GEORGIA POWER COMPANY
PETTION FOR RULE NISI TO EXAMINE
GEORGIA POWER COMPANY'S REAL TIME PRICING STRUCTURE
DOCKET NO. 11708-U

Data Request No. STF-2-9

Q. **Please provide the specific citations to any Georgia PSC order that authorizes Georgia Power to recover only average fuel costs from RTP sales.**

A. In the testimony of Georgia Power Company witnesses Jonathan Kubler and Michael O'Sheasy filed in support of the Company's application to establish the RTP tariff a description of the tariff design with respect to the payment of fuel costs by RTP customers was provided. On page 28 lines 5-28 of the May 19, 1992 hearing, the transcript reads as follows:

> *Q. IF THE FCR SCHEDULE IS NOT APPLICABLE, HOW IS FUEL COST RECOVERED FOR RTP USERS?*
>
> *A. The hourly price sent to customers on the RTP-X tariff already includes fuel. One of the components of the hourly real-time price is the running cost of the incremental unit (or units) which would supply the next increment of electricity consumption. This running cost (also called "lambda") consists of the fuel cost plus the variable operation and maintenance cost of this incremental unit.*
>
> *Q. HOW CAN YOU BE SURE THAT THE FUEL COST PAID BY NON-RTP USERS IS NOT AFFECTED BY THE EXISTENCE OF THE RTP TARIFF?*
>
> *A. At the end of each billing period, each RTP customer's energy consumption for that month is multiplied by the current FCR amount, and this amount is backed out of the total bill and assigned to fuel cost, just as with any other tariff. The remaining revenue is treated as "base rate" revenue. This insures that RTP users pay exactly the same fuel cost recovery rate as any other ratepayer.*

In its June 19, 1992 Order approving the RTP-X tariff, the Commission stated that "the RTP tariff rate design is appropriate . . ." The Order goes on to approve the RTP-X tariff as filed.

EXHIBIT
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GIPL-SF
3

In Georgia Power's November 10, 1993 application to establish the RTP tariff as a permanent rate, the design of the relationship between RTP and the fuel clause was again mentioned. In the prefiled testimony of Jon Kubler and Michael O'Sheasy on page 18 lines 1-15, the witnesses stated:

> *Q. IS THE FUEL COST RECOVERY (FCR) SCHEDULE APPLICABLE TO THE RTP TARIFF?*
>
> *A. Yes, the FCR schedule applies to the Standard Bill portion of the tariff. Since the RTP prices already contain fuel, no additional fuel charge is added to the RTP prices.*
>
> *Q. HOW CAN YOU BE SURE THAT THE FUEL COST PAID BY NON-RTP USERS IS NOT AFFECTED BY THE EXISTENCE OF THE RTP TARIFF?*
>
> *A. At the end of each billing period, each RTP customer's energy consumption for that month is multiplied by the current FCR amount, and this amount is backed out of the total bill and assigned to fuel cost, just as with any other tariff. This insures that RTP users pay exactly the same fuel cost recovery rate as any other ratepayer.*

Following a March 1, 1994 approval of the tariff, the Commission in its Order dated July 8, 1994 stated, "The Commission finds that the RTP tariff rate design is appropriate . . ."

Finally, in a non-docket matter, the Commission issued an order responding to a complaint raised by the Georgia Electric Membership Corporation regarding several issues related to RTP. In the Order dated September 22, 1995 and attached as Attachment STF 2-9-A, the Commission directed Georgia Power to refile the RTP tariff including specific language describing how fuel cost recovery charges are applied to the energy sold under the RTP tariff. The revised tariff containing the ordered language was filed on October 31, 1995. That tariff is attached as Attachment STF-2-9-B. On December 21, 1995 a letter was sent to the Company from the Director of the Rates and Tariffs Section of the Public Service Commission affirming that the filed tariff conformed to the directives in the Commission's Order. That correspondence is attached as Attachment STF-2-9-C.

Georgia Power Company
Docket No. 56765
Fuel Cost Recovery (FCR-27) Application
STF-PIA Data Request Set No. 3

STF-PIA-3-5

Question:

If you answered "yes," to the question, "Do RTP customers pay the cost of natural gas transportation," is that revenue credited to the fuel balance (to be recovered from customers through the FCR tariff)?

a. Please provide values for the credits on a monthly basis (or however else maintained by the Company) for 2022 through 2025.

b. Which segment of the RTP Pricing structure is designed to recover for natural gas transportation costs?

Response:

a. For load priced at real time pricing ("RTP"), the RTP revenue is designed to contribute towards fixed costs including firm transportation ("FT"), but revenue beyond the average hourly marginal fuel cost ("RTP Fuel Rate") is not credited to the fuel balance. Please see MFRH-1 Attachment C in the Company's initial filing for the monthly RTP fuel credit revenues from January 2023 through December 2025. Please see STF-PIA-3-5 Attachment for the monthly RTP fuel credit revenues for 2022.

b. The delta between lambda and RTP Fuel Rate is designed to contribute towards natural gas transportation costs.

Contact: Kyung Kim

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4

Excerpted Pages

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

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In the Matter of: :

GEORGIA POWER COMPANY'S : Docket No. 36989

2013 Rate Case :

- - - - - - - - - - - - - - - - - - -

Hearing Room
Georgia Public Service Commission
244 Washington Street
Atlanta, Georgia

Thursday, October 3, 2013

The above-entitled matter came on for hearing pursuant to adjournment at 10:00 a.m.

BEFORE:

CHUCK EATON, Chairman
DOUG EVERETT, Vice Chairman
TIM G. ECHOLS, Commissioner
STAN WISE, Commissioner
LAUREN McDONALD, Commissioner

Brandenburg & Hasty
435 Cheek Road
Monroe, Georgia 30655

EXHIBIT
GIPL-SF-8

3802

CHAIRMAN EATON: What was the primary purpose of the smart meters or a couple of primary drivers behind the smart meters?

THE WITNESS: Well, Chairman, the main reason we put them out there was that -- the business case was built on reducing our costs. So we put them out there to be able to reduce the number of meter readers and the amount of miles we had on the trucks and all those types of things. So the business case was actually built on just simply reducing our costs.

CHAIRMAN EATON: Any questions from the Commissioners?

(No response.)

CHAIRMAN EATON: All right. Georgia Public Service Commission.

CROSS EXAMINATION

BY MS. COHEN:

Q Good afternoon, Mr. Roberts.

A Yeah, hello.

Q It is actually afternoon.

A Yes, it is.

Q Okay. I'm going to start where I left off with Mr. O'Sheasy this morning. So I want to start with the company's RTP, day ahead and hour ahead.

A Uh-huh.

Q For new customers, as well as for existing RTP customers with new load, am I correct that an industrial customer's CBL could be as low as 60 percent of its total load?

A Yes, that's correct. If you look at the tariff, it says that a new industrial customer could have their CBL set at 60 percent; that's correct.

Q Okay. So that for these industrial customers, it would only reflect 60 percent of their expected load for each and every hour; correct?

A Well, no, not --

Q CBL.

A CBL, that's right.

Q Therefore, 40 percent of the expected load is not reflected in the class cost of service study; right?

A No, I don't think that's right. I think Mr. O'Sheasy would have to answer that. But he does take into account the marginal load in his cost of service study.

Q Okay. So do you think it would be fair to say that the allocation factors understate the actual peak loads for RTP customers?

A No, I don't think so. Again, Mr. O'Sheasy would have to answer allocation factors on cost of service study. But no, I don't think so.

Q Okay. And -- okay. But for these new CBLs -- for these new industrial customers that are only paying 60 percent of their total load, these customers are only paying generation and transmission costs on that 60 percent of their expected load; is that right?

A No, that's not right. They're paying the embedded generation and transmission costs on the CBL portion of their load. But they're paying the marginal transmission and generation costs on their marginal or on RTP piece of their load.

Q Can you explain to me the difference -- you're talking about embedded and marginal.

A Certainly. So if you have a system that you've built or you're getting ready to build over the next year and it's composed of generating plants and the transmission lines and all the rest of it, that's your embedded system. Now, if a new RTP customer comes along, he's going to pay part of that. But he's also going to say, we're going to allow him to expand his load at a marginal price, in that we'll only charge him for the cost he's causing to expand that system. So if he's causing us to have to expand that system, that's what we call the marginal cost. And that cost is the incremental cost of the fuel, as Mr. O'Sheasy said, LAMBDA. And it's also the incremental cost of generation and transmission that that customer is making us add to that current embedded system.

Q Okay. So they're only paying 60 percent of those original generation costs. The original plant costs and elements like that.

A That's right. Because they're on a tariff that's a marginal tariff. And they're going to pay the marginal cost every hour of the day so they're going to be exposed to those marginal price signals. So in times when our generation is short or our transmission is getting more constrained, they're going to pay very high prices during those times. But at other times, they're not causing us to expand our system, so we don't charge them for those costs. So they're paying the costs that they are causing on a marginal basis.

Q Okay. I'm going to hand you back what I'd given Mr. O'Sheasy earlier. That's exhibits 20 -- Staff Exhibits 20, 21 and 22.

MS. COHEN: Oh, may we approach? Can we approach, Commissioner Everett.

VICE CHAIRMAN EVERETT: He can approach.

MS. COHEN: You also have those?

COMMISSIONER ECHOLS: Can you just tell what the exhibit is again, these aren't numbered.

MS. COHEN: 20, which is Staff Data Request TAI-1-11. 21, which is response to Staff TAI2-21. And 22, which is the economic study.

BY MS. COHEN:

Q If you would look at STF-TAI-1-11, this is Staff Exhibit Number 20. I asked some of these questions to Mr. O'Sheasy. But this is a document -- it is a trade secret document and it shows the company's forecast or estimate of the annual RTP reliability capacity cost per kilowatt, for the period of 2013 through 2016. Is that correct?

A Correct.

Q Okay. And under -- you see the numbers there, under -- next to 213 -- 2013, 2014, 2015 and 2016; correct?

A Correct.

Q Okay. Now if you look at the second exhibit, 21, which STF-TAI-2-21. That document is from the 2010 case, Docket 31958. And it also indicates that it shows capacity, projected capacity costs for the year 2012 through 2015. Well, it actually has -- starting from 2001. Is that correct?

A Yeah. It's got historical, '01, through 10. And think, the bottom, '11 through '15 are projected.

Q Correct. Okay. Now the numbers for the reliability capacity cost forecast for 2013, 2014, and 2015, in the 2010 document, those were considerably higher than the numbers currently forecast for the same years; is that correct?

A Yes, that's right.

Q Okay. Can you explain the reason for these dramatic differences?

A Yes, I can. These numbers, in both cases, are our forecasts of market capacity. And so that's what our marginal customers, the RTP on their RTP portion of their bill, they pay marginal generation capacity costs. And that's what these are. So in the short term, the marginal capacity cost, the marginal generation capacity cost is the market price of capacity in the market. In the long term, it's equal to what a combustion turbine would be.

And so, in 2010, we had expectations that our -- as we've heard from numerous witnesses before me, we had expectations that our load was going to grow a lot more than it has. So the market price of capacity would have been worth a lot more in 2010 based on our load projections and where the overall southeast market would be in relations to market capacity.

Obviously, now, in 2013, we find ourselves in a much different market. The load hasn't showed up so the price for capacity in the market right now is very low because all utilities, including Georgia Power, are long and well above their reserve margins. So it's no surprise that the numbers in 2013 are much less than the numbers in 2010.

Q Okay. If you look at -- can you look at page 30, on -- in the economic study document, Exhibit 22.

A Sure.
Q Are you aware that this document was submitted to staff in the IRP this summer, the 2013 IRP?
A I am.
Q Now if you look under -- next to letter, P, capacity costs.
A The letter P, capacity costs. Okay, right.
Q Let's see, does this document show the avoided or marginal cost of capacity, in terms of dollars per kilowatt year?
A No. What it really shows is the cost of avoiding paying for a CT in any one year. So it's what I explained a minute ago. If you were in equilibrium, if you needed to add capacity and you needed to add a CT, this would be the yearly cost of it.
Q Okay. So by not having to add the CT, that's the amount -- in the highlighted grey area, that would be the amount per year, per kilowatt year?
A That's right.
Q Okay.
A Or if you had to add one. What this document is for -- I think we need to keep in mind -- and I'd also like to say, I was not a witness in the IRP. I am familiar with the IRP and I've seen this document but I'm not the expert in the IRP. But what this document is for, is to do a

reserve margin study and to figure out our optimal reserve margin. And if you go to the very back of the document, the very last page or so, it lays out -- there's really three components to figuring out what the marginal -- or what the ideal reserve margin of a system ought to be. And that's made up of either building your own generation, which that's what the cost you just showed me is, is a CT. So it's either building your own generation, it's buying that generation on the market or interrupting your customers. What the customer cost is of lower reliability. So there's a chart on page 54, which shows those three components.

And so if you had to build a system, what it's showing is the optimal mix of building -- which is the amount you showed me a minute ago versus buying versus interrupting customers. You want to minimize those costs. And you can see that cost is minimized somewhere around 15 percent. So what this is showing, is a planning document to figure out how do we get to that optimal system reserve margin. That's what this document is.

Q Right. And can you explain then, why that number on page 30, is so different from the numbers on the other two exhibits? Well, on Exhibit 20?

A Sure. Because if we were actually at that 15 percent margin, that would be the cost that would go -- these costs you showed me in these trade secrete documents, that would be the cost that would go into the reliability capacity component. But we're not at our optimal reserve margin, that 15 percent number, we are well below it. So that market capacity cost is much, much lower. We only charge our RTP customers that market capacity cost every year. And some years it could be lower, like now, when we are really long on our reserve margins. And sometimes it could be a lot higher if we got short on our reserve margins. So the, the amount that's in here, is what the market price of capacity is every year. That's what goes into the reliability capacity component. And it can vary from the actual number that you're at when you're at your optimal reserve margin mix, which is 15 percent.

Q Okay. So the number in the study, that's the optimal amount. That's not what if would be if you were at the optimal --

A That's if you were at equilibrium, right. So if we were at our target reserve market of 15 percent, that would be the number that would go into that capacity component. Well, we're not at that number. We are well below it. And you know, our reserve margins are much longer.

Q Right.

A So the, the resulting market capacity cost is much less.

Q Okay. You may have just answered this but when Georgia Power conducted its revenue forecast for 2014, 2015, and '16, are the revenues associated with reliability capacity charges the ones shown on Exhibit 20, that's Staff TAI-1-11?

A That's right. We forecast what's going to go into that component. And it would those numbers. That's right.

Q Okay. Thank you.

A That's right.

Q Am I correct, that for the last several rate cases, Georgia Power has proposed an approximately equal percentage increases to all retail rate classes?

A I believe that's the case. In the last several, at least since 2007, I think that's what we proposed coming into the case.

Q Okay. And over the period of the last several rate cases, had you observed any general movement towards or away from parity for rate classes?

A Yeah, we have. If you look at parity in this rate case, for the forecasted period versus that same period from the 2010 case, we've actually made a pretty good move towards parity in all the rate groups. And so, if you'll remember, we purposely did that in the last case we settled. According to witness Watkins' testimony, to move our rate groups closer to parity. So the parity of the domestic group actually came up a pretty good bit. And the parity of the small, medium and large business came down a decent amount. And the agricultural group came up. So all those groups really moved towards that parity number, pretty significantly in the last case.

Q Okay. And would it be fair to characterize the RTP rates as a promotional device used to attract new, large customers?

A It certainly has been used for that. Absolutely.

Q Okay. And am I also correct, that large new customers had a one time ability to choose electricity suppliers?

A They do.

Q Now with respect to the main residential rate, the rate schedule are -- I believe, Mr. Ebersbach was asking Mr. O'Sheasy some questions like this -- about this. Those charges are seasonally differentiated; is that right?

A That's right.

Q And the company considers the winter months to be October through May?

A Yep. That's right.

Q And during the winter period, the energy charge is a three tier, declining block rate structure?

A That's correct.

Q Right. So the more energy a customer uses, the lower the marginal and average price per kilowatt hour?

A That's right.

Q Okay. And in the summer, it's the opposite. It's three tier, inverted block rate structure?

A Correct.

Q Can you explain how Georgia Power determined that summer usage blocking, in terms of kilowatt hours, was appropriate?

A Sure. I think that that three tier rate came into effect -- I think it's been in the early '90s, maybe late '80s. And so what it was explicitly designed for, was in the summertime, as customers use more, our costs are more and so those customers ought to then pay more to cover those costs in the summer, as they add more air conditioning load because our costs are higher in the summer.

In the winter, just the opposite is true. Our costs are lower and so we actually have those three tiered declining blocks, in the winter, to actually encourage customers to use our product in the wintertime. And this is good for all customers because, as you said a minute ago, our marginal cost during those times, in the off summer months, are low. And so, we're recovering well above our marginal costs in the wintertime. And that contributes a lot of kilowatt hours and revenue much above cost in those hours, to help drive down cost for all customers.

So it's good for the customers that use more load in the wintertime. It balances out our system and it's good for all other customers because when those customers add load in the winter, they're adding it at a rate that is more than covering their marginal cost.

Q Okay. Thank you. And can you explain on how the company originally decided on the relative differences in the prices between the blocks in the summer?

A I don't know that exactly. I think -- I know what we've done, is looked in recent histories to look to see, did those blocks at least cover their marginal costs during that time. So as a customer uses over 1000 kilowatt hours in the summertime, are we at least covering our marginal cost during that time. And the same thing we've done in off peak, in the wintertime, is to make sure at least they're covering their marginal cost. And then of course, the total rate gets our total embedded cost.

Q Okay. Moving into a different area, actually the one that Commissioner Everett and Echols and Eaton asked you a little bit about, the smart meters.

A Sure.

Q This is the first time you are proposing to allow customers to opt out of the use of the smart meter; is that right?

A It is.

(Laughter.)

MR. JONES: I would point out that I'm wearing a white shirt, but --

COMMISSIONER McDONALD: I saw those in the window at some shopping mall. I think they were about $95 apiece.

(Laughter.)

COMMISSIONER McDONALD: You lawyers do pretty good, don't you?

MR. JONES: Well, Mr. Marzo not only outdresses me, he probably outdoes me in a lot of other ways, too.

FURTHER CROSS EXAMINATION

BY MR. JONES:

Q Mr. Roberts, just following up real quick on the questions that Mr. Jenkins was just asking.

A Yes.

Q If I could get you to -- could you expand a little bit on what -- just your experience in dealing with customers, both commercial and industrial customers, in terms of the -- what you were talking about, where they locate their investment. What are the differences that you've seen over time with those two customers, in terms of the competitive pressures they face and how energy rates might affect where they locate production?

A Sure. I mean, if you talk to almost any industrial customer, they are -- and these days especially -

cost would be getting borne by the shareholders. And then say in the next rate case, if we didn't address it, then that cost, to the extent we could project it, would be borne by all other customers. So we want to be able to have a way to deal with that.

Q Okay. And the Commission is certainly available as a forum to the company --

A They are.

Q -- to seek redress in that regard.

A They are.

Q All right. Thank you. I think that gets us where we need to be on that.

Just in general, I wanted to go back and ask, there's been a lot of questions about RTP, and you've had a lot of experience with that rate; haven't you?

A I have.

Q And can you just tell us, when did the Commission first approve the RTP rate for Georgia Power?

A I think back in 1993 or so, and it became a permanent tariff in '95, I believe.

Q Okay. And how would you, as the director of rates for Georgia Power Company, how would you describe the rationale for the usage of RTP? Why is it a rate that you think is appropriate?

A Well, I think it's very appropriate for a lot of reasons. Number one is that if we allowed our largest customers to -- they used to be on a program where if we had a need, we would call them to shut down. And so they came to us and said, look, we're on this tariff where we've got to reduce our usage to a certain base amount every day. We also know that your marginal cost is different from that, just let us buy through. So if it's too high, we won't buy. If it's low, we'll produce more and that's good for everybody.

And so it started in that way. And the great thing about that is, we know how customers will respond as the prices get higher, and that amount of generation that they come off of, their load that they reduce, that's generation that we don't have to build. And it's actually included in our IRP, and it's a fairly -- it's a very substantial number. So all customers are benefiting from these industrial customers' ability to respond to high price signals.

In addition, it's been an excellent tool for us to bring new load into the state and let them come onto our system and pay those marginal costs that they're imposing on the system. And to the extent they pay a little bit above those marginal costs, fully cover those marginal costs, and then they're making a contribution back to all our other fixed cost, which drives down rates for everybody. So it's been a great tool for our large customers to keep them here and to bring in new customers. And it's been great for all our other non-RTP customers.

MR. JONES: I don't have any further questions. Thank you.

CHAIRMAN EATON: Georgia Industrial Group?

MR. QUINTRELL: No questions, Mr. Chairman.

CHAIRMAN EATON: Okay. We're going to take -- some people are on kind of tight time frames, so we're going to take a five-minute break and try to get back here as soon as possible.

(A short recess was taken.)

CHAIRMAN EATON: All right, everybody, if you'd get your seats, we'll get going.

Are you ready, Mr. Roberts?

THE WITNESS: I am.

CHAIRMAN EATON: All right. Go ahead, Mr. Galloway.

FURTHER CROSS EXAMINATION

BY MR. GALLOWAY:

Q Mr. Roberts, Newton Galloway on behalf --

A Yes.

Q -- of the Georgia Solar Industry Energy Association.

Before I get to the script, I want to follow up on

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 29 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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Q. WHY IS IT APPROPRIATE TO INCREASE THE BASIC SERVICE CHARGE AS PART OF THE COMPANY'S REQUEST?

A. The increased basic service charge better aligns with the Company's costs to serve customers. As stated by Mr. Legg during the Company's direct hearings, Georgia Power has proposed to increase all traditional base rates on an equal percentage basis, including rate elements. This includes the residential basic service charge, which recovers the customer-related costs the Company incurs to serve a customer, regardless of the amount of energy that customer may use. As proposed, the monthly increase to the basic service charge would be approximately $2.27 for a residential customer.

Q. DOES THE COMPANY AGREE WITH STAFF'S PROPOSAL TO INCREASE THE INCOME QUALIFIED SENIOR CITIZEN DISCOUNT BY THE AMOUNT OF ANY INCREASE TO THE BASIC SERVICE CHARGE?

A. Yes.

III. <u>COMMERCIAL RATES</u>

Q. DO YOU AGREE WITH PIA STAFF'S RECOMMENDATION THAT CUSTOMERS ON MARGINAL RATES SHOULD BE ASSESSED THE FULL EMBEDDED COST OF THE ENVIRONMENTAL COMPLIANCE COST RECOVERY ("ECCR") TARIFF?

A. No. Staff's recommendation is fundamentally inconsistent with how marginal rates like RTP are designed to operate. For RTP as designed, the Company's fully embedded costs are recovered from the CBL portion of the rate, while marginal costs are recovered from the marginal portion of the rate. The ECCR costs include coal combustion residual asset retirement obligations ("CCR ARO") that are fully embedded costs incurred by the Company independent of a customer's kWh usage. As such, they are appropriately recovered through the CBL portion of marginally priced rates. To include fully embedded costs such as ECCR in the marginal portion of the RTP rate would not only undermine the rate structure, but also prevent these rates from actually functioning as marginal rates. The hourly prices would no longer reflect marginal costs or real-time prices.

Q. WHAT WOULD HAPPEN IF ECCR COSTS WERE ALLOCATED TO THE MARGINAL PORTION OF RTP AND OTHER INCREMENTAL RATES?

A. If ECCR costs, or other fully embedded costs, were allocated to the marginal portion of RTP rates, RTP costs would increase by approximately $150 million overall. A cost shift of this magnitude would significantly decrease the appeal of the rate to current and future customers. The RTP rate is a critical rate for large, economic development customers that are considering locating, relocating, or expanding operations in Georgia. PIA Staff's proposal undermines the principles of marginal rate design by dramatically altering the allocation of ECCR costs within the RTP rate and would have a significant negative impact on the Company's ability to help attract economic development opportunities to the state.

Q. DOES PIA STAFF'S PROPOSED 50% MOVEMENT OF ECCR IN INCREMENTAL RATES MITIGATE THE IMPACT OF STAFF'S RECOMMENDATION?

A. No. As described above, even an incremental move of 50% would have a dramatic and negative impact on RTP customers by fundamentally changing the rate and undermining the core principles of a marginal rate structure.

Q. DOES GEORGIA POWER AGREE WITH DEPARTMENT OF DEFENSE WITNESS BLANK'S RECOMMENDATION TO MODIFY THE CBL REDUCTION CRITERIA?

A. No. CBLs may be reduced when load originally represented in the CBL has been permanently removed. Mr. Blank proposes to reduce CBLs when customers install generation that runs "at least 6,000 hours" (68%) of the year, even though no load has been removed. For almost one third of the year, the customer's usage on the system would be the same as it was before the installation of the generation. Generation does not

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Ex. 10
05-06-26

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re: Petition for Rule NISI to Examine Georgia Power Company's Real Time Pricing Structure

Docket No. 11708-U

Testimony of Ron Hinson, Jonathan M. Kubler and Michael T. O'Sheasy on behalf of Georgia Power Company

REDACTED COPY
PUBLIC DISCLOSURE VERSION

March 17, 2000

Direct Testimony of Ron Hinson, Jonathan M. Kubler and Michael T. O'Sheasy on Behalf of Georgia Power Company

Q. PLEASE STATE YOUR NAMES, TITLES AND BUSINESS ADDRESSES.

A. Ron Hinson, Assistant Comptroller, Georgia Power Company, 241 Ralph McGill Boulevard, Atlanta, Georgia 30308; Jonathan M. Kubler, Manager, Pricing and Rates, Georgia Power Company, 241 Ralph McGill Boulevard, Atlanta, Georgia 30308; and Michael T. O'Sheasy, Manager of Rate Research and Design, Georgia Power Company, 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

Q. MR. HINSON, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I hold an Associate of Science degree from Young Harris College, a Bachelor of Business Administration degree from the University of Georgia and a Masters of Business Administration degree from Mercer University. I am a Certified Public Accountant and a Certified Management Accountant. I began my employment with Georgia Power in 1979. I have held a number of positions in the Company's Accounting Department, including Financial Reporting Manager and Regulatory Accounting Manager, before being named Assistant Comptroller in 1995.

As Assistant Comptroller, I am responsible for the financial and regulatory accounting functions of the Company. My duties include maintaining the corporate accounting records in accordance with generally accepted accounting principles and various regulatory requirements; preparing and filing financial reports and preparing regulatory filings, including rate cases. I have previously testified before this Commission in the 1998 retail rate case and fuel cost recovery matters.

Q. MR. KUBLER, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology and a Master's degree in Business Administration from Georgia State University. I am a Registered Professional Engineer in the State of Georgia. During my 38 years with Georgia Power Company, I have held the positions of Industrial Marketing Supervisor, Manager of Information Technologies, Assistant Plant Manager, and Manager of Commercial Marketing.

I was named Manager, Pricing and Rates in 1990. My responsibilities include managing the pricing and rates research activities of the Company and administering the Company's rates, rules and regulations. I direct my Department's efforts toward the development and implementation of new rates, as appropriate that meet the needs of our customers and the Company. Additionally, existing rates require continuous review and monitoring to ensure that the present applicability, structure and format are effective.

Q. MR. O'SHEASY, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

I received a Bachelor of Industrial Engineering from the Georgia Institute of Technology in 1970. In 1974, I earned a Master's in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company – Division of the Carnation Company – as a plant superintendent in their Chamblee, Georgia location. From 1975 to 1980, I worked for the John Harland Corporation initially as an assistant plant manager and then as a plant manager in their Jacksonville, Florida plant and finally as their plant manager in Miami, Florida. I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions in the Marketing and Regulatory Support Department, specializing in allocated cost of service studies. I became supervisor of the section and testified as a cost of service witness. In 1991, I joined Georgia Power Company in the position of Manager, Rate Research and Design.

My responsibilities encompass managing the rates research and design function. These activities include pricing strategy development and future rate planning; rate research, design and evaluation; and the preparation and filing of retail rates with the Georgia Public Service Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to address the questions which have been raised by the Georgia Textile Manufacturing Association (GTMA) and the Georgia Industrial Group (GIG) regarding the Company's Real Time Pricing Day-Ahead and Hour-Ahead Tariffs (RTP-DA and RTP-HA, respectively).

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. With regard to each of the four proposals made by GTMA and GIG, we respond as follows:

1. GTMA and GIG argue that the risk adder (of 5 mills for RTP-DA and 4.5 mills for RTP-HA) be reduced. This is the same position they took in the last rate case which concluded less than 15 months ago and is the position which was rejected by the Commission in the Accounting Order. Plainly, the current GTMA and GIG position in this case is simply an attempt to relitigate the issue after the Commission has decided it. As importantly, the GTMA/GIG position has no merit. The adder remains an important component of revenues for the Company, which if it is not collected from RTP customers, would be collected from other customers.

2. GTMA and GIG argue that either (a) purchased power costs should not be included in RTP, or (b) the "lambda" which helps determine the RTP price should be averaged. Again, this position has no merit. While it is true that the 1998

Accounting Order left open the possibility that the Commission would examine the possibility of using a lambda based on an average of purchased power costs, that is not what GTMA and GIG seek here. They seek to exclude all purchase power costs, or average all lambda, including Company owned generation. Plainly, the Commission's Accounting Order correctly recognized that purchased power was part of the lambda that set the RTP price. Thus, the GIG / GTMA assertion that RTP was never intended to include purchases is without merit. And, the Commission's willingness to look at a lambda set by averaging purchases can not support the current attempt to average all generation and purchases. In fact, GIG and GTMA each rejected a proposal to average purchases after the Accounting Order went into effect. The rates which were set by this Commission to put the Accounting Order's rate reductions into effect were based upon the fact that GTMA and GIG had rejected purchased power averaging.

3. GTMA and GIG argue that the Commission should modify the fuel accounting to provide that the fuel account is charged with hour by hour costs and credited with hour by hour revenues, including virtually all RTP revenues when RTP prices are based on energy purchases. This is without merit. First, such a change in accounting practice would have no effect on the RTP price, which is the focus of this complaint. Second, it would be unlawful because it would allow recovery into the FCR dollars which are not for fuel or purchases. Third, it would distort and radically change the "average fuel cost" method that this Commission has used for years to set the FCR. Finally, it would merely shift base cost dollars that should be going to pay for power plants and to offset higher rates for commercial and residential customers, and it would lower fuel costs. But the lost base rate dollars would need to be made up in increased base rates of those same customers who now had lower FCR charges. The shell game would have no lasting effect on the cost of power, not even to GIG or GTMA members.

4. Finally, GTMA and GIG ask that the Company's power procurement practices be reviewed. On this point the Company merely shows that the Commission and its Staff have always had the responsibility to review the prudence of the Company's activities, including its fuel and power procurement practices. The Company has always been committed to working with the Commission and its Staff in this regard, and it did not take the filing of the GTMA/GIG petition to accomplish that.

For all of the reason set forth in our testimony, the Petition should be denied.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. We will present an overview of the RTP tariffs describing how they are composed and presenting a brief history of the tariffs. Then we will discuss the intent of the RTP tariffs including how the prices are affected by purchases and the response of customers to RTP prices. We will provide a discussion of the regulatory treatment of the RTP tariffs including how they impact the revenue requirements of the Company, how they were dealt with in the Company's last rate case, and how fuel cost recovery is handled in the tariff. We will also discuss how RTP covers marginal costs and what would happen if purchased power costs were removed from RTP. We then will discuss whether RTP is appropriately structured for the future. We will discuss the competitiveness of RTP and industrial rates in general. We will also present alternatives to RTP that the Company has developed to meet the ongoing needs of our customers. Finally, we will address some of the most egregious errors and misunderstandings in the testimony submitted by Mr. Pollock.

<u>RTP OVERVIEW</u>

Q. PLEASE DESCRIBE BRIEFLY THE REAL TIME PRICING TARIFF (RTP).

A. RTP is an innovative and powerful tariff that blends embedded cost rates with a marginal cost rate. There is a customer baseline load (CBL) which represents a customer's historical hourly loadshape to which standard embedded rates such as Power and Light-Large (PLL) apply. Embedded rates collect variable and fixed cost incurred by Georgia Power Company (GPC). Marginal costs represent only those hourly costs that will change with relatively small changes in output. Therefore, the theory of the RTP tariff is that embedded cost (both fixed and variable) were incurred to serve a customer's historical load such that embedded rates should apply here while changes to this hourly historical loadshape can be priced at the hourly marginal costs which they cause. Therefore, there are two parts to an RTP customer's bill: (1) a "standard bill" which reflects a standard, embedded rate applied to his CBL; and (2) an incremental RTP portion which represents hourly changes from the customer's CBL priced at hourly marginal cost called the RTP price.

The hourly RTP price has 5 components to it:

1. <u>Lambda which is the marginal cost of the last resource used to serve the last increment of load.</u> The IEEE Standard Dictionary of Electrical Terms defines lambda to be "the additional cost of delivering another one MW of power to the load center". This marginal cost component could be from the last generating unit dispatched to serve retail load in this hour or it could be a purchase from another supplier. [Purchases are employed whenever a purchase is cheaper than dispatching an owned unit or if all available owned units are already dispatched and purchases are therefore necessary to serve additional load. We have historically purchased at any price in order to avoid customer interruptions; it is only when <u>all</u> possible purchases have been made that we have asked our interruptible customers (IS) to interrupt]. Lambda is the largest component in the RTP prices amounting to 75-80% of the average annual RTP price and is found in the price every hour of the year.

2. <u>Losses which represent physical electrical losses in transmitting and distributing electricity.</u> This is a small component amounting to 3-5% of the average RTP price and is found in each hourly price.

3. Risk adder of 5 mills/kWh for Day-Ahead RTP and 4.5 mills/kWh for Hour-Ahead RTP. This component is found in each hourly price and serves to cover GPC's forecasting risk (RTP prices are based on a forecast of marginal cost and are not trued-up) and provide a contribution to other fixed costs above marginal cost. It also accommodates other marginal cost considerations not in that tariff including unit commitment costs and Clean Air Compliance (SO_2) costs.

4. Marginal cost of transmission covers any marginal cost that may occur during critical hours. This component only arises in 200-300 hours per year (2.2 to 3.4 % of the total hours) and only amounts to 1-2% of the average annual RTP price.

5. Outage/reliability capacity cost which reflects the cost of the cheapest generation resource, a combustion turbine. This component is driven by the probability that the reliability of the system is in danger. It normally only occurs 50-100 hours (.6 to 1.1% of the total hours)and has been only 1% of the annual RTP price.

Q. IS THERE MORE THAN ONE RTP TARIFF AT GPC?

A. Yes, there is a day-ahead version (RTP-DA) and an hour-ahead version (RTP-HA). Both versions have the same components and structure, they simply are forecasted either a day ahead or an hour ahead. There are 1,526 customers on RTP-DA and 34 customers on RTP-HA.

Q. WHEN WAS THE TARIFF APPROVED?

A. There was a very successful pilot conducted in 1992-1993. The two tariffs were approved as permanent tariffs in 1994, with a couple of approved modifications authorized later.

Q. WHAT ARE THE MAJOR FACTORS WHICH INFLUENCE OVERALL RTP PRICES?

A. There are 6 primary factors which influence RTP: state of the economy, weather, fuel prices, wholesale markets, tie line availability, and unit availability. The weather and wholesale markets have the greatest effect of the six.

Q. CAN YOU PROVIDE US A HISTORY OF THE RTP-DA PRICES?

A. Please see Exhibit ___(HKO-1).

Q. IS RTP A COMMON TARIFF IN THE UTILITY INDUSTRY?

A. Yes. There are a lot of utilities that offer RTP, none however nearly as successful as GPC. In fact you could add up all the customers participating in RTP programs throughout the United States and the total would not equal that of GPC. Please see response to STF-2-17.

RTP TARIFF INTENT

Q. WHAT IS THE PHILOSOPHY AND INTENT OF RTP?

A. RTP is an important tariff in any progressive utility's pricing portfolio because it gives flexible customers an option to take on risk in order to obtain potential cost savings (see Exhibits___(HKO-2) and (HKO-3)).

Simply put, it is to provide an hourly price that reflects our expectations of the marginal cost of electricity. In most of the hours, these prices will be low although some hours can reach very high levels. Since electricity cannot be stored to any large degree, when the capability of the system to supply the customers' demand is constrained, risk is created and prices can reach high levels. Those customers who then have a high value of electricity can choose to buy. Those whose value of electricity is less than the RTP price can elect to reduce consumption. In fact if the RTP customer chooses to reduce consumption below historical levels (the CBL), GPC will pay the customer the RTP price for these reductions. Since the prices reflect the hourly expected marginal cost, the customer chooses whether to purchase, or not, based upon a comparison of the real, hourly cost of electricity to his current value of electricity.

Q. DOES RTP TRY TO CAPTURE THE AVERAGE COST OR TOTAL COST OF THE ENTIRE AMOUNT OF RTP LOAD?

A. Neither. The intent of RTP is and always has been to reveal the marginal cost of making marginal changes in load. Standard rates reflect the total cost changes over large increments of load changes.

Q. HOW IS THE COST OF PRODUCING ELECTRICITY COVERED IN THE RTP PRICE SINCE MARGINALLY SPEAKING THERE ARE SO MANY RESOURCES WHICH MAY BE PROVIDING ALL OF THE LOAD?

A. RTP is based upon the theory of capital substitution and the peaker methodology, which has been approved by many, including the National Electric Research Association (NERA). This theory states that if you charge the marginal running cost and the "cheapest" capital cost, then you should collect enough revenue to cover your cost. Please see Exhibit___(HKO-4) as to how a choice of two generating technologies could be combined to serve a system loadshape. Exhibit___(HKO-4) also shows how an RTP tariff combining the cheaper capital cost with the hourly running cost (lambda) would equal the cost to serve regardless of which technology was actually serving the load. In this simple example of a system, assume for illustrative purposes that RTP would be charging \$30/kW representing the cheapest generating resource (a combustion turbine (CT)) and lambda of 6¢/kWh for the 1,500 hours in which the CT was the marginal unit and 2¢/kWh for the remaining hours of the year in which the base load coal unit was the marginal unit.

Q. IF SOME OF THE RTP LOAD WAS ACTUALLY BEING SERVED BY THE BASE LOAD COAL UNIT WITH A RUNNING COST OF 2¢/KWH, WHAT IS THE PURPOSE OF THE ADDITIONAL 4¢/KWH WHICH WILL BE CHARGED WITH A LAMBDA OF 6¢/KWH UNDER RTP?

A. That difference of 4¢/kWh above the actual running cost of the base load unit will pay for the "extra" capital cost of the base load unit. Remember the RTP tariff will only collect capital cost for the cheapest generating resource, in this case a CT, at $30/kw. By collecting an extra 4¢/kWh over 1,500 hours, there will be contribution of $60/kw thereby effectively covering the $90/kw capital cost of the base load coal unit. Its only fair that if an RTP customer is allowed to enjoy the lower economical running cost of this base load unit that he also contribute towards the higher capital cost of this unit.

Q. SO, DOES LAMBDA THEN CONTAIN NOT ONLY FUEL COST BUT ALSO A CONTRIBUTION TO THE CAPITAL COST OF A MORE EFFICIENT BASE UNIT?

A. Yes. It also contains variable operation and maintenance expense.

Q. IF YOU WERE TO AVERAGE THE RUNNING COST IN THOSE HOURS IN WHICH BOTH UNITS WERE RUNNING AND PRICE ACCORDINGLY, WOULD YOU COVER YOUR COSTS?

A. No. You would fall short in this example by $30/kw. You must charge the marginal lambda price coupled with the most economical generation capital cost to properly cover your cost. Otherwise, you violate the peaker theory and capital substitution logic.

Q. ARE PURCHASES A RESOURCE IN THE HOURLY DISPATCH OF RESOURCES?

A. Yes, they are correctly treated as another resource in order to minimize the cost of power to our all of customers.

Q. HOW DO PURCHASES IMPACT THIS PRICING MODEL BASED UPON CAPITAL SUBSTITUTION?

A. As mentioned earlier, we will purchase power whenever it can be obtained cheaper than dispatching its own units or when it has run out of its own units. Therefore the marginal unit can be a purchase and this purchase price can be more or less than the lambda of the last available owned unit lambda. This fact can be observed in Exhibit ___(HKO-5). The exhibit indicates there are hours in which the cheaper purchase will not contribute sufficient capital contribution necessary to pay for the high capital, base-load owned units serving RTP load. However the presumption is that hours in which the purchase sets a lambda higher than the most expensive owned unit will compensate for this deficit.

Note: Bold faced type in answers indicates trade secret material. Please refer to the assigned name when discussing.

Q. HOW HAVE ECONOMICAL LOWER COST PURCHASES COMPENSATED FOR THE HIGHER COST PURCHASES SINCE THE INCEPTION OF RTP?

A. Prior to 1999, lower cost purchases compensated for the additional cost of higher cost purchases. During 1999, it appears that higher cost purchases were greater than the lower cost purchase effects. Over time the assumption is that this will average out.

Q. WHAT WOULD HAPPEN IF YOU ARTIFICIALLY REMOVED PURCHASES FROM THE LAMBDA CALCULATION IN HOURS WHERE PURCHASES WERE BEING MADE TO SERVE RETAIL LOAD?

A. Lambda would not reflect marginal cost and would send the wrong price signal to RTP customers. During high-priced hours, it would signal to an RTP customer a price that could encourage him to add load at a price less than the corresponding cost of electricity and vice versa in a low-cost hour.

Q. DO RTP CUSTOMERS RESPOND TO HIGH PRICES?

A. Yes. They do as an aggregate group. Some customers have specific trigger prices to which they respond consistently. Others change their response triggers as their business conditions change throughout the month and the year. As a result of this dynamic interaction of a large group of customers, GPC can depend upon a consistent level of response that effectively becomes the equivalent of a generating resource when conditions worsen and RTP prices rise. In GPC's most recent IRP filing, the RTP price response resource provided 328 MW's for a typical peak day response. During the very hot summer month of August 1999, the response in the highest priced hours was a phenomenal 864 MW's. This response provides a valuable resource no other utilities possess and prevents the need to construct similar MW's of new generation. Please see Exhibits___(HKO-6-1) and (HKO-6-2).

Q. HOW DOES GEORGIA POWER'S RTP TARIFF AFFECT THE COMPANY'S INTEGRATED RESOURCE PLAN (IRP)?

A. The Company's approved IRP contains approximately 1000 MW of Combustion Turbine equivalent capacity associated with our customers' load response to pricing signals and interruptible service. The RTP tariff effect is slightly less than half of this capacity.

Q. HAS THIS PRICING SIGNAL TO CUSTOMERS BEEN EFFECTIVE IN REDUCING THE NEED TO OBTAIN ADDITIONAL RESOURCES?

A. Yes. During the 1999 peak when the RTP prices included the higher cost of spot market purchases, the Company's capacity need was reduced by 864 MW. Since the prices paid for spot energy in 1999 were higher than the projected values used in the IRP, the customers load response was greater than projected. This response demonstrates that the concept behind the development of the RTP tariff is performing as it was intended.

Q. DOES THIS REDUCTION IN CAPACITY NEED BENEFIT THE COMPANY'S CUSTOMERS?

A. Yes. All of the Company's customers benefit from the RTP response. The customers receive near-term and long-term benefits.

Q. WOULD YOU EXPLAIN THE NEAR-TERM BENEFITS?

A. Yes. In the near-term, all customers benefit because the Company does not have to purchase additional high priced resources from the spot market. If the Company had to purchase the resources avoided by the RTP response, then the cost of these higher priced resources would be passed through to all of our customers. Also, these purchases would force the RTP prices to be even higher.

Q. WOULD YOU EXPLAIN THE LONG-TERM BENEFITS?

A. Yes. Due to the expected continuing RTP response, the Company's long-term capacity requirements are reduced. Our customers benefit from the avoided resources costs that would have been incurred if this capacity had to have been built or purchased and included in future rates.

Q. CAN YOU GIVE AN EXAMPLE OF THIS AVOIDED COST?

A. Yes. The IRP projects approximately 500 MW of RTP CT equivalent capacity in 2003. Using the installed cost of a generic CT to replace this 500 MW of capacity, our customers would be responsible for this increase in cost of $17.6 million. Since the RTP response is assumed to continue through the IRP plan, this avoided cost adjusted for inflation and market pricing would be an annual avoidance.

Q. DO DIFFERENT CUSTOMERS CAUSE DIFFERENT FUEL COST EFFECTS ON GPC DEPENDING UPON WHEN THEY CONSUME ELECTRICITY?

A. Yes, they do. However, this Commission has determined that it is appropriate to account for fuel cost on an average basis across all hours for all customers.

Q. WOULD RTP CUSTOMERS' FUEL COST BE DIFFERENT FROM SIMILAR CUSTOMERS ON OTHER RATES?

A. Probably so, and this is another advantage of RTP. When fuel costs are high during a specific time period, a standard-rate customer using the FCR mechanism does not sense that fuel costs are high at this time since his bill is predicated on this average FCR rate. An RTP customer on the other hand is sent an RTP price signal which reveals the high cost of fuel during this time period, and the customer often times reduces consumption accordingly. This not only lowers the RTP customer's bill by reducing consumption but also has a dampening effect upon the fuel clause since now expensive fuel cost will not have to be incurred as it would have, had this RTP customer been on a standard rate with the FCR price signal.

Q. CAN YOU ELABORATE ON THE DIFFERENT COMPONENTS WITHIN LAMBDA BESIDES FUEL COST?

A. Yes. The two common additional components are 1) variable operating and maintenance expenses, and 2) capital substitution contribution mentioned earlier in the discussion on the definition of lambda. Even the fuel cost itself for the unit varies as the unit ramps up from cold start to maximum output. For instance the average fuel cost per mile of an automobile running at 10 miles per hour (mph) is greater than when it is operating at 45 miles per hour. The point here is that if in a 30-minute cycle, an auto sped up from 10 mph to 45 mph, you could not measure the cost of fuel at the 10 mph speed and allege that this would be the actual cost of fuel for the entire 30-minute period.

Q. ARE THESE TWO ADDITIONAL COMPONENTS WITHIN LAMBDA ALLOWED TO BE COLLECTED THROUGH THE FUEL CLAUSE (FCR)?

A. No, only fuel cost and related purchased power are permitted. The FCR tariff defines costs permissible in the FCR and does not allow these.

Q. SHOULD THESE TWO ADDITIONAL COMPONENTS BE ALLOWED IN THE FCR?

A. No. The proper way to account for fuel cost according to this Commission is the FCR, and the RTP methodology of removing fuel cost responsibility as defined by the FCR is correct. If one were to credit lambda (or anything other than the FCR), revenue would be flowing into the fuel clause that was non-fuel cost related creating an inequality. This accounting error would be compounded in that the resultant revenue flowing to base cost recovery would be diminished creating a likely under-recovery of non-fuel expenses. It would move the important capital substitution component from base rate recovery to the fuel account. The FCR rate might go down, just like if revenues were removed from any other base rate component and moved over into the FCR. But the capital substitution component would still have to be recovered from somewhere – either residential, commercial or some other customer group with higher base rates resulting.

Q. CAN LAMBDA IN ANY PARTICULAR HOUR EVER BE LESS THAN THE FCR RATE (WHICH IS CREDITED TO THE FUEL CLAUSE)?

A. Yes, it can and does for a couple of reasons. Since the FCR is an average of all hours of the year, the marginal unit with its lambda during some off-peak hours can easily be below the FCR rate. In addition, the FCR includes fuel cost related to unit commitment while unit commitment cost is not currently included in the lambda component of RTP.

Q. IF LAMBDA IS HIGHER THAN THE FCR RATE THAT IS CREDITED TO THE FUEL CLAUSE, DOES THIS DIFFERENCE FLOW DIRECTLY TO GPC EARNINGS?

A. Absolutely not. There is no separate accounting for revenue received from an RTP customer's bill than that of any other GPC customer. For example assume that a PL customer paid a bill of $10,000 to GPC at an overall average rate of 5¢/kWh including the FCR. Furthermore assume that an RTP customer likewise paid a bill of $10,000 to GPC at an overall average of 5¢/kWh (this incorporates both his standard bill portion and the incremental RTP bill with all the components in the RTP price). In both cases, GPC will remove fuel cost revenue defined by the FCR (assume that rate is 1.4¢/kWh). In both cases the remaining revenue (3.6¢/kWh in this simple example for both customers) flows to pay for non-fuel embedded expenses. If after contributing towards these non-fuel costs, there is still some revenue remaining, then in both cases the remaining revenue contributes to earnings. As a matter of fact, in almost all cases, the PL customer's cents per kWh contributed will be higher than a similar RTP customer's cents per kWh, such that the resultant contribution to non-fuel embedded expenses and any resultant contribution to earnings will almost always be greater for the PL customer.

In addition, we must remember that GPC is a weather sensitive, summer peaking utility. Hot summers like 1998 and 1999 result in increased annual revenues even as they place greater costs on the utility. Whether one is talking about Power and Light, or residential rates, or RTP, a hot summer will likely result in an increase in annual revenues. This increase in revenues through rates is then credited against correspondingly higher costs. In hot years, the increase in revenue contributions from all rates produces an increase in company earnings. Likewise, a milder year reduces revenues and resultant earnings. Since tariffs are designed based on the cost to serve in a typical weather year, there will always be some years with higher earnings and some with lower earnings.

REGULATORY TREATMENT OF RTP TARIFFS

Q. HOW WERE REVENUES FROM THE RTP TARIFFS REFLECTED IN THE COMPANY'S 1998 RETAIL RATE CASE FILING?

A. The base and fuel revenues associated with the RTP tariffs were calculated according to the terms of the tariffs and were explicitly included in the overall determination of test period revenue requirements. The RTP revenues are specified in the Commission's minimum filing requirement F-4 found in Appendix Volume 1, Exhibit 2 of the GPC filing in Docket 9355-U.

Q. **ARE THERE OTHER EFFECTS ON REVENUE REQUIREMENTS AS A RESULT OF THE RTP TARIFFS?**

A. Yes. RTP tariffs are a component of the Company's Integrated Resource Plan (IRP). The expected customer response to the RTP price signal is reflected as a resource in determining GPC's available supply. Therefore, the operation of the tariffs directly

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impacts the need for additional capacity resources. The amount of RTP reflected in the IRP directly affected the level of purchased power expense included in calculating the test period revenue requirement. Any changes to the RTP tariffs that reduce the degree of customer response will reduce the availability of this resource and result in increased revenue requirements through either purchased power expense or new generation.

Q. WAS THE EFFECT OF THE RTP TARIFFS ON TEST PERIOD REVENUE REQUIREMENTS ULTIMATELY CONSIDERED IN THE 1998 RETAIL RATE CASE DECISION?

A. Yes. The Commission Staff and other parties of record conducted an exhaustive review of the Company's test period revenue requirement calculation, including revenues from all existing tariffs. No party, including the GTMA and the GIG, took issue with the determination of RTP revenues as reflected in the filing. Also, the effect of RTP tariffs on the Company's IRP was properly considered in prior IRP proceedings. The Commission, based on the Company's test period expenses and revenues, and other evidence presented in Docket 9355-U, concluded that the rate reductions included in the modified stipulation adopted as the "Accounting Order Alternative Rate Plan" resulted in rates that were "fair, just and reasonable".

Q. DOES THE COMMISSION'S ORDER IN DOCKET NO. 9355-U SPECIFICALLY REFERENCE RTP TARIFFS?

A. Yes. The Order in paragraph 5, page 4 of 7, which discusses the allocation of rate reductions, specifically states that "Georgia Power's Real Time Pricing rates will not be reduced."

Q. WOULD YOU PLEASE SUMMARIZE THE GENERAL TERMS OF THE COMMISSION'S ACCOUNTING ORDER ALTERNATIVE RATE PLAN.

A. The Accounting Order reduced rates $262 million effective January 1, 1999 and an additional $24 million effective January 1, 2000. The Order requires the Company to record $85 million per year in accelerated amortization of regulatory assets. The Company's earnings are evaluated against a retail return on equity (ROE) range of 10.0% to 12.5%. In 1999, two-thirds of any revenues above the 12.5% ROE are used for additional rate reductions, with the Company retaining the remaining one-third. In 2000 and 2001, the first $50 million of any revenue above the 12.5% will go to additional accelerated amortization of regulatory assets, after which any remaining amounts will be subject to the aforementioned sharing mechanism.

Q. WOULD THE CHANGES TO THE RTP TARIFFS PROPOSED BY GTMA & GIG IMPACT THE OPERATION OF THE ACCOUNTING ORDER?

A. Yes. The proposed changes to the RTP tariffs would reduce base revenues billed under the RTP tariffs. A reduction in base revenue would impact the sharing provision of the Accounting Order and the ability to accelerate amortization of regulatory assets. A reduction in rates paid by RTP customers could result in smaller rate reductions for other customers (through the sharing mechanism), less ability to accelerate amortization of regulatory assets and a reduction in the Company's earnings.

Q. IS THE COMPANY CORRECTLY ACCOUNTING FOR THE FUEL ASPECT OF THE RTP RATE?

A. Yes. GPC is accounting for fuel in the RTP tariff exactly as this Commission has approved on at least three occasions and it is specifically prescribed in the RTP tariffs.

Q. HOW IS FUEL COST HANDLED IN THE RTP TARIFF?

A. Fuel cost incurred when generating electricity out of our plants is accounted for and recovered separately from other GPC costs, as dictated by Georgia State law and this Commission. This separate accountability for fuel cost is deemed the Fuel Clause Recovery (FCR) mechanism. Non-fuel costs are recovered through base rates. When electricity is purchased from other suppliers on a per-kWh basis, these costs also flow through the FCR. The FCR is a cost pass through mechanism with no profit feature. <u>All</u> retail customers of GPC whether residential, commercial, or RTP customers have the same fuel cost responsibility (broken down into 3 distinct voltage levels of service). This average costing mechanism has been deemed a fair way by this Commission for the strict collection of fuel cost and related purchase power expenses.

With most GPC tariffs, there is a separate, distinct FCR component. This component is produced by multiplying the customer's monthly kWh consumption times the current applicable FCR rate. This procedure is also performed on the standard bill (CBL) portion of an RTP customer since a base rate is applied to the CBL. However, with the incremental RTP portion of the bill, there is already a component (lambda) in the RTP price which collects for several costs, one of which is fuel. So to prevent double recovery, the FCR rate does not show up as an additional component in the incremental RTP bill. And to continue with the precedent of equal and average fuel cost accountability, an equivalent FCR rate is removed from the incremental RTP rate revenue and credited to the fuel clause. This procedure ensures that equal fuel cost accountability is maintained.

Q. IS IT APPROPRIATE UNDER THE ACCOUNTING ORDER TO CHANGE THE RTP TARIFFS AND FUEL ACCOUNTING TREATMENT AS PROPOSED BY GTMA & GIG?

A. No. As stated earlier, the Commission concluded in the 1998 rate case that the Company's tariffs, as reduced by the Accounting Order, are fair, just and reasonable. The Commission made that determination based on an extensive review of test period expenses and revenues and other evidence presented in the rate case. The fuel accounting is being performed correctly. To now selectively change the RTP tariffs and reduce base revenues would be contrary to the multi-year Accounting Order concept. The Commission made its determination and allocation of rate reductions based on the

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evidence presented in the case. The sharing mechanism approved by the Commission recognizes that actual revenues will vary based on weather, sales growth, and general economic conditions and accordingly provides a balance of benefits to our customers and the Company. In requesting these changes to the RTP tariffs GIG and GTMA are simply trying to supercede the Commission's allocation of rate reductions in the 1998 rate case and the balancing of customer and Company interests through the sharing mechanism.

CURRENT MARGINAL COST COVERAGE

Q. DOES THE CURRENT RTP PRICE ADEQUATELY COVER MARGINAL COST FOR GPC?

A. Yes it does. With the inclusion of the present risk adder, lambda definition and overall tariff structure, any additional cost risk can be covered adequately.

Q. YOU MENTIONED "ADDITIONAL COST RISK." WHAT ADDITIONAL COST RISKS ARE THERE WHICH ARE NOT CURRENTLY COVERED IN THE RTP INCREMENTAL PRICE?

A. There are several:

1. As mentioned previously, unit commitment costs are not included in the RTP price signal. Unit commitment costs are fuel and variable Operating and Maintenance (O&M) cost experienced when a unit is run out of economic dispatch (i.e. at a time when it would not normally be running if it were not needed for a future time in order to achieve overall total cost minimization) in order to most optimally serve load in a future period under a goal of overall cost minimization. These fuel costs are recovered through the FCR. However, since unit commitment costs are incurred when the unit is "out of economic dispatch," it does not show up in the lambda during these out-of-dispatch hours, but does later actually lower the lambdas in those hours it is planned for in cost minimization. So, the RTP customer gets a lower lambda later without paying for the cost experienced earlier, which allows the later benefit. An enhancement to RTP would be to add onto the later hours to which the unit is committed a cost reflecting this pre-commitment expense.

2. Also mentioned earlier, Clean Air Cost, which is the value of SO_2 emissions allowances, is emissions allowances that the SES has been granted for designated units. The revenue from these sales can be credited to the FCR thereby lowering everyone's FCR rate. Currently this clean air cost for corresponding units is not reflected in the RTP hourly price even though it has a "revenue/cost" effect. If these units are not run, these allowances can be sold in the marketplace. This clean air cost effect could easily be added to lambda in order to signal to an RTP customer the true economic effect of his decision to consume a kWh on the margin.

Note: Bold faced type in answers indicates trade secret material. Please refer to the assigned name when discussing.

3. The RTP price has a marginal cost component for generating and transmission (G&T) expenses. These are included because a decision by a customer to consume a kWh on the margin can have a direct effect upon G&T costs. On the other hand, there is nothing within the incremental RTP price for distribution or overheads. The reason for this omission is that these costs do not vary directly with a customer's decision to consume a kWh on the margin, but do so more in an indirect manner. The original RTP design assumed that existing distribution and overheads would be compensated for through the CBL mechanism and any incremental effects would be small enough that they could be accommodated by GPC through the approved contribution effect of the RTP rate. But as customers have been on RTP for 5-7 years enjoying load growth from these economic RTP prices, they have indirectly influenced additional distribution and overhead cost to the extent that the present approved contribution effect of RTP must remain in place to provide the appropriate cost contribution.

4. In spite of the petitioners' allegations, there is still forecasting risk to GPC. Even though there now is 6-7 years experience forecasting RTP prices, as the petitioners point out, the last 2 years have experienced extreme price volatility. This has made it even more difficult to predict our hourly marginal cost and be assured we will cover our cost. As shown in the Company's response to Staff data requests, for the 1999 year, we actually under-forecasted our actual lambda for RTP-DA. Also contrary to the petitioners' allegations, this can have a damaging effect on eventual earnings even with the FCR in place – this fact is clearly revealed in response to Staff data requests.

Q. WHAT WOULD BE THE EFFECT OF REMOVING PURCHASED POWER FROM LAMBDA IN SETTING THE RTP PRICE?

A. If this change were made to the RTP price, it would no longer be a marginal cost rate. Lambda is the marginal cost consequence of a marginal consumption decision much like Last-In-First-Out (LIFO) is used with inventory evaluations. RTP would no longer signal to an RTP customer what the true cost consequences are of his making a marginal change to his consumption. This, therefore, would then violate the original intent of the rate.

Q. WOULD THE OVERALL RTP PRICE GO DOWN IF YOU WERE TO REMOVE PURCHASES?

A. Because economic purchases are often made rather than dispatching more expensive owned units in addition to the times when expensive purchases are made when we are out of owned units, in a normal year the RTP might actually go up. It is highly likely that it would have gone up during the early years of RTP. 1999 was a hot year across the United States such that had purchases been removed the overall 1999 RTP price would likely have been less than it actually was. But one must realize that had this been done in 1999, RTP would not have reflected marginal cost, resultant prices would likely have been lower, resultant RTP price response would have been less thereby requiring even more expensive purchases, and possibly impairing the reliability of the system such that

Interruptible Service (IS) customers would have to have been interrupted even more than they actually were during 1999.

Q. HAVE THERE BEEN SOME QUESTIONS ABOUT INTERRUPTIBLE SERVICE (IS) BY THE COMMISSION STAFF ABOUT HOW "IS" CUSTOMERS ARE CALLED AND THE IMPACT ON RTP CUSTOMERS. PLEASE ELABORATE ON THIS?

A. Yes. "IS" customers have contracted with GPC to interrupt their interruptible load with at least 30 minutes notice whenever requested up to 240 hours per year. As compensation, customers are paid an IS credit of up to $45/kw-year, plus an energy credit of 3.22¢/kWh. Historically, these calls have been strictly for reliability purposes when the system is in jeopardy. Please see Exhibit___(HKO-7) for a history of "IS" calls. However, with the recent advent of very high wholesale power prices, if the "IS" resource were also called for economics (i.e. whenever wholesale purchases exceeded a threshold), there would be a significant drop in the resultant RTP price. The threshold could be set high resulting in few economics calls but significant cost savings to the system and lower RTP prices would result. For instance, the expected average RTP-DA price for 2000 is 3.09¢/kWh assuming "IS" is called only for reliability purposes. If "IS" were also called for economic reasons at a threshold price of $350/mWh (35¢/kWh), there would be only 6 additional hours of expected calls, and yet the expected RTP price would fall from 3.09 cents per kWh to 2.9 cents per kWh, almost 2 mills/kWh.

Q. THE PETITIONERS CLAIM THAT PURCHASES HAVE JUST RECENTLY SURFACED IN RTP. IS THIS TRUE?

A. No. Purchased power has been influencing RTP since its inception. It has been a major influence in keeping RTP prices down during the early to mid-90's. It has always been within our stack of resources, which is why when we refer to "generation", it naturally applies to owned units and purchases. It is very common for utilities such as Kansas City Power and Light along with Virginia Power Company to include purchases in their "generation" component of RTP. Kansas City Power and Light Company states in its RTP tariff "Marginal Cost = Projections of the hourly running costs of incremental generation and wholesale prices, … so that the algorithm for our RTP price calculation includes market prices so as to best approximate opportunity cost on the transaction." (KCPL rate name – "Schedule RTP") Purchases are merely another resource similar to a generating unit. This is why when we refer to "generation," we're referring to all generation resources, which naturally includes purchases.

COMPETITIVENESS OF RTP PRICES AND INDUSTRIAL RATES

Q. WHAT SOURCES ARE AVAILABLE TO SEE HOW COMPETITIVE GEORGIA POWER RATES ARE AS COMPARED TO OTHER UTILITIES IN THE SOUTHEAST?

A. There are many sources of utility pricing information. The Edison Electric Institute (EEI) and the Department of Energy (DOE) routinely publish information on utility prices. Many private firms, such as Regulatory Research Associates (RRA) and Resource Data International (RDI) also publish utility pricing information. I review each of these sources.

Each source uses their own methodology and should be carefully evaluated before being adopted as a sole criterion.

Q. DESCRIBE THE PUBLICATION BY THE EDISON ELECTRIC INSTITUTE?

A. EEI publishes several comparisons of investor owned utility prices. One of these is EEI's Typical Bills and Average Rates Report, which is published twice a year and covers all classes of customers and usage levels. Although the information for the typical bill report is prepared and submitted by the utilities themselves, there are variations in how each utility prepares its information.

This is particularly true for industrial customers who have rate options and riders such as interruptible service and real time pricing riders.

Q. DOES THIS MEAN THAT THE NUMBERS PUBLISHED IN THE EEI TYPICAL BILLS REPORT ARE WRONG?

A. No, the numbers are not wrong, but they are not always done the same way by each utility. For example, in GPC's case, our calculations are based on our standard tariffs such as our Power and Light (PL) rate and do not include any usage under GPC's Real Time Pricing rider or interruptible service credits.

While comparisons in EEI's report of small and medium sized commercial customers and residential customers do not suffer from these drawbacks, comparisons of industrial customers can be quite misleading, depending on what riders and rate options were used by each utility.

For example, Georgia Power's RTP hour-ahead (HA) customers rely on RTP for over 32% of their total usage. Therefore, to rely on standard tariffs alone for these customers is to leave out 32% of their usage in determining what these customers actually pay for electricity. RTP's day-ahead (DA) customers rely on RTP for almost 36% of their total usage. Customers with load factors over 80% can often rely on RTP for even more of their usage.

When a customer evaluates energy usage and cost it is much more appropriate to look at what the customer actually pays in total, rather than just a portion of his usage. This is particularly true for Georgia Power since a large portion of our industrial load is served under the RTP tariff. Looking only at the standard bill portion would leave out a large portion of our industrial customer's usage. In fact, in 1999, energy sold to customers under Georgia Power's RTP tariff would have amounted to almost 35% of total industrial class usage.

For these reasons the comparisons in the testimony filed in this docket for GIG and GTMA customers made using standard tariffs alone form an incomplete and in fact misleading picture of a group as unique as GIG and GTMA.

Q. CAN APPROPRIATE COMPARISONS BE MADE USING OTHER SOURCES?

A. Yes, they can. Similar information is also published each fall by the Department of Energy's Energy Information Agency in its Electric Sales and Revenue report. This report is in fact available publicly at no charge on DOE's web site -- WWW.EIA.DOE.GOV.

Q. WHY DO YOU CONSIDER THESE COMPARISONS APPROPRIATE?

A. These comparisons include prices for all pricing options used by industrial customers, therefore giving a complete picture of what industrial customers are paying for their total usage. Further, the report includes examples of industrial prices in other regions of the country as well as the national average for all industrial kWhs sold in 1998.

Q. HAVE YOU MADE THESE COMPARISONS?

A. Yes. We routinely review prices for all classes of customers on both a regional and national basis in the normal course of business.

Exhibit___(HKO-8) 1998 Industrial Price per kWh Comparisons, summarizes information obtained from DOE's 1998 Electric Sales and Revenue, the last year complete information is publicly available. This exhibit lists the total average price per kWh paid by industrial customers for utilities in the United States.

Q. WHAT DOES THIS EXHIBIT INDICATE?

A. This exhibit indicates Georgia Power ranks 10th out of 19 investor owned suppliers in the southeastern United States. A line item was added to show Georgia Power's 1999 average industrial price per kWh which reflects the effect of the most recent rate reduction implemented in January 1999.

Additionally the prices all GIG and GTMA customers paid on average in 1998 as well as 1999 was added to this exhibit as a reference point. GTMA's 1999 overall average price was 3.7 cents per kWh and GIG's 1999 overall average price was 3.26 cents per kWh, well below almost all suppliers on the exhibit and certainly much lower than portrayed in the comparison offered by Mr. Pollock in his testimony filed in this docket.

The exhibit also indicates GPC's average industrial price is almost 7% below the national average.

It should be noted that if you look outside the southeast, that Georgia Power's average industrial price is at least 50% below those in states such as California, Pennsylvania and Massachusetts who are in the process of deregulation.

Q. ARE PRICES IN THE SOUTHEAST LOWER THAN IN THE REST OF THE UNITED STATES?

A. Yes, prices are quite low in the southeast. Many utilities in our region have industrial class prices well below the national average. Our region has a number of very price competitive utilities.

The joint efforts of the public utility commissions and the utilities are responsible for this. Clearly, economic development in our region has been and continues to be positively influenced by low prices for industrial manufacturers.

Q. SHOULD WE BE MORE CONCERNED ABOUT PRICES WITHIN THE REGION OR ACROSS THE COUNTRY?

A. Both comparisons are important. It is appropriate to continue to examine and compare prices not only among southeastern suppliers but also to national averages and other regions.

The state of Georgia and our industries compete in a national marketplace. We should always be aware of how competitive we are on a national basis.

Q. PRICE COMPARISONS WITH THE TENNESSEE VALLEY AUTHORITY ARE NOT INCLUDED, WHY?

A. It is inappropriate to place TVA in the same category as investor owned utilities that are subject to state and federal tax codes and must compete for investor's capital. The Tennessee Valley Authority (TVA) is a major electric supplier in the southeast. TVA is an entity created by the United States government and in its initial stages was funded entirely by United States government backed capital. Even today TVA pays no federal income taxes and is not subject to any regulatory body; its sole oversight is by the United States Congress.

Q. ARE MARGINAL PRICES HIGHER THAN EMBEDDED PRICES?

A. No. The annual average marginal prices are below annual average embedded prices. In testimony sponsored by GIG and GTMA for this docket on page 12, Mr. Pollock incorrectly states that marginal costs are significantly higher than embedded costs. As a simple example, a 100% load factor load shape priced on RTP-DA in 1999 would be priced at 3.57¢ per kWh. This same load shape would cost an average of 4.1¢ per kWh or 15% more on our embedded rate PLL with the Off Peak (OP) rider. Another example is a customer with a 75% load factor load shape. In 1999, if a sample customer had 70%

of their load on RTP and 30% of their load on our embedded PLL rate, then the total average annual price would have been 4.60¢ per kWh. If the entire load shape was priced on PLL/OP it would have been 4.96¢ per kWh.

Q. WHAT WERE THE AVERAGE PRICES PAID BY RTP CUSTOMERS IN 1999?

A. Because RTP customers respond to RTP prices differently and because they have different load shapes, the average price paid is always different from the prices offered. In 1999, the RTP-HA customers paid an average of **(Redacted) per kWh (1999 RTP-HA average paid price)** as compared to the offered price of **(Redacted) (1999 RTP-HA average offered price)**. (See Exhibit___(HKO-9)) The RTP-DA customers paid an average of **(Redacted) per kWh (1999 RTP-DA average paid price)** as compared to the offered price of **(Redacted) (1999 RTP-DA average offered price).** (See Exhibit___(HKO-10)) This of course is due to the fact that these customers bought slightly more kWh on-peak than off-peak.

Q. WHAT WERE THE AVERAGE PRICES PAID BY GIG AND GTMA RTP ACCOUNTS FOR 1999?

A. There are 64 GIG and 68 GTMA accounts on RTP tariffs. The average incremental RTP-DA price paid by GIG and GTMA was 3.39¢ and 3.61¢ per kWh respectively. For RTP-HA the average incremental price paid was 2.90¢ per kWh for GIG and 2.98¢ per kWh for GTMA.

If you combine the incremental energy with the energy in the Customer Baseline Load (CBL), the average price paid by all GIG RTP accounts was 3.26¢ per kWh and the average price paid by all GTMA RTP accounts was 3.70¢ per kWh. These prices are well below Georgia Power's average 1999 industrial price of 4.19¢ per kWh, and approximately 50% below average residential price of 7.27¢ per kWh and the average commercial price of 6.44¢ per kWh.

Q HOW SUCCESSFUL IS THE CURRENT RTP PROGRAM AT GEORGIA POWER?

A. It is extremely successful for both our Customers and the Company and it is working the way it was designed.

The RTP Program has 1560 Commercial and Industrial customers ranging in size from 250 kW to 145,000 kW. We are adding, on average, 10 accounts to the program each month and since 1992 less than 20 customers have left the rate.

For the year 1999, the average paid by all RTP-DA customers for all energy was 4.10¢ per kWh and the average price paid by all RTP-HA customers for all energy was 3.05¢ per kWh, both of which are lower than their costs would have been under other firm tariff rates. During the month of August 1999, 18 customers received a negative bill because the credit they received for being below their CBL was greater than the standard bill for the CBL portion of their rate.

The customers and the Company have both benefited from the shift in load and price response. During 1999 customers responded to high RTP prices and established a need for less generation or purchased power. (See Exhibits___(HKO-6-1) and (HKO-6-2)). On the highest priced day the total load response from the RTP customers was 864 MW's, providing a significant savings to all customers of Georgia Power.

Q. WHAT HAS BEEN THE IMPACT OF VOLATILITY ON RTP PRICES?

A. During both 1998 and 1999, the marketplace has seen a change due to FERC Order 888, which was issued in 1996. The Order established the ability for power marketers to buy energy from and sell energy to utilities. No longer were utilities just selling to utilities. Now there was a third party setting the price. During 1998, the Southern Company was not exposed to the extreme market prices, and the most expensive energy purchased was \$500 per MWh or 50¢ per kWh. During 1999, however, there were a few hours in which the Southern Company did purchase power at \$6,000 per MWh or \$6.00 per kWh. The number of hours with these high prices are very few as compared to the total number of hours in a year (8,760 hours). Also this extreme volatility observed in 1999 is not forseen in 2000 or 2001 as new generation has come on-line in the Southeast.

For RTP-DA in 1999, there were only **(Redacted) hours (1999 RTP-DA hours over 40.0¢ per kWh)** in which the price exceeded 40.0¢ per kWh and if the customer responded down to their CBL for these hours, their average RTP costs for the year would have been **(Redacted) per kWh (1999 RTP-DA average price for response during hours over 40.0¢ per kWh).** For RTP-HA in 1999, there were only **(Redacted) hours (1999 RTP-HA hours over 40.0¢ per kWh)** in which the price exceeded 40.0¢ per kWh and if the customer responded down to their CBL for these hours, their average RTP costs for the year would have been **(Redacted) per kWh (1999 RTP-HA average price for response during hours over 40.0¢ per kWh).** Exhibit___(HKO-11) shows the impact of responding to prices for 50 hours or more for the year 1999.

Even greater reduction in average prices would be achieved if the actual response was below the CBL.

<u>RTP STRUCTURE FOR THE FUTURE</u>

Q. IS RTP, AS IT IS CURRENTLY STRUCTURED, APPROPRIATE FOR THE FUTURE?

A. Yes. RTP is working in the way it was designed to work. It will continue to do so if unaltered. RTP was designed to signal marginal cost to a customer in the event of a marginal consumption change. It continues to do so. The problem is not in the structure of the tariff; the problem, simply put, is that marginal costs have risen over the life of RTP, especially the last two years. RTP customers have enjoyed the benefits of marginal

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cost pricing for years and can continue to enjoy them. And, RTP will continue in the long run to be a cheaper alternative than an embedded rate (see Exhibit___(HKO-12)), and it should since it shifts risk from the utility to the customer. (Note there may be some years when RTP is greater than the alternative embedded rates, but in the long run it should be cheaper.)

However, the gap between embedded rates and RTP in the near future may not be as great as it was during the early to mid-1990's when there was excess base capacity and greater reserves in the industry. But this simply reflects a capital intensive industry in which there are broad swings in surplus and deficit capacity. To merely compare a period of large surpluses like the early 1990's to one of tight conditions like now and ignore the wisdom of cycles is foolhardy. It would be similar to a knee jerk reaction to the recent run-up in gasoline prices at the pump. Once again, the problem is not in the tariff structure and its designed purpose, the problem is that the gap between embedded costs and marginal costs has narrowed, and RTP is correctly revealing this.

Q. CAN THE CURRENT ADDER IN RTP BE LOWERED?

A. No. The current adder is reasonable and necessary, and there are several reasons why it should not be lowered:

(a) The adder helps cover forecasting risk. The wholesale market has become MANY times more volatile over the last two years making it more risky to forecast marginal cost than ever before. For 1999, the RTP-DA lambda (which was forecasted a day ahead) was almost 2 mills/kWh less than the actual lambda incurred the next day. In addition, forecast risk occurs in the other three components of the RTP prices.

(b) To reduce the risk adder could negatively impact non-RTP customers (through the Accounting Order) and the Company. The adder, like all components of all tariffs was included in the revenue projections in the Accounting Order. In that docket, the petitioners wanted the rate reduction applied to the adder, but the Commission decided there not to reduce the RTP tariff.

(c) GPC actually credits the entire RTP, including the adder, for decrements. This is done for simplicity purposes since it makes no logical sense for GPC to also credit the adder, thereby giving away its profits for a customer's non-consumption. To reduce the adder would lower customer's credits for reductions below the CBL.

(d) As inflation has increased RTP prices, the adder has remained constant since 1992, thereby becoming a smaller and smaller component of the overall price, and indeed a smaller benefit to GPC in terms of current economic value.

(e) The current risk adder helps lessen the pressure to include clean air and unit commitment cost in RTP, and also contributes to any distribution and overhead costs driven by incremental RTP sales.

(f) The equivalent mark-up in non-RTP rates is considerably higher. The minimum PLL mark-up is 6.5 mills/kWh.

(g) RTP adders by other utilities are typically equal to or higher than GPC's:

i. Duke's RTP (Schedule HP) is 5 mills/kWh
ii. TVA's RTP (ESP Options D&E) is 8 mills/kWh
iii. SCE&G's RTP (Large Power Service RTP-Rate 27) is 5 mills/kWh.

Q. WILL THE RTP PRICE INCREASE OBSERVED IN 1998 AND 1999 CONTINUE IN 2000?

A. It could for a particular year if that year is extremely hot like 1998 and 1999. But, if future years return to normal weather, RTP will not rise dramatically and will be below those levels observed in 1998 and 1999. In fact, our expected RTP-DA price for 2000 is **(Redacted) cents/kWh (2000 RTP-DA expected price),** which is **(Redacted) (percentage reduction in RTP-DA price for 2000)** below the 1999 actual. (Please see Exhibit___(HKO-13)). And, with some of the new rate alternatives included in this filing, we are willing to assure our RTP customers who take these options that this will be the most they will have to pay for any RTP load that they want to place on the alternative.

Q. DO YOU EXPECT THE RTP PRICES TO CONTINUE TO REMAIN HIGH OR MODERATE?

A. Since the high RTP prices are related to: extreme weather conditions; unit outages; regional reserves; and the spot market price of purchase, we expect that RTP prices will moderate over time. The reason for this is simple. Since the current high spot market prices are a result of a tight supply market, we believe that the industry and independent developers are responding to this tight market by adding significant amounts of new capacity in the Southeast and around the nation. As these new resources become available to the market, the prices paid in the spot market should moderate and be lower cost in real terms. Thus, the RTP price signals should reflect this change as well.

Q. MR. POLLOCK STATED THAT 1999 WAS NOT THAT HOT A YEAR, AND YOU'RE SAYING THAT HOT WEATHER DID CAUSE THE HIGH 1999 PRICES. HOW DO YOU EXPLAIN THIS?

A. While it is true that the summer of 1998 was hotter on average than the summer of 1999, the summer of 1998 heat was spread throughout the summer months and not concentrated in any one period. On the other hand, the period between July and the end of August 1999 had more extreme weather than any comparable period in 1998. For instance, August 1999 had 21.5% more cooling degree days than a normal August. This 21.5% difference in cooling degree days was higher than the difference between actual and normal weather for any summer month in 1998. This concentration of extreme temperatures in late July and early August drove the peak load to record levels day after day, thus contributing to record-level wholesale spot market prices and extreme RTP prices.

An indication of the difference in the concentration of heat during 1999 can be seen in the energy weighted maximum temperatures. Georgia Power Company uses seven weather stations located across the state. These hourly temperatures of weather stations are weighted based on energy consumption for the area surrounding each station. This weighting provides an hourly temperature that is representative of Georgia Power's entire service area. During 1998, the maximum hourly weighted temperature for the year was only 96.2 degrees. However, in 1999 the maximum hourly weighted temperature for the year was 98.8 degrees, a difference of almost 2.6 degrees. Moreover, 1999 had a period of about a week with such extreme temperatures. Even though over the course of the entire year, 1999 was slightly cooler than 1998, the extended high temperatures in 1999 had a very significant impact on peak demand and RTP prices.

We are a summer peaking utility. Each individual hour is critical and its load must be served. As a utility becomes constrained, its hourly marginal cost accelerates at a non-linear, exponential rate. In other words, a one degree temperature change in a summer afternoon day averaging 95ºF can have an extraordinary influence on load, while a one degree temperature change when the temperature is averaging 85ºF can have a very mild influence. (One-degree change when temperatures are in the 90's can add 750mW's of load to the SES). One cannot merely look at overall heating degree and cooling degree days for the year to ascertain if weather has influenced load and prices. If during one hour the actual temperature were 84ºF instead of the expected 85ºF, and in another hour the actual temperature were 96ºF instead of the expected 95ºF, Mr. Pollock's methodology would ask you to believe that you had normal weather over these two hours, and therefore, loads and prices should be normal.

Q. WERE THERE SPECIFIC CRITICAL TIME PERIODS DURING 1999 WHEN TEMPERATURES AND LOADS WERE EXTRAORDINARILY HIGH?

A. For the first 6¾ months of 1999, the weather was somewhat normal, and prices were near expectations. Then on July 23 a heat wave came across the U.S. and lasted through August. The cooling degree days (CDDs) from 7/23/99-8/31/99 in the territory that we serve were the hottest ever recorded, amounting to over 20% above the average of the past 20 years! Loads skyrocketed with the SES setting numerous all-time peaks along with many other utilities (some of these other utilities even experienced blackouts). As a result, wholesale prices and RTP prices skyrocketed during this period. The result was average RTP prices for July and August at extremely high levels (note the one hot week in July caused prices that week that more than offset the relatively mild RTP prices for the first three weeks of July). The average RTP price for 1999 was greatly influenced by these two months. The 1998 peak was exceeded for a total of 64 hours during late July and early August. The bottom line is, we don't <u>expect</u> extraordinary weather patterns like this to continue. We have RTP price expectations reflecting this belief, and we're willing to offer RTP Alternatives that will assure the customers of these prices.

REAL-TIME PRICING (RTP) ALTERNATIVES

Note: Bold faced type in answers indicates trade secret material. Please refer to the assigned name when discussing.

Q. WHAT IS THE PURPOSE OF THE RTP ALTERNATIVES?

A. The RTP Alternatives are excellent pricing solutions for RTP customers who have a need for additional control over their exposure to RTP prices. The purpose of the RTP Alternatives is to allow RTP customers to <u>manage, reduce or remove price risk</u> associated with RTP. While many RTP customers will prefer to stay on the RTP tariff, others will have the opportunity to move to an alternative that will provide more <u>stability and certainty</u> than RTP alone. They are not to replace RTP or to suggest that RTP is not a good tariff that is doing what it was designed to do.

Q. WHY HAS GPC FILED AND OFFERED THE RTP ALTERNATIVES?

A. First of all, many customers want more pricing options and more control over their electricity costs. GPC always desires to meet the needs of our customers with innovative pricing products. For example, GPC has supported the offering of Price Protection Products to RTP customers for several years. The portfolio of new RTP Alternatives will successfully meet the needs of RTP customers to mitigate RTP price risk. The Alternatives provide fair, reasonable and competitive rate options. They are excellent pricing solutions for RTP customers.

Second, customers have requested the development and offering of these specific rate alternatives. The W.A.N.T. Project (What Are The Needs Today; see Exhibit___(HKO-14)) was a year-long Georgia Power initiative in 1999 aimed at developing innovative pricing products to meet the needs in our marketplace. In this extensive market research project, we surveyed and interviewed many RTP customers to understand their needs. We designed the Alternatives around their needs and tested the Alternatives with those customers. Customer feedback on this package of Alternatives has been clearly positive and favorable because of the Alternatives' ability to alleviate risk at fair and reasonable prices.

Q. BRIEFLY DESCRIBE THE RTP ALTERNATIVES.

A. A general analogy to illustrate the value of the RTP Alternatives would be home mortgage rate options. A prospective homeowner's alternatives for paying the mortgage company for the loan service include a range of choices, from purely adjustable rates to 30-year fixed rates. The adjustable mortgage rates obviously represent RTP in this analogy, and the range of other alternatives, which could be part-adjustable/part-fixed options or completely fixed options, represent the new RTP Alternatives. With the adjustable mortgage rates and RTP, you take on more risk to get access to the lower cost. With the fixed mortgage rates and the RTP Alternatives, you agree to pay a little more to lock in an attractive rate and protect yourself against possible increases during some periods of time.

GPC proposes the following four RTP Alternatives. A tabular summary is provided as well as a brief written description on each of the Alternatives. In addition, a "scorecard" on specific attributes is shown on Exhibit___(HKO-15).

Alternative	Description
RTP with Adjustable CBL	Raise or lower CBL at expected RTP prices
RTP with Price Protection Products	Financial hedge contracts (CfDs, Caps, Collars and Index Pricing)
Variable Incremental Pricing	Time of Use (TOU) pricing; interruptible for reliability and economics
Fixed Incremental Pricing	TOU pricing

1) <u>RTP with Adjustable CBL</u>

RTP with Adjustable CBL allows an RTP customer to manage RTP price risk. The customer may adjust the Customer Baseline Load (CBL) once a year to manage the level of exposure to RTP prices. The customer may select to raise the CBL for a twelve-month period in order to lock in expected RTP prices for some or all of the incremental load. Or the customer may select to lower the CBL for a twelve-month period in order to apply RTP prices to more load. The monthly Standard Bills will be recalculated to reflect the adjustment to the CBL. See Exhibit___(HKO-16-1) and (HKO-16-2) for illustrations. Refer to Exhibits___(HKO-16-3) and (HKO-16-4) for copies of the tariffs.

2) <u>RTP with Price Protection Products</u>

RTP with Price Protection Products (PPP) allows a RTP customer to manage RTP price risk. PPPs are separate financial hedge contracts (Caps, CfDs, Collars and Index Prices) that may be used to achieve price stability during specific time periods. GPC has offered PPPs on a limited, pilot basis in the past and seeks to improve and expand the program to more customers with more products. See Exhibits___(HKO-17-1) and (HKO-17-2) and (HKO-17-3) for an example. Refer to Exhibit___(HKO-17-4) for a copy of the tariff.

3) <u>Variable Incremental Pricing</u>

Variable Incremental Pricing (VIP) allows a RTP customer to reduce RTP price risk. VIP provides TOU pricing in most hours for the incremental load, that is, load in excess of the CBL. The incremental load is interruptible for both economic and reliability considerations. During the economic and reliability periods the customer may choose to "buy through" by paying RTP-HA (Hour Ahead) prices and RTP-HA plus $3.50/kWh, respectively. VIP should be thought of as a non-RTP rate alternative. In fact, it is similar to PL plus the SE rider, but with a lot of improvements. See Exhibit___(HKO-18-1) for an illustration. Refer to Exhibit___(HKO-18-2) for a copy of the tariff.

4) <u>Fixed Incremental Pricing</u>

Fixed Incremental Pricing (FIP) allows an RTP customer to remove RTP price risk. FIP provides simple, fixed, firm Time-Of-Use (TOU) pricing for those customers who prefer a stable price. To simplify the pricing and billing under this tariff, all of the customer's usage is actually priced at the FIP TOU energy charges, and a fixed charge is developed to cover the fixed costs of serving the customer. This economic TOU tariff should also be thought of as a non-RTP rate alternative. It is a simple, economically priced TOU rate. Refer to Exhibit___(HKO-19) for a copy of the tariff. Refer also to Exhibit___(HKO-20) for an updated version of the Large Business Reduction Rider (LBR-2) which now includes FIP. See Exhibit___(HKO-21) for an example.

See Exhibit___(HKO-22) which shows a menu of RTP Alternatives. See Exhibit___(HKO-23) which illustrates cost versus price risk for the RTP Alternatives.

Q. HOW MANY CUSTOMERS ARE EXPECTED TO GO ON THE RTP ALTERNATIVES?

A. The following table describes the possible participation rates for each alternative.

Alternative	**Possible Participation Rates**
RTP with Adjustable CBL	200- 400 customers
RTP with Price Protection Products	200- 400 customers
Variable Incremental Pricing	50-200 customers
Fixed Incremental Pricing	100-300 customers
Remain with Standard RTP Tariff	600-1000 customers

Q. WHAT ARE THE BENEFITS OF THE RTP ALTERNATIVES?

A. There are many significant benefits of the RTP Alternatives to customers, the Company and non-participants. Some of them are:

- Improves customers' operating budget stability
- Allows customers to transfer more or additional price risk to Georgia Power
- Allows customers to lock in profits from their products and services
- Insures customers against extreme weather and other events which drive RTP prices up
- Improves customer satisfaction
- Provides simplicity (e.g., FIP)
- Maintains competitive pricing
- Maintains efficient price signals which will retain on-peak load response

Q. DESCRIBE GPC'S EXPERIENCE WITH PRICE PROTECTION PRODUCTS.

A. The Company has completed very successful pilot programs with Price Protection Products. Informal surveys of account representatives and customers have revealed significant interest in PPPs. Customers who have purchased PPPs are very satisfied, and it is highly likely they will use them again. Many customers who have not purchased PPPs have indicated that it is highly likely they will purchase them in the future if they are available. Some customers would like to see more options, and all customers need more time prior to the summer to complete their decision analysis. Therefore, it is important that the company be able to have firm plans from year to year to offer PPPs in order to help customers plan for upcoming periods. It is very difficult for a customer to plan if they are not sure whether or not PPPs will be available.

Customers appreciate the options and have shown significant interest in PPPs as demonstrated by the following information. In 1996, 13 contracts were signed (9 Caps and 4 CfDs). The company collected $343,000 which was driven by the relatively mild summer weather in 1996. In 1999, 64 contracts were signed (49 CfDs, 12 Caps and 3 Collars). The company collected $337,000 and paid out $2,166,000. The payouts were driven by the severe heat in late July and early August. In summary, PPPs have been very successful for both the customers and the company, and RTP customers have expressed their desire that the program continue and be expanded.

Q. HAVE YOU ASKED YOUR CUSTOMERS WHETHER THEY WOULD BE INTERESTED IN POTENTIAL PRICING PRODUCTS?

A. Yes, and we have found a lot of excitement and eagerness on our customers' part to get them approved. There will be a considerable number (maybe 1/3 to 2/3) of the present RTP population who will choose to stay on the RTP tariff since, as previously stated, in the long run RTP should be the cheapest option. In fact, a number of the customers represented by GIG and GTMA may remain with RTP for this reason, but a considerable number may volunteer for the Alternatives.

SPECIFIC ERRORS AND MISSTATEMENT IN PETITIONER'S TESTIMONY

Q. DID MR. POLLOCK CORRECTLY CALCULATE THE REVENUE VARIANCE ASSOCIATED WITH HIGH REAL TIME PRICES IN 1999?

A. No, the $63 million figure calculated by Mr. Pollock is incorrect. Actual RTP revenues during 1999 were $48,976,678 above the forecasted revenues. Since total 1999 Georgia Power revenues were $131.7 million over the forecasted revenues, the RTP revenue variance was about 37% of the total, instead of 60% quoted by Mr. Pollock. For comparison, 14.5% of the revenue variance was supplied by residential customers and 50% of the revenues variance was supplied by commercial customers.

Q. DO YOU AGREE WITH MR. POLLOCK WHERE HE STATES THAT RTP IS NO LONGER A COST-BASED RATE BECAUSE OF GPC'S "…APPARENT UNWILLINGNESS TO PROTECT ITS CAPTIVE CUSTOMERS FROM THE EXTREME HIGH PRICES AND VOLATILITY CAUSED BY TIGHT CAPACITY SUPPLIES…"?

A. No. This is not a true statement, but demonstrates a misunderstanding of the difference between marginal costs and average costs. Rates based on real time system lambda (system incremental cost) are inherently both marginal cost based and volatile. System incremental cost, as calculated in real time, is highly sensitive to the available system

Note: Bold faced type in answers indicates trade secret material. Please refer to the assigned name when discussing.

generation mix (which is subject to resource outage variations), load variations (which are in turn highly sensitive to weather variations) and various congestion factors, all of which can be and are monetized for use in the calculation of RTP prices. This is distinctly different from average cost methodology where volatility is averaged out over time.

Mr. Pollock states that "… the RTP tariffs do not allow purchased power costs to be included in the hourly price…" This is not true. The original RTP tariff was developed based on the resource stack concept utilized by Southern Company for economic dispatch and unit commitment. Power purchases were considered a part of the resource stack and included in the calculation of system incremental costs at the time RTP was developed as they are today. They were not nearly as common at that time, but they were part of the stack. The Resource Stack concept was used at Southern Company and throughout the electric utility industry considerably prior to the development of the RTP tariff. In this concept, all dispatchable resources, including both generation and purchases as well as (potentially) economically driven interruptible customers, are included in a resource stack that is ordered on an economic basis. Resources are drawn from the stack to serve system needs as required and the economic point in the stack from which the resource is drawn effectively sets system incremental cost or lambda. All dispatchable resources are included in the stack unless specifically excluded for contractual or technical reasons.

Q. CAN YOU COMMENT ON MR. POLLOCK'S COMPLAINTS ON THE INCREASE IN RTP PRICES?

A. There is no doubt that 1998 and 1999 RTP prices have been higher. One must be cautious however in presuming that the most recent two years are absolute indicators of the future. Please see Exhibit___(HKO-24) for the RTP price increase over the first 5 years. As we have stated earlier, the last two years have had extraordinary weather conditions when compared to the past 20 years. In addition, the cycle of this capital intensive industry in terms of capacity is very relevant. Exhibit___(HKO-25) shows an expected RTP price growth rate from inception to expected year 2000.

Q. IS MR. POLLOCK'S ANALOGY OF "SELLING A LOT FULL OF FORD AUTOMOBILES AT A MERCEDES PRICE JUST BECAUSE ONE MERCEDES HAPPENS TO BE PARKED ON THE SAME LOT" A FAIR ANALOGY?

A. No, absolutely not. Whether a kWh is generated by a base load unit, a combustion turbine, or a purchase, that kWh is identical in make-up. To use his construct you have a lot full of identical kWhs. The fact is that the last kWhs that you added to the lot are expensive, in fact the most expensive on the lot and indicative of what you will have to pay to add additional kWhs to your lot and possibly the future cost to replace any kWhs currently on your lot. So the products are sold on your lot at this recent cost (much like an accountant uses last-in-first-out --LIFO—for inventory valuation).

Q. IS MR. POLLOCK'S ALLEGATION ON PAGE 19 STATING THAT RTP SALES COULD SUPPORT PRODUCTION INVESTMENT 123% HIGHER THAN GPC'S NET PRODUCTION PLANT CORRECT?

A. No, and it contains numerous flaws. For one thing we have clearly shown previously that what Mr. Pollock is using as margin is not purely production plant margin. Mr. Pollock's testimony calculated "margin" as the difference between the total selling price and the associated Fuel Cost Rate (FCR). However, a margin should be calculated as the difference between the selling price and the costs of production. His approach ignores several key issues: (1) FCR recovers the total average fuel costs for all of the energy supplied by Georgia Power Company. The correct method of calculating RTP margin would include subtracting marginal fuel and purchase power costs from RTP revenues. (2) Subtracting certain transmission costs associated with RTP. (3) Subtracting certain generation reliability costs associated with RTP. (4) Subtracting risk cost associated with RTP. In addition, there are clean air, commitment costs, additional distribution plant, and incremental overheads that "margin" must cover.

The RTP rate was designed to provide customers with the benefits of marginal pricing while capturing marginal cost associated with serving RTP loads. It is incorrect to assume that fuel is the only marginal cost associated with RTP load and it also incorrect to assume that RTP fuel costs are equal to average fuel costs for the entire company.

Second, even if you performed the computation correctly, you certainly could not compare this marginal cost margin to GPC's "net production plant, which has a book value of about $340 per kW…". Marginal cost are distinctly different from net plant book value, just like replacement cost are very different from vintage cost. The SES could certainly not replace its production plant today at $340 per kW. Finally, if Mr. Pollock's idea here is to compare a "margin contribution" from RTP after removing the FCR, even if one thought this were a reasonable exercise, the fact is that CT investment cost is recovered through the outage cost component. This so-called lambda contribution above FCR is not necessary for recovery of CT cost per kW. Therefore, one should remove CT cost from the $340 per kW before making a comparison using this line of reasoning.

Q. PLEASE EXPAND ON MR. POLLOCK'S DEFINITION OF LAMBDA AS EXCLUDING PURCHASE POWER.

A. His definition applies to unit lambda only, not to system lambda. Lambda, as it applies to individual, fuel fired generating units per the IIC, includes:

- Unit Incremental Heat Rate at output P (b + 2cP)
- Marginal Fuel Cost (FC)
- Incremental emissions cost (EC, excluded from GPC RTP lambda)
- Fuel Handling Cost (FH)
- Variable Operating and Maintenance Cost (VOM)
- Transmission Penalty Factor (TPF)

Note: Bold faced type in answers indicates trade secret material. Please refer to the assigned name when discussing.

The equation for Unit Lambda is:

$\lambda_\upsilon = [(b + 2c)(FC + EC) + FH + VOM]TPF$

Note, however, that unit lambda does not a system lambda make. System lambda is the incremental cost to serve the next MWH of load on the system. If it is served by fuel fired generating units, then the equation above is essentially correct, although somewhat simplistic (there are over one hundred units, each with its own unit lambda that go into the calculation of system lambda). However, if the next MWH of generation is being supplied by other than a fuel fired generating unit, then the incremental cost of that resource is used and not the equation above. This is typically the case for purchases at the top of the loading stack, but can apply equally well for nuclear resources at the bottom. Thus, as stated earlier, system lambda is set by the incremental cost of the resource being utilized from the resource stack, which may or may not be a fuel fired generating unit.

Q. ARE THE PURCHASE DECISIONS OF THE TRADING FLOOR INFLUENCED BY COST RECOVERY CONSIDERATIONS?

A. No. The trading floor seeks to obtain the most cost effective short-term products for the Operating Companies, with due regard for reliability and risk mitigation. Retail cost recovery considerations are not a motivating factor in the trading floor's decision making process. As explained in response to Staff Data Requests, the following are the general principles followed when making purchases and sales.

- Direct the lowest cost off-system energy available to territorial customers if it can reasonably be expected to result in savings.

- To extent energy from retail jurisdictional resources is marketed elsewhere, the transaction will be treated as an economy sale.

- If energy from resources that are not retail jurisdictional is marketed elsewhere, all losses or gains will be directed to the wholesale jurisdiction.

- Energy from retail jurisdictional resources, which have been replaced with lower cost energy, may be marketed elsewhere with impacts being direct to the wholesale jurisdiction.

SUMMARY RESPONSE TO PETITION

Q. WOULD YOU SUMMARIZE YOUR RESPONSES TO THE MAIN ISSUES RAISED BY THE PETITIONERS?

A. With respect to the issues raised by GTMA and GIG, it is Georgia Power Company's position that:

1. RTP should continue to be based upon marginal cost reflected in the last resource to serve the last increment of load.

2. The fuel clause should continue to be credited at the prevailing fuel cost recovery (FCR) rate.
3. The present risk adders of 5 mills for RTP-DA and 4.5 mills for RTP-HA are appropriate, reasonable and necessary.
4. The RTP tariffs were properly considered in prior IRP proceedings and in the Company's last retail rate case and the Commission determined that the rate reductions included in the modified stipulation adopted as the "Accounting Order Alternative Rate Plan" resulted in rates that were "fair, just and reasonable". Those tariffs should not be modified now.

Q. IN CONCLUSION SHOULD THIS COMMISSION MAKE ANY CHANGES TO THE RTP TARIFFS BASED ON THE PETITIONERS' DEMANDS?

A. No. The Commission should deny the requests of the petitioners and leave the RTP-DA and RTP-HA tariffs intact as they are. Also the Commission should approve the RTP Alternatives to allow for implementation for this summer.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Georgia Power Company
Docket No. 56298 & 56310
Certification of 2029-2031 All-Source RFP & 2028-2031 Supplemental Resources
STF-PIA Data Request Set No. 1

STF-PIA-1-7

Question:

Procurement Impacts: Refer to the Company's load and resource balance tables provided in "2029-2031 All-Source RFP Certification Application Needs Charts Workpaper.xlsx"

a. Describe any approved or ongoing procurement activities (BESS RFP, CARES RFP, DG RFP, etc.) that are planned or underway.

b. For each procurement, please indicate if an amount of capacity has been included in the load and resource balance and the support for the assumed capacity contribution.

c. For each dispatchable demand-side option (DSO) in the table, please describe any approved or ongoing rate initiatives that may increase the amount of DSO anticipated in years included in the analysis and how those changes are captured in the projected years.

Response:

a. The following table summarizes the approved or ongoing procurement activities that are planned or underway.

Approved or Ongoing Procurement Activities	Status	Nominal Capacity Contribution MW
2029-2031 All-Source RFP	Certification Application Filed	7,999
Proposed Supplemental Resources	Certification Application Filed	1,886
Winter 27_28 BESS RFP	Stipulation Agreement	200
2022 IRP SOLAR US RFP 2 (CARES 2023 US RFP)	Stipulation Agreement	1,068
2022 IRP ESS RFP	Underway	500
2022 IRP SOLAR US RFP 2 (CARES 2025 US RFP)[1]	Underway	1,897
Approved requests from the 2025 IRP, as agreed upon in the 2025 IRP Stipulation and approved by the Commission for Docket Nos. 56002 & 56003		
2032-2033 All-Source RFP[2]	Planned	Capacity Needs Based
Utility-Scale Renewable RFP	Planned	1,000
Distributed Generation Renewable RFPs	Planned	100

Notes:

Contact: Jeff Grubb

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1. The "2022 IRP SOLAR US RFP 2" (CARES 2025 US RFP) represents the Company's plan to procure 475 MW as well as any rollover unprocured capacity from the CARES 2023 RFP.
2. The Company shall issue an All-Source RFP for capacity needs in 2032-2033 in the first quarter of 2026. At least twelve months in advance of issuing any subsequent All-Source RFP, the Company will coordinate with Staff on the selection of an Independent Evaluator. The certified capacity will be based on the projected capacity needs at the time of certification application filing for the 2032-2033 All-Source RFP.

b. For each procurement listed in Subpart (a), the nominal capacity contribution adjusted for the effective load carrying capability ("ELCC") has been included in the "2029-2031 All-Source RFP Certification Application Needs Charts Workpaper.xlsx." Moreover, the values stated in ELCC terms are estimated based on the projected commercial operation dates. The 2032-2033 All-Source RFP will be issued in the first quarter of 2026 to procure resources for projected capacity needs in 2032-2033; therefore, no capacity values are assumed for this RFP in the workpapers.

c. Demand-side options ("DSO") capacity refers to Georgia Power's demand response programs, including interruptible or curtailable load customer programs and incentives. The approved and ongoing DSOs that support the need years are summarized in the tables below. Each program is described, along with the associated rate initiatives for the DSOs. The ratings are based on the program capacity adjusted for ELCC and losses. The ELCC is a measure of the effect of a demand-side option on generating system reliability. In alignment with the approved requests from the 2025 IRP as agreed upon in the 2025 IRP Stipulation and approved by the Commission in Docket Nos. 56002 and 56003, the Company has included the Temp Check increase program DSO capacity.

	Winter Capacity (MW)				
Approved or Ongoing DSOs	**2027**	**2028**	**2029**	**2030**	**2031**
CVR Level 1	204	204	205	207	209
CVR Level 2	204	204	205	207	209
DER Customer Program	0	0	0	0	0
DPEC	92	92	92	92	92
RTPeDA	3	3	3	3	3
RTPeHA	124	124	124	124	124
Temp Check	29	29	29	29	29
Temp Check Increase[1]	58	58	58	58	58
Total	**714**	**714**	**716**	**720**	**724**

	Summer Capacity (MW)				
Approved or Ongoing DSOs	**2027**	**2028**	**2029**	**2030**	**2031**
CVR Level 1	237	236	238	240	242
CVR Level 2	237	236	238	240	242
DER Customer Program	0	0	0	0	0
DPEC	92	92	92	92	92
RTPeDA	5	5	5	5	5
RTPeHA	135	135	135	135	135
Temp Check	34	34	34	34	34
Temp Check Increase[1]	68	68	68	68	68
Total	**808**	**806**	**810**	**814**	**818**

Note:
1. The Temp Check Increase was approved in the 2025 IRP, as agreed upon in the 2025 IRP Stipulation and approved by the Commission in Docket Nos. 56002 and 56003.

DSO Program Description

- CVR Level 1 (Conservation Voltage Reduction Level 1) is a power delivery program where voltage is lowered within allowable standards using Company-installed voltage control devices on distribution circuits.

- CVR Level 2 (Conservation Voltage Reduction Level 2) is a power delivery program where voltage is lowered for limited duration events when reliability is at risk.
- DER Customer Program (Distributed Energy Resource Customer Program) is a program designed for customers that install and use distributed energy resources to reduce demand on the grid, especially during peaking periods.
- DPEC (Demand Plus Energy Credit) is an interruptible load program offered to commercial and industrial customers where Pricing & Rates maintains the capacity available and tracks supply during interruptions.
- RTPeDA (Real-Time Pricing Extreme Day Ahead) is a price response demand program for RTP-DA tariff customers that offers dispatchable resource pricing based on day-ahead forecasts.
- RTPeHA (Real-Time Pricing Extreme Hour Ahead) is a price response demand program for RTP-HA tariff customers that provides dispatchable resource pricing based on hour-ahead forecasts.
- Temp Check (Thermostat Energy Management Program) is an interruptible load program that is a residential air conditioning cycling program and provides dispatchable demand reductions during the summer.

Sierra Club/SACE/NRDC
Ex. 12
05-06-26

STF-JKA-2-2

Question:

Refer to page 4, lines 4-8, "No. The Company is not proposing a specific date for its next fuel case."

a. Confirm the forecast period ends May 2028.

b. Provide the incremental amount of generating capacity the Company anticipates bringing online over the FCR-27 forecast period through May 2028.

c. Provide the incremental load growth the Company anticipates adding over the FCR-27 forecast period through May 2028.

d. Please explain if the Company anticipates new capacity and large loads to increase overall fuel costs, for example the magnitude of fuel and purchase power assessed and evaluated in a fuel case.

e. Has the Company considered aligning future FCR proceedings with an IRP or rate case filings? Why or why not?

Response:

a. Yes, the test period proposed in FCR-27 ends in May 2028.

b. Please see MFRP-11 submitted in the Company's initial filing submitted February 17, 2026 for the incremental generation capacity expected to come online in the projected test period. Of the megawatts ("MW") of generation capacity listed, the following units are expected to come online:

Resource	Resource Effective Date
O1_US_TIMBERLAND	6/13/2026
O3_MCGRAU_FORD_PHASE_2_4Hr	8/1/2026
O3_HAMMOND_BESS_4Hr	8/1/2026
O3_2022_IRP_MCGRAU_FORD_2Hr	8/15/2026
QF_ALLIGATOR_CREEK_SOLAR	11/1/2026
YATES_8	12/1/2026

YATES_9	5/1/2027
YATES_10	8/1/2027
O3_TWIGGS_COUNTY_4Hr	11/1/2027
O3_DECATUR_BESS_4Hr	11/30/2027
O3_WASHINGTON_CO_BESS_4Hr	11/30/2027
O3_DOUGHERTY_CO_BESS_4Hr	11/30/2027
O3_WHITE_PINE_BESS_4Hr	11/30/2027
O3_WHITE_OAK_BESS_4Hr	11/30/2027
O1_SR_BACON_III_PB	12/1/2027
O3_WADLEY_BESS_4Hr	12/1/2027
O1_GA_SOLAR_5	12/1/2027
QF_DRAWHORN SOLAR LLC	1/1/2028
QF_SANDERSVILLE SOLAR LLC	1/1/2028
O3_2019_DEMO_BESS	4/30/2028

c. Please see MFRP-17 and MFRP-13.4 submitted in the Company's initial filing for the projected retail sales and wholesale sales, respectively, for the test period.

- The projected increase in retail load and wholesale sales will increase overall fuel expense as described in the Company's Direct Testimony on page 16, line 16 through page 17, line 18. The projected incremental generation capacity noted in item (b) above is intended to serve the Georgia Power system as a whole and not specific individual customers. The Company expects any increase in overall fuel costs from additional load to be mostly offset by the additional expected revenues from the incremental load. Please see the Company's response to STF-JKA-2-12.

d. There are administrative challenges to concurrently filing multiple regulatory proceedings in a given year. Based on prior precedence, the Company's Integrated Resource Plan ("IRP") and base rate case filings are already scheduled to be filed triennially in the same year going forward. Adding the fuel case filing to this schedule within the same year will provide significant administrative challenges and will be overly burdensome.