequacy program?

A Their Resource Adequacy program?

Q Yes, sir.

A It is a -- it is an intended part of their policy; their policy objective is to grow solar.

Q But are you familiar with the California Resource Adequacy framework that's meant to keep the lights on?

A No.

Q You are not? Okay.

COMMISSIONER MCDONALD: They don't keep them on all the time either.

BY MS. BROWN:

Q And as far as costs go, are there any reasons besides rooftop solar or net metering that California might have high rates?

A I am sure there are reasons other -- in addition to solar.

Q In your research would you happen to know what any of those are?

A Not specifically.

Q Okay. We will move on then.

You do talk about some other states. In the same section, in the page 17 range, you mentioned specifically Utah, Arizona, and Kentucky as some states that

had net metering and then moved on from it.

Is that familiar?

A Yes.

Q Okay. Let's start by talking about Kentucky.

A Okay.

Q What decision did their Commission recently reach in terms of reviewing the net metering program in that state?

A Well, I think it was in May of 2021 their PSC implemented a reduced rate for net metering customers.

Q Are you aware that there was a decision in September of 2021 as well? There are multiple utilities in Kentucky.

A Yeah, right. There -- right.

Q Okay. And in that decision, you said the rates were reduced.

Are those the export rates, as we think of them in Georgia where it is instantaneously netted, or is that net excess generation after monthly netting?

A I am not sure which category they put it under. There are several interpretations of metering, net metering, monthly net metering. So I am not sure which one theirs is under. I know that they reduced the rate.

MS. BROWN: Madam Chair, can Mr. Seydel approach the witness?

**MADAM CHAIR PRIDEMORE: Yes. Do you have a handout?**

**MS. BROWN: I do.**

**MR. SEYDEL: I do.**

**BY MS. BROWN:**

**Q So in lieu of printing a very long Commission order, I do have a news article addressing the Commission order.**

**Dr. Gattie, can you read the highlighted portion?**

**A "Although the new net metering rates are about 25 percent lower than current retail rates, this reduced value only applies to net exports at the end of each monthly billing cycle. All solar energy produced and consumed on site within a billing period is still fully credited against usage.**

**"The end result is that the changes adopted by the Commission would only reduce the value of a solar PV system by about 5 percent for future net metering -- net metering customers who install enough solar to meet 100 percent of their annual needs. For customers with smaller solar generators, the impact on their savings will be even less."**

**Q So does that sound like Kentucky is just running away from solar?**

A I really -- I would need to look at this. I see the source here is the Mountain Association. So it is -- I am assuming it is a news article.

Q Yes. As I said, the Commission order is quite long, and you wouldn't have had time to read through it. This is a summary.

So subject to check, would you say that the Kentucky Commission is running away from solar?

A Well, I -- that's kind of a hyperbolic term, "running away." So I am not going to agree with that.

MADAM CHAIR PRIDEMORE: I would like to put in the record, too, that the Kentucky Public Service Commission has been a one-person commission during the time of this article and when this was passed.

MS. BROWN: All right. Well, we can talk about some other states. Can Mr. Seydel approach again?

MADAM CHAIR PRIDEMORE: Of course. You may approach, Mr. Seydel.

MS. BROWN: All right. This will be looking at Utah, which I believe has a quorum in their commission.

MADAM CHAIR PRIDEMORE: They do have a quorum, but -- today. I don't know the date of your issue. But today they do.

BY MS. BROWN:

Q All right. So while this is being passed out, just, Dr. Gattie, can you tell me anything about the distributed generation situation in Utah?

A I know that -- I know that recently Utah has been reevaluating their net metering program, too.

Q But do you know what programs are currently available in Utah?

A No. I -- again, the point of this testimony that I have here is that states are reevaluating.

Q That's fair. Now, looking at Utah, have you heard of the Wattsmart Solar and Battery program?

A I have heard of it.

Q Okay. So if I told you that the utility in question there, Rocky Mountain Power, is offering an upfront incentive of $400 per kilowatt for batteries and an ongoing --

A Excuse me. For batteries?

Q For batteries connected to solar. I will get to the rest of my question in just a second.

But if I told you that they are offering these incentives for solar and storage, would you be surprised to hear that?

A I would be indifferent to hearing it.

Q Fair enough. Now, is Georgia Power offering in their testimony any kind of program, any kind of policy to

make solar more workable for the grid or to maintain value for customers?

A My testimony is about monthly net metering in general. I am not in the deep weeds on Georgia Power's particular program.

Q Did you review the company's proposal?

A I did. And I have agreed with their conclusions. I -- the conclusions.

Q Do you think that what they are proposing creates the most value for the system and customers as some of these alternative programs?

A Again, I am recommending only that monthly net metering not be extended.

Q All right. Fair enough.

So you talk about the states that are reevaluating and specifically looking at successor tariffs.

Just for our baselining, can you tell us how many states have chosen to offer net metering at one point or another?

A I don't have that number.

Q Can you give me like rounded to the nearest ten?

A Rounded to the nearest ten, that gives you five numbers to choose from.

Q Right. That's why I was hoping that would be

helpful.

A Okay. I will go with 20.

Q Would you be surprised to know that it was more than 40?

A I would not be surprised nor not surprised.

Q Okay. And then just -- this is the last question. More than 40 states have offered net metering at one point or another. And as time has gone along, there have also been innovations like meter aggregation, community solar, virtual net metering that add on to this same construct.

If it is so bad, why are so many states -- why have so many states pursued it, and why are they continuing to pursue different forms of it?

A You want me to answer the motivations of other states?

Q Have you not -- you have read industry publications.

Can you get some sense of why states make the decisions they make?

A It varies quite a bit. A lot of it is just simply the policy of the individual states. I know here in Georgia, we have pursued solar very pragmatically.

North Carolina has done the same thing. Florida has done the same thing, as far as just solar in

general. When it gets down into incentivizing them, perhaps overly incentivizing them, it is very political.

Q And when you look at 40-plus states, are 40 plus out of the 50 states, all have the same political motivation, or is that a pretty broad cross-section of the country?

A I think every state has its position on how it wants to handle solar, and that's exactly the way it should remain.

Q All right. Thank you, Dr. Gattie, commissioners. No further questions.

MADAM CHAIR PRIDEMORE: Georgia Interfaith Power and Light?

CROSS-EXAMINATION

BY MS. KYSOR:

Q Good afternoon, Dr. Gattie.

A Good afternoon. Good evening -- afternoon.

Q Crossed into evening.

A I don't know what time it is actually. And I don't know -- I don't know your name.

Q My name is Jill Kysor. I am here representing Georgia Interfaith Power and Light. Nice to meet you.

A It is nice to meet you.

Q I am going to ask you some questions about the analysis you did on page 12 of your testimony. It is

basically 12 through 14 where you use the EIA data. So I will just let you get there.

A Oh, on the net metering participation rate?

Q That's right. I am starting at page 12, but just -- my questions are generally about the next three pages.

A Yes.

Q It looks like to develop the chart on page 12 you relied on EIA data from set 861M.

A Right.

Q Does that sound right?

A That's right.

Q And I am curious, why did you choose to rely on 861M rather than 861?

A Well, 861M, as far as I understand it, is what has the net metering statistics, the net metering customers.

Q So then are you aware that 861M is just a sampling of utilities, and set 861 is a census of all utilities that sell electricity to end-use customers --

A Yes, yes.

Q -- rather than a sampling?

A Right.

Q And the 861 data also has net metering information available.

Did you know that?

A Yeah, and I used the most recent one, the one with the most recent data.

Q Okay. I think at this point both 861 and 861M have 2021.

A I think they were just released.

Q Okay. And I mentioned that because would it surprise you to know that under the 861M data that you use, for instance, Georgia only has two reporting utilities for net metering, and under 861 there is 39 Georgia utilities that report?

A Okay. What was -- what was the question then?

Q I am just -- I guess I am asking, do -- would you agree that there might be a significant difference if you looked at the data where all utilities reported versus just a sampling of the utilities?

A No, I am not sure if it would be significant, statistically significant.

Q Okay. Would it surprise you that only two Georgia utilities report on the 861M data versus 39 to the 861 data on net metering?

A Not -- wouldn't surprise me.

Q And in your analysis, how many -- did you look at how many net metering customers Georgia Power reported?

A No.

Q Would it surprise you to know that they didn't

report any net metering customers under the 861M data?

A I would not be surprised -- or I mean, I would be indifferent to hearing it really.

Q Do you have any guesses as to why they didn't report any net metering customers?

A No, no, I don't. The point of the graphs here really was to just give an overview of what it looked like across the country.

Q And on page 14, generally looking at that chart and some of your testimony around it, you note the high penetration levels of net metering for California.

Do you see that?

A Right.

Q You would agree that even if this Commission decided -- made a policy decision to expand monthly net metering, that it certainly would have the authority to change course or reevaluate before they got anywhere near the California penetration; right?

A I am not sure how policy works here, if it can be reversed that quickly.

Q It would probably take a while to get to over 8 percent net metering penetration; right?

A If that's what the Commission wants to target is an 8 percent rate.

Q Well, they can target a rate lower; right?

A They are the Commission.

Q That's all I have, Dr. Gattie. Thanks so much for your time.

A Nice to meet you.

Q Nice to meet you as well.

MADAM CHAIR PRIDEMORE: Thank you, Ms. Kysor. GASEIA?

CROSS-EXAMINATION

BY MR. THOMASSON:

Q Hi, Dr. Gattie, Scott Thomasson for GASEIA. I think your testimony was pretty straightforward. I just want to clarify some of the questions that Commissioner Shaw had for you when he was asking about the production tax credits for American made.

Those are primarily, if not exclusively incentives for utility-scale and wholesale type of resources like utility-scale solar and wind? Is that your understanding?

A According to -- I mean, what I understand about the -- are you talking about the IRA?

Q I am talking about those specific ones that he was asking about with the kW adder for -- I can ask it a different way if you want.

A Well, I am -- I thought he was referring to the Inflation Reduction Act.

Q I am referring to the IRA also.
A Well, that was what I was asking.
Q Okay.
A No, I think it was also for rooftop solar.
Q Okay. Well, we will handle that in our testimony, but I don't believe it was.
A In fact, I think that was much of what President Biden targeted was families. I think he said over 7-1/2 million families would be -- would benefit from this.
Q But, I mean, would you agree that when we talk about rooftop solar -- I brought this up with Witness Legg -- we are primarily talking about the investment tax credit as the federal incentive that the market kind of moves around?
A Okay.
Q Is that --
A Well, I am referring to the --
Q Would you agree with that?
A Well, I am referring to the -- just strictly to the Inflation Reduction Act that I -- talking about the 30 percent tax credit that's in the Inflation Reduction Act.
Q Right. And that 30 percent tax credit is actually an extension of an existing law; is that correct?
A With much more stability now 10 years out.
Q But that law has been around for 17 years,

since 2005?

A Well, the IRA has been around for a couple months.

Q But the incentive that we are talking about for rooftop solar has been around for 17 years?

A And I am not sure if it was 30 percent all that time.

Q Okay. Well, it was in 2005.

A Right.

Q So it is not a first-of-its-kind incentive for --

A At this level, I would say it was a first of its kind, with this level of -- with the objectives that it's -- and so maybe I should rephrase the entire -- the IRA itself is a first of its kind.

Q I would agree with that for sure.

A Yes.

Q But there is a lot of things in the IRA for electric vehicles and all kinds of other things?

A There is a lot things in there.

Q Right. And certainly the scale is first of its kind.

But we are just talking about growth of rooftop and how it affects this net metering question.

A Which is targeted in the IRA.

Q With an existing tool that's been 30 percent most of the time since 2005?

A And has been extended for 10 years.

Q Okay. That's all I have.

MADAM CHAIR PRIDEMORE: GA Solar?

CROSS-EXAMINATION

BY MR. MORELAND:

Q Hey, Dr. Gattie. How are you doing?

A I am good.

Q Good. I was just going to finish -- you know, pick up where he left off on the IRA. On page 22, line 7 through 11 in your testimony, you talk about "The IRA provides historic federal support to the solar industry from tax incentives for both businesses and individuals to direct investments. The significance of the IRA to the solar industry is difficult to overstate. According to a recent study, the IRA will be a massive growth catalyst for the solar industry and will triple solar installations by 2027."

Is the study you are referencing the Wood McKenzie and Solar Energy Industry Association?

A That's the one.

Q September 2022?

A Right.

Q All right. That study includes -- you know, it looks at solar in multiple market segments in addition to

rooftop solar; right?

A Right.

Q So it covers utility scale, community solar, commercial, and residential?

A Rooftop, residential, utility, right.

Q Okay. Is it correct to say that rooftop solar installations will triple by 2027?

A The President in his statement when he announced this IRA said --

Q We are sticking with this particular study that you are referencing here.

MADAM CHAIR PRIDEMORE: Mr. Moreland -- Mr. Hewitson, I got it.

Mr. Moreland, let the witness finish his answer; okay?

MR. MORELAND: Okay.

MADAM CHAIR PRIDEMORE: Thank you.

BY MR. MORELAND:

Q I'm sorry. Go ahead.

A Restate your question if you would. Just re-ask me the question.

Q So I am just sticking with this study here.

A Okay.

Q And I am saying, is it correct to say that rooftop solar installations will triple by 2027?

A Solar installations. Solar installations.

Q That's right. Yeah, in fact, is it true in the study that it projects that residential rooftop solar will grow by just 26 percent when considering the IRA?

A I don't have -- I mean, I listed that there. So I don't know what it says in there.

MR. MORELAND: Permission to approach?

MADAM CHAIR PRIDEMORE: You may approach.

BY MR. MORELAND:

Q All right. Looking at this, on page 11, please.

A Of the report?

Q Yes, sir.

A Okay.

Q On page 11, it is under -- we're on "Market Segment Outlooks," and 3.1 refers to residential PV.

A Uh-huh.

Q And in that third paragraph above the chart, it mentions, "Over the next five years, the recent passage of the IRA has resulted in an increase of their projections to 26 percent."

Do you see that?

A This is residential PV.

Q That's right.

A Yes.

Q Okay. That's not -- that's not the same as tripling; is that right?

A Well, again, my word here is "triple the solar industry." I didn't say strictly residential.

Q Right. Okay. Fair enough.

If you could --

COMMISSIONER MCDONALD: What -- may I ask a question? What does California, Florida, and Texas have to do with the solar program in Georgia?

MR. MORELAND: That's a great question. I can't answer that.

COMMISSIONER MCDONALD: Well, why do you put it out here for us?

MR. MORELAND: This is the study that Mr. Gattie referred to in his testimony.

COMMISSIONER MCDONALD: Well, with all due respect, though, you know, if we followed California in the solar business and the renewable energy business, we wouldn't have the economic developments in Georgia that we so enjoy, because what -- what these people are looking for is reliability, and they certainly don't have it.

BY MR. MORELAND:

Q All right. Well, I mean, I can cut to the chase. I know it is late. We are all a little tired here.

But is the utility-scale market projected to increase due to the IRA as well?

A I don't know.

Q Okay. If you could --

MR. HEWITSON: While Mr. Moreland is looking for the reference, since the utility-scale market was not within Dr. Gattie's testimony, I would object to any questions about the utility-scale market.

MADAM CHAIR PRIDEMORE: Mr. Moreland, I would recommend that you keep your questions to his prefiled testimony.

BY MR. MORELAND:

Q Does -- does the company stand to benefit from the IRA as well, Dr. Gattie?

A I don't have any insight on the company's financial benefit from the IRA.

Q If the company were to self-build solar facilities or battery facilities --

A I don't have any data, any analysis for that.

Q Would you be surprised to learn in the data request that Georgia Power specifically mentions that they could benefit -- projected benefit up to 33 million?

MR. GATTIE: So to the Commission, I am here to talk about this as a policy issue. I don't have any financial analysis of Georgia Power's position in any

of this. I am only talking about this as a policy issue.

And, Commissioner McDonald, I don't want us to be California either.

BY MR. MORELAND:

Q If you could turn to page 25 of your testimony, line 9, please.

A Yes, sir.

Q You say, "However, I do recommend moving forward, the Commission guard against" --

A Is this line 9?

Q I sure hope so.

A "When adopting such a compensation rate"?

Q I am sorry. One second, please.

A Yes.

Q I must have the wrong line. Sorry.

COMMISSIONER MCDONALD: You have had a week to get all this together, and you have been only crossing in the last two panels. Why can't you have it together? I am tired.

MR. MORELAND: Yes, I know. We are all tired. I mean, I can read the line that is quoted out of his testimony.

COMMISSIONER MCDONALD: What is your question?

MR. MORELAND: The question is -- he recommends

that the Commission guard against enacting any program that over-subsidizes solar customer generators because of the IRA.

MR. GATTIE: In part because of the IRA.

BY MR. MORELAND:

Q And my question is, does that also apply if the company is going to benefit from the IRA as well? Would you also guard against the Commission against enacting any measures that are going to over-subsidize the company?

A I -- I don't even know what over-subsidizing the company means.

Q Well, it is in your testimony.

A That I said over-subsidizing the company?

Q You used the word "over-subsidize."

A The company?

Q Over-subsidize.

A I am at a loss.

MADAM CHAIR PRIDEMORE: Mr. -- Mr. Moreland?

MR. MORELAND: I am finished. Thank you.

MADAM CHAIR PRIDEMORE: Okay. For the record, his testimony does not say over-subsidize the company.

MR. MORELAND: No.

MADAM CHAIR PRIDEMORE: Just over-subsidy.

MR. MORELAND: Thank you.

MADAM CHAIR PRIDEMORE: Okay. Georgia Watch?

(No response.)

MADAM CHAIR PRIDEMORE: Georgia Watch?

(No response.)

MADAM CHAIR PRIDEMORE: MARTA?

MS. STURM: No questions.

MADAM CHAIR PRIDEMORE: Resource Supply Management?

(No response.)

MADAM CHAIR PRIDEMORE: He is gone.

Sierra Club?

MS. ARIZA: No questions.

MADAM CHAIR PRIDEMORE: SACE?

MR. DOWDY: No questions.

MADAM CHAIR PRIDEMORE: U.S. Department of Defense?

(No response.)

MADAM CHAIR PRIDEMORE: She is gone.

Redirect?

MR. HEWITSON: I will ask this for Commissioner McDonald. How about them dogs?

COMMISSIONER MCDONALD: Yes. Yes.

MR. HEWITSON: I have no redirect for Dr. Gattie. We ask that he be excused. All exhibits that we haven't previously moved into evidence in

this hearing, I ask that they be moved into evidence.

MADAM CHAIR PRIDEMORE: So moved. Witness is excused.

MR. GATTIE: Thank you.

MADAM CHAIR PRIDEMORE: Staff, any final housekeeping matters for you? Do you have all your exhibits in?

MR. THOMAS: To the extent that any exhibits have not been entered into the record, we ask that they would be.

MADAM CHAIR PRIDEMORE: So moved. Very good.

We are adjourned.

MR. HEWITSON: One -- one thing that we do have to add is Exhibit 41, I believe, is trade secret. We would like that to be kept trade secret in the record. That was the one that Mr. Marzo handed out and identified.

MADAM CHAIR PRIDEMORE: Please open the record. Exhibit 41 for Georgia Power is trade secret.

MR. HEWITSON: Yes.

MADAM CHAIR PRIDEMORE: Okay. Now we are adjourned.

(Proceedings were adjourned at 4:40 p.m.)

C E R T I F I C A T E

We, Kelley Nadotti, Debbie Eickhoff and Brenda P. Elwell, Certified Court Reporters, do hereby certify that the foregoing transcript is an accurate record to the best of our abilities of the proceedings in the above-entitled matter at the time and place therein set forth.

Kelley Marie Nadotti, RPR
CCR-6256-8388-8026-4192

Debbie A. Eickhoff, RPR
CCR-5090-9084-2699-3664

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