Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 7

STF-DEA-7-12

Question:

Referring to the Company's Quarterly Economic Development Reports, please respond to the following questions:

a. Since the 2023 IRP Update, has the Company analyzed the tendency for projects to accelerate or delay initially proposed load ramps? If so, please provide any such analysis in its original format in addition to a narrative description of the analysis performed. For any spreadsheet responses, please ensure the file is provided in spreadsheet format with any formulas and references intact.

b. Since the 2023 IRP update, has the Company observed any trends in the tendency for projects to accelerate or delay initially proposed load ramps? If so, do these trends differ from the assumptions in the Load Realization model?

c. Since the 2023 IRP Update, has the Company analyzed the tendency for projects to select Georgia Power as the ultimate service provider, referring to the P1, P2, and P3 probabilities? If so, please provide any such analysis in its original format in addition to a narrative description of the analysis performed. For any spreadsheet responses, please ensure the file is provided in spreadsheet format with any formulas and references intact.

d. Since the 2023 IRP Update, has the Company observed any trends in the tendency for projects to select Georgia Power as the ultimate service provider, referring to the P1, P2, and P3 probabilities? If so, do these trends differ from the assumptions in the Load Realization Model?

e. Since the 2023 IRP Update, has the Company analyzed the tendency for projects to materialize load as expected? If so, please provide any such analysis in its original format in addition to a narrative description of the analysis performed. For any spreadsheet responses, please ensure the file is provided in spreadsheet format with any formulas and references intact.

f. Since the 2023 IRP Update, has the Company observed any trends in the tendency for projects to materialize as expected? If so, do these trends differ from the assumptions in the Load Realization Model?

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Response:

a. Since the 2023 Integrated Resource Plan ("IRP") Update, the Company has not analyzed the tendency for projects to accelerate or delay initially proposed load ramps. For details on changes to customer proposed load ramps and initial service dates please refer to the "Ramp Change" and "Initial Service Change" tabs of STF-PIA-8-2 Attachments A-D TRADE SECRET, which contain the Company's quarterly 2024 Large Load Economic Development Reports.

b. Since the 2023 IRP Update, the Company has observed certain projects accelerate their load ramp and other projects delay their load ramp. Such trends are incomparable to the assumptions in the Load Realization Model ("LRM") as the LRM assesses the risk that a project's initial service date and load ramp schedule delay beyond their proposed load ramp. As projects change their proposed load ramp that input is updated in the model and then subject to the delay assumptions within the LRM rather than comparing back to the original load ramp no longer applicable to the project.

c. Since the 2023 IRP Update, the Company has not analyzed the tendency for projects to select Georgia Power as the ultimate service provider.

d. Since the 2023 IRP Update, the Company has not observed any trends in the tendency for projects to select Georgia Power as the ultimate service provider.

e. Since the 2023 IRP Update, the Company has not analyzed the tendency for projects' load to materialize as expected. Such an analysis would require a larger sample size of large load projects to have reached a mature stage in their load ramps. Given the early stages of large loads, the Company lacks the adequate sample size of mature projects to make such an assessment.

f. Since the 2023 IRP Update, the Company has not observed any trends in the tendency for projects' load to materialize as expected. As previously stated, such an analysis would require a larger sample size of large load projects to have reached a mature stage in their load ramps.

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Docket Nos. 55378
Georgia Power Company's 2023 IRP Update
STF-DEA Data Request Set Number 5

STF-DEA-5-3

Question:

Please refer to the large Load Realization Model

a. On the "Assumptions" tab,

  i. Describe the extent to which historical data was used to determine the Low/Mid/High probabilities in columns G:I. Please name specific Class/Segment combinations and refer to a source where applicable.
  ii. Describe why Cryptocurrency and Datacenter load is more likely to materialize than the other industrial segments.

Response:

a.

  i. The Company has limited historical experience with large contracted loads across the various industry segments that are considering Georgia Power. Consequently, the company relied on informed judgment to establish key assumptions, including the Low, Mid, and High percentages shown in columns G to I. These percentages reflect the ratio between actual metered load and the announced load.
  ii. Columns G:I on the "Assumptions" tab of the Load Realization Model represent the ratio (in %) between actual metered load and announced load. Due to the continuous operation of their equipment, Cryptocurrency and Datacenters are expected to use most of their connected load. Consequently, their percentage is higher than that of other segments included in the model. In contrast, industrial segments, which do not operate their connected load simultaneously, are assigned a lower percentage.

Contact: Francisco Valle

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Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-JKA Data Request Set No. 6

STF-JKA-6-1

Question:

During the Company's Direct Testimony hearing on 3/25/2025, the Company discussed that it will have to plan for resources to accommodate the fact that a large amount of data center load will be added to the system that will be energy intensive and will be expected to operate with load factors of around 90 to 95% on an annual basis.

a. What is the Company's support for the projection of 90 to 95% load factors on an annual basis, for example is it based on the Company's current experience with existing data centers, or discussions within the industry, or some other way?

b. The Company indicated it has direct experience providing electric service to data centers. Please identify the specific data centers, the date they initially took service, each data center's annual max load (MW) and annual consumption (MWH) through 2024.

c. Please provide any analyses, narratives or other writings prepared by or available to the Company that support the high load factor projections.

d. Please provide any analyses, narratives or other writings prepared by or available to the Company that address weather sensitivity of large data center loads to both winter low temperatures and summer high temperatures.

Response:

a. See response to subpart (c).

b. See STF-JKA-6-1 Attachment TRADE SECRET.

c. Among the data centers the Company is serving as of the end of 2024, only the largest two have a peak demand above the threshold for Large Load projects (115MW for Commercial). Their load factors in 2024 are 90% and 82%, respectively. Given the increasingly important role data centers play as artificial intelligence ("AI") technology is being developed and deployed, the Company believes it is reasonable to expect data centers in the Large Load pipeline will operate with load factors that are more elevated than observed to date.

d. The Company does not have analysis about the weather sensitivity of data centers. However, data centers do display a seasonality in the load. The load in the summer is 10% higher than in the non-summer.

Contact: Francisco Valle

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Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 3

STF-DEA-3-7

Question:

Referring to the B2025 Load Realization Model, please respond to the following questions:

a. Please describe how the Company applies the results of the model to adjust the organic load forecast on an energy basis.

b. Please describe how the Company applies the results of the model to adjust the organic load forecast on a peak load basis.

Response:

a. As stated in Section 7.0 in Technical Appendix Volume 1, p. 102, energy sales from the Load Realization Model ("LRM") are treated as an external adjustment to the baseline organic sales forecast. This means that the risk-adjusted large load energy forecasts are added on to the baseline/organic energy forecasts.

b. Peaks are also treated as an external adjustment to the organic forecast. The large load data center energy forecast from the LRM gets a data center load shape applied to it to get hourly load values. These values are then added to the organic hourly load forecast values for the commercial class load and resulting class peak. Similarly, the energy forecast for new large load industrial customers gets an industrial load shape applied to it, and the hourly values are added to the baseline organic hourly load forecast to get the total industrial class peak.

Contact: Francisco Valle

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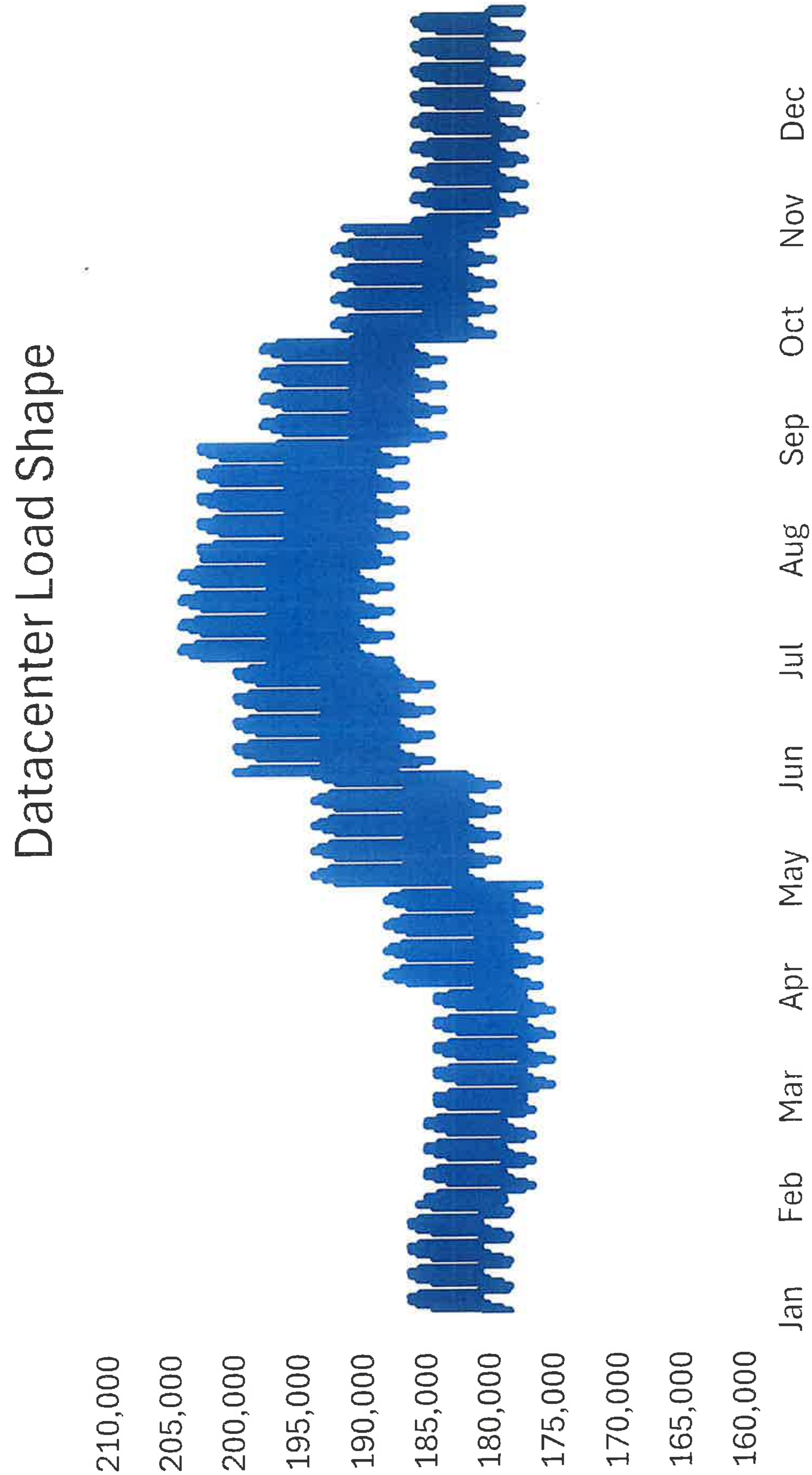
Datacenter Load Shape
210,000
205,000
200,000
195,000
190,000
185,000
180,000
175,000
170,000
165,000
160,000
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

1976

GPC EXHIBIT 9

STF-JKA-1-3 Attachment A

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Table 4.6.1b - Georgia Power Territorial Base Case Load vs. Existing Capability 111-MG0 (Summer)

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Demand (MW), (A)	17,802	18,770	20,552	22,730	24,621	25,841	26,554	26,695	27,268	27,550	27,790	27,939	28,206	28,412	28,675	28,839	29,219	29,619	30,030	30,514
Owned Generating Capacity (MW)	13,868	14,708	16,028	16,751	15,747	15,752	15,752	15,752	15,752	15,752	15,752	15,752	15,752	15,752	11,718	11,718	11,718	11,718	11,718	11,718
Purchased Generating Capacity (MW), (B)	7,410	7,522	7,522	7,446	6,981	5,701	5,915	5,915	5,859	5,845	4,128	4,000	3,841	3,617	3,617	3,308	3,256	3,246	3,241	3,238
Dispatchable DSOs (MW), (C)	729	735	739	739	742	746	751	754	759	763	766	770	777	783	789	803	813	824	835	846
Total Capacity (MW)	22,007	22,965	24,290	24,936	23,470	22,200	22,419	22,422	22,371	22,360	20,647	20,523	20,370	20,152	16,123	15,828	15,787	15,788	15,794	15,802
Capacity Required to Meet GPC Target (MW), (D)	(898)	(708)	80	2,132	5,851	8,573	9,203	9,606	10,101	10,448	12,447	12,748	13,218	13,682	18,025	18,515	19,009	19,484	19,968	20,536
GPC Reserve Margin (%)	23.6%	22.3%	18.2%	9.7%	-4.7%	-14.1%	-15.6%	-16.6%	-18.0%	-18.8%	-25.7%	-26.5%	-27.8%	-29.1%	-43.8%	-45.1%	-46.0%	-46.7%	-47.4%	-48.2%

Notes
(A) Territorial Load requirements less non-dispatchable DSOs
(B) Includes territorial and imported power purchases. Capacity does not include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update to show total procurement needs
(C) Values stated in combustion turbine equivalence terms
(D) Does not consider planning reserve sharing. Reflects GPC's Target Reserve Margin, resulting from a System Target Reserve Margin of 19.5% (2025-2027) and 20% (2028 and beyond)

Existing Capability

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Owned Generating Capacity (MW)	13,868	14,708	16,028	16,751	15,747	15,752	15,752	15,752	15,752	15,752	15,752	15,752	15,752	15,752	11,718	11,718	11,718	11,718	11,718	11,718
Nuclear	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980
HATCH 1	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439
HATCH 2	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
VOGTLE 1	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539	539
VOGTLE 2	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540	540
VOGTLE 3	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
VOGTLE 4	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Coal	3,924	3,924	3,924	3,924	3,386	3,386	3,386	3,386	3,386	3,386	3,386	3,386	3,386	3,386	-	-	-	-	-	-
BOWEN 1	714	714	714	714	714	714	714	714	714	714	714	714	714	714						
BOWEN 2	705	705	705	705	705	705	705	705	705	705	705	705	705	700						
BOWEN 3	910	910	910	910	910	910	910	910	910	910	910	910	910	910						
BOWEN 4	916	916	916	916	916	916	916	916	916	916	916	916	916	916						
SCHERER 1	75	75	75	75	75	75	75	75	75	75	75	75	75	75						
SCHERER 2	72	72	72	72	72	72	72	72	72	72	72	72	72	72						
SCHERER 3	537	537	537	537																
WANSLEY 1																				
WANSLEY 2																				
Combined Cycle	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885	3,885
MCDONOUGH 4	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855
MCDONOUGH 5	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850
MCDONOUGH 6	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840
MCINTOSH 10	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670
MCINTOSH 11	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670	670
Oil/Gas Steam	1,108	1,108	1,108	1,108	648	648	648	648	648	648	648	648	648	648	-	-	-	-	-	-
GASTON 1 GAS	127	127	127	127																
GASTON 2 GAS	126	126	126	126																
GASTON 3 GAS	102	102	102	102																
GASTON 4 GAS	105	105	105	105																
YATES 6 GAS	323	323	323	323	323	323	323	323	323	323	323	323	323	323						
YATES 7 GAS	325	325	325	325	325	325	325	325	325	325	325	325	325	325						
Combustion Turbine	1,491	1,491	2,091	2,814	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807	2,807
GASTON A	8	8	8	4																
MCDONOUGH 3A																				
MCDONOUGH 3B																				
MCINTOSH 1A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCINTOSH 2A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCINTOSH 3A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCINTOSH 4A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCINTOSH 5A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCINTOSH 6A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCINTOSH 7A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCINTOSH 8A	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
MCMANUS 3A	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS 3B	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS 3C	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS 4A	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44

MCMANUS 4B	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS 4C	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS 4D	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS 4E	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS 4F	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
MCMANUS DIESEL																				
WANSLEY 5A																				
WARNER ROBINS 1	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
WARNER ROBINS 2	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
WILSON 1A	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
WILSON 1B	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
WILSON 1C	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
WILSON 1D	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
WILSON 1E	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
WILSON 1F	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
WILSON DIESEL																				
YATES 10				441	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441
YATES 8			300	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441
YATES 9			300	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441	441
Pump Storage	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
ROCKY MTN 1 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
ROCKY MTN 2 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
ROCKY MTN 3 PS	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
WALLACE DAM 1 PS	53	53	53	53	[illegible]	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
WALLACE DAM 2 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
WALLACE DAM 5 PS	53	53	53	53	[illegible]	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
WALLACE DAM 6 PS	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
Hydro	**688**	**688**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**
BARTLETT'S FERRY 1 HY	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
BARTLETT'S FERRY 2 HY	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
BARTLETT'S FERRY 3 HY	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
BARTLETT'S FERRY 4 HY	22	22	22	22	22	[illegible]	22	22	22	22	22	22	22	22	22	22	22	22	22	22
BARTLETT'S FERRY 5 HY	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
BARTLETT'S FERRY 6 HY	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59	59
BURTON 1 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
BURTON 2 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
ESTATOAH 1 HY																				
FLINT RIVER 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
FLINT RIVER 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
FLINT RIVER 3 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
GOAT ROCK 3 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
GOAT ROCK 4 HY																				
GOAT ROCK 5 HY																				
GOAT ROCK 6 HY	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
GOAT ROCK 7 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
GOAT ROCK 8 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LANGDALE 5 HY																				
LANGDALE 6 HY																				
LLOYD SHOALS 1 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LLOYD SHOALS 2 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LLOYD SHOALS 3 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LLOYD SHOALS 4 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LLOYD SHOALS 5 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
LLOYD SHOALS 6 HY	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
MORGAN FALLS 1 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
MORGAN FALLS 2 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
MORGAN FALLS 3 HY																				
MORGAN FALLS 4 HY																				
MORGAN FALLS 5 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
MORGAN FALLS 6 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
MORGAN FALLS 7 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
NACOOCHEE 1 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
NACOOCHEE 2 HY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
NORTH HIGHLANDS 1 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
NORTH HIGHLANDS 2 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
NORTH HIGHLANDS 3 HY	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
NORTH HIGHLANDS 4 HY	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
OLIVER 1 HY	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
OLIVER 2 HY	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
OLIVER 3 HY	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
OLIVER 4 HY			6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
RIVERVIEW 1 HY																				
RIVERVIEW 2 HY																				
SINCLAIR 1 HY	22	22	22	22	[illegible]	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
SINCLAIR 2 HY	22	22	22	22	[illegible]	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
TALLULAH 1 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
TALLULAH 2 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
TALLULAH 3 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
TALLULAH 4 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
TALLULAH 5 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
TALLULAH 6 HY	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
TERRORA 1 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
TERRORA 2 HY	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
TUGALO 1 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 2 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 3 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
TUGALO 4 HY	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
WALLACE DAM 3 HY	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57

STF-JKA-1-3 Attachment A

WALLACE DAM 4 Hr	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
YONAH 1 Hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 2 Hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
YONAH 3 Hr	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar	**228**	**228**	**228**	**228**	**228**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**	**234**
COMMUNITY SOLAR - CLIPPER	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
COMMUNITY SOLAR - DALTON	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
COMMUNITY SOLAR - WAYNESBORO	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
FALCONS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
FORT BENNING	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
FORT GORDON	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
FORT STEWART SOLAR	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
FORT VALLEY STATE UNIVERSITY	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
KINGS BAY SOLAR	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
PL BRANCH CLOSED ASH POND	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
MCLB	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
MOODY AFB	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
RIGHT OF WAY SOLAR	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ROBINS AFB	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96	96
SNA SOLAR	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Unassigned Self Build Solar						6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
System Sales	**(840)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SYSTEM SALE	(840)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Generating Capacity (MW)	**7,410**	**7,522**	**7,522**	**7,446**	**6,981**	**5,701**	**5,915**	**5,915**	**5,859**	**5,845**	**4,128**	**4,000**	**3,841**	**3,617**	**3,617**	**3,308**	**3,256**	**3,246**	**3,241**	**3,238**
2017 IRP RENEWABLES - DG S2230	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2019 IRP RENEWABLES - DG S2330	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
2019 IRP RENEWABLES - DG S2430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019 IRP RENEWABLES - DG W2330	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
2019 IRP RENEWABLES - DG W2430	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
2022 IRP BIOMASS - ASR						35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
2022 IRP ESS RFP					500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
2022 IRP SOLAR DG RFP 1	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
2022 IRP SOLAR DG RFP 2		112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112
2022 IRP SOLAR US RFP 1						647	647	647	647	647	647	647	647	647	647	647	647	647	647	647
2022 IRP SOLAR US RFP 2							214	214	214	214	214	214	214	214	214	214	214	214	214	214
2022/2023 US - FLINT RIVER SOLAR	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
2022-2023 US - TIMBERLAND SOLAR	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
2022/2023 US - WADLEY SOLAR	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117
2022/2023 US - WASHINGTON COUNTY SOLAR	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
2023 IRP UPDATE BESS RFP																				
ADDISON 1 (WEST GA)	153	153	153	153	153															
ADDISON 3 (WEST GA)	148	148	148	148	148															
ALBANY RENEWABLE ENERGY	50	50	50	50	50	50	50	50	50	50	50	50								
ASI CLASSIC 210 MW - DG S1320	0	0	0	0	0	0	0	0												
ASI CLASSIC 210 MW - DG S1420	5	5	5	5	5	5	5	5	5											
ASI CLASSIC 210 MW - DG S1520	16	16	16	16	16	16	16	16	16	16										
ASI CLASSIC 210 MW - DG S1620	1	1	1	1	1	1	1	1	1	1	1									
ASI CLASSIC 210 MW - DG W1420	9	9	9	9	9	9	9	9	9											
ASI CLASSIC 210 MW - DG W1520	10	10	10	10	10	10	10	10	10	10										
ASI CLASSIC 210 MW - DG W1620	1	1	1	1	1	1	1	1	1	1	1									
ASI CLASSIC 210 MW - US 1 DUBLIN SOLAR CENTER - DUBLIN	3	3	3	3	3	3	3	3	3	3										
ASI CLASSIC 210 MW - US 1 RICHLAND SOLAR CENTER	13	13	13	13	13	13	13	13	13	13	13									
ASI CLASSIC 210 MW - US 1 RINCON SOLAR CENTER	10	10	10	10	10	10	10	10	10	10	10	10								
ASI CLASSIC 210 MW - US 2 BUTLER SOLAR FARM	11	11	11	11	11	11	11	11	11	11	11									
ASI CLASSIC 210 MW - US 2 DECATUR COUNTY SOLAR PROJECT	12	12	12	12	12	12	12	12	12	12	12									
ASI CLASSIC 210 MW - US 2 HECATE ENERGY - OLD MIDVILLE RD LLC	13	13	13	13	13	13	13	13	13	13	13	13								
ASI CLASSIC 210 MW - US 2 SOLAR GLYNN	10	10	10	10	10	10	10	10	10	10	10	10								
ASI PRIME 525 MW - DG S1625	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
ASI PRIME 525 MW - DG S1635	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASI PRIME 525 MW - DG S1725	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2			
ASI PRIME 525 MW - DG S1730	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
ASI PRIME 525 MW - DG S1735	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
ASI PRIME 525 MW - DG S1815	0	0	0	0	0	0	0													
ASI PRIME 525 MW - DG S1820	0	0	0	0	0	0	0	0	0	0	0	0	0							
ASI PRIME 525 MW - DG S1825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
ASI PRIME 525 MW - DG S1830	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
ASI PRIME 525 MW - DG W1725	7	7	7			7	7	7	7	7	7	7	7	7	7	7	7			
ASI PRIME 525 MW - DG W1730	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
ASI PRIME 525 MW - DG W1735	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ASI PRIME 525 MW - DG W1815	0	0	0	0	0	0	0	0												
ASI PRIME 525 MW - DG W1820	0	0	0	0	0	0	0	0	0	0	0	0	0							
ASI PRIME 525 MW - DG W1825	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5		
ASI PRIME 525 MW - DG W1830	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
ASI PRIME 525 MW - DG W1835	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
ASI PRIME 525 MW - US 1 BUTLER SOLAR	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
ASI PRIME 525 MW - US 1 DECATUR PARKWAY SOLAR PROJECT	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52				
ASI PRIME 525 MW - US 1 PAWPAW SOLAR	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
ASI PRIME 525 MW - US 2 LIVE OAK SOLAR	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
ASI PRIME 525 MW - US 2 WHITE OAK SOLAR	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
ASI PRIME 525 MW - US 2 WHITE PINE SOLAR	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
AXIUM US SOLAR HOLDINGS (SD&D)	1	1																		
BLUE CANYON	71	71	71	71	71	71	71	71	71	71	71									
CCSP DG - ONLINE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCSP DG - REMAINING	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
COCA COLA	6	6	6	6	6	6	6	6	6	6	6									
CONTERRA RENEWABLE ENERGY	3	3	3	3	3	3	3	3	3	3	3	3								

1982

DAHLBERG 1				75	[illegible]	[illegible]	[illegible]	[illegible]	75	75	75	75	75	76						
DAHLBERG 10	75	[illegible]	75	75	[illegible]	[illegible]	[illegible]	[illegible]	75	75	75									
DAHLBERG 2	74	[illegible]	74	74	[illegible]	[illegible]	74	74	74	74	74									
DAHLBERG 3				75	[illegible]	[illegible]	[illegible]	[illegible]	75	75	75	[illegible]	75	75						
DAHLBERG 4	74	[illegible]	74	74	[illegible]															
DAHLBERG 5				75		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	75	75	75	76						
DAHLBERG 6	75	75	75	75	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]									
DAHLBERG 8	74	74	74	74	74	[illegible]	74	74	74	74	74									
DAHLBERG 9	75	75	75	[illegible]	75	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	75									
EXELON HEARD 1	158	158	158	158	158															
EXELON HEARD 2	158	158	158	158	158															
EXELON HEARD 3	158	158	158	158	158															
EXELON HEARD 4	158	158	158	158	158															
EXELON HEARD 5	158	158	158	158	158															
EXELON HEARD 6	158	158	158	158	158															
GEORGIA RENEWABLE POWER FRANKLIN LLC	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GEORGIA RENEWABLE POWER MADISON	58	58	58	58	58	[illegible]	58	58	58	58	58	58	58	58	58	58	58	58	58	58
GREEN POWER SOLUTIONS	29	29	29	[illegible]	29	[illegible]	29	29	29	29	29									
HARRIS 1	641	641	641	641	641															
HARRIS 2	660	660	660	660	660	[illegible]	660	660	660	660	660									
INTERNATIONAL PAPER - FLINT RIVER	27	27	27	27	27	[illegible]	27	27	27	27	27	27	27							
INTERNATIONAL PAPER - PORT WENTWORTH	30	30	30	30	30	[illegible]	30	30	30	30	30	[illegible]	[illegible]							
LSS 50 MW - HSH PEMBROOKE	1	1	1	1	1	1	1	1	1	1	1									
LSS 50 MW - [illegible] SOLAR FARM	17	17	17	17	17	17	17	17	17	17	17									
LSS 50 MW - SOLAR D&D CAMILLA	9	9	9	9	9	[illegible]	9	9	9	9	9									
LSS 50 MW - SOLAR D&D CAMP (MERIWETHER COUNTY)	2	2	2	2	2	[illegible]	[illegible]	2	2	2	2									
MAS GEORGIA LFG - OAK GROVE	6	6	6	6	6	[illegible]	6	6	6	6	6	[illegible]								
MAS GEORGIA LFG - PINE RIDGE	6	6	6	6	6	[illegible]	6	6	6	6	6	[illegible]								
MAS GEORGIA LFG - RICHLAND CREEK	10	10	10	10	10	[illegible]	10	10	10	10	10	10	10							
MPC GEORGIA COGEN	300	300	300																	
MONROE POWER	309	309	309	309	309	[illegible]	309	309	309	309	309	309	309	309	309	309				
[illegible] PPA	750	750	750	750																
PIEDMONT GREEN POWER	55	55	55	55	55	[illegible]	55	55												
REDI 1400 MW - L&I DOUGHERTY COUNTY SOLAR	78	78	78	78	78	[illegible]	78	78	78	78	78	78	78	78	78	78	78	78	78	78
REDI 1400 MW - L&I TANGLEWOOD SOLAR	37	37	37	37	37	[illegible]	37	37	37	37	37	37	37	37	37	37	37	37	37	37
REDI 1400 MW - DG CS S1920	0	0	0	0	0	[illegible]	0	0	0	0	0	0	0	0	0					
REDI 1400 MW - DG CS S1925	2	2	2	2	2	[illegible]	2	2	2	2	2	2	2	2	2	2	2	2	2	
REDI 1400 MW - DG CS S1930	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
REDI 1400 MW - DG CS S1935	[illegible]	9	9	9	[illegible]	[illegible]	9	9	9	9	9	9	9	9	9	9	9	9	9	[illegible]
REDI 1400 MW - DG CS W1925	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
REDI 1400 MW - DG CS W1930	[illegible]	0	0	0	[illegible]	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REDI 1400 MW - DG CS W1935	[illegible]	7	7	7	[illegible]	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
REDI 1400 MW - DG S2030	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG S2035	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
REDI 1400 MW - DG W2030	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
REDI 1400 MW - DG W2035	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
REDI 1400 MW - US 1 QUITMAN SOLAR	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
REDI 1400 MW - US 1 [illegible] SOLAR	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
REDI 1400 MW - US 1 TWIGGS COUNTY SOLAR	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
REDI 1400 MW - US 2 COOL SPRINGS	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
REDI 1400 MW - US 2 HICKORY PARK	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147	147
REDI 1400 MW - US 2 QUITMAN II	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
REDI CS2	[illegible]	0	0	0	0	[illegible]	0	[illegible]	0	0	0	0	0	0	0	0	0	0	0	[illegible]
SANTA ROSA	215	215	215	215																
[illegible] WASTE [illegible]	[illegible]	6	6	6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6	[illegible]	[illegible]								
WALTON COUNTY																				
WANSLEY 6																				
WANSLEY 7	[illegible]	598	598	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	598										
WASHINGTON COUNTY																				
Dispatchable DSOs (MW)	**729**	**735**	**739**	**739**	**742**	**746**	**751**	**754**	**759**	**763**	**766**	**770**	**777**	**783**	**789**	**803**	**813**	**824**	**835**	**846**
CM Level 1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
CM Level 2	231	234	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	240	[illegible]	[illegible]	252	255	258	261	268	274	278	285	290
DER Customer Program																				
[illegible]	92	92	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	92	[illegible]	[illegible]	92	92	92	92	92	92	92	92	92
[illegible]	5	5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5	[illegible]	[illegible]	5	5	5	5	5	5	5	5	5
[illegible]	135	135	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	135	[illegible]	[illegible]	135	135	135	135	135	135	135	135	135
[illegible]	34	34	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	34	[illegible]	[illegible]	34	34	34	34	34	34	34	34	34
Energy Storage	-	-	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**	**715**
2019 IRP BESS DEMO																				
2019 IRP BESS DEMO - FORT STEWART [illegible] BESS			13	13	[illegible]	13	[illegible]	13	13	[illegible]	13	[illegible]	13	13	13	13	13	13	13	13
2022 IRP MCGRAU FORD [illegible] BATTERY			265	265	[illegible]	265	[illegible]	265	265	[illegible]	265	[illegible]	265	265	265	265	265	265	265	265
2022 IRP UPDATE - HAMMOND			58	58	[illegible]	58	[illegible]	58	58	58	58	[illegible]	58	58	58	56	58	58	58	58
2023 IRP Update - MCGRAU FORD PHASE 2			265	265	[illegible]	265	[illegible]	265	265	[illegible]	265	[illegible]	265	265	265	265	265	265	265	265
2023 IRP UPDATE - MOODY AFB			17	17	[illegible]	17	[illegible]	17	17	[illegible]	17	[illegible]	17	17	17	17	17	17	17	17
2023 IRP UPDATE - ROBINS AFB			32	32	[illegible]	32	[illegible]	32	32	[illegible]	32	[illegible]	32	32	32	32	32	32	32	32
MOSSY BRANCH			65	65	[illegible]	65	[illegible]	65	65	[illegible]	65	[illegible]	65	65	65	65	65	65	65	65

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-JKA Data Request Set 4

STF-JKA-4-4

Question:

Please rerun the SERVM reserve margin study without including the modeling of the impact of the Load Forecast Error.

Response:

This simulation was performed as part of the development of Figure III.13 on page 61 of the 2024 Reserve Margin Study in Technical Appendix Volume 1, Section 2. The no load forecast error ("NoLFE") study considered a reserve margin simulation with a 0% load forecast error.

The results of the NoLFE study resulted in a 0.75% decrease in the winter reserve margin. A summer-only NoLFE study was not performed. The table below shows the results of the winter NoLFE study in comparison to the base case study.

Reserve Margin	Base Study	NoLFE Study	Delta
Expected Case Optimal	22.75%	22.00%	0.75%
Risk Adjusted Optimal	25.00%	24.25%	0.75%
1:10 LOLE Threshold	25.75%	25.00%	0.75%

Contact: Brandon Looney

GPC EXHIBIT 11

ASTRAPÉ CONSULTING
innovation in electric system planning

Reserve Margin and Effective Load Carrying Capability (ELCC) Study

Public Report

3/30/2023

PREPARED FOR

Santee Cooper

PREPARED BY

Astrapé Consulting

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ABBREVIATIONS USED IN REPORT

BAA	Balancing Authority Area
BESS	Battery Energy Storage System
CC	Combined Cycle Generator
CT	Combustion Turbine Generator
DR	Demand Response
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EIA	Energy Information Authority
EIDB	Eastern Interconnection Data Base
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
GADS	Generating Availability Data System
GDP	Gross Domestic Product
IRP	Integrated Resource Plan
LFE	Economic Load Forecast Error
LOLE	Loss of Load Expectation
MO	Maintenance Outage
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
ORDC	Operating Reserve Demand Curve
PO	Planned Maintenance Outage
PRM	Planning Reserve Margin
TTF	Time to Fail
TTR	Time to Repair
SAM	NREL System Advisory Model
SERVM	Astrapé's Strategic Energy and Risk Evaluation Model
SEPA	Southeastern Power Administration

EXECUTIVE SUMMARY

This document provides details concerning a two-fold study performed by Astrapé Consulting for Santee Cooper to accomplish the following goals:

1. Determine the Planning Reserve Margin (PRM) associated with the Santee Cooper system.
2. Determine the Effective Load Carrying Capability (ELCC) for a range of solar and Battery Energy Storage System (BESS) penetrations on the Santee Cooper system.

The following summarizes the results of this study.

PRM RESULTS

The PRM of a system represents the amount of additional capacity in excess of forecasted peak load that a system would need in order to maintain an acceptable level of system reliability. In this study, this was accomplished by determining the amount of capacity that would be necessary to maintain a Loss of Load Expecation (LOLE) of 0.1 days/year. This level of reliability corresponds to an expectation of one loss of load event every 10 years, which is consistent with industry practice.

The base case PRM for the Santee Cooper system was performed for two different study years, 2026 and 2029. The 2026 study year represents the near term condition of the Santee Cooper system, while the 2029 study year corresponds with the retirement and subsequent replacement of the Winyah coal facility. The figure below shows the winter PRM produced from the analysis.

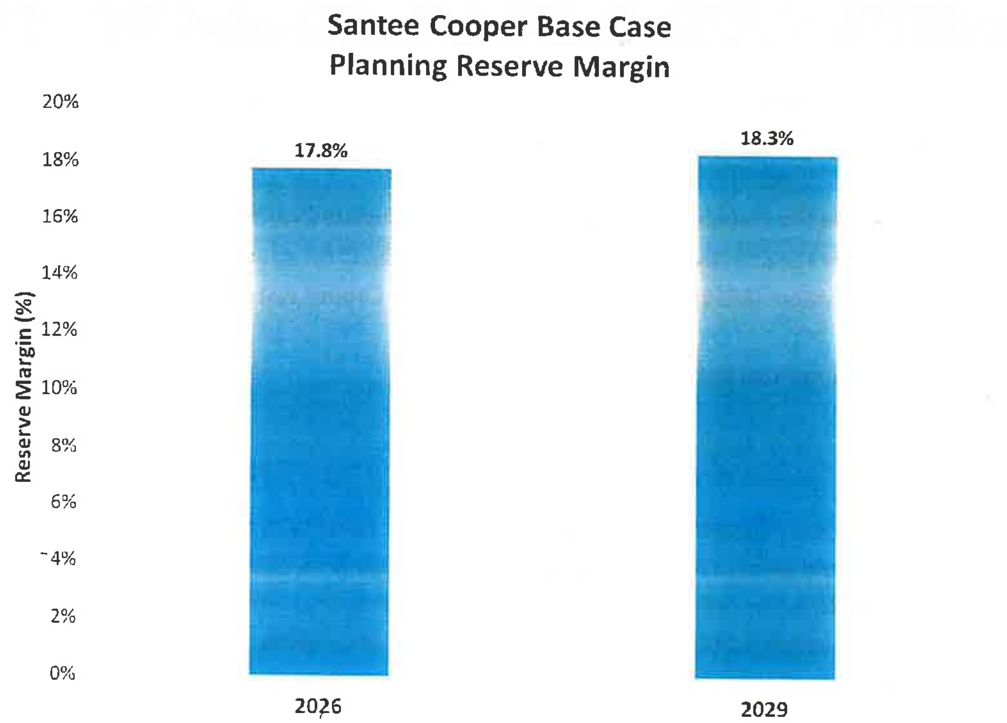


Figure ES 1. Planning Reserve Margin Results

The difference between the 2029 results and the 2026 results are driven primarily by differences in available capacity from the market and small changes system EFOR assoicated with a different capacity mix.

As shown in the figure below containing the monthly breakdown of LOLE at these established PRM levels, the overwhelming majority of LOLE occurs in the winter, making winter the dominant season for establishing reliability criteria.

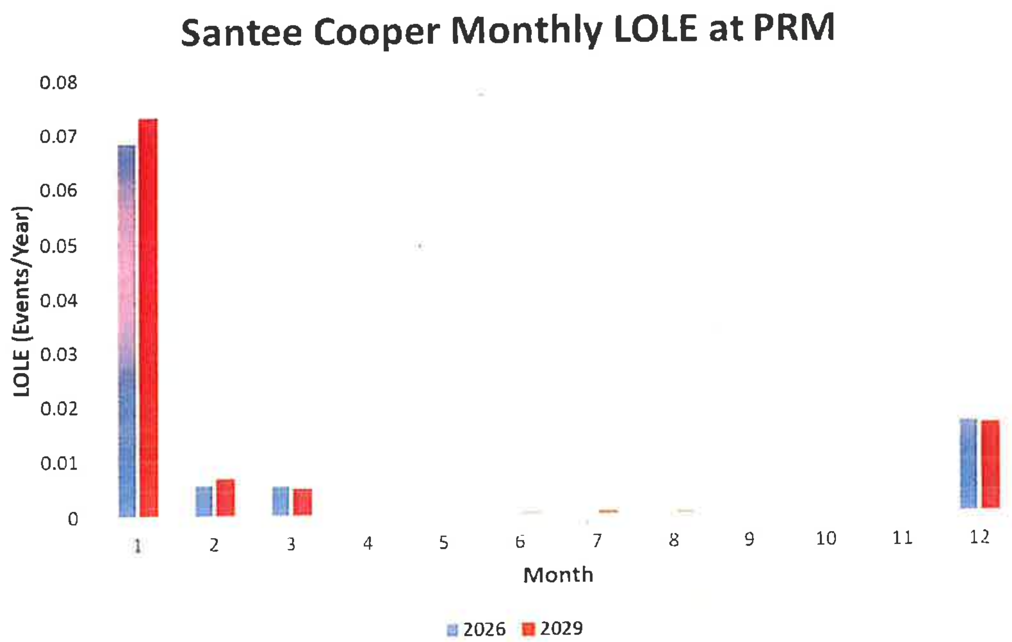


Figure ES 2. Monthly Breakdown of LOLE at PRM

To determine a reasonable summer planning target, an analysis of the summer LOLE was performed. That analysis indicated that a summer PRM in the 14-16% range would adequately maintain system reliability.

The following three items were primary drivers in the Reserve Margin Study.

1. The historical weather window included in the analysis,
2. Load response to extreme weather conditions, and
3. Available market assistance.

Based on these drivers, the following sensitivities were evaluated to test the robustness of the base case PRM:

1. Islanded Base Case (i.e., no market assistance),
2. Climate Change (i.e., compensate for the effects of increasing average temperatures),
3. Load response lower than base case assumptions,
4. Load response higher than base case assumptions, and
5. More restricted import capability.

The table below shows the results of each of these sensitities for both 2026 and 2029.

Table ES 1. PRM Results

	2026	2029
Base Case w/Market	17.8%	18.3%
Base Case Island	27.1%	27.7%
Climate Change	16.8%	17.2%
High Load Response	22.0%	22.9%
Low Load Response	14.2%	15.2%
Transmission Import	17.8%	18.5%

As indicated by the results in the table, there is a significant benefit to the interconnected Santee Cooper system, with the market providing approximately 10% benefit to the reserve margin requirement. The Climate Change sensitivity results in a reserve margin reduction of approximately 1% while the high and low load response sensitivities resulted in approximately +5% and -13% reserve margin adjustments, respectively. The lack of change in reserve margin for the transmission import sensitivity suggests that it is regional generation capacity, not transmission import capability, that is the limiting factor on the amount of market benefit that may be considered.

ELCC RESULTS

The ELCC of a renewable resource/portfolio represents the amount of dependable capacity that can be counted on by the renewable resource/portfolio for resource adequacy purposes. The ELCC is determined by finding the amount of additional load that can be served by the renewable resource/portfolio without adversely affecting system reliability as compared to a system without the renewable resource/portfolio. The ELCC is represented as a percent of nameplate capacity and is calculated by dividing the amount of additional peak load served by the nameplate capacity of the additional renewable resource/portfolio.

The table below shows the various levels of solar and BESS penetrations, as well as combined portfolios of solar and BESS, for which ELCCs were calculated.

Table ES 2. ELCC Scenarios

	BESS MW				
Solar MW ->	0	1,000	1,250	1,500	2,000
	200			200\1,500	
	400				400\2,000

The tables below show the winter and summer ELCCs, respectively that were calculated as part of this analysis.

Table ES 3. Winter ELCC Results

BESS\Solar	0	1000	1250	1500	2000
0		2.0%	1.8%	1.8%	1.4%
200	100.0%			100.0%\5.3%	
400	88.0%				93.8%\1.5%

Table ES 4. Summer ELCC Results

BESS\Solar	0	1000	1250	1500	2000
0		39.3%	36.6%	32.7%	26.9%
200	10.0%			100.0%/33.9%	
400	94.8%				100.0%/28.5%

CONCLUSIONS

Upon examination of the study analysis, including all the sensitivity results, it is evident that winter reliability is the driving factor in establishing an appropriate reserve margin requirement for Santee Cooper. Thus, Santee Cooper's primary reserve margin requirement should be a winter requirement. Furthermore, based on these results, it can be concluded that a winter reserve margin in the range of 17-18% can be justified. It is therefore recommended that the winter PRM requirement be set at 17%.

The summer reserve margin requirement should be considered a secondary requirement. Based on the analysis of the summer LOLE, it can be concluded that a summer reserve margin requirement in the 14-16% range is appropriate. It is therefore recommended that the summer PRM requirement be set at 15%.

INTRODUCTION

The purpose of this document is to report on the results of a study performed by Astrapé Consulting to determine the Planning Reserve Margin (PRM) necessary for Santee Cooper to maintain a Loss of Load Expectation (LOLE) of 0.1 Days/year or the equivalent of the common industry practice of one loss of load event in 10 years. The study examined the reserve margin requirements for two study years, 2026 and 2029.

In addition, this document will also report on the results of a study to determine the Effective Load Carrying Capability (ELCC) of the portfolio of solar resources expected to be installed on the Santee Cooper system for the two study years.

STUDY FRAMEWORK

This study was performed using the Strategic Energy & Risk Valuation Model (SERVM) and its associated study framework. The SERVM framework combines an hourly (i.e., 8760-hour) production cost model coupled with Monte Carlo outage simulation and comprehensive scenario management that considers load and weather uncertainty in order to determine key reliability parameters such as Loss of Load Expectation (LOLE). The following describes the key parameters and uncertainties that are considered and how they are applied within the study framework.

WEATHER UNCERTAINTY

To account for weather uncertainty, SERVM performs hourly production cost simulations using multiple load shapes representing historical weather years. The uncertainties that are modeled for each modeled weather year include load shapes, renewable profiles, and hydro availability. Load shapes for each weather year are developed to represent the expected future load response to the historical weather (temp). For example, a 1990 weather year represents how loads would respond if 1990 weather were to repeat itself in the future. These load shapes are then scaled so that the median of the peak demands from the various weather year load shapes equals the study year weather normal peak load forecast. Similarly, renewable profiles and hydro schedules are developed to represent the expected future availability associated with the historical weather profile. For purposes of this study, 41 weather year scenarios were simulated representing weather conditions for the years 1980-2020.

ECONOMIC LOAD FORECAST ERROR

Economic Load Forecast Error represents the potential error in the weather normal peak load forecast associated with uncertainty in economic forecasts. Using the Office of Congressional Budget's historical forecasts for Gross Domestic Product (GDP), it is possible to predict both the magnitude and probility of error in the forecast of the GDP economic indicator 3, 4, or 5 years out into the future. This probability of error can then be converted into a Load Forecast Error (LFE). For purposes of this study, 5 LFE scenarios were chosen. These are described in the Model Development section of this document. Each of the 41 weather year scenarios are combined with each of the 5 LFE scenarios to create 205 unique load scenarios, or "cases".

MONTE-CARLO OUTAGE ITERATIONS

SERVM uses monte-carlo techniques to simulate generator outages. Multiple hourly production cost simulations are run for each of the 205 load cases. With each outage iteration, random monte-carlo draws are made to determine the outage profile associated with that scenario. For purposes of this study, 100 outage draw iterations were made for each case. The specifics associated with how these outages were modeled are detailed in the Model Development section of this document.

As shown in the figure below, the SERVM uncertainty framework used for this study required at least 20,500 hourly (8760-hour) production cost simulations for a single analytical run of the Santee Cooper system and its first tier neighbors.

41 **Weather Years** (Equal Probability)	x	**5** **LFE Points** (Associated Probabilities)	=	**205** **Load Scenarios** (Associated Probabilities)
205 **Load Scenarios**	x	**100** **Unit Outage Draws**	=	**20,500** **8760 Hour Simulations**

Figure 1. SERVM Uncertainty Framework

The Study Methodology section of this document describes the numerous "analytical runs" required to perform the reserve margin analysis, its associated sensitivities, as well as the ELCC analysis.

MODEL DEVELOPMENT

The SERVM data model utilized for this study was based upon load and resource profiles for the Santee Cooper Balancing Authority Area (BAA) and its immediate first tier interconnected BAAs, including the BAAs associated with Southern Company, Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), and Dominion Energy SC (DESC). The figure below shows the configuration of the study model with its associated transmission interface connections using a pipe and bubble configuration.

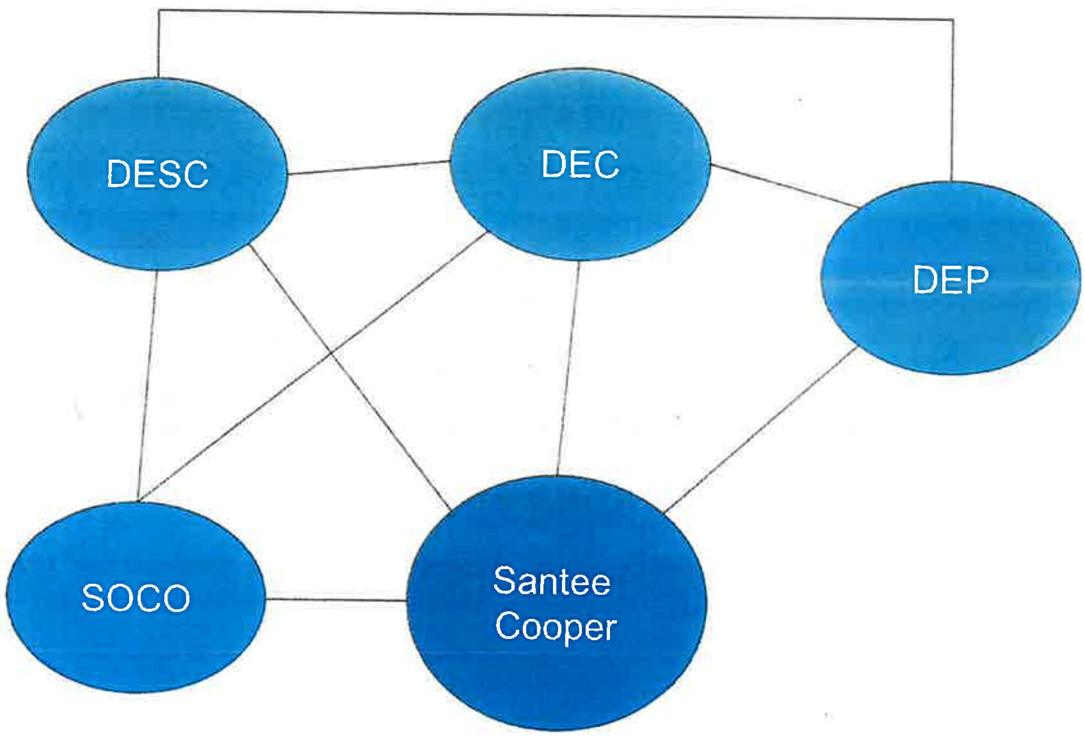


Figure 2. Study Model Configuration

BASIS FOR MODEL DEVELOPMENT

The basis for the SERVM model used in this study was the data included in Astrapé Consulting's Eastern Interconnection Database (EIDB) with revisions to the Santee Cooper region per data provided directly by Santee Cooper. Astrapé's EIDB was developed and is maintained using publicly available data from sources such as the Energy Information Authority (EIA) Form 860, available documents from the North Americal Reliability Corporation (NERC), various publicly available Integrated Resource Plans (IRPs), FERC Forms, and the like.

The following provides the specifics of the Santee Cooper data as provided by Santee Cooper for purposes of this study.

STUDY YEARS

As indicated in the Introduction section above, the study years chosen for this analysis included 2026 and 2029.

PEAK DEMAND FORECAST

For this study the peak demand forecast represented the gross load (i.e., before any reductions due to curtailable load or renewable load injections) reduced for anticipated Energy Efficiency (EE) impacts. The summer and winter peak demand forecasts as provided by Santee Cooper are shown in the figure below.

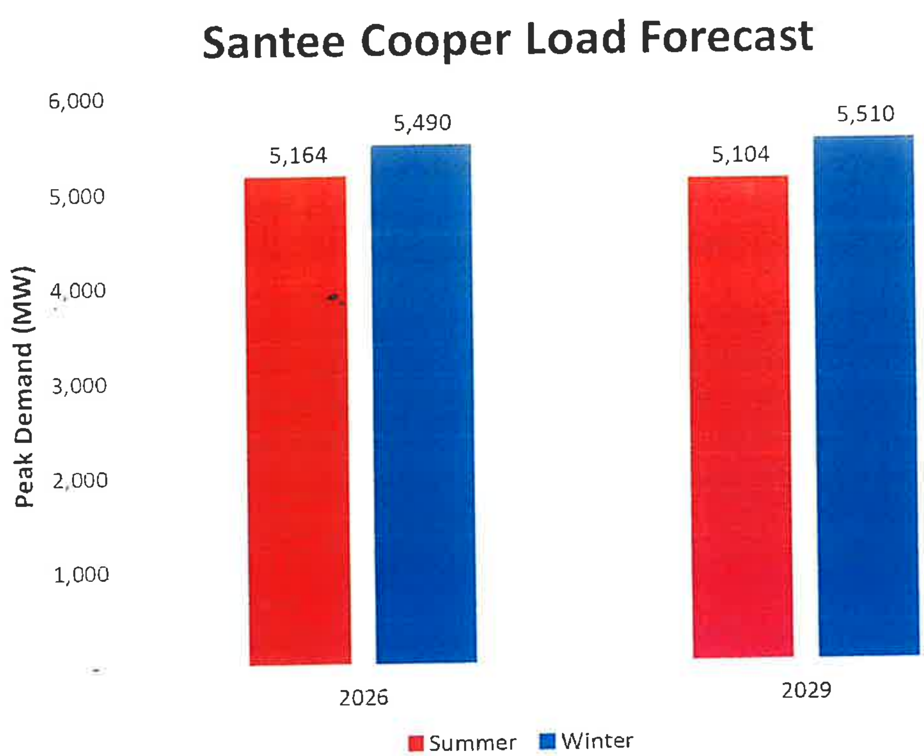


Figure 3. Peak Demand Forecast

LOAD MODELING

As described in the Study Framework subsection of the Introduction section above, load shapes were developed for each of the 41 study years 1980-2020. These load shapes were developed based on trends and relationships between load and weather for the years 2017-2021.

The five historical load shapes trended using a neural network that was trained using weighted hourly historical temperatures from the National Oceanic and Atmospheric Administration (NOAA) and other key variables. The following NOAA weather stations along with the indicated weighting were used to develop the temperature variables. Gaps in the weather data were filled using adjusted weightings of the remaining stations.

Table 1. NOAA Weather Stations and Weightings

Station	Weighting
Myrtle Beach	21.4%
Florence	15.7%
Charleston	10.7%
Columbia	41.7%
Savannah	10.5%

In addition to temperature, the neural net was provided with training variables that included day of week, hour of day, hour of week, 8-hour rolling average temperature, 24-hour rolling average temperature, and 48-hour rolling average temperature. "Networks" were created for Winter, Summer, and Shoulder periods. These trained networks were then applied to the NOAA weather data for the historical years 1980-2020 to develop synthetic load shapes for each of the 41 weather years.

Since the 41 years of historical weather data contains temperature data outside the range of that contained in the historical load set used to train the neural networks, those values were determined using peak load regressions developed outside the neural network. Peak load regressions were developed for summer afternoon, winter morning, and winter afternoon periods. These adjustment regressions were only applied to those hours in which the temperature fell outside the range of the 5-year historical data set.

The final load shapes were a combination of those hours developed using the neural net and those developed using the peak load regressions. The synthetic load shapes were then quality checked against the actual historical shapes to ensure their validity.

The figure below shows a plot of the daily peak loads as a function of either the daily max or daily min temperature as appropriate. The figure compares the 5 years of historical data with the 41 years of synthetic data.

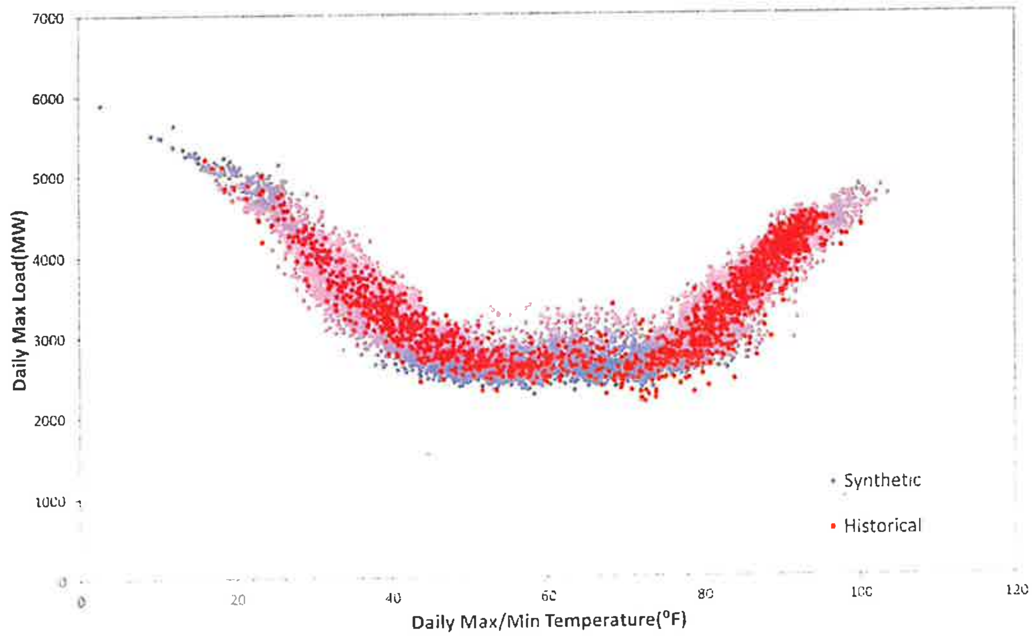


Figure 4. Synthetic vs. Historical Daily Peak Loads

The development of the 41 synthetic load shapes results in a diverse set of annual peak loads. Within SERVM, these shapes will be scaled such that the median of the annual peak loads will equal the weather normal peak load for both summer and winter. The figures below show the summer and winter peak load variance resulting from the 41 synthetic load shapes. The variance is shown in terms of its divergence from the weather normal peak load on a percentage basis.

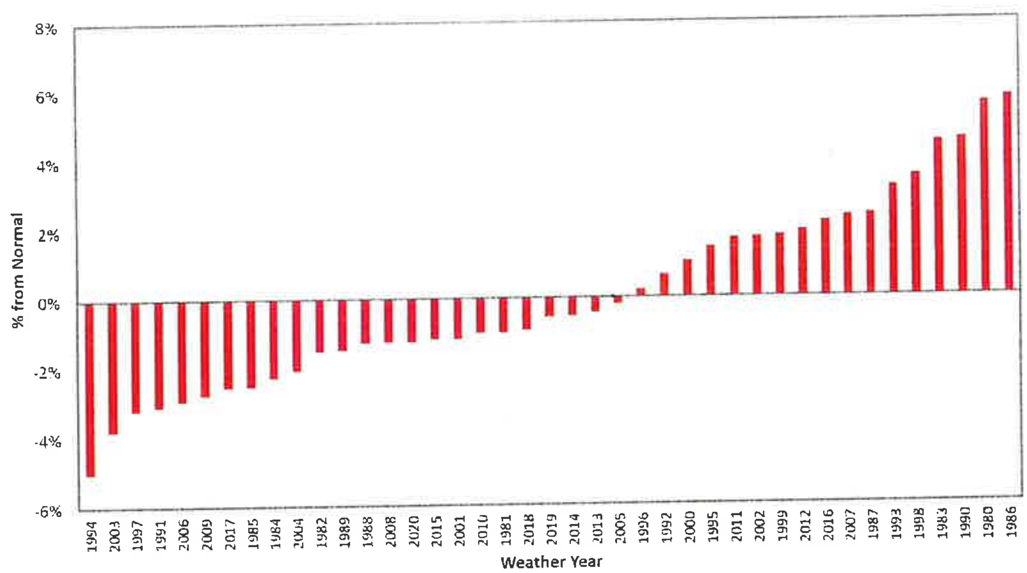


Figure 5. Summer Peak Load Variance

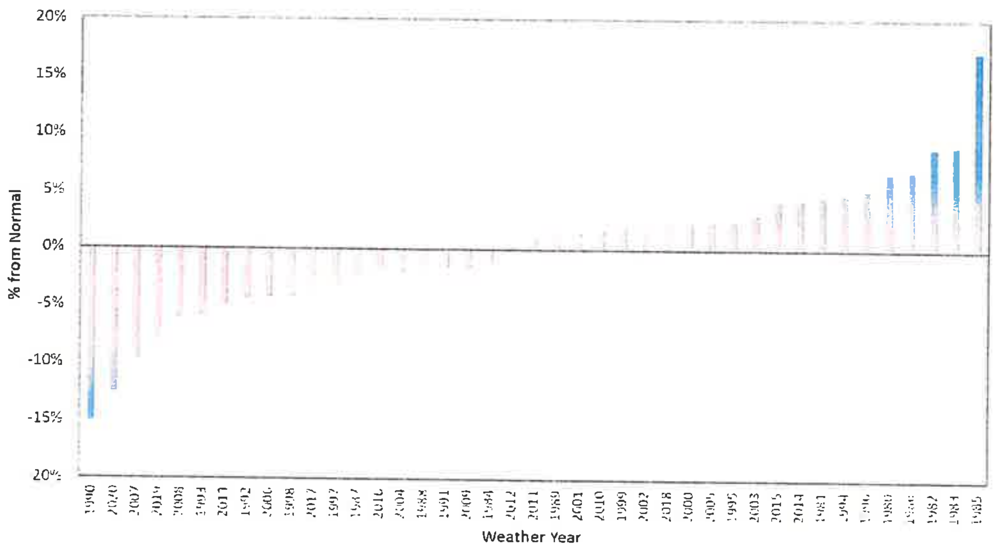


Figure 6. Winter Peak Load Variance

ECONOMIC FORECAST ERROR

As described in the Study Framework subsection of the Introduction section of this document, five Load Forecast Error (LFE) multipliers with their associated probabilities were applied to each of the 41 historical load shapes. The LFE multipliers simulate the expected probability that the peak demand forecast would be missed because of errors in the forecast of national economic indicators. The multipliers were developed by looking at the historical error in the 4-year out forecast GDP assuming a peak demand sensitivity to changes in GDP of 0.4% per 1% change in GDP. The set of LFE multipliers along with their probability of occurrence used in this study are shown in the table below with a graphic representation in the figure that follows.

Table 2. LFE Model

LFE	Probability
-4%	10.4%
-2%	23.3%
0%	32.5%
2%	23.3%
4%	10.4%

CONVENTIONAL RESOURCE MODELING

Resources for the first tier BAAs were developed using publicly available information. Resources for Santee Cooper were developed using data provided by Santee Cooper as outlined in the subsections below.

GENERATING CAPACITY

The following table shows the list of conventional resources and their corresponding summer and winter generating capabilities available to Santee Cooper for the 2026 study year.

Table 3. Santee Cooper Conventional Resource Capacities

Unit Name	Unit Category	Summer Capacity	Winter Capacity
Cross 1	Coal	580	585
Cross 2	Coal	565	570
Cross 3	Coal	610	610
Cross 4	Coal	615	615
Hilton Head 1	CT-Oil	16	20
Hilton Head 2	CT-Oil	16	20
Hilton Head 3	CT-Oil	52	60
John S Rainey CT2A	CT- Gas	146	180
John S Rainey CT2B	CT- Gas	146	180
John S Rainey CT3A	CT- Gas	75	90
John S Rainey CT3B	CT- Gas	75	90
John S Rainey CT4A	CT- Gas	75	90
John S Rainey PB1	GCC	460	520
Myrtle Beach 1	CT-Oil	8	10
Myrtle Beach 2	CT-Oil	8	10
Myrtle Beach 3	CT-Oil	19	20
Myrtle Beach 5	CT-Oil	21	25
V. C. Summer Nuclear Station	Nuclear	322	322
Winyah 1	Coal	275	280
Winyah 2	Coal	285	290
Winyah 3	Coal	285	290

For the 2026 study year, Winyah 4 is assumed idled/unavailable. For the 2029 study year, the remaining three coal units at Plant Winyah were assumed to be retired and a new 1,119 MW 2x1 Combined Cycle was assumed available as a replacement.

To model the transition from summer ratings to winter ratings, technology curves were developed for each unit that adjusted the maximum capacity of the resource based on ambient temperature. The figure below shows an example technology curve based on Hilton Head Unit 1. Other curves are similar.

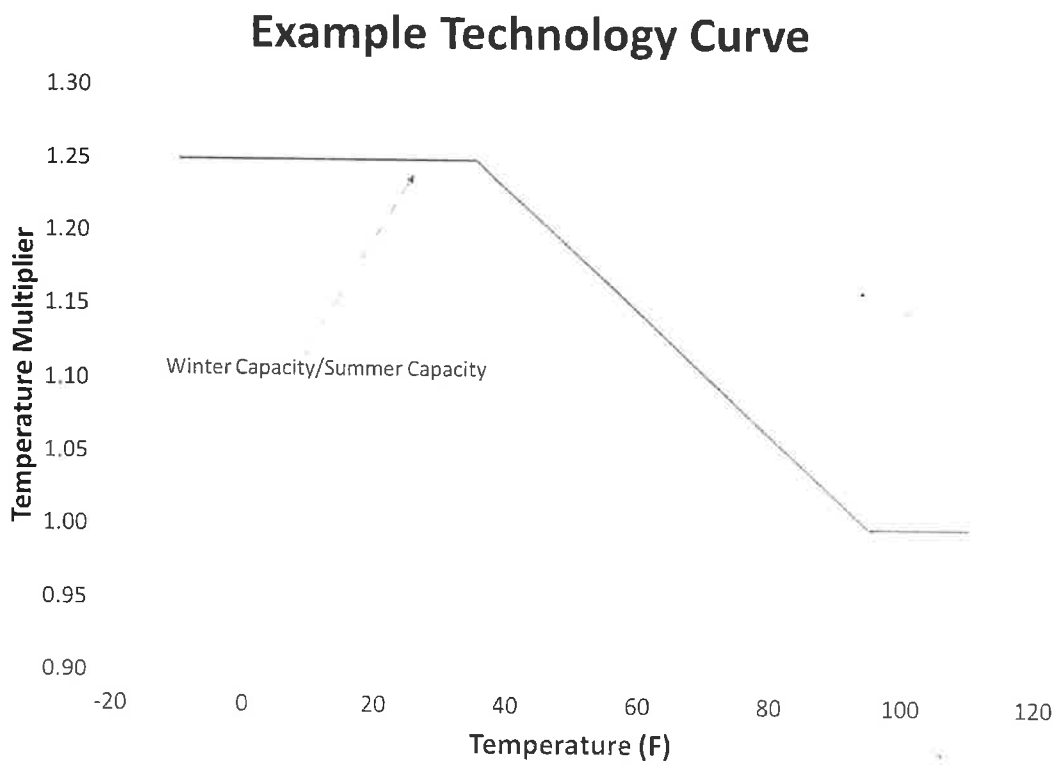


Figure 7. Example Technology Curve

In addition to these dispatchable resources, Santee Cooper also has access to output from 13 small landfill gas (LFG) resources as well as one biomass resource, which are owned by third parties. The capacities of these resources are shown in the table below below.

Table 4. LFG and Biomass Resource Capacity

Unit Name	Unit Category	Summer Capacity (MW)
Anderson Regional Landfill	LFG	3
Berkeley County Landfill	LFG	3
Georgetown LFGTE G1	LFG	1
Horry Landfill	LFG	3
Lee County Landfill	LFG	11
Richland County Landfill	LFG	8
EDF Renewable	Biomass	35.6

The LFG and biomass units were modeled as must-run units. See the outage section below for further discussion on their operation.

OUTAGE MODELING

Outage modeling consisted of three primary types of outages, planned maintenance, unplanned maintenance, and forced outages.

Planned Maintenance. SERVM can model planned maintenance, often called planned outages (PO), as either discrete schedules or an annual rate in percent of hours. If modeled as a PO rate, SERVM schedules planned maintenance in seasons where there would not typically be an expectation of reliability concerns. This determination is made by looking at all available weather year load shapes and developing a schedule that is least likely to cause reliability concerns. Thus, while it may be generally expected that planned maintenance will not create reliability issues, there may be some weather years in which that is not the case.

Santee Cooper provided explicit future planned outage schedules for several years into the future. However, because the two years evaluated in this study were considered representative years, planned maintenace was modeled using the annual rate method rather than the discrete schedules for the two study years, 2026 and 2029. The annul rate was developed by converting the specific future maintenance schedules into annual rates (in percent of hours per year) and then averaging all of these future annual rates by unit. This was done to ensure that the PRM is developed based on typical expected system conditions rather than specific system conditions associated with any one year. The figure below shows the result of this process and represents the maintenance rates modeled for the Santee Cooper resources.

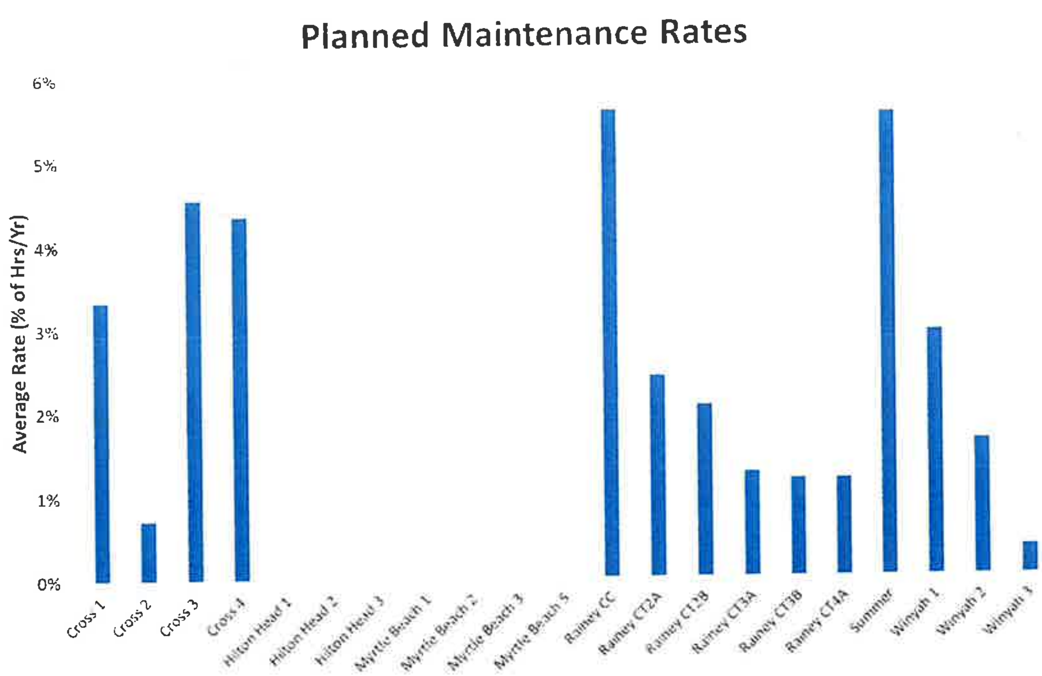


Figure 8. Santee Cooper Resource PO Rates

See the discussion below on forced outages for LFG and biomass modeling.

Unplanned Maintenance. SERVM also models unplanned maintenance, often referred to as Maintenance Outages (MO), as a rate. SERVM uses these rates to determine the amount of time that a resource should be offline due to maintenance outages and attempts to schedule those hours during off-peak periods. However, because SERVM models these outages during hours without reliability risk, they have no material impact on the reserve margin study. MO rates for the Santee Cooper units were determined based on five years of historical NERC GADS data as provided by Santee Cooper.

Forced Outages. SERVM modeled forced outages using multiple sets of time to fail (TTF) and time to repair (TTR) inputs for both full and partial outages. Each resource has its own set of TTF and TTR inputs that are used to establish that resource's equivalent forced outage rate (EFOR). Using monte carlo techniques, a TTF value is chosen randomly for each generating resource. That resource is then allowed to operate until it reaches the TTF threshold, at which point it is forced offline. Once it is forced offline, a TTR value is chosen randomly to determine how long the resource will be unavailable. That resource remains offline until is reaches the TTR threshold, at which point it is once again made available and a new TTF variable is chosen for the resoruce.

TTF and TTR values for Santee Cooper were developed using five years of historical NERC GADS data. The EFOR values resulting from these TTF/TTR values were then examined by key experts at Santee Cooper and recommendations for the final EFOR values to be used in this study were made. The TTR and TTF values were then modified appropriately so that the resulting EFOR values would match the Santee Cooper recommendations. The figure below shows the final modeled EFOR rates by unit.

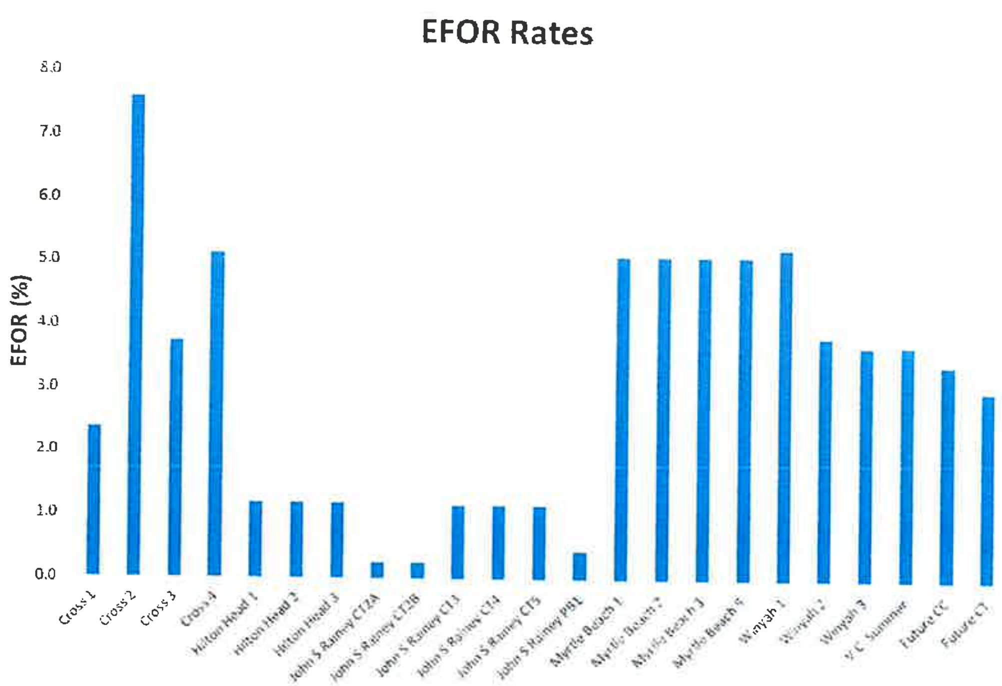


Figure 9. Santee Cooper EFOR Rates

Per recommendations from Santee Cooper and based on historical capacity factors, all LFG resources were modeled with TTRs and TTFs that could result in a 78% EFOR (i.e., a resulting 22% capacity factor).

Per recommendations from Santee Cooper and based on historical capacity factors, the EDF Renewable biomass resource was modeled with a 100% availability.

OTHER CONVENTIONAL DATA

Other conventional resources data provided by Santee Cooper included minimum capacities, minimum uptime, minimum downtime, and ramp rates. These were modeled as part of the analysis but had no direct bearing on the determination of the reserve margin.

SOLAR RESOURCE MODELING

SERVM models renewable resources as an hourly profile for each weather year. For this study, eight existing solar facilities were modeled and nine future solar facilities were modeled. The eight existing facilities, along with their tracking technology, assumed Inverter Loading Ratios (ILR), average expected capacity factors, and 2026/2029 installed capacities are shown in the table below.

Table 5. Solar Resource Summary

Resource	ILR	Average CF	2026 Capacity (MW)	2029 Capacity (MW)
Colleton (TIG)	1.0	20.3%	2.5	2.5
Allora	1.1	24.9%	75	0
Gunsight	1.1	25.5%	75	0
Landrace	1.0	18.8%	55	0
Chester White	1.4	31.4%	75	75
Lambert I & II	1.1	24.8%	200	200
Hemingway	1.3	29.1%	75	75
Watson Hill	1.2	27.1%	75	75
Future Solar	1.3	29.3%	370	825
Total			1,003	1,253

While the table above shows the future solar resources aggregated as a single row, future solar was modeled as nine discrete facilities at various geographic locations to capture expected geographic diversity of solar output. The nine locations modeled for the future solar were assumed to be at locations similar to the eight existing locations plus one additional location of an existing solar resource

(Centerfield Cooper; contract to expire before the 2026 study year). Thus, for modeling purposes, the nine site locations chosen are shown in the table below.

Table 6. Future Solar Facility Locations

Site	City	Reference Solar Resource
1	Walterboro, SC	Collteon (TIG)
2	Gilbert, SC	Allora
3	Swansea, SC	Gunsight
4	Conway, SC	Landrace
5	Aiken, SC	Chester White
6	Andrews, SC	Lambert I & II
7	Kingstree, SC	Hemingway
8	Summerville, SC	Watson Hill
9	Chesterfield, SC	Centerfield Cooper

To create the weather year profiles, irradiance data for these nine locations were downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer for the years 1998 to 2020.[1] The data obtained from the NSRDB Data Viewer was input into NREL's System Advisor Model (SAM) [2] for each year and location to generate the hourly solar profiles based on the solar weather data for fixed and tracking solar plants. Solar profiles for 1980 to 1997 were selected by using the daily solar profiles from the day that most closely matched the peak load for the Santee Cooper load out of all the days +/- 3 days of the source day for the 1998 to 2020 interval. The profiles for the remaining years 1998 to 2020 came directly from the solar shape output data from SAM. The figures below show the resulting summer and winter, respectively, average[3] daily output profiles for each of the eight existing solar facilities plus the aggregate average profile for the future solar.

[1] https://maps.nrel.gov/nsrdb-viewer/

[2] https://sam.nrel.gov/

[3] i.e., the average of all July/January days including all weather years.

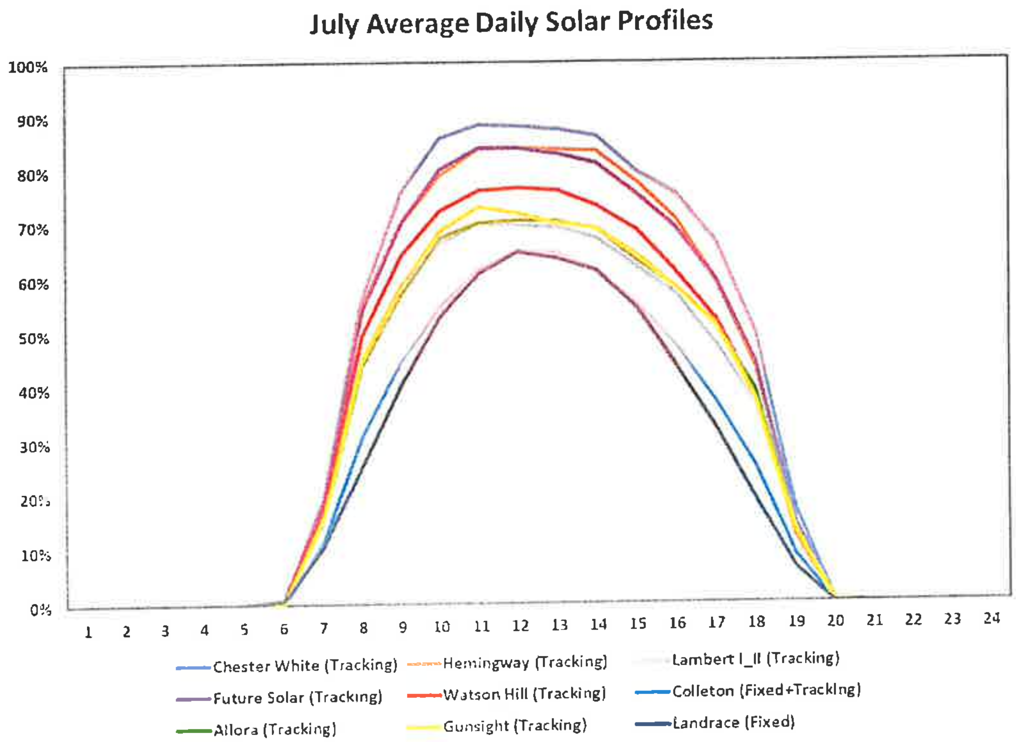


Figure 10. Average Summer Solar Profiles

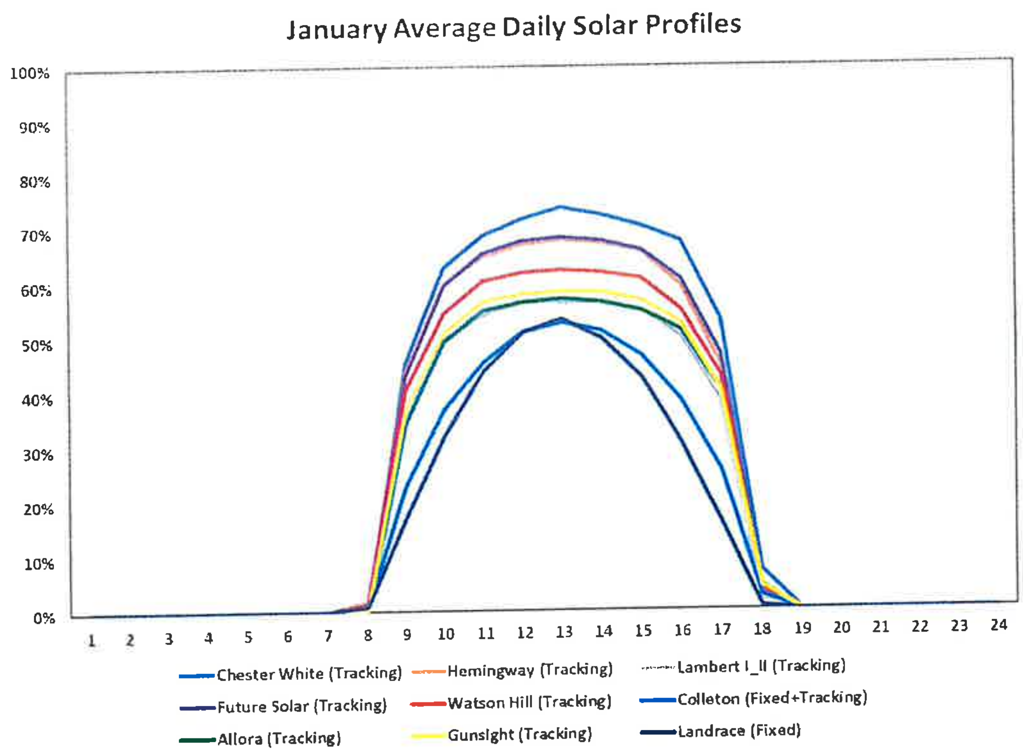


Figure 11. Average Winter Solar Profile

HYDRO RESOURCE MODELING

Hydro was modeled as two aggregate resources. Hydro facilities owned by Santee Cooper and the Corps of Engineers are referred to in this report as Santee Coooepr hydro resources. Hydro resources owned by the Southeastern Power Authority (SEPA), for which Santee Coooper has access for load serving purposes, are referred to as SEPA Hydro resources. The three Santee Cooper hydro facilities[4] total 226 MW and the SEPA facilities total 305 MW. SERVM models hydro facilities by scheduling available hydro energy to shave the daily net peak load using four different parameters for each month for each weather year. Those parameters include:

1. Monthly total energy output,
2. Daily scheduled maximum output,
3. Daily scheduled minimum output, and
4. Monthly maximum scheduled output.

The daily minimum hydro dispatch is scheduled at the minimum net load hour of the day, and the daily maximum hydro is scheduled at the maximum net load hour of the day, and the monthly maximum hydro is scheduled at the max load hour of the month, all while observing the monthly total energy output constraint. The monthly maximum scheduled output sets the available hydro capacity for that month.

To develop these parameters, available hydro energy data from 1980 to 2020 was collected from the EIA Form 923[5] and actual hourly hydro data was provided by Santee Cooper for the years 2018 to 2021. Using this data, average daily minimum and maximum dispatch levels, the total monthly energy, as well as the monthly maximum dispatch levels were identified from the historical hourly data and a regression of each was formed. These regressions were then applied to the historical monthly energy data obtained from EIA forms. The resulting parameters were then applied to the corresponding weather year as appropriate.

The following figures show the result of the regression analyses for the Santee Cooper and SEPA hydro facilities, respectively.

[4] Jefferies and Spillway are Santee Cooper owned while St. Stephens is owned by the Corps of Engineers.

[5] https://www.eia.gov/electricity/data/eia923/

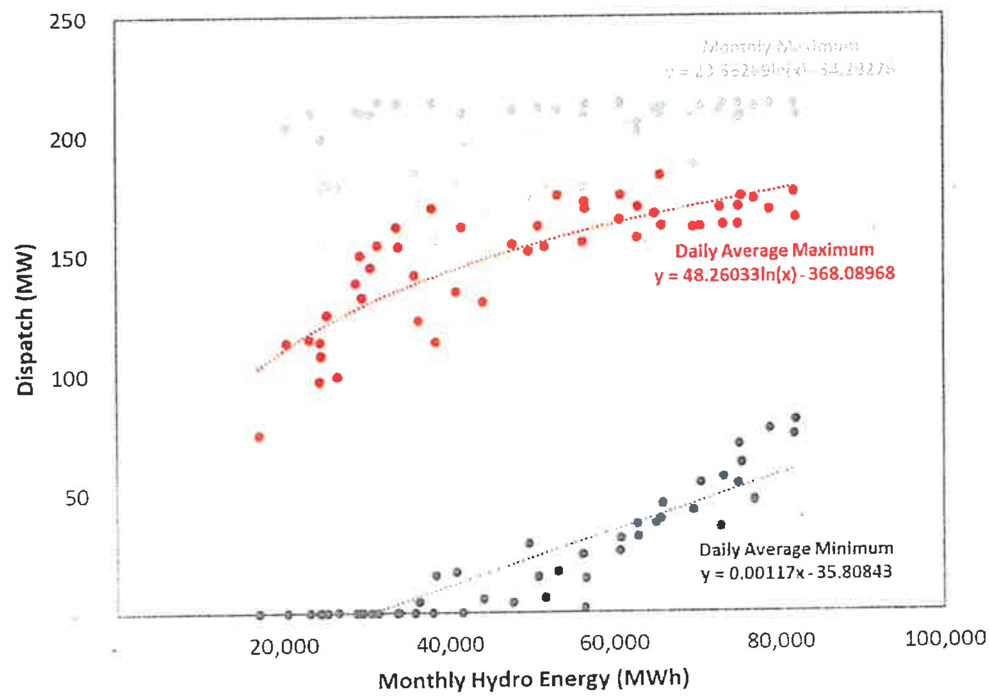


Figure 12. Santee Cooper Hydro Regression Results

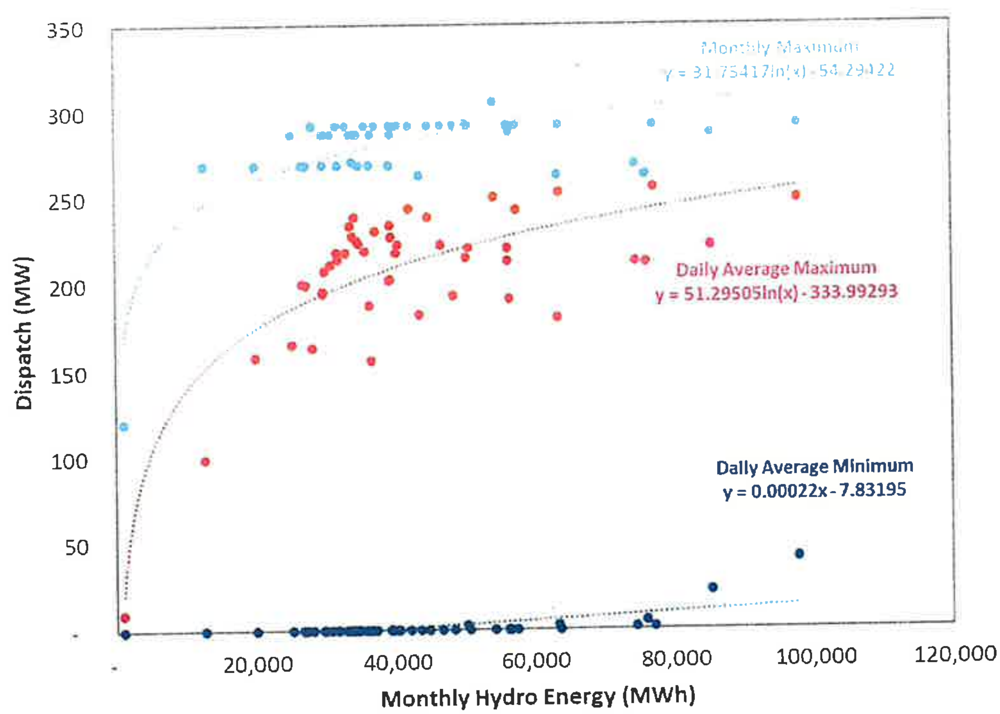


Figure 13.Santee Cooper SEPA Hydro Regression Results

The following figures show the available hydro energy by weather year for the Santee Cooper and SEPA hydro facilities, respectively.

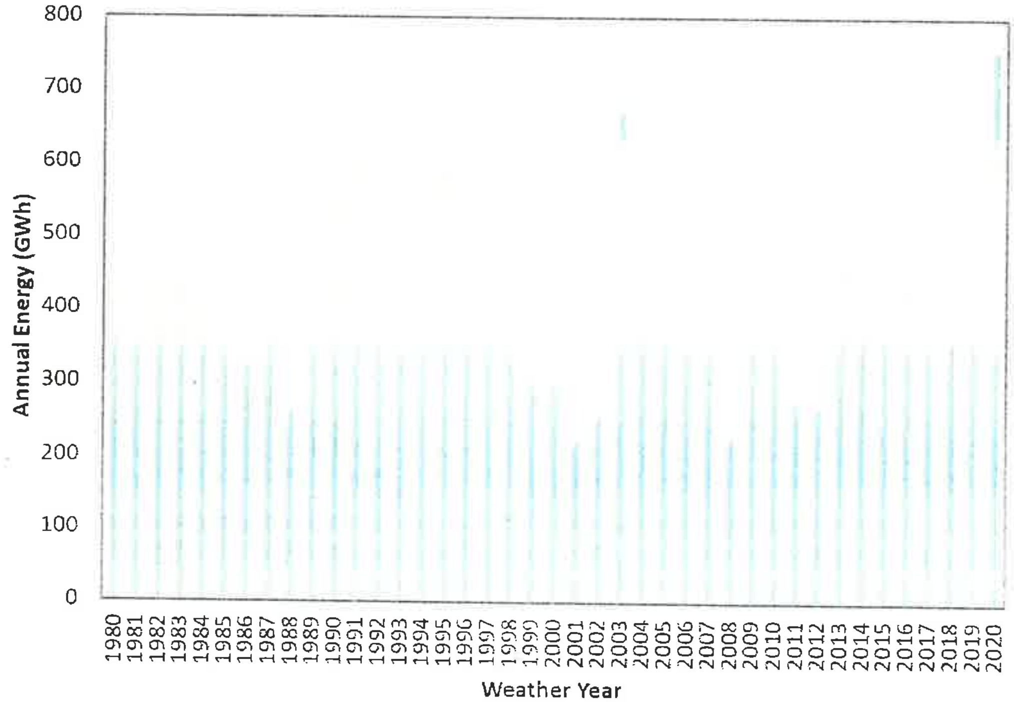


Figure 14. Santee Cooper Energy by Weather Year

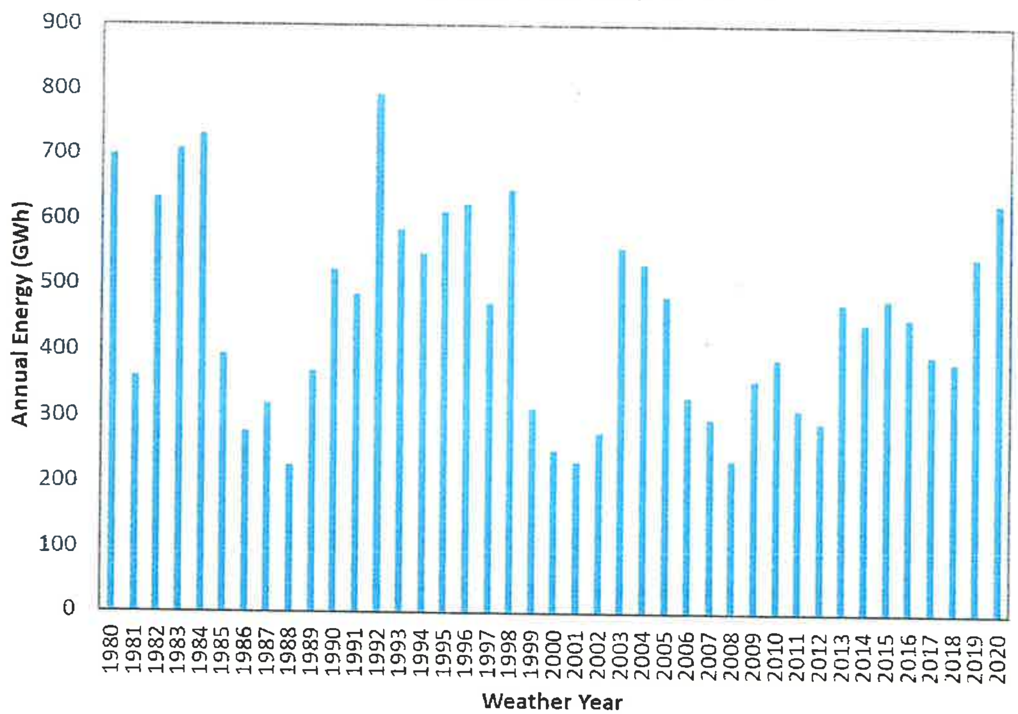


Figure 15. Santee Cooper SEPA Hydro Energy by Weather Year

The following figures show the monthly available capacity for Santee Cooper and SEPA hydro, respectively.

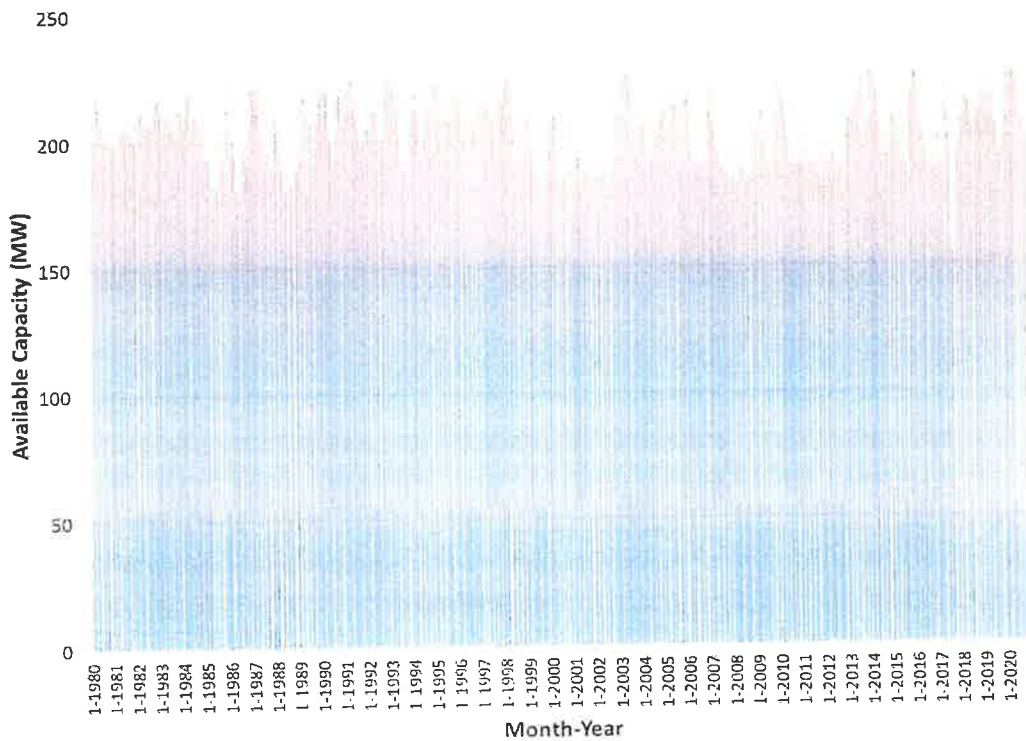


Figure 16. Santee Cooper Monthly Hydro Capacity

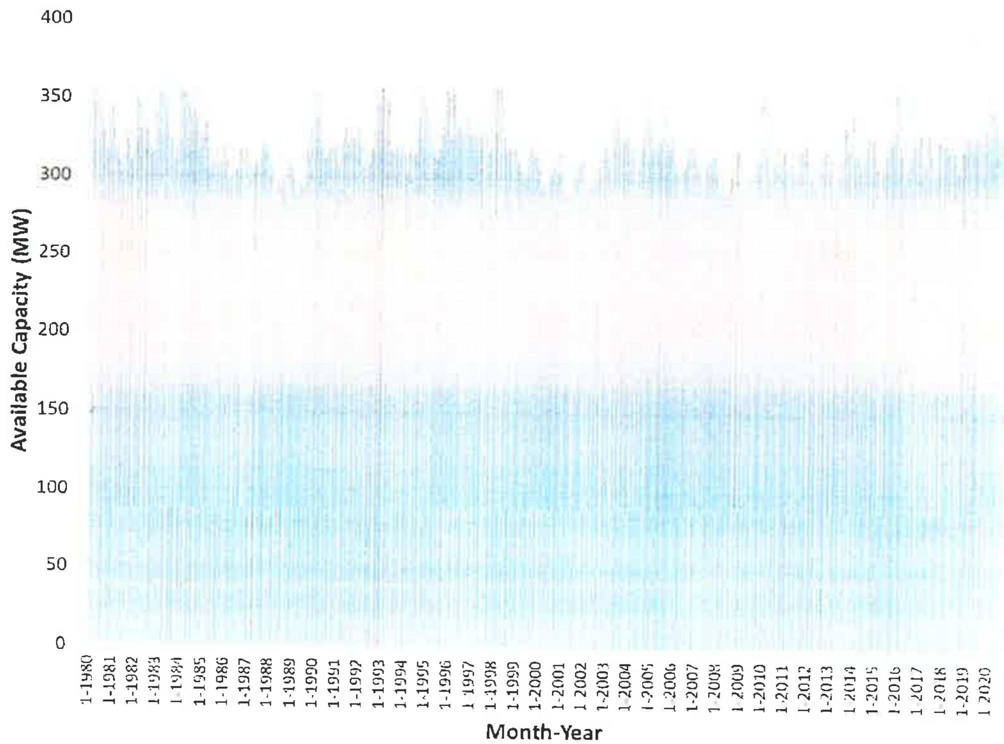


Figure 17. Santee Cooper SEPA Monthly Hydro Capacity

DEMAND RESPONSE MODELING

For purposes of this study, Energy Efficiency (EE) is modeled as a reduction in load. All load shapes and peak demand forecasts were developed net of EE.

Santee Cooper has four active Demand Response (DR) programs available to respond to reliability conditions, including:

1. Interruptible (I) customers,
2. Economy Power (EP) customers,
3. Direct Load Control (DLC) customers, and
4. Conservation Voltage Reduction (CVR).

Additional DR is available through Santee Cooper's largest customer, Central Electric Power Cooperative (Central).

While each of these programs has its own tariff provisions, all have in common the unlimited ability to curtail the customer for purposes of avoided a firm load shed event. The following table shows the capacity modeled for each of the programs as well as for Central.

Table 7. Santee Cooper DR Assumptions

	2026 Summer	2026 Winter	2029 Summer	2029 Winter
I & EP	371.0	330.0	371.0	330.0
DLC	20.4	28.8	28.5	40.2
CVR	16.5	14.5	16.5	14.5
Central	20.0	20.0	30.0	30.0
Total	427.9	393.3	446.0	414.7

FIRM SYSTEM PURCHASES

To meet its existing reserve margin requirements, Santee Cooper has placeholders in its plan for potential firm purchase agreements with third-party providers of capacity. For purposes of this study to determine Santee Cooper's PRM requirements, these purchases were not modeled. Instead CT capacity was added to achieve the target LOLE as discussed in the methodology section.

RESOURCE CAPACITY MIX

The model of the system described above resulted in a system with the mix of resources shown in the figures below for the 2026 and 2029 study years. All values are in MW representing summer capacity values with solar resources shown with nameplate values.

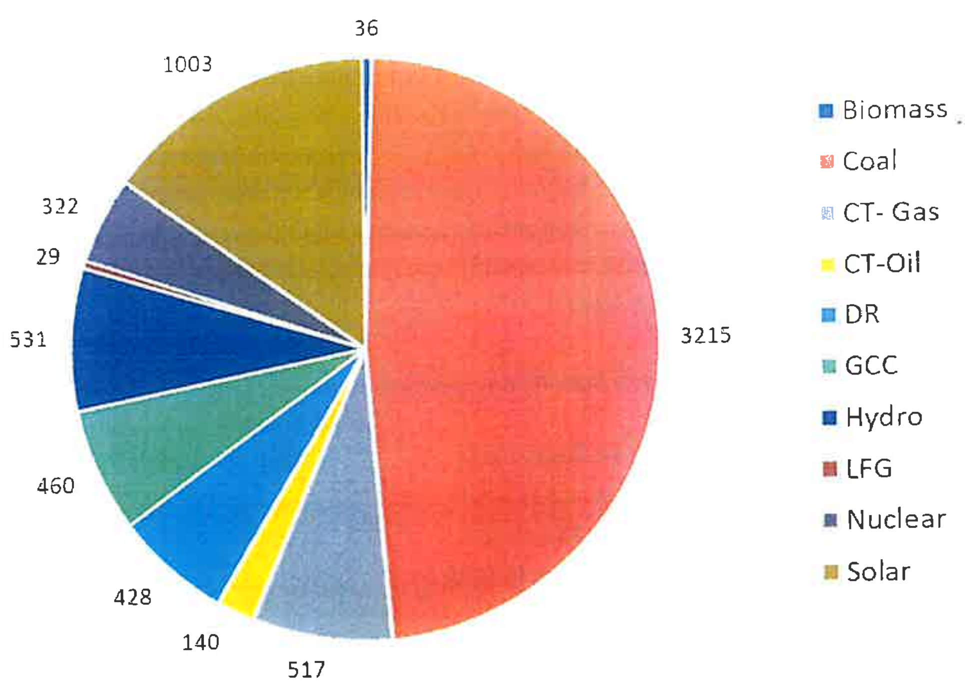


Figure 18. 2026 Resource Capacity Mix (Summer Ratings)

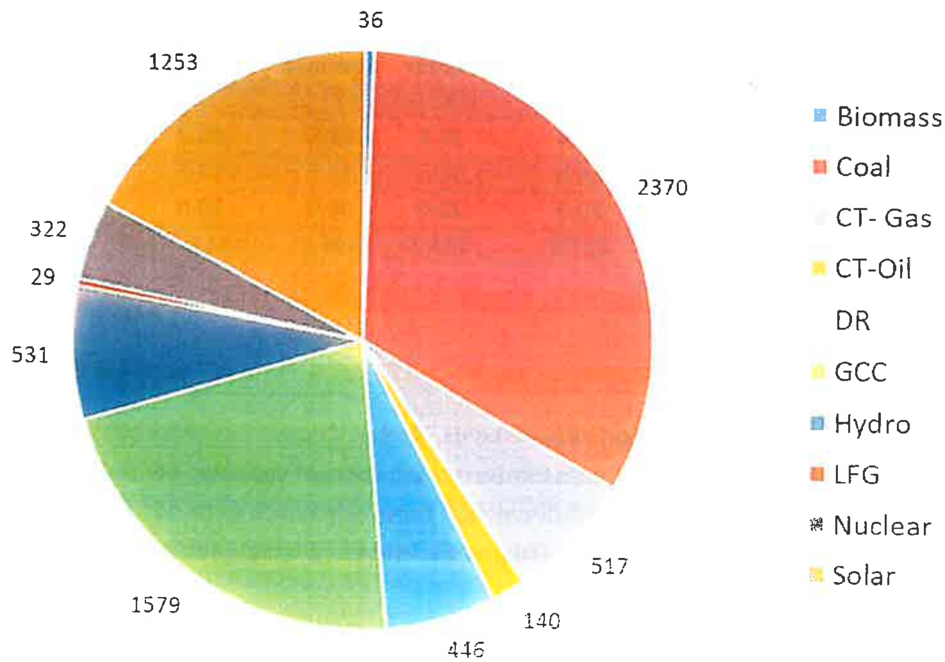


Figure 19. 2029 Resource Capacity Mix (Summer Ratings)

ANCILLARY SERVICES MODEL

The ancillary services model included as part of this study included the modeling of regulating reserves, contingency reserves spinning (spinning reserves), and contingency reserve supplemental (non-spinning reserves). SERVM will commit the system to maintain all ancillary services requirements. However, per guidance provided by Santee Cooper, spinning and non-spinning reserves would be allowed to deplete to zero to avoid a load shedding event. Regulating reserves would be maintained during load shedding events. Based on information provided by Santee Cooper, the following baseline set of operating reserves were modeled.

Table 8. Base Ancillary Services Requirements

Reserve Component	Requirement (MW)
Regulating Reserves	100
Spinning Reserves	110
Non-Spinning Reserves	110

In addition to the base ancillary services requirement, Santee Cooper requires an additional amount of regulating reserves for hour ending (HE) 9-22 to accommodate the intermittent nature of solar resources. The additional regulating reserves amount to roughly 30% of nameplate solar capacity. However, these reserves would not be maintained to avoid a load shedding event. Thus for modeling purposes within SERVM, these additonal reserve requirements were modeled as spinning reserves, so that they would be depleted prior to load curtailment. The total spinning reserves modeled (base plus solar requirement) for 2026 for HE 9-22 was 410 MW and the total spinning reserves modeled for 2029 for HE 9-22 was 485 MW.

TRANSMISSION MODEL

The values used for the non-Santee Cooper interconnections were taken directly from the SERC Long Term Working Group 2026 Summer Future Year Study, dated December 16, 2021. The table below depicts the Santee Cooper import limit assumptions used in this study.

Table 9. Santee Cooper Transmission Import Limits

[redacted]

The values for the Santee Cooper interconnects were also based upon the values from that study, but were modified by Santee Cooper to reflect expectations on simultaneous import.

MARKET ASSUMPTIONS

As SERVM performs its 8760-hour production cost simulation, it makes a determination each hour as to the availability and price of potential market transactions between BAAs. This determination is made through development of both a day ahead and an hourly market price for each region that is based on a combination of an energy price and a scarcity price according to the equation

$$MP = MEP + ORDC$$

Where
MP= Market Price
MEP= Marginal Energy Price (a.k.a, the marginal dispatch price), and
ORDC=the Operating Reserve Demand Curve price.

The ORDC price simplys provies a scarcity price signalbased on the amount of remaining undispatched operarating reserves.

SERVM allows economic transactions based on each region's resulting market price subject to transmission constraints.

STUDY METHODOLOGY

The two objectives of this study were to (a) establish the PRM for the Santee Cooper system and (b) determine the ELCC for various penetrations of solar and battery energy storage system (BESS) resources. The sections below describe the approach for each of these two objectives.

ESTABLISHING MW ADJUSTMENT

The PRM for the Santee Cooper system was determined for two separate study years, 2026 and 2029. The establishment of the PRM should be fairly stable with minor changes in system configuration. Thus the 2026 study year should be reasonably representative of existing and near future PRM. However, the retirement of the three Winyah coal units and its replacement with a single 2x1 CC in 2029 was significant enough to warrant performing the analysis for 2029 as well to determine the extent to which the PRM might change. In addition, if any major changes in the system occur prior to conducting another PRM study then the conclusions of this study should be reconsidered. Major changes in the system refer to any significant changes in the demand or resources of the system. This may include but are not limited to changes in load beyond the load forecast projections, unit retirements, or unit additions.

To determine the PRM, expansion CTs were iteratively added to the base case system until the annual LOLE reached 0.1 days/year. Practically speaking, because of the size of the expansion CT relative to the size of the Santee Cooper system[6], this required making multiple runs with differing amounts of expansion CTs (e.g., 1 CT, 2 CTs, etc.) and trending the resulting LOLE so that the 0.1 LOLE point could be interpolated. The result of this extrapolation was the MW adjustment necessary to achieve 0.1 LOLE. This analysis was performed on both an islanded basis as well as a regional basis that included the Santee Cooper first tier BAAs.

Converting the results of this analysis into a resulting PRM required the establishment of an ELCC for the existing solar resources as described in the next subsection below. The final determination of the PRM (in %) was determined as follows:

PRM = [(Existing Capacity[7,8] + Adjustment Capacity) / Peak Load – 1] * 100.

---

[6] One expansion CT (355 MW in the winter) represents approximately 6.5% of system load.

[7] For PRM calculation purposes, demand response and hydro are treated as a resource, and solar resources are applied at the appropriate ELCC value.

[8] For the reserve margin calculation and simulations, interruptible load is included as a resource and not subtracted from load. The interruptible load is called before a firm load shed event when calculating LOLE. If non-firm load increases significantly from what is assumed in this study then the PRM should be reviewed through a study update or sensitivity.

DETERMINING ELCC

To calculate ELCC values for Santee Cooper, the 2026 study year was chosen as representative for all future years. The figure below shows the general approach taken to calculate ELCC.

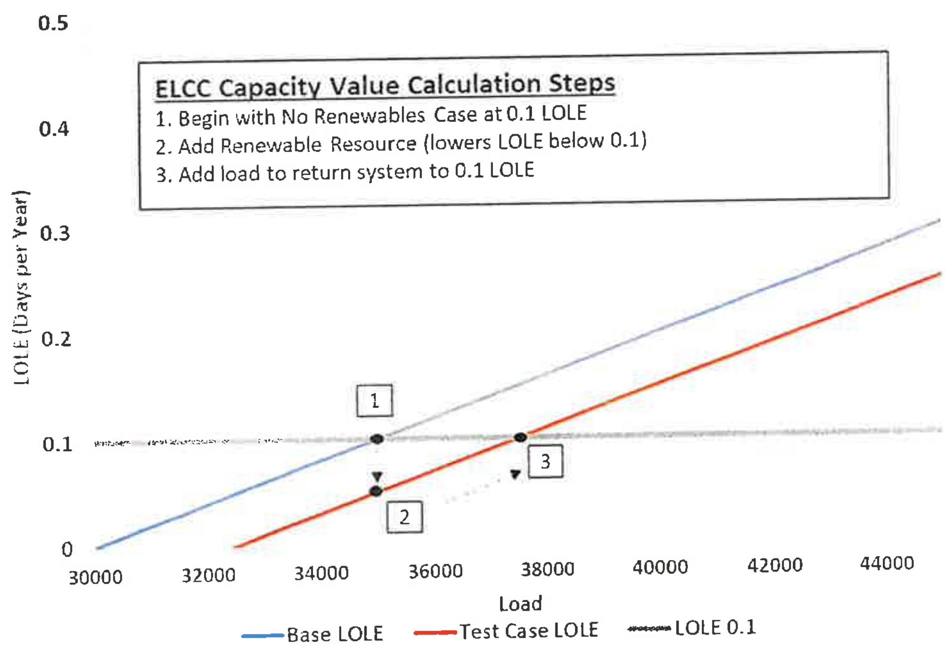


Figure 20. Generic ELCC Methodology

As indicated by the figure, an ELCC base case is established that contains no renewable resources but has been tuned to 0.1 days/year LOLE. When the renewable resources are added to that system, LOLE drops below 0.1 days/year. The system is then returned to the 0.1 days/year LOLE point by adding load (generally accomplished by injecting negative generation into the system).

This figure, however, shows how ELCC is calculated on an annual basis. For purposes of this study, ELCC was calculated seasonally for summer (June-September) and winter (January, February, and December). In this case, rather than targeting a 0.1 days/year annual LOLE, the monthly LOLE of the base case is grouped by season and each becomes the associated target for that season.

Seasonal ELCCs were calculated for 1000 MW of solar (approximately equal to the solar modeled in the 2026 PRM analysis), 1250 MW of solar (approximately equal to the solar modeled in the 2029 PRM analysis), 1500 MW of solar, and 2000 MW of solar. In addition, ELCCs were calculated for 200 MW of BESS and 400 MW of BESS. Finally, ELCCs were calculated for a 200/1500 MW combination of of BESS and Solar as well as a 400/2000 MW combination of BESS and Solar. The figure below shows a representation of the ELCC scenarios evaluated.

Table 10. ELCC Scenarios

BESS MW

Solar MW ->	0	1,000	1,250	1,500	2,000
	200			200\1,500	
	400				400\2,000

STUDY RESULTS

The following outlines the results of the base case PRM analysis as well as the ELCC analysis.

BASE CASE ISLANDED PRM

As described in the Study Methdology section above, the Santee Cooper system PRM was evaluated in 2026 and 2029. In each study year, the system was simulated with the addition of multiple CTs as necessary to find the capacity necessary to achieve 0.1 days/year LOLE.

The table below shows the scenarios simulated as well as the resulting LOLE for the Santee Cooper system on an islanded basis.

Table 11. Islanded PRM Simulated Results

No CTs	Winter MW	2026 LOLE	2029 LOLE
2	710	N/A	0.1743
3	1,066	0.1093	0.0352
4	1,421	0.0190	0.0076
5	1,776	0.0043	N/A

The figure below shows the Santee Cooper annual LOLE for 2026 and 2029 as a function of winter reserve margin[8].

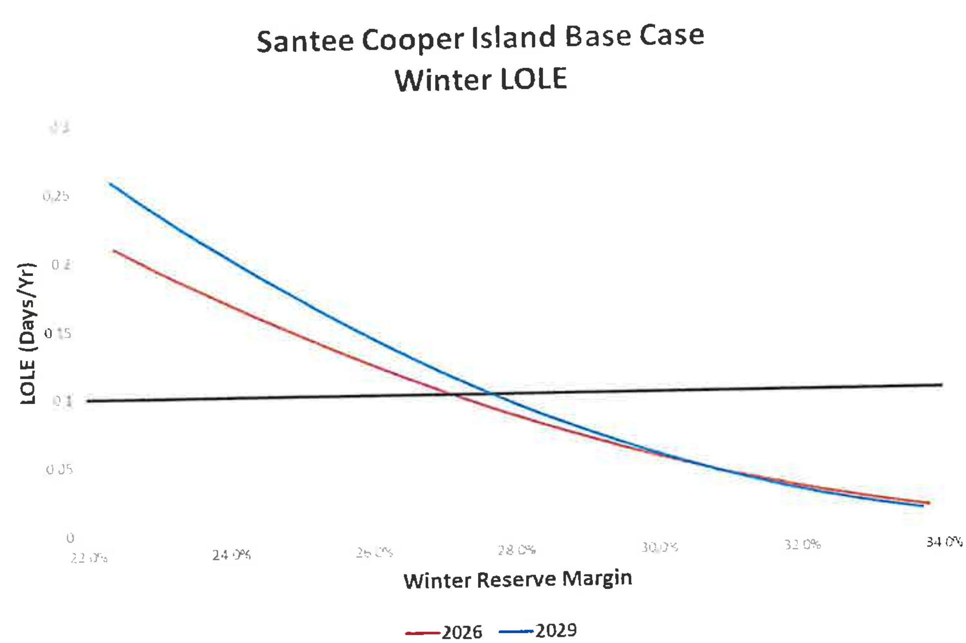


Figure 21. Islanded LOLE as a Function of PRM

[8] Winter ELCC for the solar resources per the ELCC results calculated during the ELCC analysis.

The final MW adjustment and resulting PRM for the islanded Santee Cooper system is shown in the table below.

Table 12. Islanded PRM Interpolated Results

Year	Winter MW Adjustment	Winter PRM
2026	1,092	27.1%
2029	865	27.7%

It should be expected that the islanded PRM would not significantly change from one year to another unless there is a significant difference in the underlying system. The difference between the 2026 and 2029 results shown here are driven primarily by minor differences in outages.

BASE CASE INTERCONNECTED PRM

The table below shows the scenarios simulated as well as the resulting LOLE for the Santee Cooper interconnected system that included first tier Balancing Authorities.

Table 13. Interconnected PRM Simulated Results

No CTs	Winter MW	2026 LOLE	2029 LOLE
1	355	0.1614	0.0988
2	710	0.0721	0.0300
3	1,066	0.0232	0.0122

The figure below shows the Santee Cooper annual LOLE for 2026 and 2029 as a function of winter reserve margin[9].

[9] Winter ELCC for the solar resources per the ELCC results calculated during the ELCC analysis.

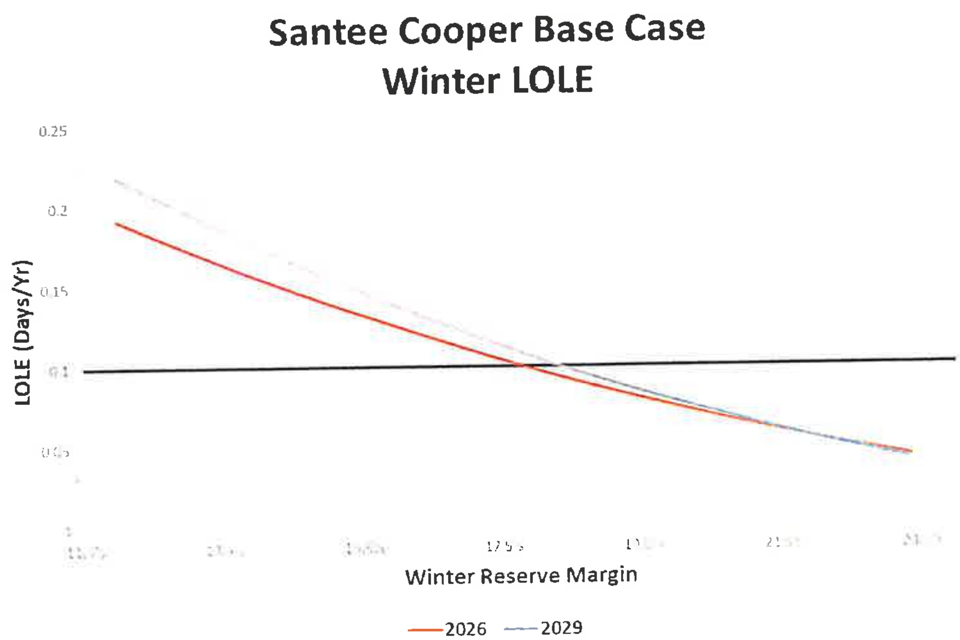


Figure 22. Interconnected LOLE as a Function of PRM

The final MW adjustment and resulting PRM for the interconnected Santee Cooper system is shown in the table below.

Table 14. Interconnected PRM Interpolated Results

Year	Winter MW Adjustment	Winter PRM
2026	580	17.8%
2029	351	18.3%

The difference between the 2029 results and the 2026 results are driven primarily by differences in available capacity from the market and small changes system EFOR assoicated with a different capacity mix.

The following figure shows the monthly breakdown of LOLE at PRM.

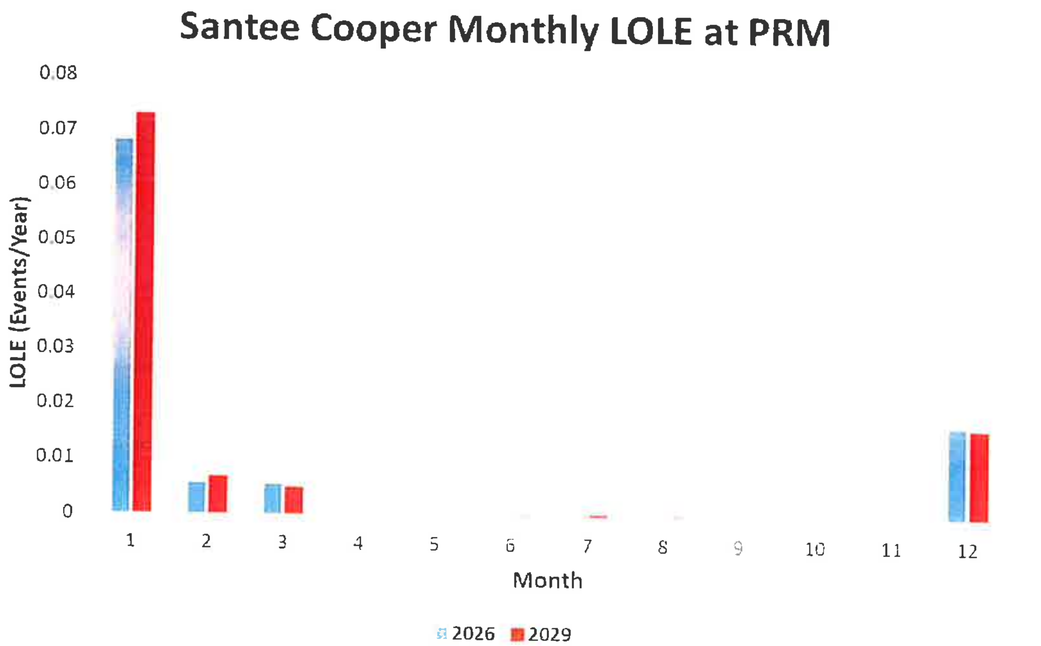


Figure 23. Monthly LOLE at PRM

As the figure demonstrates, the overwhelming majority of the LOLE occurs during the winter months of January, February, and December. There is also a noticable risk in March. This is due to an overlap of planned maintenance, forced outages, and the potential for unusally cold weather. Despite the risk of extremely hot weather, the lower summer peak loads, regional solar penetrations, and the availability of purchases from the market make reliability concerns in the summer low.

This can also be seen by examining the hourly EUE profile. The tables below show the probability weighted average hourly 12x24 EUE profile (as a percent of the total EUE for the year) for 2026 and 2029, respectively. These tables also demonstrate that the greatest risk for reliability events is not just on winter mornings, but in the overnight and early morning hours of the winter as well.

Table 15. 2026 Weighted LOLE by Hour

2026 12x24 EUE (Percent of Annual Expecation)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	5%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	10%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%
7	16%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	3%
8	20%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%
9	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%
10	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
20	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
21	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 16. 2029 Weighted EUE by Hour

2029 12x24 EUE (Percent of Annual Expecation)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	5%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%
6	10%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	3%
7	16%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	5%
8	20%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
9	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
10	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
20	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
21	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

BASE CASE SUMMER PRM

As discussed above, the constraining season in this PRM study is winter. Meeting the winter PRM requirement will result in a summer reliability that is considerably more reliable than 0.1 days/year LOLE.[10] As shown in Figure 24 above, the LOLE in the summer months (June-September) is almost non-existent. This can also be seen in the hourly EUE tables above, Tables 15 and 16. Because such a high percentage of the LOLE is in the winter months, developing a summer PRM in which the summer PRM was allowed to increase significantly would result in an unacceptably high annual LOLE. For example, if both the summer and the winter were each allowed to approach 0.1 days/year LOLE, the total annual LOLE would approach 0.2 days/year or 1 event every 5 years. This would not meet industry practice for acceptable system reliabilily.

To establish a summer PRM requires finding the reserve margin in which summer LOLE begins to appreciably materialize and yet total annual LOLE does not increase unacceptably. As shown in the figure below, summer LOLE increases slightly once summer PRM falls below 17%.

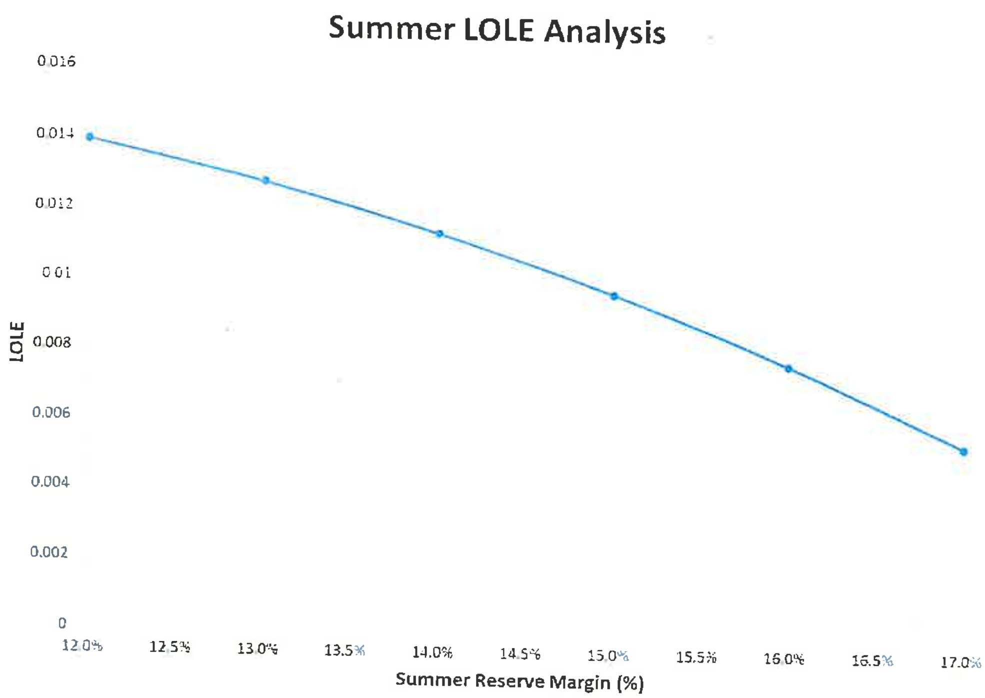


Figure 24. Summer LOLE Analysis

At a summer reserve margin of 16%, the summer LOLE is just under 0.008 days/year; at a summer reserve margin of 15% the summer LOLE is just under 0.01 days/year; and at a summer reserve margin of 14% the summer LOLE is just under 0.012 days/year. These levels of seasonal LOLE will not

[10] For example, meeting the 2026 winter PRM of 17.1% will result in a system with a summer reserve margin of roughly 28%.

significantly increase the overall annual LOLE. Thus, it would be reasonable to establish a summer reserve margin requirement somewhere in this range. It should be noted that given current portfolios and the anticipated addition of solar resources, Santee Cooper will automatically meet this requirement so long as they are meeting the established winter target. For this reason, the summer reserve margin target should be considered a secondary constraint.

BASE CASE RESULTS DRIVERS

There are a number of factors driving the Base Case results. The primary ones are as follows:

WEATHER WINDOW

The 40-year weather window was chosen as representative of long term weather patterns and includes periods of both mild and cold weather for consideration in the PRM determination. The following graph shows the resulting weighted average LOLE by weather year.

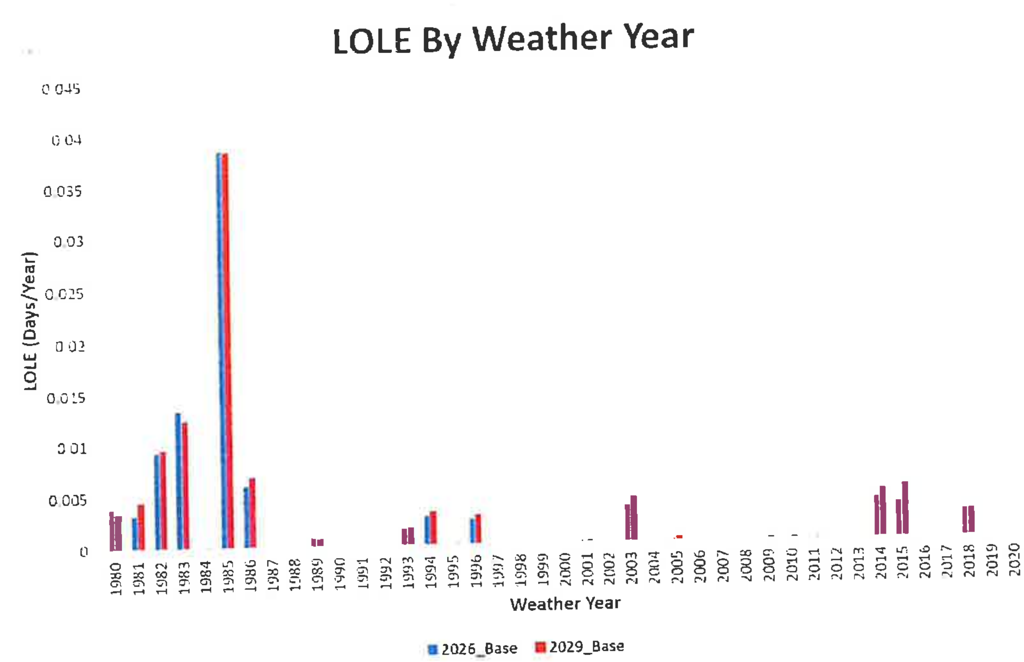


Figure 25. LOLE By Weather Year

LOAD RESPONSE ASSUMPTIONS

As discussed in the Load Modeling section of this report, the historical temperatures used to train the neural networks that were employed to develop the weather year load data did not contain some of the most extreme temperatures. Thus, a MW/degree load response assumption was developed based on the historical data so that loads could be extrapolated on those days. On cold winter mornings, this load response assumption was 57 MW/degree. It is this load response that drives the +18% peak demand variance from the normal winter forecast.

There is uncertainty as to whether this response holds true at colder temperatures or whether saturation is experienced such that the load reponse under extreme conditions is actually less than 57 MW/degree. Experience from other regions of the country suggests that little saturation exists for extreme cold temperatures. In fact, as a result of recent extreme cold weather events in other regions of the country[11], some regions have experienced load variance significantly higher that what was assumed in this analysis, suggesting that load response actually increases at much colder temperatures. As a result, both a high and low load response sensitivity were performed to determine the impacts of load response to PRM results (see sensitivities section below).

MARKET INFLUENCE

As demonstrated through comparison of the islanded PRM vs. the integrated PRM, the market is a significant driver in the results of this analysis, contributing a significant reliability benefit of almost 10%. Although the transmission import assumptions were based upon regional studies and expectations of simultaneous import, there is some concern that the combined import capabilities of Santee Cooper and DESC may be overstated due to the highly interconnected and interdependent nature of the Total Transfer Capabilities of those systems. As a result, a sensitivity was performed that considered a more restrictive joint import capability for DESC and Santee Cooper to determine if transmission capability is allowing too great a market influence (see sensitivities section below).

[11] e.g., ERCOT in February 2021.

SENSITIVY RESULTS

The following sensitivities were performed, with the results from each sensitivity analysis presented in the sub-sections that follow:

- Climate Change Sensitivity
- Low Load Sensitivity
- High Load Sensitivity
- Transmission Sensitivity

CLIMATE CHANGE SENSITIVITY

There is general consensus that there has been a gradual increase in average temperatures over the last several decades. According to a climate change study[12] performed by the National Oceanic and Atmospheric Administration (NOAA), global temperatures have increased since 1981 at a rate of approximately 0.3 degrees Farenheight per decade.

Thus, to better understand the impact of rising temperatures on reserve margin requirements, a sensitivity was performed by increasing historical temperatures according to this 0.3°F/decade heuristic. Thus, temperatures were simply increased on a graduated scale, with 1980 temperatures increased most significantly by 1.2°F. Loads were then re-developed based on these revised temperatures and the PRM analysis repeated.

The figure below shows the results of this sensitivity analysis as compared to the basecase and demonstrates that rising temperatures would result in a slight decrease in PRM of approximately 1%.

[12] NOAA. "Global Climate Report – 2020." Accessed 4/8/2022 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/global/202013

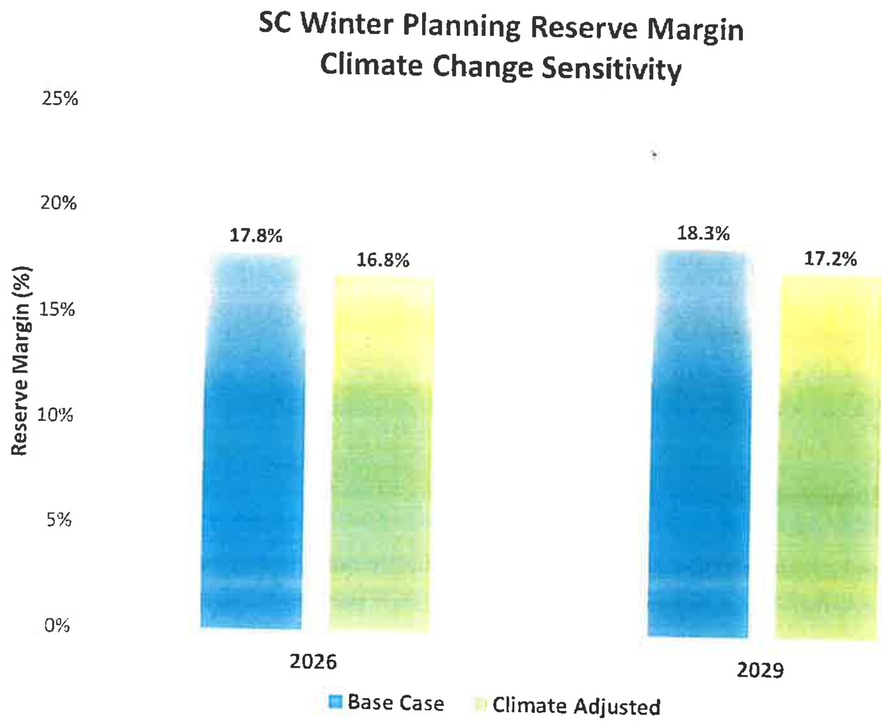


Figure 26. Climate Change Sensitivity Results

LOW LOAD RESPONSE SENSITIVITY

To simulate a low load response sensitivity, loads were re-developed in such a way that loads for Santee Cooper were never allowed to exceed that seen in the five year historical data used to train the neural networks, representing a load response of 0 MW/degree at temperatures below approximately 13°F. Although extreme, this represents a low sensitivity as it is certain there will be some increase in loads at lower temperatures. The results of that analysis are shown in the figure below.

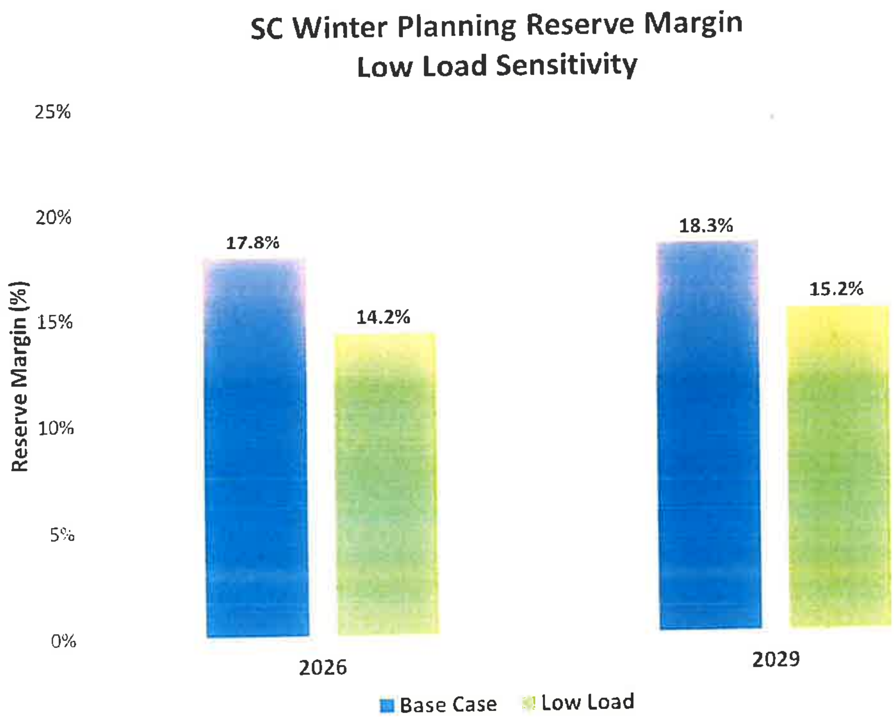


Figure 27. Low Load Response Sensitivity Results

HIGH LOAD RESPONSE SENSITIVITY

In February of 2021, ERCOT experienced load variance due to extreme cold weather of approximately +30%[13] versus the normal weather forecast To simulate a high load response sensitivity, loads were re-developed with an increased load response assumption such that the maximum peak load variance for Santee Cooper reached +30%. This sensitivity represents a high bookend for load response. The results of that analysis are shown in the figure below.

[13] Data from ERCOT shows that the winter peaks in February 2021 were approximately 29% above the weather normal forecast. The weather normal forecast going into the winter was 59,567 MW and while actual loads at the coldest temperature were not known precisely due to load shedding procedures, ERCOT projected a peak load of 76,819 MW. This represents a load volatility of 29% (76,819 MW / 59,567 MW)-1) above the weather normal forecast developed prior to the winter season.

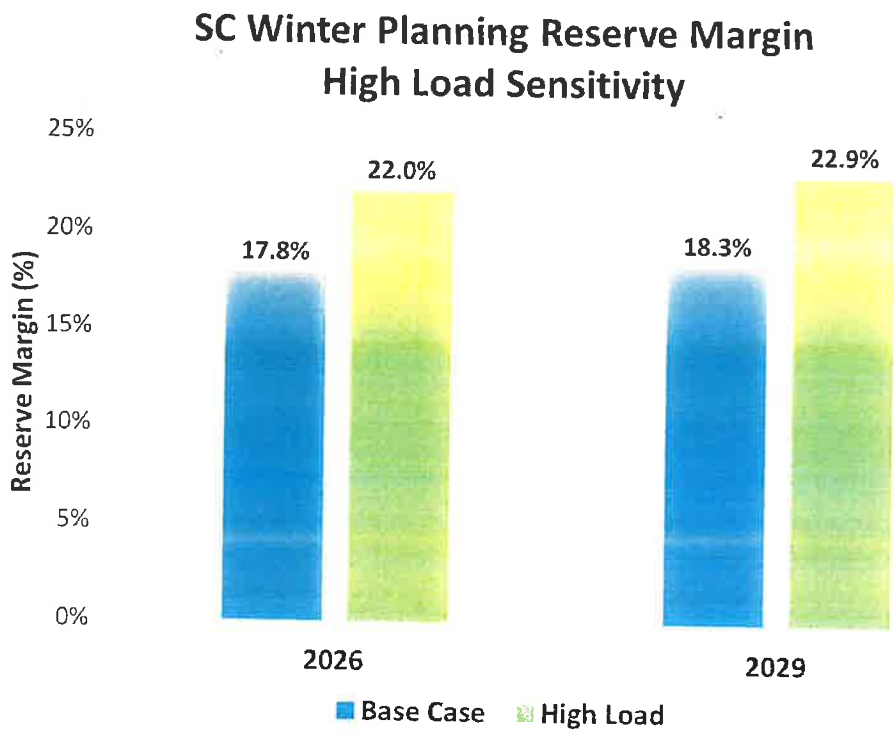


Figure 28. High Load Response Sensitivity Results

TRANSMISSION SENSITIVITY

To simulate a more constrained import capability between DESC and Santee Cooper, a sensitivity was performed in which the combined import capability was limited to a total of 1,500 MW. The result is shown in the figure below.

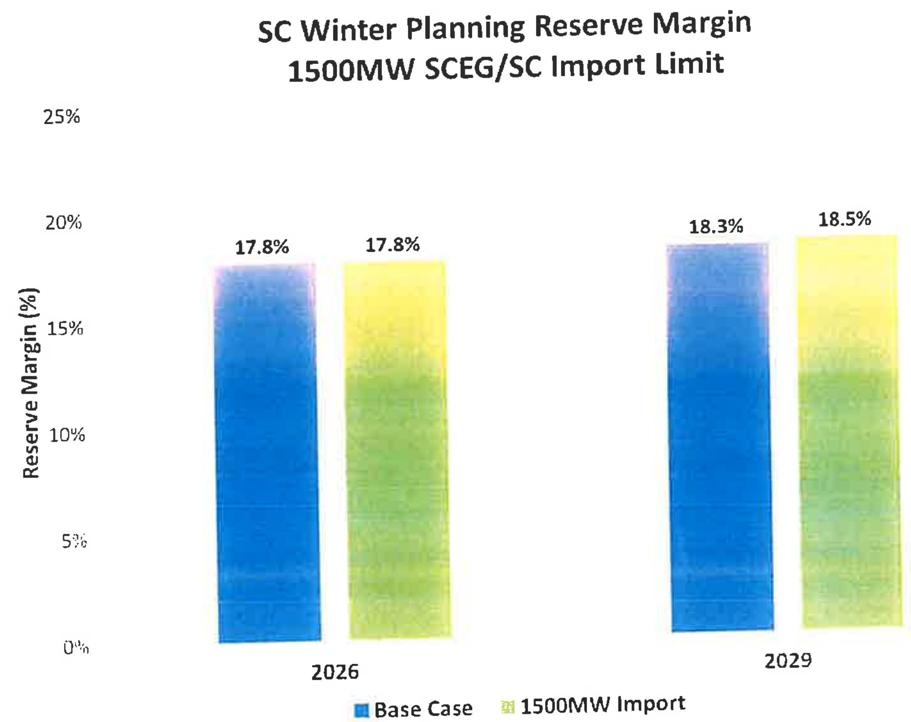


Figure 29. Transmission Sensitivity Results

The lack of increase in PRM suggests that regional capacity constraints, not transmission import capability is the limiting factor driving results in the analysis.

ELCC RESULTS

The process used in determining the ELCC of renewables on the Santee Cooper system was described in the Determining ELCC subsection of the Study Methodology section of this report above. The results of the ELCC analysis are as follows.

The table below shows the resulting allocated winter and summer ELCC's respectively. Any synergistic value between the resources was allocated based on the individual value of each resource as measured in the BESS only and Solar only cases. For this analysis, the BESS resources are operated in a conservative manner on cold winter days providing them their maximum value.

Table 17. Allocated Winter Portfolio ELCC

BESS\Solar	0	1000	1250	1500	2000
0		2.0%	1.8%	1.8%	1.4%
200	100.0%			100.0%\5.3%[14]	
400	88.0%				93.8%\1.5%

Table 18. Allocated Summer Portfolio ELCC

BESS\Solar	0	1000	1250	1500	2000
0		39.3%	36.6%	32.7%	26.9%
200	10.0%			100.0%/33.9%	
400	94.8%				100.0%/28.5%

[14] First Value is BESS ELCC, and second value is solar ELCC.

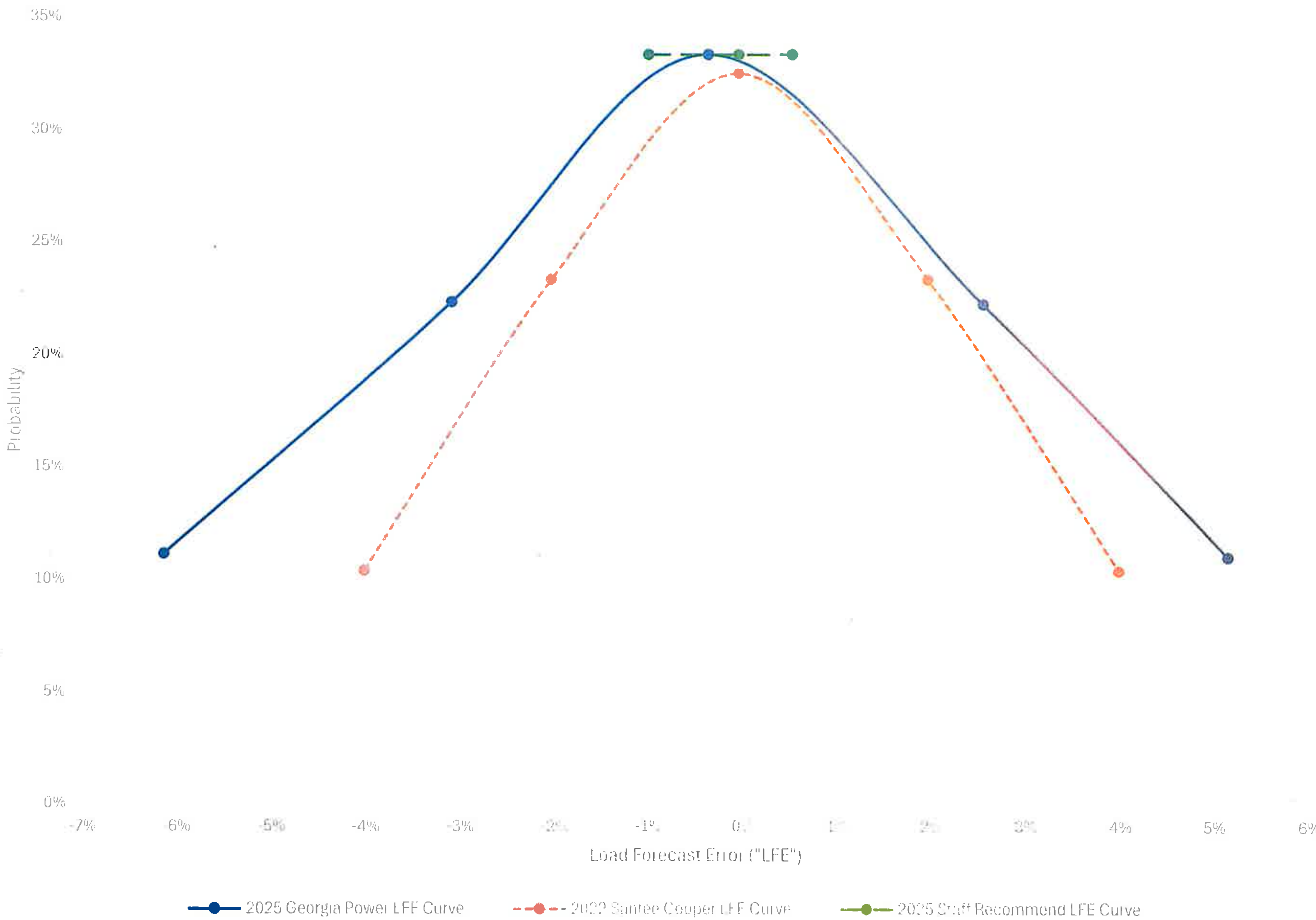
CONCLUSIONS

Upon examination of the study analysis, including all the sensitivity results, it is evident that winter reliability is the driving factor in establishing an appropriate reserve margin requirement for Santee Cooper. Thus, Santee Cooper's primary reserve margin requirement should be a winter requirement. Furthermore, based on these results, it can be concluded that a winter reserve margin in the range of 17-18% can be justified. It is therefore recommended that the winter PRM requirement be set at 17%.

The summer reserve margin requirement should be considered a secondary requirement. Based on the analysis of the summer LOLE, it can be concluded that a summer reserve margin requirement in the 14-16% range can be justified. It is therefore recommended that the summer PRM requirement be set at 15%.

GPC EXHIBIT 12

Reserve Margin Study Probabilistic Distribution of Load Forecast Errors ("LFE")



GPC EXHIBIT 13

DEMONSTRATE DEPLOY DECARBONIZE 2024

Deploy Dialogues Summary Report

Advanced Transmission Technologies

Prepared by Nexight Group for the U.S. Department of Energy

December 2024

* *This report summarizes comments made by a variety of participants, and does not reflect or imply an endorsement by DOE of any of the ideas shared within.*

Introduction

On December 4-5, 2024, the U.S. Department of Energy hosted a series of Deploy Dialogue workshops at the second annual Demonstrate, Deploy, Decarbonize conference (Deploy24) in Washington, D.C.

The Deploy Dialogues were launched as part of Deploy23 in September 2023. Deploy Dialogues aim to provide an independent platform to further discussions around current and potential future Pathways to Commercial Liftoff reports and sectors, in ultimate service of accelerating deployment of clean energy projects. The workshop brought together senior leaders from industry (e.g., utilities, vendors, and asset owners and operators), the broader ecosystem (e.g., investors and non-profit organizations), and government (e.g., DOE, federal interagency partners, and state and local task forces, regulators, and governmental entities) to discuss barriers to and solutions for deploying advanced transmission technologies (ATTs).

This report summarizes the "Innovative Grid Deployment: Next Steps for Advanced Transmission Liftoff" Deploy Dialogue. It is not a verbatim transcript, but rather a summary of topics and ideas discussed in the session. Dialogues were not designed to result in consensus opinions, and none were formed during the Dialogues..

** This report summarizes comments made by a variety of participants, and does not reflect or imply an endorsement by DOE of any of the ideas shared within.*

Innovative Grid Deployment: Next Steps for Advanced Transmission Liftoff

The deployment of commercially available advanced transmission technologies (ATTs) will be critical to modernizing the existing U.S. transmission grid. Since the DOE published the *Pathways to Commercial Liftoff: Innovative Grid Deployment* report in April 2024, significant progress has continued to support broader deployment of these solutions.

The ATTs in scope for discussion included solutions that could enhance effective system capacity: advanced conductors, dynamic line rating, topology optimization, advanced power flow control, and storage as transmission.

This Deploy Dialogue focused on:

1. **Taking stock of recent public and private sector progress** that supports liftoff of advanced transmission solutions and identifying outstanding gaps
2. **Breakout discussions on three topics of ongoing work:**
    a. Frameworks for integrating grid-enhancing technologies (GETs) into grid planning
    b. Regulatory and policy solutions necessary to support continued deployment
    c. Considerations for capturing and disseminating data from new deployments to further de-risk technologies

Taking Stock

As summarized in the workshop sheets used during the Dialogue (see appendix below on page 8), there have been several deployments, industry

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resources, and case study examples throughout 2024 that are advancing the priorities needed for liftoff and deployment at scale of ATTs (see the *Innovative Grid Deployment* Liftoff report for a deeper discussion of the priorities needed for liftoff).

Lessons learned shared by participants from these deployments include:

- **ATTs offer a wide range of benefits, which creates a variety of ways to build a compelling business case** for deployment based on utilities' individual needs (e.g., enhancing wildfire resilience, increasing capacity, reducing congestion costs). For example, the primary motivator for one dynamic line rating (DLR) deployment was the low cost of DLR as a capacity enhancing solution, but the additional value of the situational awareness that DLR provides was a key secondary motivator.
- It can be **easier to build public support for new transmission when it can be proved to customers that a utility has done everything possible to maximize the existing transmission system** (e.g., reconductoring with advanced conductors).
- **Policy or regulatory requirements to consider alternative transmission technologies before new transmission** has been effective at integrating these tools into early planning processes in some states.
- A common industry perception is that sharing data with RTOs is prohibitive for advanced transmission deployments (e.g., topology optimization, DLR), but **several utilities said they did not find this to be a prohibitive challenge**; for example, one utility cited it only cost a few hundred thousand dollars to set up a data sharing system to enable deployment.
- **CAISO was referenced as an example market that has developed supportive policies and effective planning processes to deploy storage as transmission,** helping alleviate transmission constraints and needs.
- **There is an opportunity to proactively build out needed foundational systems** (e.g., communications, data management systems) to enable ATTs, which can support other advanced grid solutions longer-term. Business cases can be constructed to account for this long-term view and value of these foundational investments.

Outstanding challenges that participants mentioned include:

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- **Existing grid planning and operational software tools do not have the functionality to integrate ATTs** (e.g., GETs, storage as transmission).
- **Implementing appropriate cybersecurity protocols and broadly building industry trust in cloud-based solutions is still needed,** which can help unlock new use cases and efficient use of advanced technologies. There is an opportunity to implement new methods to address cybersecurity concerns (e.g., small, decentralized telemetry networks across assets).
- Operators often interpret NERC standards conservatively to reduce risks; there is a need for **education and clarity on NERC standards for ATTs to improve decision-making.**
- Several challenges to realize the full value of "**storage as transmission**" specifically, including:
    - Improved ways to understand and plan for the value of storage as transmission to understand the value and build a business case (for example, a mesh network creates value while storage along one point-to-point transmission line has limited value).
    - A clear accounting framework is needed to address double counting concerns between storage as transmission and as capacity.
    - Operational tools to manage storage as transmission are still needed.
    - ISO/RTOs market rule reforms along with policy and regulatory support for storage as transmission could help progress solutions.

Looking forward to 2025, participants ranked i) system planning, ii) regulatory support, and iii) benefit/cost investment frameworks for ATTs as the top three areas to address in the next year.

Breakout discussion on key topic areas

Integrating Into Planning:

This discussion focused on soliciting feedback from participants on draft frameworks for integrating GETs into transmission planning and into interconnection studies. Key discussion points on these draft frameworks:

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- A need for upfront information about how to plan for technology operationalization, including how to remove siloes between planning and operational departments.
- Greater clarity on the workflow from planning to operationalization could help set expectations early on **how much time and effort is needed** as well as **who needs to buy-in** at critical stages to ensure success.
- For integrating GETs into interconnection studies, open questions remain on the availability of GETs data for interconnection studies, a need to build software and transmission operator capabilities to integrate GETs, and a need to build study processes (timelines, status and key milestone updates, who to involve at key stages) that differentiate between vertically integrated vs. restructured markets.
- NERC Critical Infrastructure Protection (CIP) and cybersecurity standards and continued improvement in planning software capabilities are needed to integrate ATTs.

Regulatory & Policy Considerations:

This discussion focused on ways that federal and state leaders can enhance ATT deployments.

Five possible federal/state options considered include:

a) setting incentives
b) requiring ATTs in specific circumstances (e.g., DLR on highly constrained lines)
c) requiring ATTs in utility transmission planning
d) requiring specific ATT studies (e.g., for expensive constraints, unlock capacity for new load or generation), v) increase regulatory oversight of transmission planning (e.g., transmission monitor, parallel studies to evaluate ATTs)
e) requiring utility reporting on ATT evaluation and deployment (e.g., IRPs, CPNC applications).

The benefits of some of these options include:

a) Setting clearer standards and expectations for utilities

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b) Capturing system value in ways that individual utilities may not be able to (e.g., regional planning, system resilience benefits)
c) Creating short-term and targeted incentives (e.g., performance-based incentives)

Potential associated challenge include:

a) Potential increases in administrative burdens
b) The risks associated with not capturing all the benefits of GETs (which could inadvertently inhibit deployment)
c) Regulatory efforts that turn into a "check the box" exercise vs. Ensuring meaningful outcomes are achieved (e.g., only requiring ATT specific studies may not lead to actual deployments)

Deployment data to support adoption:

This discussion focused on data collection and dissemination from ATT deployments, with a focus on surfacing key considerations to ensure deployment data efforts best support industry awareness and ATT adoption. Key considerations include:

- Using deployment experiences to develop **basic, standardized benefit-cost frameworks** for ATTs to support utility decision making.
- Reporting could include **unexpected costs and benefits** information to build a fuller picture of actual technology impacts.
- **Importance of normalizing that not all deployments will perform as expected** (e.g., expected benefits may not always materialize); deployment information from these experiences still critical to enabling better industry decision-making.
- **Anonymized synthetic data from deployments could be publicly shared** with a limited security risk
- Trusted forums to share outcomes include the North America Transmission Forum (NATF) and ESIG GETs working group.

Key quantitative and qualitative data to capture in deployments include: performance over a year (e.g., 8760 hourly data to see technology

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performance in different contexts), operational process and workflow followed, change management and workforce experiences, unexpected challenges, total investment (including expected and unexpected costs, tangential investments into foundational systems, etc.), business case used upfront and realized value at the end, utility's expected next steps for the technology.

Conclusion

This Deploy Dialogue highlighted the significant lessons learned and progress towards liftoff for ATTs that have already happened across the United States that can help inform continued investment. Additionally, continued progress to enhance system planning and policy and regulatory approaches, as well as capturing and transparently sharing information from existing and planned deployments will further support continued investment.

Several participants noted a strong desire to continue collaboration and information sharing across industry to support further progress on capturing the full value of ATTs.

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Appendix: "Taking Stock" Worksheet

Catalog of Deployments to Date *(additional input on missing deployments welcome)*

Technology	Status	Utility	State	Date	DOE Award?	Liftoff Priority 1	2	3	4
Dynamic Line Rating (DLR)	Deployed	AES	OH	2023	No	X		X	
Dynamic Line Rating (DLR)	Announced	Dominion	VA	2024	GRIP	X			
Dynamic Line Rating (DLR)	Deployed	PPL	PA	2022	No	X			
Dynamic Line Rating (DLR)	Deployed	National Grid	NY	2024	No	X			
Dynamic Line Rating (DLR)	Deployed	Great River Energy	MN	2024	No	X			
Dynamic Line Rating (DLR)	Announced	Georgia Power	GA	2024	GRIP	X	X		
Topology Optimization	Deployed	Alliant	IA	2021	No	X			
Topology Optimization	Deployed	Evergy	KS	2022	No	X			
Topology Optimization	Deployed	SPP		2022	No	X			
Advanced Power Flow Control	Announced	Algonquin Power Fund US	IL, TX	2023	GRIP	X			
Advanced Power Flow Control	Announced	Avista Utilities, Idaho Power Company	ID	2024	GRIP	X			
Advanced Power Flow Control	Announced	VELCO	VT	2024	GRIP	X		X	
Advanced Power Flow Control	Deployed	Minnesota Power	MN	2016	No	X			
Advanced Conductors	Announced	Georgia Power	GA	2024	GRIP	X	X		
Advanced Conductors	Announced	12 Rural Utilities	*11 states*	2024	GRIP	X	X		
Advanced Conductors	Deployed	23 Advanced Conductor case studies (EPRI) + (INL case studies)	*Varies, includes global*			X			
Advanced Conductors	Deployed	*Southern California Edison*	CA	2016	No	X			
Advanced Conductors	Deployed	*AEP*	TX	2015	No	X			
Advanced Conductors	Deployed	Dominion	VA	2022	No	X			
Advanced Flexible Transformers	Deployed	Cooperative Energy	MS	2021	OE	X		X	
Storage as Transmission	Deployed	Rappahannock Electric Coop	VA	2021	No	X			
Storage as Transmission	Deployed	MISO	WI	2020	No	X		X	
Storage as Transmission	Deployed	National Grid	MA	2019	No	X		X	

Note: Demonstration projects and deployments overseas not included in this catalog but are also important to supporting industry know how.

Priority 1: Build and transparently share the bank of industry evidence of the technology value proposition

Progress Indicators

Progress – General:

- Multiple deployments have happened and been announced (page 1)
- ESIG's GETs Industry Working Group exists to share industry experiences

Progress – Technology-specific:

Advanced Conductors:

- EPRI released 23 case studies on various types of advanced conductor deployments
- INL's Advanced Conductor Scan includes multiple case studies

Dynamic Line Rating:

- AES' DLR white paper included detailed performance results
- PPL's DLR reports included some performance data
- EPRI is conducting independent, objective, third party testing of DLR in field sites

Under-developed Areas (preliminary, for discussion)

- Clarifying what data should be captured and how it can be best shared to inform decision-making
- Broadly agreed upon benefit/cost frameworks to evaluate deployments

Discussion Questions

What other key progress has been made to advance industry understanding of these technologies' performance and value?

Are there key underdeveloped areas or outstanding questions that need to be addressed soon?

Priority 2: Develop implementation and operational know how

Progress Indicators

Progress – General:

- **INL** GETs Resource Hub includes multiple resources on DLR, APFC, and advanced conductors to support implementation and operations
- **EPRI GET SET** initiative launched in 2024 focused on preparing energy companies to confidently evaluate, select, plan, and accelerate deployments of GETs; includes: third-party lab and field testing; compilations of experiences from pilots and implementations; APFC user group; training materials; study process and framework, and practical guidelines for system operators and operation engineers to maximize GETs' benefits under different operating conditions while reducing potential risks.

Progress – Technology-specific:

Advanced Conductors:

- Conductor Specification and Operational Guides (EPRI)

Under-developed Areas (preliminary, for discussion)

- Developing procurement, implementation, and operational protocols and guides for DLR, APFC, topology optimization, storage as transmission

Discussion Questions

What other key progress has been made to advance industry understanding of how to implement and operate these solutions?

Are there key underdeveloped areas or outstanding questions that need to be addressed soon?

Priority 3: Refine planning and investment case approaches

Progress Indicators

Progress – General:

- **FERC Order 1920** requires consideration of advanced transmission technologies in regional planning (May 2024)
- **EPRI GET SET** initiative (described previously) includes tools and case studies for planning with GETs
- **State level actions integrating GETs & advanced conductors into planning:**

Technology	State	Actor	Links/Bill	Notes
GETs	MN	Legislature	HF 5247	Planning requirement
GETs & Adv Conductors	ME	Legislature	LD 589	Planning requirement
GETs & Adv Conductors	CA	Legislature	SB 1006	Planning requirement
GETs & Adv Conductors	VA	Legislature	HB 862	Planning requirement
GETs & Adv Conductors	GA	PUC	Docket 55378	Will explore GETs

Progress – Technology-specific:

Advanced Conductors:

- Reconductoring Economic Financial Analysis (REFA) designed to help utility transmission planners better understand the financial, environmental and economic benefits of reconductoring using traditional or advanced conductors (DOE, Spring 2024)
- DOE ruling established a Categorical Exemption to NEPA for reconductoring, supporting faster planning and deployment (2024)

Under-developed Areas (preliminary, for discussion)

- Specific guidance ("how to") on integrating advanced transmission technologies into planning
- Benefit/cost assessment framework for advanced transmission technologies

Discussion Questions

What other key progress has been made to advance planning processes to effectively plan for and evaluate the benefits/costs of these technologies?

Are there key underdeveloped areas or outstanding questions that need to be addressed soon?

Priority 4: Align economic models & incentives (policy & regulatory progress)

Progress Indicators

Progress – General:

- **NARUC passed a resolution expressing support for Grid Enhancing Technologies (GETs) and High-Performance Conductors (HPCs)** as solutions to save customers money and improve reliability. (Nov 2024)
- Federal-State Modern Grid Deployment Initiative: 22 states signed on to prioritize near-term grid solutions (e.g., GETs, advanced conductors, etc.) and commit state action in support (May 2024)
- **DOE State Technical Assistance program** launched to support state regulators and state energy offices with high-impact technical assistance and resources at three different levels of depth and duration: Help Desk, Expert Match, and Deep Dive. (Dec 2023)

Progress – Technology-specific:

- State actions to incentivize deployment:

Technology	State	Actor	Links/Bill	Notes
Adv. Conductors	MT	Legislature	HB 729	Financial adder for use of adv. conductors

-

Under-developed Areas (preliminary, for discussion)

- Example regulatory models to implement supportive regulatory practices (e.g., model regulation, guidebooks)

Discussion Questions

What other key progress has been made to advance supportive regulatory and policy practices to align economic models?

Are there key underdeveloped areas or outstanding questions that need to be addressed soon?

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DEPLOY24

Other Resources and Industry Updates (not exhaustive):

- DOE Resources:
  - State Technical Assistance for Regulators & Policymakers
  - Technical Assistance for Utilities
  - GRIP Round 3 expected in 2025
- White House set a national ambition to upgrade 100,000 miles of transmission in the next five years (April 2024)
- Other industry reports:
  - The 2035 Report: Reconductoring With Advanced Conductors Can Accelerate The Rapid Transmission Expansion Required For A Clean Grid (Energy Innovation)
  - GETting Interconnected in PJM (RMI, Feb 2024)
- ESIG GETs Working Group
- EPRI GET SET Initiative

Additional deployment case study information:

- A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf
- inl.gov/content/uploads/2024/02/23-50856_R4a_-Use-Case-Studies.pdf
- Case Studies by Conductor Type | EPRI Micro Sites
- Pathways to Commercial Liftoff: Innovative Grid Deployment (Appendix E)
- Storage as Transmission Asset Market Study

Additional resources that you would recommend we add? Email Louise White (louise.white@hq.doe.gov)

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Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-GS Data Request Set No. 2

STF-GS-2-13

Question:

Please see the statement on page 115 of the Main Document that "the Company continues to evaluate the potential benefits of dynamic line rating ("DLR") capabilities." Please list any current operational DLR deployments on the Company's system.

Response:

The Company is in the process of deploying dynamic line rating ("DLR") capabilities but does not currently have any operational DLR deployments on the System. The Company's upcoming deployment of DLR follows the longstanding use of ambient adjusted ratings ("AAR") in real-time transmission operations. Both of these methodologies fall within the adaptive line rating portion of a portfolio of grid-enhancing technologies and include a combination of technology deployments and operational experience to provide data-driven real-time transmission line ratings. Similar to AAR, DLR calculations include ambient temperature conditions for a transmission line; however, DLR also includes other location-specific factors such as temperature, wind speed, and wind angle. The Company's upcoming DLR deployment will provide insights into DLR operational considerations including potential use cases and a comparison to the existing use of AAR throughout the state.

GPC EXHIBIT 15

EPRI's GET SET Initiative Gets Going

eprijournal.com [illegible]

October 21, 2024

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Monday, October 21, 2024

Category: Energy Delivery and Customer Solutions, Features

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As the need for transmission capacity grows, EPRI launches a new effort to evaluate the performance of grid-enhancing technologies.

By Chris Warren

America needs a lot more transmission grid capacity. That was the basic finding in the U.S. Department of Energy's (DOE) National Transmission Needs Study released last year. There are many reasons why an expansion of transmission grid capacity is a priority, including the system's role in providing reliable and resilient electricity as demand grows and extreme weather increases in frequency and severity.

Abundant transmission system capacity is also integral to the clean energy transition. For example, the DOE study found that the U.S. must double its current regional transmission capacity and increase interregional transmission capacity over five-fold to reach the federal government's goal of a carbon-free power system by 2035. Princeton University estimates that 75,000 miles of new high-voltage transmission lines—enough to stretch around the world three times—need to be built to reach that 2035 goal.

While there is widespread agreement and increasing levels of incentives and investments to support critical new transmission system infrastructure, the reality is that these projects take many years to get approved, permitted, designed, and built. As the essential work of developing, financing, and building new projects moves forward, however, the need for more transmission grid capacity grows by the day.

The pressing imperative to expand transmission grid capacity quickly has focused attention on grid-enhancing technologies (GETs). GETs are hardware and software that can improve the efficiency, reliability, capacity, and safety of existing transmission lines. GETs are seen as a potentially powerful tool to reduce congestion and speed the integration of renewable generation.

In its Transmission Needs Study, the DOE highlights GETs and describes them as, "solutions capable of managing transmission congestion and increasing line utilization rates by expanding existing transmission system capacity and improving operational efficiencies." The DOE's Grid Resilience and Innovation Partnerships (GRIP) Program is making significant investments in technologies, including GETs, that can bolster the flexibility and reliability of the existing grid.

A Known Unknown

While the potential role of GETs in supporting the transition to a decarbonized and reliable electric power system is widely accepted, the utilities and grid operators that would deploy them have limited experience installing and operating them. This raises a challenge for utilities that want to quickly leverage the benefits of GETs but don't have the time or resources to vet them alone. Closing the gap between the potential GETs have to augment transmission grid capacity and providing confidence that they will operate as expected is the main mission of EPRI's Grid Enhancing Technologies for a Smart Energy Transition (GET SET) initiative.

Launched in July of 2024, GET SET builds on years of research EPRI has devoted to GETs to help utilities understand and be comfortable that the hardware and software will perform reliably. "EPRI has been doing research about grid enhancing technologies for over a decade. The reason that we wanted to have an initiative now is because the technology has advanced to a level where that transition from pilot to deployment stage is happening now," said Anna Lafoyiannis, an EPRI deputy program manager whose work focuses on operations and planning research.

GET SET is driven both by a sense of urgency and practicality. “The idea is that we can put in substantial and focused work that looks at all the technologies in a collaborative way,” Lafoyiannis said. “And that will allow utilities to use the findings immediately.”

A Focus on Four GETs

Gaining Confidence with GETs

Though these four GETs have meaningful potential to improve transmission grid capacity, utilities need confidence about their performance, benefits, and impacts as they are deploying them. The GET SET initiative has already produced high-level executive summaries about each of the GETs (which are linked above in the technology descriptions) to raise awareness and understanding; more detailed white papers, case studies, and regular workshops and user groups will also share lessons learned and experiences.

GET SET will also include lab testing and the collation of results from field implementations that will inform the development of everything from frameworks for effective GETs deployments to a quantification of the value they can deliver in local operating conditions.

“We want to take the participants in GET SET on a journey. We are going to begin with several deliverables related to understanding the reliability and uncertainty of these technologies by doing laboratory testing and then sharing overall results so people know what they can expect from a specific class of technology,” said Alberto Del Rosso, an EPRI senior manager who oversees grid modernization research and development (R&D) projects. “Then we will be providing a framework and guidance about planning and the best way to operate them from a system perspective.”

There have been numerous studies assessing how GETs can improve transmission grid capacity. But what past analysis has lacked is a local focus that makes findings immediately relevant and practical for utilities. “Saying GETs provide benefits across North America doesn’t provide meaning for someone that needs to do the work,” Lafoyiannis said. “Being able to quantify benefits and impacts at a more regional level, or even at a utility level, is helpful because electric conditions and environmental conditions can vary. And an assessment should also include practical considerations, like deployment timelines, permitting considerations, and supply chain, to fully prepare for the future.”

The Role of EPRI Laboratories

Besides EPRI’s long history researching GETs, new investments in the capabilities of EPRI Laboratories in Lenox, Massachusetts, Charlotte, North Carolina, and Knoxville, Tennessee, will help utilities get comfortable with the technologies before they’re deployed. “When GETs really emerged as a priority about a year ago, industry stakeholders came to EPRI because we’ve been doing testing on advanced conductors for more than a decade,” said Drew

McGuire, director of transmission and substations R&D at EPRI. "So, when the industry needed to understand advanced conductors, we could raise our hand and say we've already done it. Here are the test results. We aren't just responding quickly; we are ahead."

For example, in Lenox, Massachusetts, EPRI has commissioned a DLR test facility that includes a new outdoor 625-foot three-phase test span where the current flowing through individual conductors can be controlled, and a wide range of loading conditions can be simulated and monitored. This new test span adds to EPRI's DLR research capabilities, which presently includes thirteen one-to-two-year-long field demonstrations building on dozens that have been ongoing since the 1990s.

Another example: EPRI's Charlotte lab includes a conductor test rig, where conductor-connector systems undergo intense thermal and mechanical stresses, including mechanical loads of 30,000 pounds and temperatures up to 250° Celsius. The GET SET project will also include real-world, fully monitored deployments of technologies with member utilities, including carbon core conductors in the Northwestern U.S. to better understand how resilient they are to icing.

With all the testing, the goal is to first assess categories of GETs rather than the features and performance of individual technologies. "While we will bring out technology providers and do individual tests for them, what we hear from decision makers is before they're even selecting individual technologies, they want to know as a class how DLR, advanced power flow controllers, or advanced conductors perform," Del Rosso said. "They want to know what to expect so they can use the information to evaluate it against other technologies and solutions."

While GET SET will last for three years, the project will regularly share results from its testing and research. Even before the initiative officially launched, Lafoyiannis was reminded of the thirst for knowledge about GETs when EPRI gathered over 200 participants for a workshop about the state of the science of the four technologies. "We had participants from over 75 utilities. We had technology providers, NERC, and other companies and developers in the room," Lafoyiannis said. "There's broad interest." And the audience was all saying there's a strong need for new capacity, and they need to connect new loads and generators on short notice. That's where we can help."

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EPRI

GPC EXHIBIT 16

2025 White Paper

Dynamic Line Ratings Status, Applications and Opportunities

A GET SET White Paper

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FOREWORD

What is GET SET?

Energy companies are seeking options for increasing transmission capacity to support energy transition objectives and large demand increases from artificial intelligence (AI) and manufacturing growth [1]. EPRI's GET SET (Grid-Enhancing Technologies for a Smart Energy Transition) initiative aims to support the deployment of a subset of technologies to respond to the rapid load growth, changing generation mix, and extreme weather that energy companies are facing today. These solutions can potentially maximize the capacity of existing assets quickly while working to build new capacity in the long term. For example, one driver for increased grid congestion is the differing speed of construction for data centers as compared to transmission lines. The intermediate increased electrical loading can push transmission lines to or beyond their safe operating limits. While deploying grid-enhancing technologies (GET) is seen as a potential method to increase capacity from transmission lines and satisfy load growth, deployments must also ensure system stability, asset health, and public safety are maintained.

The GET SET initiative is committed to assimilating and disseminating existing GET knowledge to support utilities in assessing and deploying GET now, as well as leveraging those deployments and additional research to answer remaining questions and provide the tools that utilities need to evaluate and deploy more broadly.

GET SET White Paper Series

The GET SET white paper series is a collection of papers that describe four promising GET: Dynamic Line Ratings (DLR), Advanced Conductors, Advanced Power Flow Controllers (APFC), and Transmission Topology Optimization (TTO). This white paper series aims to document the current state of the science regarding GETs and their potential applications and identify opportunities for greater research and collaboration.

INTRODUCTION

The general benefits and limitations of dynamic line ratings (DLR) are presented in Table 1.

Table 1. General benefits and limitations of DLR

BENEFITS	LIMITIATIONS
Increases transmission capacity on existing circuits without physical changes (non-wires solution).	Can be costly to safely upgrade lines, particularly on lines with no clearance buffer, aged conductors, surge impedance loading (SIL) limits, stability limits, or limiting substation ratings.
Can increase capacity if weather is more favorable than static/seasonal assumptions.	May reduce ratings as often as 30–40% of the time.
There are many technology providers available.	Accuracy, reliability, and cost vary across technologies, complicating finding best-fit solutions.
Adoption of ambient adjusted rating (AAR) later simplifies adoption of DLR.	Adopting AAR reduces the return on investment of adopting DLR relative to using static ratings.
DLR technologies can provide insight into other system conditions.	There are presently no industry standards for specifying or validating DLR systems.
Capacity gains can loosely align with peak demand and peak renewable generation in some systems.	Capacity gains are not completely correlated to when transmission is limited.

DLR are a method for determining how much power can flow through overhead lines for a given allowable operating temperature. What differentiates DLR from other methods is the use of real-time data to account for local weather conditions that change every few minutes, such as wind speed and direction. [1] Because DLR can be relatively affordable and quickly deployed, interest in them has grown significantly in the last decade. While DLR have been around for many years, the performance of DLR technology has recently increased with the higher deployment rate of cell towers needed to carry data from the field to the processing server, allowing for an acceleration in adoption. This paper is aimed at industry professionals who are seeking to better understand the fundamentals of DLR, recent industry experiences, and the associated headwinds and tailwinds for adoption.

The aim of DLR is to develop more precise estimates of wind to be applied in ratings calculations. The capacity of a circuit is determined by the lowest thermal or stability limit across all assets in the circuit. Traditionally, static ratings are used which assume near worst-case conditions to reduce the risk of a circuit exceeding asset design limits. When conditions are favorable, such as a windy cool day, the DLR may unlock additional capacity. If the DLR is below the traditional ratings, a utility may improve its safety and reliability margins by reducing power flow, which helps ensure assets stay within their design limits.

Capacity Changes with DLR

Previous studies have demonstrated DLR can increase line utilization [2, 3]; however, there are situations where other upgrades are optimal. There are many metrics that determine what upgrade is optimal such as time to implement, costs (upfront, maintenance, life cycle, etc.), reliability, and cyber-security requirements; a key decision factor is the amount of capacity DLR can unlock and what percentage of time capacity gains are available. DLR are a valuable tool in our toolbox, but not a "silver bullet" solution to all challenges.

Based on the analysis of a small number of spans, DLR could indicate a high theoretical benefit. However, there are several factors that can result in capacity gains below the theoretical limit such as the existence of wind-sheltered spans, ratings of terminal equipment, system stability, energy demand, etc. A 2024 survey of utilities with DLR experience indicated that annual average capacity gains are expected to be below 15% in many situations. In a case study presented at the 2024 GET SET workshop in Atlanta, average capacity gains ranged from 2–8% depending on evaluation criteria.

EPRI studies have found that when utilities have existing ratings that are less conservative, DLR could reduce capacity below a utility's legacy ratings a significant amount of the time (30–45%) [4, 7]. In 2021, FERC Order 881 required the adoption of ambient adjusted ratings in the United States.

Many existing studies show capacity benefits of DLR relative to legacy rating methods that will no longer be utilized. To generalize, DLR capacity gains should be lower for a utility applying ambient adjusted ratings (AAR) than if it were using static ratings. Additional studies are needed to better understand what the real-world benefits will be as compared to theoretical gains.

DLR Compared to Other Ratings Methods

Because DLR benefits are relative to the legacy ratings methods, it is prudent to discuss the different rating practices used in the field today:

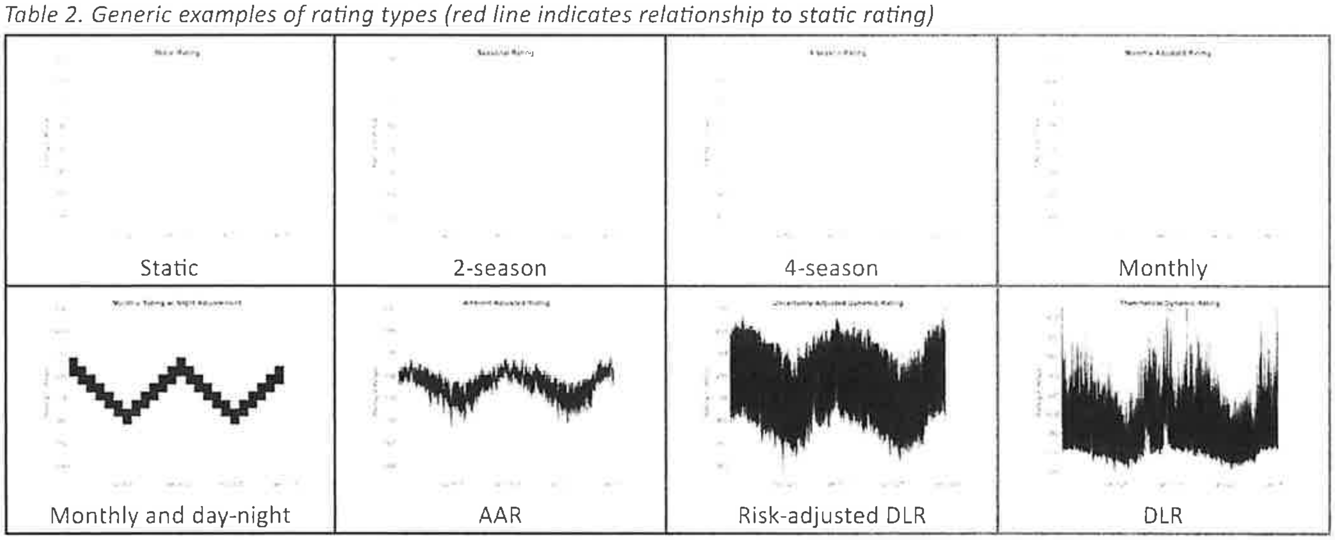
- **Static line ratings (SLR)** are a fixed single value that do not change with time. SLR are typically determined by estimating peak summer weather conditions and a moderate wind speed.
- **Variable line ratings (VLR)** adjust ratings for specific time intervals based on likely weather conditions within a specified time frame. VLR can include seasonal ratings, day/night ratings, or monthly adjustments. VLR still leverage fixed assumptions and do not change year over year.
- **Study-based ratings (SBR)** are similar to VLR, but the ratings are derived from a statistical analysis of recent local weather instead of following an industry guide.
- **Ambient adjusted ratings (AAR)** use either hourly or daily air temperatures to determine capacity. Solar heating values may be fixed, use day/night values, or be updated hourly.
  - FERC 881 specifies U.S. utilities to have hourly AAR with either day/night or hourly solar adjustments. The hours of daylight change monthly based on local conditions.
- **Dynamic line ratings (DLR)** are updated most frequently, every 5–30 minutes. DLR consider wind speed and direction changes along an entire circuit as well as temperature and solar heating. Rather than measure weather directly, some DLR vendors measure other properties and infer the weather parameters needed for a rating calculation instead.

A generic depiction of the rating methods over time is shown in Table 2.

DLR COMPARED TO CONVENTIONAL SOLUTIONS

Conventional upgrades such as reconductoring, retensioning, structure modifications, voltage upgrades, and direct current (DC) conversions could all increase average capacity (see Figure 1). These methods may be the best fit in scenarios where firm gains are needed or high ampacity gains are required. As discussed earlier, current research indicates DLR is well suited for situations where average transmission capacity needs are below 15%, where it is tolerable for capacity to decrease for periods of time, and/or where a constant known gain is not required. Alternatively, DLR may be used in combination with traditional upgrades to allow the combined smaller upgrades to unlock as much capacity as a larger effort. [12] Further studies may significantly improve our understanding of how to best pair or sequence upgrades.

Table 2. Generic examples of rating types (red line indicates relationship to static rating)



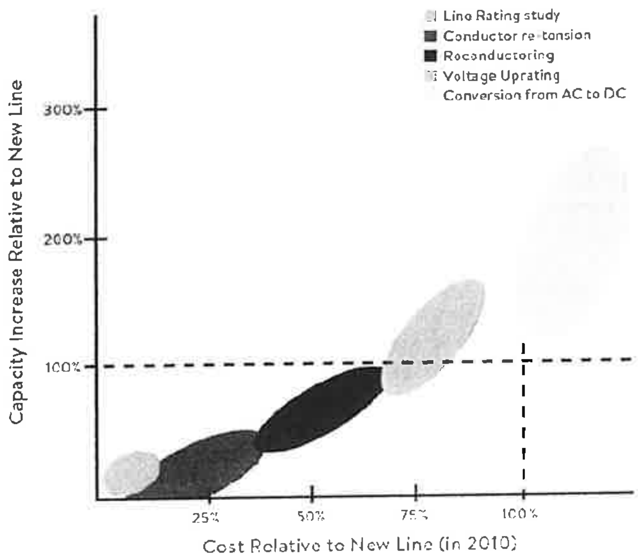


Figure 1. Comparison of year-one costs for traditional upgrades

One method to assess whether to deploy DLR or a conventional solution is a comparison of cost per mile for different solutions; it is also important to compare cost per megawatt (MW) and life-cycle costs. For example, retensioning a conductor is a one-time cost. Deploying DLR carries ongoing capital expenditures (CAP EX) and operations and maintenance (O&M) costs; increasing line current also increases losses. These factors naturally affect decision making and could be missed if only upfront costs are considered. In one study, DLR technology was found to be more cost-effective than a reconductoring effort [13]. While the initial cost for DLR was below the reconductoring, over a 40-year design life for new conductors, DLR could have been significantly more expensive than reconductoring considering lifetime costs [5, 13]. The cost difference varies based on site-specific conditions and depends on the DLR technology deployed. If energy management system (EMS) upgrades were required or load growth continued beyond what DLR provided, the scales would tip further in favor of conventional upgrades. In this specific hypothetical, DLR would be the lower-cost solution in the first few years, but perhaps not over the life cycle of the line. This may indicate that DLR offer a stronger use case when used as a "bridge technology" to reduce congestion during the design and buildout of traditional upgrades. In such a case, a utility should plan to recover its investment before the DLR technology needs significant maintenance or replacements to gain the most benefit.

The advantage of traditional upgrades is the existence of industry standards, best practices, specification documents, tests to validate performance, market integration methods, planning processes, and broad experience with the effects on system performance. Traditional upgrades also avoid concerns with communications issues and potential cybersecurity threat surfaces. The downside is that some traditional upgrades can take longer to implement and may require lengthy outages. When comparing DLR with traditional solutions to increase capacity, one critical aspect to consider is that DLR do not provide firm capacity. Therefore, planners must carefully consider the probability and inherent risks when the increased capacity is not available in real time. Developing an appropriate planning framework that considers these risks and mitigations for them is a key element of the GET SET initiative.

OVERVIEW OF AVAILABLE DLR APPROACHES

The equations within ratings standards are based on having accurate measurements of ambient temperature, solar irradiation, wind speed, wind direction, and physical conductor characteristics. These data can be directly input into ratings equations. The ratings equations follow the same general form whether they are used for static ratings, AAR, or DLR.

While there are several industry standards for calculating ratings (discussed later in this paper), they all follow the same general form:

$$Rating\ (Operating\ Temperature) = \sqrt{\frac{Wind\ Cooling + Emissive\ Cooling - Solar\ Heating}{Resistive\ Heating\ (Operating\ Temperature)}}$$

Some methods to obtain DLR measure other parameters, requiring the use of extra equations and models to establish the appropriate inputs for the rating equations. These intermediary calculations can provide added insights but also are an avenue for errors and uncertainty to be introduced or amplified. The key point is that when weather parameters are not measured or modeled, additional conversions must take place. Each method is nuanced, but DLR technologies can be placed in four general categories (see Table 3).

Table 3. *High-level overview of approaches to DLR (vendor agnostic)*

	CONDUCTOR MEASUREMENT	WEATHER MEASUREMENT	WEATHER MODELING	ENHANCED MODELING
	HARDWARE		SOFTWARE	
Definition	Hardware-based DLR that monitors physical properties of transmission assets (temperature, sag, etc.).	Hardware-based DLR that monitors weather conditions (i.e., weather stations).	Software-based DLR leveraging existing weather stations and models.	Software-based DLR that takes publicly available data and augments it using fluid dynamics or AI.
Potential Benefits	Can be most accurate DLR method when done correctly.	Weather data can be used for other needs. No calibration period. Robust supply chain. Many existing standards and guides.	Lower cost alternative that leverages existing public resources. No calibration period.	Is intended to be more accurate than public weather data.
Accuracy Drivers	Number of sites monitored. Quality of hardware and design. Fundamental approach and equations.	Distance of weather station from lines. Quality of hardware. Installation practices.	Number and quality of nearby weather stations. Weather model applied. Presence of wind sheltering objects.	Number and quality of nearby weather stations. Weather model applied. Presence of wind sheltering objects.
Challenges	Typically highest cost (CAP EX and O&M). Mixed experiences from the field. Continuous changes blur maturity level. Communication issues in many areas.	Added cost of hardware and hardware maintenance (unless coordinated with public weather network).	Expected to be lower accuracy, particularly in areas with dense vegetation.	Requires significantly more data, processing power, and resources to set up and correctly maintain models.

Note: This is a generalized example; there is no standardization of terms, definitions, etc. across the DLR space

Hardware-based methods can identify transmission capacity in near-real-time. *Software-based methods* are needed to forecast hours to weeks ahead, albeit with declining accuracy as the forecast extends into the future [8]. It is important to note that often DLR technologies blur these distinctions. For example, SentriSense has a DLR technology based on conductor measurement, but it can also be paired with a weather measurement to increase accuracy and redundancy. WindSim has an enhanced modeling approach, but if the local weather networks do not provide sufficient data, utilities may need to add weather measurements in a small number of locations to improve their models' accuracy and reliability.

DLR Landscape in 2024

In theory, DLR enable the use of less conservative assumptions while maintaining safe, reliable operation. Each technology and method will have some degree of uncertainty (potential error) in the rating based on the quality of the data, the methods and equations applied, and other factors.

There are many different DLR technology providers and methods available (see Figure 2). Understanding the strengths and limitations of all technologies can help ratings engineers select the best option for their systems based on a method's alignment with their existing practices, the expected performance, and their risk tolerance.

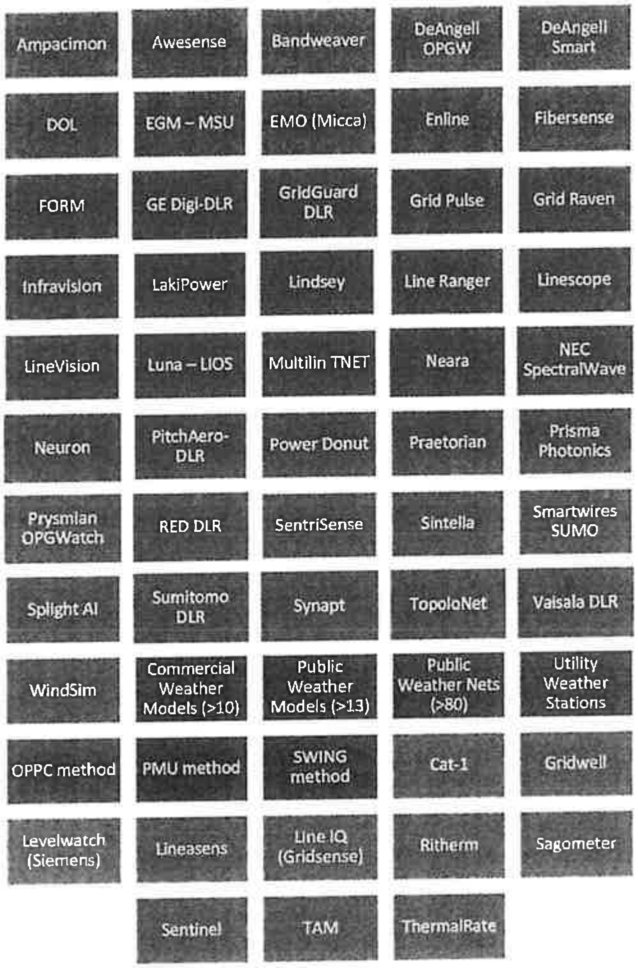


Figure 2. *DLR technologies (blue), alternative methods (purple), and legacy systems (grey)*

DLR Coordination with GETs and Emerging Technologies

In addition to DLR, there are other technologies that can help unlock and better utilize transmission capacity. These may be referred to as advanced transmission solutions, emerging technologies, grid enhancing technologies, etc. Regardless of definition, there is a common understanding that there are many options that can be used in place of or in parallel with DLR in addition to traditional upgrade methods. Figure 3 shows technologies that could have strong synergies with DLR for specific line designs, network configurations, and/or load profiles.

As an example, advanced conductors and virtual power plants (VPP) can be operated closer to their limits when combined with DLR, allowing a higher degree of utilization for an incremental cost. Technologies like advanced power flow controllers (APFC) and transmission topology optimization (TTO) can offer increased benefit alone or when paired with DLR. Pairing these tools with DLR allows power to be routed more effectively to lines with spare capacity available and away from those with constraints. This pairing also prevents APFC or TTO from sending power down a line that cannot handle additional loading due to unfavorable weather (such as during a period of low wind).

Advanced conductors: conductors designed to operate at higher temperatures than traditional conductors (i.e., above 100°C continuously) can allow higher capacity to be sent down rights-of-way on new or existing infrastructure.

Advanced power-flow control: technologies like PFC and phase-shifting transformers can adjust line impedance to manage flows and improve stability during higher loads.

Transmission topology optimization: leverages software to control switchgear/breakers to route power around congested areas more efficiently.

Advanced storage: refers to a wide array of techniques and systems designed to store energy in various forms, including electrical, chemical, mechanical, and thermal storage solutions.

Virtual plant: Virtual power plants (VPP) are systems of distributed energy resources that work together to balance energy supply and demand on a large scale. These resources can include rooftop solar panels, electric vehicle chargers, smart water heaters, etc.

Superconductors: These lines use liquid nitrogen to cool superconducting materials, which can transmit up to 500% more electricity in a given right-of-way.

Figure 3. *Emerging technologies that can augment DLR deployments*

If DLR are high but there is no demand, a utility cannot fully leverage the value of the extra capacity. When advanced storage is in place, operators can utilize periods of high DLR to top off storage. Strategic release of storage can also smooth out the variability of DLR and help maintain power flow in key areas during periods of low DLR. When considered in conjunction, it is possible there will be more scenarios where storage is an acceptable solution/pairing.

While there are some circumstances where it is best to apply only one technology, in general, combining upgrades or other technologies with DLR can offer more flexibility, safer operation, and higher system utilization. For some technology pairings, the return on investment (ROI) from parallel deployments may be reduced [2, 13]. There is comparatively little research or guidance available to help the industry downselect grouped or sequential upgrades; this is an area for future work.

Examples of Rating Standards and Regulations

In the United States, FERC Order 881 mandates system operators to enable data exchange between relevant organizations for hourly updates with rating forecasts for the coming 10 days. Utilities are deploying changes to their EMS to simplify the management of rating data and automate the data exchange process with transmission owners. As identified in FERC Order 881, NOPR 22-5, and other federal and local proposals, requirements for AAR are intended to pave the way for easier DLR adoption [10, 11, 13]. To generalize, in the European Union and Australasia, DLR pilot/adoption rates are higher than in the United States.

Utilities may apply international or regional standards and guides to calculate their ratings. The most common overhead line rating calculation methods—published by IEEE and CIGRE—are broadly equivalent but will differ slightly (see Table 4) [2, 9]. The most common standards applied by DLR systems include:

- IEEE 738, "IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors"
- CIGRE TB207, "Thermal behaviour of overhead conductors"
- CIGRE TB601, "Guide for thermal rating calculations of overhead lines"

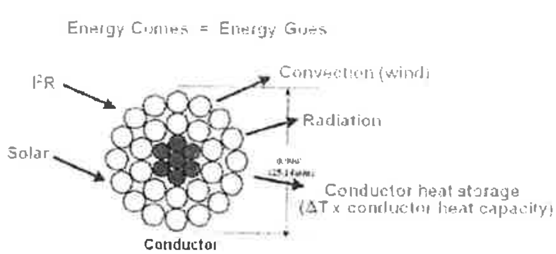
All existing bare overhead conductor thermal ratings standards leverage a heat balance equation. This couples the conductor temperature (which is limited by design factors) to the rated ampacity for a given set of weather conditions. The general relationship is shown in Figure 4.

While there are standards for the calculation of ratings and conductor temperatures, the industry presently lacks standards for the specification, selection, maintenance, or integration of DLR technologies. EPRI is presently working with member utilities (in coordinationwith DLR technology providers) to develop such specifications and best practices guidance [11]. New participants are welcome to engage, share learnings, and obtain access to these methods and guides.

Table 4. *Example comparison of ratings for a 425 mm² aluminum conductor steel-reinforced (ACSR) conductor*

Daytime ☼	Line Rating (MVA)		
Ambient Temperature (°C)	IEEE 738	Cigre TB207	Difference
0	229	213	**-7.0%**
5	223	206	**-7.6%**
10	216	199	**-7.9%**
15	208	191	**-8.2%**
20	201	182	**-9.5%**
25	193	176	**-8.8%**
30	184	163	**-11.4%**

Nighttime ☾	Line Rating (MVA)		
Ambient Temperature (°C)	IEEE 738	Cigre TB207	Difference
0	230	233	**1.3%**
5	223	226	**1.3%**
10	216	219	**1.4%**
15	209	212	**1.4%**
20	201	204	**1.5%**
25	194	196	**1.0%**
30	185	188	**1.6%**



Condition	Rating (Amps)
Air Temperature ↑	↓
Wind Speed ↑	↑↑
Sun Intensity ↑	↓
Conductor Emissivity ↑ (cooling in absence of wind)	↑
Conductor Absorptivity ↑ (rate of heating by the sun)	↓

Figure 4. *Depiction of the heat balance equation used in line ratings*

EXAMPLES OF DLR TECHNOLOGY DEPLOYMENTS

As part of ongoing research, EPRI engages with utilities to understand their industry needs, best practices, and lessons learned from overcoming challenges. While DLR adoption is increasing in the United States, several international utilities have also gained experience with DLR, including:

- **National Grid UK:** Provides updated line ratings based on weather measurements and forecasts upon request to the system operator through a manual process.
- **Elia Group:** Calculates day-ahead and intraday transmission capacity with conductor measurement sensors on 30 lines.
- **ELES:** Calculates ratings based on a weather model complemented with data from on-site weather measurement devices along the lines on over 30 lines.
- **Red Eléctrica:** Uses a combination of weather stations and conductor monitoring to establish DLR; plans through 2026 will increase DLR deployment to about 2% of the system.
- **Austria Power Grid:** Deployed weather stations for DLR at 16 locations across two circuits.
- **Transpower:** Applies a fixed rating that is based on time of day instead of static or seasonal methods; while not a true DLR, it provides similar benefits on 15 lines.
- **PPL:** Deployed conductor measurement-based DLR within two transmission corridors; these ratings are integrated into day-ahead markets.

Key Differences of a DLR Implementation from Pilots/Demos

DLR implementation requires strategic integration of technologies into established processes, operations, and market systems. System operator approaches to this work are specific to each organization, local regulations, and their corresponding market structure. A general flow of information is shown in Figure 5. To fully deploy DLR, a utility should consider:

- **System integration** – The industry does not provide standards for integrating DLR into established processes and software systems. In one EPRI survey, every participating utility reported the use of a customized method [8]. The methods vary widely, from fully manual processes for using DLR on an as-required basis, to fully automated DLR solutions integrated into the control room and EMS systems. In cases where transmission operator (TO) and system operator (SO) functions are unbundled, TOs and SOs can exchange ratings in different ways. For example, if an SO requests line ratings in response to grid conditions, the TO might submit ratings to the SO or simply provide look-up tables.
- **Operational implementation** – Experience with operational implementation varies. Utilities have reported implementations ranging from DLR applied on specific lines in response to outage-caused congestion to full integration of DLR into real-time, day-ahead, and intraday operations.

  Typically, the asset owner is responsible for calculating the DLRs and providing updated ratings to the SO, but data exchange methods vary between organizations. In regions where AAR have been applied, usually, the TO and SO use an agreed-upon process for updating look-up tables or choosing ratings based on weather measurements or forecasts. As FERC Order 881 takes force, the data exchange process is expected to become fully automated.

  Some organizations may opt to use "black box" line rating calculation models that feed the ratings directly into the EMS and/or supervisory control and data acquisition (SCADA) system. Fully integrating DLR into operations requires integrating raw measurement data into the EMS and/or SCADA system for internal rating calculations.
- **Market integration** – European utilities have reported varied experience integrating DLR into market systems. They also use different methods when integrating forecast ratings for use in intraday and day-ahead market calculations. The most common practice is to input updated line ratings into power flow simulation files because this approach requires few, if any, changes in the market system. Some SOs enable the EMS to automatically consider ratings used for market calculations. Others create rating files separately from the EMS and program the EMS to automatically update line ratings based on external inputs. Some use manual processes for updating rating files.

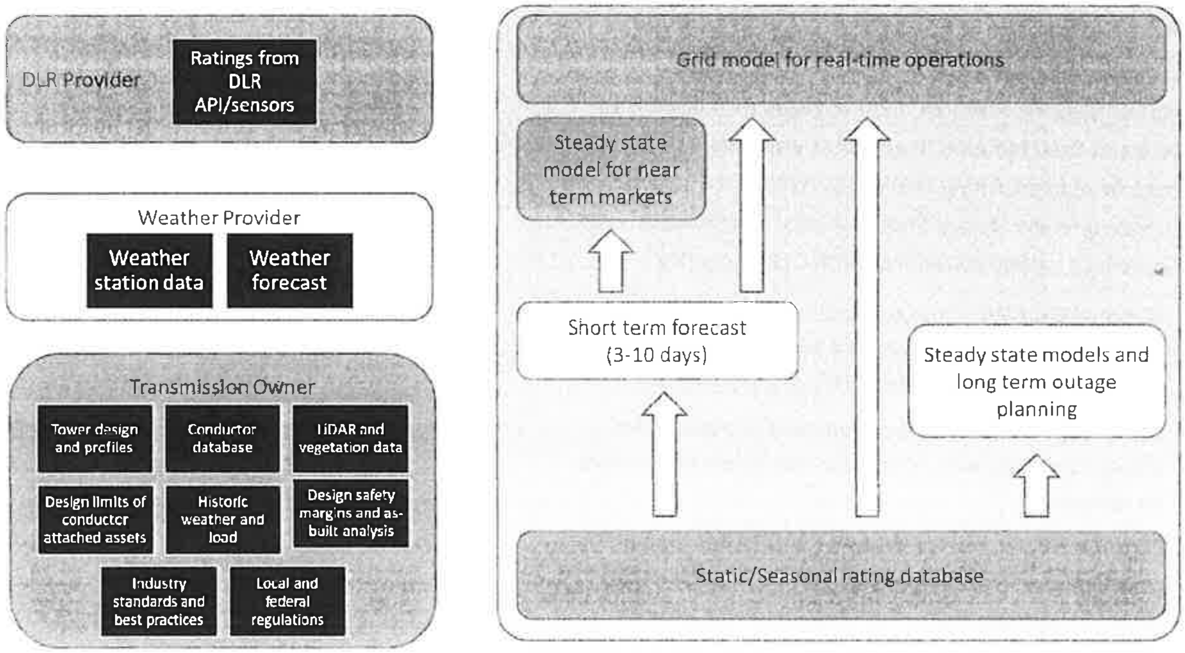


Figure 5. *DLR data flow for operations and planning*

Industry Experiences Shared from DLR Stakeholders

As part of efforts to document the experiences of utilities that have piloted or deployed DLR, EPRI developed a survey and specifically targeted responses from DLR stakeholders. This included existing EPRI members and non-members both within the United States and around the globe. Some of the key takeaways from the 34 respondents collected in 2024 include:

- There were many drivers for DLR adoption, including reducing renewable curtailment, post-contingency flow mitigation, increasing connection capacity, and others. The prevailing driver was reducing congestion costs.
- The majority of experience to date has come from limited pilots and limited deployments.
- Deployments were most common on lines in the 230–345 kV voltage class, closely followed by the 115–161 kV class.
  - There were a small number of sub-transmission deployments.
  - No ongoing deployments were noted at 400 kV or above.
- The overwhelming majority of respondents do not include DLR in planning or cost modeling.
  - A small number of utilities have developed methods for performing short-term planning.
- The majority of respondents saw an average capacity increase of 15% or less, with many seeing no average ampacity increase (as compared to their legacy ratings).
  - The largest increases are expected when legacy ratings were static and/or poorly optimized initially.
- Independent evaluations of the DLR technologies' performance were performed in less than 18% of pilots or deployments.
  - In several deployments the DLR technology provider performed the evaluation.
  - In the majority of cases no performance evaluation was reported.
- 26 of 34 respondents reported issues or concerns based on their experiences that could deter or slow their rate of DLR adoption, and, at a minimum, will require additional research to allow them to deploy DLR with confidence.

DLR IMPLEMENTATION BARRIERS AND SOLUTIONS

Improving the accuracy and reliability of DLR is critical to successful deployment and realization of peak benefits. As noted by the U.S. Department of Energy (DOE), inaccuracies can arise through both measurement and modeling errors [14]. Previous experiences with DLR in demonstrations that had accuracy and reliability challenges may reduce industry confidence in the capability of DLR. Developing methodologies and solutions to address these concerns will be critical to accelerating broader DLR adoption.

Utilities participating in EPRI studies have described the main barriers their organizations encountered when implementing DLR for trials and deployments [4, 9, 15, 16, 21]. The barriers identified by utilities aligned with barriers identified in DLR publications by the DOE [14]. The reported barriers and suggested solutions include (but are not limited to) those shown in Table 5. These headwinds demonstrate the value of collaboration and research to ensure deployments are done safely and provide the desired benefits. EPRI is working with technology providers and DLR stakeholders to prioritize the issues and facilitate developing solutions with an independent and technology-agnostic technical basis.

There are several questions regarding multiple aspects of DLR technologies that we as an industry need to research. Needing more research does not mean we cannot deploy DLR for specific applications at present, particularly for strategic deployments where DLR implementation is staged, allowing utilities to adapt their practices as they gain experience.

Table 5. *DLR implementation barriers and potential solutions*

DLR IMPLEMENTATION BARRIERS AND SOLUTIONS	
BARRIERS	**STEPS TO RESOLVE**
Data accuracy/risk management	• Establish specification requirements and processes to validate accuracy including the required derisking algorithms (similar to those used in international deployments). • Performing non-biased laboratory and field testing of DLR can address knowledge gaps on accuracy, risk management, and life-cycle costing.
Communications and cybersecurity	• Continuing improvements in cellular and satellite networks will increase communication reliability. • The industry can collaborate to apply cybersecurity tests and black box testing to existing DLR technologies to ensure safe operation.
Costs of DLR technologies	• Data can be gathered on recent DLR, GET, and traditional upgrades to document the relative costs and capacity gains to guide selection of right-sized solutions.
Data availability	• Vendors can develop new tools that improve DLR integration in EMS solutions. • The industry can develop best practices on failover solutions, spares strategies, and increasing number of monitors deployed to provide redundancy.
Operational challenges with ratings-based technologies	• Workflows and training to manage variability and uncertainty in short- and long-term planning are needed. • Variable ratings cause conflicts with other operations requirements like relay coordination. • EMS systems require updates to enable full use of DLR. • How to handle DLR for different operation and planning studies such as economic analysis, outage planning, and reliability studies will differ; work is needed to define processes. • Tools are needed to adjust for uncertainty in DLR sitting between DLR and EMS systems.
Variability of DLR with distance and with time	• DLR can be derated to correct for errors from variation over distance; this is applied in existing implementations; data is needed to establish best practices. • Capping the rate of increase and considering worst-case forecasted conditions can reduce volatility of DLR over time; studies are needed to establish best practices. • Improve methods to locate critical spans (when vendors apply varying methods, it affects accuracy, cost, and risk).
Capacity decreased with DLR	• Capacity decreased from DLR indicates periods where DLR are reducing utility risk exposure; improved methods to compare risk tolerance with economic and reliability models can be developed to guide sequential upgrades that address the capacity gap.
Unknown maintenance requirements and life-cycle cost	• Develop specification document(s). • Apply accelerated aging tests. • Perform training on error detection and maintenance practices.

Table 5 (continued). DLR implementation barriers and potential solutions

DLR IMPLEMENTATION BARRIERS AND SOLUTIONS	
BARRIERS	**STEPS TO RESOLVE**
Site selection and quantity incorrectly defined	• New algorithms and tools can be developed to more accurately define the number and location for monitoring, including identification of at-risk spans. • New tools can be developed to flag potential circuits that would most benefit from DLR.
Moving the bottleneck	• Meshed grids may require different solutions or combinations of DLR with APFC and topology control. Control and operation approaches that maximize synergies between DLR and APFC can be developed. Studies can establish guidelines, design, and implementation. • Substation limits may cap DLR or become part of staged upgrades.
Insufficient maturity level	• Work is underway to develop a new maturity model to replace TRL score. • Require documentation on changes and recalibrations by technology providers.

Risk Management with DLR

All DLR measurements have imperfections, which will generate a risk for utilities adopting DLR. Internationally some DLR deployments include derating factors to manage risks, but it is not a universal practice. There is slightly varying guidance on an acceptable level of risk. CIGRE guides suggest that DLR (validated against a baseline) be allowed to go over the true capabilities of the line 1–5% of the time based on several factors. In the United States, a recent Advanced Notice of Proposed Rulemaking on DLR suggests DLR be allowed to exceed the true capacity of the system 2% of the time. Based on the available studies, many existing DLR technologies do not have risk corrections applied that meet these thresholds. To manage risks, the DLR data received from a technology could be derated/reduced. As an example (see Figure 6), the DLR can be simply multiplied by some value between zero and one to reduce the amount of time the provided DLR (red solid line in Figure 6) is above the true DLR (green line). This results in a lower rating from the DLR technology (red dashed line), but it is likely to be above legacy static ratings a high percentage of the time. Alternatively, caps may be placed on the DLR to limit the worst-case error. For example, if a DLR were capped at 30% above the old ratings, a large potential for unlocked capacity exists, but in a worst-case scenario the ratings error cannot be more than 30% (assuming the old ratings were correct). This is a greatly simplified alignment of DLR with line design and protection and control requirements.

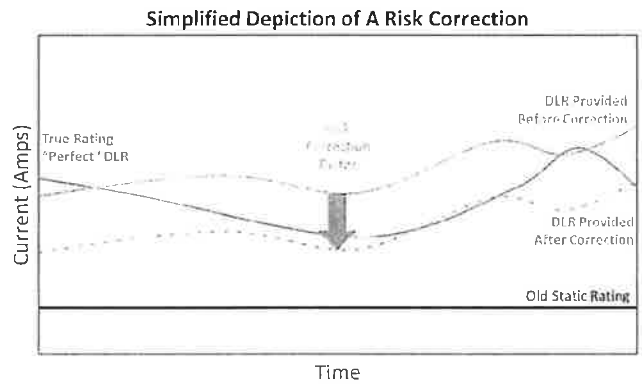


Figure 6. Example of applying risk correction to DLR data

In EPRI's DLR research, a risk-based approach is applied. A small error in the DLR of only a few amps does not pose a risk to asset health, system reliability, or public safety. These smaller errors would be considered negligible provided they do not happen continuously. The higher an error is, the higher the risks and consequences associated with it are. Using a risk-based approach, the amount of correction is focused on getting the system to function just inside its peak capabilities. In studies, we are able to achieve this by having multiple precise measurements of weather conditions and conductor conditions to establish the baseline data needed to develop the risk model. The tolerable risk level is derived using information about the line designs, system configuration, as-built condition, asset health, and other factors. If the risk drivers can be clearly identified, the derisking could be aligned with them so that small risks get small corrections and large risks get larger corrections (see Figure 7).

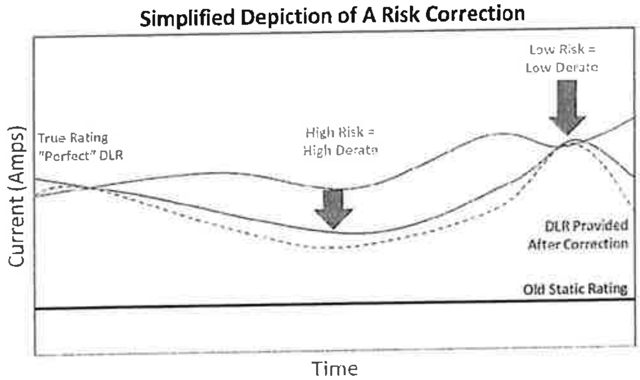


Figure 7. Example of applying risk correction to DLR data if the risk drivers can be well-defined

The Role of EPRI in Developing Solutions

EPRI is performing work across multiple topic areas to allow utilities to make decisions that are data-driven, have a transparent technical basis, are developed independently of stakeholder bias, and combine the valuable insights of utilities leading the transition to DLR.

As part of these efforts, EPRI is collaborating with utilities and technology providers to document the present capabilities and desired performance of DLR systems. This information is leveraged to develop technology specifications and identify methods to validate performance before DLR systems are tied to real-time operations or critical infrastructure. This will include all aspects of DLR performance including installation, maintenance, communications, accuracy, costing, etc.

To address areas where nonstandard tests are useful:

1. EPRI has expanded infrastructure in its outdoor lab in Lenox, MA.
2. EPRI has expanded test capabilities of the indoor lab in Charlotte, NC.
3. A significant number of field demonstrations are underway to gain experience with DLR in real-world conditions using a consistent evaluation method.
4. EPRI is evaluating methods for DLR specification and performance testing.

This establishes areas where utilities can learn rapidly without risks to their systems. The results of both lab and field tests are used to improve models that can be used to inform models and desktop studies (see Figure 8).

Field Evaluations Laboratory Testing Simulations and Modeling

Expanding on existing work [18, 19], EPRI is collaborating with utilities to improve methods and algorithms needed to identify where DLR technologies should be deployed and how many measurements are needed. While technology providers offer this service, the methods are often less transparent, difficult to scale, and can contain both false positives and false negatives [17].

EPRI is also collaborating on field evaluations with multiple U.S. utilities. This will provide insight into the performance of certain DLR technologies as well as provide learnings for improving workflows, line designs, aligning DLR with other stakeholder requirements, aligning DLR with emerging industry regulations, and facilitating knowledge sharing.

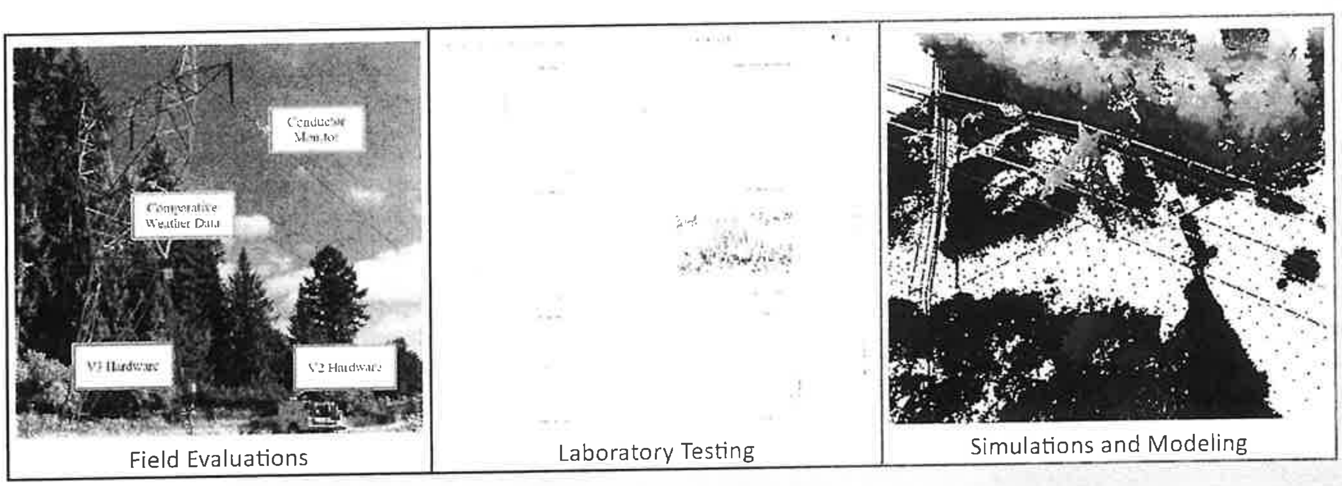


Figure 8. Areas where EPRI is contributing to the acceleration of DLR adoption

In parallel with these activities, EPRI continues to do research and help utilities apply other uprating methods such as building high-capacity advanced lines, the deployment of coated conductors [20], and performing traditional upgrades like reconductoring or voltage upgrades [3]. These efforts give meaningful scale to DLR as utilities can compare the cost, reliability, capacity gain, and time to implement multiple strategies including DLR when making decisions.

SUMMARY

The deployment of DLR is advancing quickly with growth in regulation, technology providers, and pilots. At the same time, common industry accepted methods to quantify the benefits in both planning and operations, compare against traditional or emerging technologies, and set ratings are under development.

One of the optimal use cases for DLR is as a bridge technology—a means to relieve congestion or remedial actions on heavily loaded lines while new lines are being built or to defer construction. There is also increased interest in DLR in areas where states or federal entities are planning to require the use of DLR. DLR have been more widely adopted in Europe than in the United States. One differentiator which may contribute to their successful implementation is the broader use of weather measurement-based ratings and robust derating factors to manage risks. The European utilities have reported using special protection systems (SPS) and topology optimization to maximize network utilization and prevent overloading lines during periods of low DLR. The ease of DLR integration depends on the transmission owner/system operator relationship, the data exchange mechanism employed, the EMS system's capabilities, cybersecurity regulations, and other organization-specific considerations.

Lessons Learned From Utility Implementations

Utilities participating in ratings studies have shared lessons learned from their implementations to help other organizations benefit from their experiences. They also shared recommendations other entities can follow when incorporating DLR into their operations and processes. However, there is no cookie-cutter approach to DLR implementation; the requirements, economics, risk tolerance, and best practices will be utility specific. Key findings include:

- In an ongoing industry survey (as of April 2024) only 17% of utilities that deployed or piloted DLR responded they have performed an independent evaluation of accuracy and performance.
  - While there are an increasing number of DLR projects, there is a vacuum of lessons learned because the deployments lack non-biased third-party evaluation.
- Average DLR capacity gains are likely to be in the range of 0–20%. When practices are implemented to manage risk and uncertainty, gains may be capped at around 30%.
  - As an example, if a utility is adding a small wind farm to an area, DLR could give it just enough capacity increase to avoid new line construction. However, if a utility is building a 500 MW solar plant, DLR alone is not able to prevent a traditional upgrade.
  - DLR benefits are subject to the rating limits of substation components, voltage drop, and system stability. [6]
  - Less complex ratings (seasonal, day/night, etc.) can often yield benefits more quickly with less effort than applying DLR; however, gains may be slightly lower during certain times.
- When performing cost-benefit analyses to determine which uprating method to deploy for each line, consider the lifetime cost and losses as opposed to only year-one cost.
  - Less accurate DLR methods require derating factors to manage risk; while this reduces gains these options may be lower cost and still provide suitable ROI.
- Identify skills needed for DLR and build internal knowledge prior to the deployment to ease the transition to integrated operational DLR.
  - Develop a hiring or training plan to build internal knowledge prior to implementation.
- Utilities that have had DLR success employ a gradual, phased approach for implementing line rating technologies and integrating the technologies with the EMS.
  - This allows time to compare technologies and prepare systems, processes, and procurement.

- Identify technology alternatives and potential vendors to start the procurement process. In some cases a mixture of DLR technologies/technology providers may be needed to achieve desired results and have protection from issues with sole sourcing the solution.
- Weather forecasts are needed to make DLR actionable; hours- to days-ahead ratings are needed for both operations, planning, and marketing.
  - Capacity gains and short-term forecasts will be highly variable. Utilities need to derive strategies to manage both economic risks and the risks to asset health, public safety, and reliability.
- Determine whether any mandates for improving line ratings pertain to your organization and if any regulations impose barriers to deployment.

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Nearly 100,000 affected by power outage across metro New Orleans due to forced 'load shed'

nola.com

By STEPHANIE RIEGEL | Staff writer, Stephanie Riegel

May 25, 2025

High temps, other factors triggered widespread outages in New Orleans area, grid operator says

The Sunday outage has led New Orleans officials to press for answers over why little notice was given prior to the order from grid operator MISO, which said it was necessary as a last resort.

A widespread power outage blanketed the New Orleans area Sunday afternoon, affecting nearly 100,000 Entergy customers in multiple parishes on one of the hottest days of the season so far, raising questions about the area's power grid heading into summer and the start of hurricane season.

Unlike other recent grid failures that have resulted from mechanical failures, Mylar balloons and, even, rodents in the system, Sunday's outage was a "load shed," or brown out — an intentional reduction in the supply of power ordered by the regional transmission organization, MISO — to reduce usage in order to prevent a large-scale blackout.

According to Entergy, more than 52,000 customers in Orleans Parish were without power at the height of the outage, including the entire Lakeview and lake area to the Industrial Canal, Gentilly and parts of Mid-City.

Across town, pockets of Treme, the Marigny and much of Uptown and the Garden District also were in the dark for more than two hours.

The outage represented more than half Entergy's total customers at its peak, according to PowerOutage.us.

In Jefferson Parish, about 35,800 customers were without power, on both the east and west banks.

Additionally, at the peak of the outage, more than 6,000 customers in St. Bernard Parish were affected as were another 6,500 in Plaquemines Parish.

Cleco customers on the northshore also were affected. Several Cleco customers contacted The Times-Picayune to complain about outages in Mandeville and, curiously, an inability to report the problem to Cleco's website or access the utility's outage map online.

In a prepared statement on its website, Entergy attributed the brown out to a directive from MISO, saying, "Entergy Louisiana and Entergy New Orleans have started periodic power outages for its customers. The company is taking this action as directed by its reliability coordinator, MISO, as a last resort and in order to prevent a more extensive, prolonged power outage that could severely affect the reliability of the power grid. Additionally, Entergy continues to follow a directive by MISO to reduce load."

The statement went on to say that depending on conditions, individual customers "may experience multiple outages," and that MISO "is directing actions to be taken to restore the system to normal operations as quickly as possible."

As of 7 p.m., power had been restored to Uptown and the Garden District, as well as to Cleco northshore customers. Power was fully restored by 8 p.m.

Many questions

MISO is a regional electricity grid operator that manages the bulk power transmission system and wholesale electricity markets in parts of 15 U.S. states from the Canadian border to the Gulf Coast.

Load shedding is a protective measure to prevent a gridwide failure during an emergency.

New Orleans City Council members Joe Giarrusso and Helena Moreno both said Entergy told the council that MISO gave the utility just a three-minute warning before shutting off the power.

"How does this happen?" Giarrusso said. "There are lots of questions that need answering."

Louisiana Public Service Commissioner Davante Lewis, whose district includes the New Orleans area, said the load-shed order that caused the outage was the result of several factors, according to information provided to him by MISO.

Lewis said one Entergy generator was offline Sunday for previously scheduled routine maintenance, when a second generator that powers the area failed. Lewis was unsure if the second generator belongs to Entergy or Cleco.

At the same time, demand for power was greater than had been forecast, he said, even though daytime highs Sunday were in the low 90s, far below their summer peak, which frequently approaches triple digits.

"When Entergy asked to take the generator down for maintenance, MISO would have approved it and forecast how much power people would be using to make sure there would be enough power to fund it," Lewis said. "Well, during this, a generator tripped and there was more demand than was forecasted."

Moreno said she was outraged that MISO would force Entergy New Orleans offline without adequate warning.

"Why did New Orleans get whacked by MISO? Why were we selected?" Moreno said. "That needs to be explained."

Lewis also was upset, noting that Sunday's brown out was the third in the state since April. Two others that affected north Louisiana were the result of an issue between SWEPCO, the utility in that part of the state, and the regional transmission organization, SPP, that serves it.

"There seems to not be enough capacity in Louisiana for the changing climate we are facing," Lewis said. "For three load sheds in less than 36 days of each other is a significant problem I believe the PSC needs to start talking about."

This is a developing story. Check back for more details.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-DEA Data Request Set No. 2

STF-DEA-2-11

Question:

Please refer to p. 281 of the "2024 GA ITS Ten-Year Plan" within "2025 IRP Volume 3 PUBLIC DISCLOSURE". Regarding the 2023 ITS solar sensitivity study, please answer the following questions:

a. The decision to undertake the Hatch – Wadley 500kV line references the results of this study. Please provide the results of the implementation of this line found in that 2023 ITS solar sensitivity study.

b. Please provide any power flow cases or other technical material from the ITS solar sensitivity study.

c. Please provide the 2023 ITS solar sensitivity study.

Response:

a. Please refer to STF-DEA-2-11 Attachment A TRADE SECRET.

b. Please refer to STF-DEA-2-11 Attachment A TRADE SECRET, STF-DEA-2-11 Attachment B TRADE SECRET, and STF-DEA-2-11 Attachment C TRADE SECRET. Load Flow Files will be posted in the TS STF-DEA-2-11 Folder on the PSC FTP Site.

c. Please refer to STF-DEA-2-11 Attachment A TRADE SECRET.

Solar Sensitivity Strategic Recommendations

01/25/2024 Joint Committee Update

Southern Company

GeorgiaTransmission

Purpose

- As solar generation continues to spread throughout Southern Balancing Authority Area (SBAA), the transmission system will continue to experience thermal constraints as certain levels of solar penetration are achieved.
- The purpose of this study is to analyze and develop potential strategic projects that support expansion of solar resources in south/central Georgia and Alabama.
- Several strategic projects are proposed which target areas in need of additional high voltage transmission capacity to facilitate load and generation growth and to mitigate impacts of unforeseen loop flows. The proposed projects aim to leverage existing ROW or low-capacity corridors to expedite construction.

Potential Strategic Projects

- The following projects were studied individually:
  - Hatch – Wadley Primary 500 kV Line
  - Douglas – Pine Grove Primary 230 kV Line
  - East Berlin – Thomasville 230 kV Line
  - Raccoon Creek – South Bainbridge 230 kV Line
- The following projects were studied in groups collectively:

Group 1:
1. McGrau Ford – Middle Fork 500 kV
2. Douglas – Pine Grove Primary 230 kV
3. Raccoon Creek – South Bainbridge 230 kV Line
4. Thomasville – East Moultrie 230 kV

Group 2:
1. Bonaire – North Tifton 500 kV
2. Raccoon Creek – Tazewell 230 kV
3. Talbot County – Scherer 500 kV
4. Scherer – Wadley 500 kV

Methodology and Assumptions PUBLIC DISCLOSURE

2023 versions 1&2 Southern Balancing Authority Area (SBAA) Power Flow Models were used for the studies

Case Years	2028 – 2033
Case Types	**REDACTED REDACTED REDACTED REDACTED**
Contingency	N-1
Monitored Facilities	115 kV and above Georgia including tie lines

[redacted]

Recommendations & Next Steps

PUBLIC DISCLOSURE

- Assign sponsorship and initiate project approval documentation:
  - Hatch – Wadley Primary 500 kV (~65 miles)
- Benefit:
  - Widespread transmission capacity improvements.
  - Alleviates identified thermal limitations due to 500 kV contingencies.
  - Provides at least **REDACTED** capacity for a generator to interconnect on the Hatch – Wadley 500 kV line
- Timeline: First quarter 2024

[redacted]

Recommendations & Next Steps

PUBLIC

- Conduct study for project development:
  - McGrau Ford – Middle Fork 500 kV (~64 miles)
- Benefit:
  - North Georgia capacity benefits identified for the McGrau Ford – Middle Fork 500 kV line
  - Right-of-way acquired.
- Note: Additional analysis needed to identify required supplemental infrastructure improvements.
- Timeline: Complete by Q2 2024

[redacted]

Recommendations & Next Steps

PUBLIC

- Conduct study for project development

    1. East Berlin – Thomasville 230 kV line (~30 miles)
    2. Raccoon Creek – South Bainbridge 230 kV line (~48 miles)

- Benefit:
    - Capacity benefit identified for the Raccoon Creek – South Bainbridge and the East Berlin – Thomasville 230 kV lines.
    - Existing transmission/sub-transmission corridors available to accommodate part of the route.

- Note: Analysis pending.

- Timeline: Complete by Q3 2024

[redacted]

Recommendations & Next Steps PUBLIC DISCLOSURE

- The team will test strategic projects to address the corridors that are mostly impacted by solar expansion.
    1. Address **REDACTED REDACTED** constraints
    2. Improve South to North flow in Central zone
    3. Alleviate **REDACTED REDACTED REDACTED REDACTED** constraints in Southwest Georgia
- Other area solution options may be included to enhance reliability and improve capacities.
- Note: Analysis pending.
- Timeline: Complete by Q4 2024

[redacted]

Recommendation Summary

- Immediate Action:
  - Hatch – Wadley Primary 500 kV
    - ***Goal: Complete project sponsorship & project documentation by Q1 2024***

- Analysis to support project development of following projects:
  - McGrau Ford – Middle Fork 500 kV
    - ***Goal: Complete study & documentation by Q2 2024***
  - East Berlin – Thomasville 230 kV line
    - ***Goal: Complete study & documentation by Q3 2024***
  - Raccoon Creek – South Bainbridge 230 kV line
    - ***Goal: Complete study & documentation by Q3 2024***

- Additional strategic items to address:
  - Improve central and south Georgia flow patterns
  - Address Southwest Georgia Transmission constraints
    - ***Goal: Complete study & documentation by Q4 2024***

EXHIBIT

STF-PIA-8

Exhibit RLT-1

Qualifications of Robert L. Trokey

Mr. Trokey received a Bachelor of Arts degree in Economics from the California State University, Chico in May 1993. In July 1997, he received a Master of Arts degree in Economics from the University of Colorado, Boulder.

From August 1995 to August 1998 Mr. Trokey worked as an Economist and Chief Operating Officer for Systems and Education Development International, Corporation, a Denver-based management consulting firm. His duties included managing operations, accounting, conducting economic research and developing business plans for international clients.

Mr. Trokey worked as an Auditor for Cable Audit Associates in Greenwood Village, Colorado from September 1998 to July 1999. Cable Audit Associates represents various cable programmers by conducting subscriber audits, providing accounting services and contract compliance testing.

From August 1999 to December 2000 he was employed by KeyBank National Association as a Portfolio Monitoring Analyst, becoming the lead analyst for the Colorado Upper Middle Market portfolio. Responsibilities included monitoring performance of commercial loans exceeding $25 million, collecting and analyzing financial statements and SEC reports, projecting and forecasting financial trends, establishing risk ratings, reviewing asset-based lending documents, calculating financial ratios and testing loan covenants.

Mr. Trokey began working for the Colorado Office of Consumer Counsel in January 2001 as a General Professional III, Office Manager. As of August 2004, his position was reclassified as a Budget Analyst II. In March 2006 he was promoted to the Rate/Financial Analyst III position.

In September 2007, Mr. Trokey started as a Utilities Analyst for the Electric Unit at the Georgia Public Service Commission. He was promoted to Director of the Electric Unit in May 2020.

Comments and Testimony filed on behalf of the Colorado Office of Consumer Counsel:

DOCKET NO. 06I-084T: IN THE MATTER OF AN INVESTIGATION OF REVISING THE DEFINITION OF BASIC LOCAL EXCHANGE TELEPHONE SERVICE OR BASIC SERVICE, Initial Comments of the Colorado Office of Consumer Counsel, April 10, 2006

DOCKET NO. 06S-234EG: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO FOR ADVICE LETTER NO. 1454 – ELECTRIC AND ADVICE LETTER NO. 671 – GAS, Answer Testimony and Exhibits of Robert L. Trokey, August 18, 2006

DOCKET NO. 06S-656G: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO FOR ADVICE LETTER NO. 690 – GAS, Answer Testimony and Exhibits of Robert L. Trokey, April 6, 2007

Testimony filed on behalf of the Georgia Public Service Commission, Public Interest Advocacy Staff:

DOCKET NO. 40161: IN THE MATTER OF GEORGIA POWER COMPANY'S 2016 INTEGRATED RESOURCE PLAN AND APPLICATION FOR DECERTIFICATION OF PLANT MITCHELL UNITS 3, 4A AND 4B, PLANT KRAFT UNIT 1 CT, AND INTERCESSION CITY CT, May 6, 2016

Docket No. 42310: IN THE MATTER OF GEORGIA POWER COMPANY'S 2019 INTEGRATED RESOURCE PLAN AND APPLICATION FOR CERTIFICATION OF CAPACITY FROM PLANT SCHERER UNIT 3 AND PLANT GOAT ROCK UNITS 9-12 AND APPLICATION FOR DECERTIFICATION OF PLANT HAMMOND UNITS 1-4, PLANT MCINTOSH UNIT 1, PLANT LANGDALE UNITS 5-6, PLANT RIVERVIEW UNITS 1-2, AND PLANT ESTATOAH UNIT 1, April 25, 2019

Docket No. 42516: IN THE MATTER OF GEORGIA POWER COMPANY'S 2019 RATE CASE, October 17, 2019

Docket No. 44160: IN THE MATTER OF GEORGIA POWER COMPANY'S 2022 INTEGRATED RESOURCE PLAN, May 6, 2022

Docket No. 44280: IN THE MATTER OF GEORGIA POWER COMPANY'S 2022 RATE CASE, October 2022

Docket No. 55378: IN THE MATTER OF GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE, February 2024

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EXHIBIT

STF-PIA-9

DAYMARK® ENERGY ADVISORS

Dylan Drugan

Senior Consultant

Dylan advises utilities and infrastructure developers advancing transmission and generation projects including wind, solar, storage, and gas. His experience includes integrated resource planning that optimizes generation resource selection and integrates transmission and distribution planning. He advises clients on how resource selections impact grid reliability, congestion, and operational flexibility. Dylan has testified before multiple state regulatory agencies.

SELECTED PROFESSIONAL EXPERIENCE

Regulatory economics

- Led the economic evaluation, regulatory, and public stakeholder efforts that produce Integrated Resource Plans (IRPs) to be filed with utility commissions for AEP's 5 vertically integrated operating companies.
- Directed efforts across cross-functional organizations to produce public IRP reports and defensible inputs and assumptions that withstand public and regulatory scrutiny related to forecasted resource cost and performance characteristics, load forecasts, fundamentals pricing, and myriad other modeling assumptions.
- Directed Indiana Michigan Power's first-ever state specific IRPs, which include over 4 GWs of datacenter load growth opportunities that will double the size of Indiana's load within the next 5 years.
- Evaluated battery storage optimization results to improve economic modeling so that the model maximizes revenues captured via various market products (i.e., Day Ahead, Real Time, and Ancillary Services), especially in times of market volatility.
- Directed, developed, and implemented AEP's first-ever integrated generation, transmission, and distribution planning process. Conducted modeling runs that integrated inputs/outputs between different Generation, Transmission, Distribution, and Fundamentals modeling platforms (i.e., PLEXOS, AURORA, PROMOD, PSSE, & DGP). Performed locational-based generation resource selection that evaluates new planning considerations such as how resource location impacts transmission reliability and congestion and how, when placed on the distribution system, it improves operational flexibility.
- Evaluated generation needs that AEP must procure in the next 3-7 years. Presented to executive leadership on the resource adequacy implications of evolving SPP and PJM energy policies. Developed a probabilistic risk analysis model to understand the proper amount of contingency generation needed to mitigate risk.
- Research, technical analysis, and testimony development across multiple subject areas. Evaluated utility filings, drafted data requests, and assessed customer impacts of infrastructure investment filings:

- Docket 24-052: Developed testimony on behalf of Arkansas Public Service Commission Staff for Southwestern Electric Power Company's application for a Certificate for Public Convenience and Necessity for two gas plants.
- Docket 24-072: Developed testimony on behalf of Arkansas Public Service Commission Staff for Entergy Arkansas's application for a Certificate of Environmental Compatibility and Public Need for a new gas combustion turbine.

Power system planning

- Performed complex generation resource optimization modeling using the PLEXOS modeling platform. Employed the PLEXOS model to conduct economic evaluation of resource plans for IRPs and to support numerous regulatory filings including supporting the economics of procuring renewable assets.
- Led the acquisition/disposition of strategic transmission assets and negotiated contract terms of multimillion dollar transactions with counterparties.
- Led the financial modeling and statistical risk modeling efforts that allowed Transource to win a competitive bid for a transmission project to be built in the Southwest Power Pool (SPP). Transource's winning project, Sooner-Wekiwa, is a 76-mile, 345 kV transmission line that connects two substations in Oklahoma and is projected to provide more than $465 million in transmission congestion savings over the project's life.
- Directed a multitude of cross-functional teams spanning from Transmission Planning to Engineering to external EPC firms to submit proposals for competitive transmission projects in PJM and ISO-NE, including a winning bid to construct a transmission substation to support New Jersey's offshore wind development.

Procurements and portfolios

- Conducted financial modeling on wind and solar bids from numerous RFPs under multiple financial structures including as owned assets, purchased power agreements, and through a tax equity partner.
- Served as expert witness for Indiana Michigan Power's Renewable Energy Plan filing and wrote testimony in support of acquiring wind projects for Public Service Company of Oklahoma and Southwestern Electric Power Company.
- Served as an expert witness to support $35M of capital and O&M investment in two of Public Service Company of Oklahoma's gas plants, including producing testimony and filing responses to intervenor discovery requests.
- Produced market intelligence presentations that informed strategic decision making at the Board of Directors and the Executive Leadership Team levels, specifically around decisions related to plant retirements/life extensions and the $8+ billion generation capital spend plan over the next 5 years.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc. — Worcester, MA
Senior Consultant — 2024–*Present*

American Electric Power — Columbus, OH
Manager, Resource Planning — 2023–2024
Manager, Strategic Analysis — 2022-2023
Manager, Transource Transmission Business Development — 2019-2022
Auditor Associate — 2019
Resource Planning Analyst Principal — 2016-2019
Energy Efficiency & Consumer Programs Coordinator — 2013-2016

DNV — Gahanna, OH
Energy Consultant — 2012–2013

EDUCATION

Ohio University — Athens, OH
M.S., Environmental Studies — 2013

Aurora University — Aurora, IL
M.B.A, Leadership — 2010

University of Notre Dame — Notre Dame, IN
B.A., English — 2006

TESTIMONY & FILINGS

Expert Testimony

FORUM	ON BEHALF OF	MATTER
Michigan Public Service Commission	Indiana Michigan Power Company	Application for Approval of Renewable Energy Plan. Case No. U-18233.
Oklahoma Corporation Commission	Public Service Company of Oklahoma	Application for Approval of Adjustments to Base Rates including Costs to Acquire a Wind Facility and Delay the Retirement of Two Gas Facilities. Case No. PUD 2023-000086.

Integrated Resource Plan Filings

FORUM	ON BEHALF OF	MATTER
Arkansas Public Service Commission	Southwestern Electric Power Company	Application of Approval of Integrated Resource Plan. Docket 07-011-U-Doc. 32.
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	Integrated Resource Plan Submitted Pursuant to Commission Rule 170 IAC 4-7.
Kentucky Public Service Commission	Kentucky Power Company	Application of Approval of Integrated Resource Plan. Case No. 2016-00413.
Oklahoma Corporation Commission	Public Service Company of Oklahoma	Integrated Resource Plan Submitted Pursuant to Commission Rule OAC 165:35-37.
Virginia State Corporation Commission	Appalachian Power Company	Application of Approval of Integrated Resource Plan. Case No. PUR-2018-00051.

KAP-1

EXHIBIT
STF-PIA-10

DAYMARK®
ENERGY ADVISORS

Karan Pol

Consultant

Karan provides economic analysis and regulatory services to a broad range of clients including regulatory staff and utilities. His work supports infrastructure investment decisions, market design, and electricity supply and demand forecasting. He brings experience in electricity policy, utility regulation and rates, econometric/statistical modeling, and economics.

SELECTED PROFESSIONAL EXPERIENCE

Regulatory economics

- Analyzed econometric modeling and model review methodologies for the load forecast and capacity expansion plan for Newfoundland Labrador Hydro.
- Monitored and advised on the development of extended day-ahead markets in CAISO and SPP for a clean energy association.
- Monitored and advised on Capacity Market Reforms in PJM for the East Kentucky Power Cooperative.
- Research, technical analysis, and testimony development across multiple subject areas and jurisdictions, including 18 cases for 4 public service commissions. Evaluated utility filings, drafted data requests, and assessed customer impacts of infrastructure investments and ratemaking filings.
    - Arkansas Public Service Commission
        - Dkt 07-044: Cost of gas prudence and extraordinary costs incurred during Winter Storm Uri. Associated with Summit Utilities.
        - Dkt 07-045: Cost of gas prudence and extraordinary costs incurred during Winter Storm Uri. Associated with Black Hills Energy, Arkansas.
        - Dkt 07-046: Cost of gas prudence and extraordinary costs incurred during Winter Storm Uri. Associated with Arkansas Oklahoma Gas Corporation.
        - Dkt 09-090: Assessment of the customer impact and utility of third-party demand response aggregation.
        - Dkt 13-111: Prudence of cost of electricity and extraordinary costs incurred during Winter Storm Uri. Associated with Empire District Electric Company (Liberty-Empire).
        - Dkt 15-015: Prudence of cost of electricity and extraordinary costs incurred during Winter Storm Uri. Associated with Entergy Arkansas.
        - Dkt- 16-052: Prudence of cost of electricity and extraordinary costs incurred during Winter Storm Uri. Associated with Oklahoma Gas and Electric Company.

  - Dkt 21-070: Prudence of cost of electricity and extraordinary costs incurred during Winter Storm Uri. Associated with the Southwestern Electric Power Company.
  - Dkt 22-065: Review of a certificate of Public Convenience and Necessity to Operate. Associated with the John W. Turk Jr Power Plant.
  - Dkt 22-082: Review of renewable PPAs and a tariff approval. Associated with two renewable projects for Entergy Arkansas.
  - Dkt 23-006: Prudence of cost of electricity incurred during Winter Storm Uri. Associated with the Arkansas Electric Cooperative Corporation.
  - Dkt 24-016: Review of a proposed deployment of Advanced Metering Systems by Southwestern Electric and Power Company.
  - Dkt 24-044: Review of a proposed Capacity Purchase Agreement proposed by Southwestern Electric Power Company.
  - Dkt 24-052: Reviewed of a proposed Certificate for Public Convenience and Necessity proposed by Southwestern Electric Power Company.
  - Dkt. 24-072: Review of a Certificate of Environmental Compatibility and Public Need proposed by Entergy Arkansas.
- Connecticut Public Utilities Regulatory Authority
  - Dkt 23-01-03: Prudence and accounting review of a Rate Adjustment Mechanism. Associated with Eversource/Connecticut Light & Power and United Illuminating.
- Georgia Public Service Commission
  - Dkt 55378: Expert testimony regarding the Company's revised load forecast, including the probabilistic modeling of large load customers such as datacenters. Additionally reviewed the economic analysis associated with a 500 MW BESS.
- Utah Public Service Commission/Division of Public Utilities
  - Dkt 24-034-04: Expert testimony regarding Rocky Mountain Power's proposed load forecast, focused on the review and adjustment of econometric models used to estimate load growth.

Procurements and portfolios

- Analyzed and connected four municipalities/cooperatives to funding under the Inflation Reduction Act associated with the New ERA program, expanded production/investment tax credits, and new bonus tax incentives.
  - Concordia Electric Cooperative
  - Massachusetts Port Authority
  - PC Electric Cooperative
  - Southwest Louisiana Electric Membership Corporation
  - Woodsville Water & Light District

Clean energy

- Performed a full system needs analysis toward the development of a long-term power-system investment forecast for an economic research group. This analysis identified the total generation, transmission, and distribution investment necessary to meet reliability needs and clean energy standards in the United States.
- Collected and analyzed equitable performance data for 41 rural electric cooperatives in the state of Georgia on behalf of the Partnership for Southern Equity, in collaborated with Appalachian Voices. Analysis found that Georgia co-operatives do not have adequate financial support for vulnerable families, strong member control of election, and weak overall democratic governance.
- Developed internal life-cycle analysis tools to analyze product-market fit for small modular nuclear power plants across 40+ energy-intensive industries.
- Performed cost-benefit analysis for advanced nuclear development in South America and Eastern Europe for Minister-level clientele.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc. — Worcester, MA
Consultant — 2025–Present
Senior Analyst — 2023–2025
Analyst — 2023

Partnership for Southern Equity — Atlanta, GA
Policy Manager, Energy — 2022–2023

Last Energy — Washington, DC
Research Manager — 2021–2022

Energy Impact Center — Washington, DC
Research Analyst — 2021–2022

EDUCATION

The University of Georgia — Athens, GA
Master of International Policy — 2021

The University of Georgia — Athens, GA
B.A., Economics — 2021

PUBLICATIONS, PRESENTATIONS & TESTIMONY

Expert Testimony

FORUM	ON BEHALF OF	TOPIC
Utah Public Service Commission	Division of Public Utilities	Expert testimony regarding Rocky Mountain Power's proposed load forecast, focused on the review and adjustment of econometric models used to estimate load growth. Docket 24-034-04
Georgia Public Service Commission	Georgia PSC Public Interest Advocacy Staff	Georgia Power Company's 2023 Integrated Resource Plan Update. Docket No. 55378

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EXHIBIT
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STF-PIA-11

EXHIBIT

STF-NHSW-1 - Tom Newsome Resume

Exhibit STF-NHSW-1
Tom Newsome Qualifications

Summary of Educational and Professional Experience of Tom J. Newsome

Mr. Newsome received a Bachelor of Chemical Engineering with certificates in Pulp & Paper and Polymers from the Georgia Institute of Technology in June 1986. In 1994, Mr. Newsome passed both required examinations and received a professional engineering license (PE) from the State of North Carolina. Mr. Newsome received a Master of Science in Business Economics and a Master of Science in Finance from Georgia State University in August 1996 and June 1997, respectively. Mr. Newsome is the recipient of the George J. Malanos Graduate Award for Academic Excellence for completing the finance program with a 4.0 grade-point average. In 2003, Mr. Newsome received Chartered Financial Analyst (CFA) designation from the CFA Institute after successfully completing three six-hour examinations on security analysis and portfolio management.

After graduation from Georgia Tech, Mr. Newsome worked as plant/process engineer for Shaw Industries, a carpet manufacturer. In April 1988, Mr. Newsome joined Weatherly, Inc., engineering and construction firm specializing in fertilizer plants, as a process engineer. Mr. Newsome's primary responsibilities were process design and plant start-ups, including start-ups in Korea and India. Mr. Newsome joined Midrex Direction Reduction Corp., an applied research, engineering and construction firm with proprietary iron ore processing plant technology in March 1993 as a process engineer. Mr. Newsome duties were similar to those at Weatherly, including assisting in the start-up of the world's largest Direct Reduction Iron plant in India.

Following graduation from graduate school at Georgia State, Mr. Newsome joined Georgia Gulf Corporation in 1997 as a corporate development analyst. While at Georgia Gulf, Mr. Newsome performed financial analysis and modeling for natural gas purchasing/hedging program, developed a "make-or-buy" model for methanol business, performed financial modeling for an acquisition, and calculated and summarized the financial performance of prior capital investments. In 1999, Mr. Newsome joined FMV Opinions, Inc. as a business valuation analyst and valued private companies for gift and estate tax, transactional and management planning purposes.

Mr. Newsome joined the Georgia Public Service Commission ("Commission") in January 2005 as a Financial Analyst/Economist. Mr. Newsome was promoted to Director of Utility Finance in 2008.

Mr. Newsome has testified in twenty-four Georgia Power Company ("Company" or "Georgia Power") proceedings before the Commission.

Mr. Newsome's most recent testimony was in Docket 55378 in 2023 IRP Update. Prior to that, Mr. Newsome testified Docket 29849 in 28th Vogtle Construction Monitoring ("VCM"). Prior to that, Mr. Newsome testified in Docket 44902 Fuel Cost Recovery (FCR-26). Prior to that Mr. Newsome's testified in Docket 29849 26th and 27th VCMs. Prior to that Mr. Newsome testified in Docket 44160 Integrated Resources Planning on supply side resources. Prior to that Mr. Newsome testified in Docket 29849 23rd Vogtle Construction Monitoring ("VCM"), 24th VCM and 25th VCM on Vogtle economics. Prior to that was testimony in 22nd VCM and in Docket 43011 Fuel Cost Recovery (FCR-25) on the Company's hedging program and certain other issues. Prior to that Mr. Newsome's testified in Docket 29849 20th / 21st Vogtle Construction Monitoring ("VCM") on Vogtle economics. Prior to that Mr. Newsome's testified in Docket 42310 Georgia Power Company's 2019 Integrated Resource Plan on supply side and certain other issues. Prior to that testimony Mr. Newsome testified in Docket 29849 19th Vogtle Construction Monitoring ("VCM"), 18th VCM and 17th VCM on the economics of continuing Vogtle 3 and 4 construction and provided the Commission policy recommendations to protect ratepayers. Prior to testifying in the 17th VCM Mr. Newsome testified in the 2016 Integrated Resource Plan on the Company's requested to capitalize cost for investigation of new nuclear units. Mr. Newsome's testified in Docket No. 39638 Fuel Cost Recovery (FCR-24) on the Company's natural gas hedging program. In Docket No. 22403, Mr. Newsome addressed Georgia Power Company's natural gas hedging program and in Docket No. 24506 Mr. Newsome testified on the application of AFUDC accounting for calculating financing cost of capital projects. In Docket No. 27800, Certification of Plant Vogtle Expansion, Mr. Newsome addressed the sources, impact and mitigation of financial risk from the construction and operation of new nuclear units at Plant Vogtle. Mr. Newsome testified in Docket No. 29849 concerning Georgia Power's First Semi-annual Construction Monitoring Report on Plant Vogtle expansion. Mr. Newsome evaluated the economic analysis performed by Georgia Power and developed Staff's own independent economic and risk analysis of the Project. In the Second Vogtle Semi-annual hearing, Mr. Newsome testified on the Company's proposal to change how escalation on certain project cost was calculated (Amendment 3). In the Third Vogtle Semiannual hearing and in separate proceeding, Adoption of a Risk Sharing Mechanism, Mr. Newsome testified on Staff's revised risk sharing mechanism for Vogtle 3 & 4. In Docket No. 28945 Fuel Cost Recovery FCR–21, Mr. Newsome testified on seasonal rates. Mr. Newsome also presented cost of equity testimony in Atmos Energy Corporation's Rate Case in Docket No. 30442 and Generic Proceeding to Implement House Bill 168 (small telephone companies) in Docket No. 32235 in 2011 and 2018. Mr. Newsome provided testimony before the Commission in Georgia Power's 2013 Base Rate Case in Docket No. 36989 on the Company's projected cost of debt for 2014 – 2016. Mr. Newsome's primarily responsibility, prior to presenting testimony in these dockets, has been performing analyses of the parties' cost of equity capital positions in Docket Nos. 18638 (Atlanta Gas Light Company 2004/2005 Rate Case), 19758 (Savannah Electric and Power Company 2004 Rate Case), 20298 (Atmos Energy Corporation - Georgia Division 2005 Rate Case), 25060 (Georgia Power Co. 2007 Rate Case) and 27163 (Atmos Energy Corporation - Georgia Division 2008 Rate Case) and developing the Advisory PIA Staff's cost of equity recommendation to the Commission.

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EXHIBIT

PENGAD 800-631-6989

STF-PIA-12

EXHIBIT

STF-NHSW-2 - Philip Hayet Resume

EDUCATION/CERTIFICATION

M.S., Electrical Engineering, Georgia Institute of Technology, 1980
B.S., Electrical Engineering, Purdue University, 1979
Cooperative Education Certificate, Purdue University, 1979

PROFESSIONAL AFFILIATIONS

National Society of Professional Engineers
Georgia Society of Professional Engineers
Institute of Electrical and Electronic Engineers

EXPERIENCE

Since completing his Master's program, Mr. Hayet worked for fifteen years at Energy Management Associates, now Ventyx, providing consulting services and client service support to electric utility companies for the widely used planning models, PROMOD IV and STRATEGIST. Mr. Hayet had an instrumental role in designing some of the modeling features of those tools including the competitive market modeling logic in STRATEGIST.

In 1995, Mr. Hayet formed the utility consulting firm, Hayet Power Systems Consulting ("HPSC"), and worked for customers in the United States, and internationally in Australia, Japan, Singapore, Malaysia, the United Kingdom, and Vietnam. Mr. Hayet provided consulting services to Public Utility Commissions, Regional Power Pools, State Energy Offices, Consumer Advocate Offices, Electric Utilities, Global Power Developers, and Industrial Companies. Mr. Hayet's expertise covers a number of areas including utility system planning and operations, RTO analysis, market price forecasting, Integrated Resource Planning, renewable resource evaluation, transmission planning, demand-side analysis, and economic analysis.

In 2000, Mr. Hayet also joined the consulting firm of J. Kennedy & Associates, Inc. ("Kennedy and Associates") and assisted on projects that required utility resource planning, analysis, and software modeling expertise. Mr. Hayet merged his firm and became a Vice-President and Principal of Kennedy and Associates in 2015.

Mr. Hayet has conducted numerous consulting studies in the areas of RTO Cost/Benefit Analysis, Renewable Resource Evaluation, Renewable Portfolio Standards Evaluation, Electric Market Price Forecasting, Generating Unit Cost/Benefit Analysis, Integrated Resource Planning, Demand-Side Management, Load Forecasting, Rate Case Analysis and Regulatory Support.

2000 to Present:	**J. Kennedy and Associates, Inc.** **Vice President and Principal**

- Began in 2000 as Director of Consulting.
- Became Vice President and Principal in 2015 when Hayet Power Systems Consulting merged with J. Kennedy and Associates, Inc.
- Managed electric related consulting projects.
- Responsible for business development.
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.

1996 to 2015: **Hayet Power Systems Consulting**
President and Principal

- Managed electric utility related consulting projects
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.
- Merged with J. Kennedy and Associates, Inc. in 2015

1991 to 1996: **EDS Utilities Division, Atlanta, GA (Now Ventyx)**
Lead Consultant, PROSCREEN (Now STRATEGIST) Department

- Managed a client services software team that supported approximately 75 users of the STRATEGIST electric utility strategic planning software.
- Participated in the development of STRATEGIST's competitive market modeling features and the Network Economy Interchange Module
- Provided client management direction and support, and developed new consulting business opportunities.
- Performed system planning consulting studies including integrated resource planning, DSM analysis, marketing profitability studies, optimal reserve margin analyses, etc.
- Based on experience with PROMOD IV, converted numerous PROMOD IV databases to STRATEGIST, and performed benchmark analyses of the two models.

1988 to 1991: **Energy Management Associates (EMA), Atlanta, GA**
Manager, Production Analysis Department

- Served as Project Manager of a database modeling effort to create an integrated utility operations and generation planning database. Database items were automatically fed into PROMOD IV.

- Supervised and directed a staff of five software developers working with a 4GL database programming language.
- Interfaced with clients to determine system software specifications, and provide ongoing client training and support

1980 to 1988: **Energy Management Associates (EMA), Atlanta, GA**
Senior Consultant, PROMOD IV Department

- Provided client service support to EMA's base of over 70 electric utility customers using the PROMOD IV probabilistic production cost simulation software.
- Provided consulting services in a number of areas including generation resource planning, regulatory support, and benchmarking.

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
09/98	97-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah jurisdictional Net Power Costs, PacifiCorp Rate Case Proceeding
07/01	01-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah Jurisdictional Net Power costs in General Rate Case
2001	ER00-2854-000	FERC	Louisiana Public Service Commission	Entergy	Proposed System Agreement Modifications
07/02	02-035-002	UT	Utah Committee for Consumer Services	PacifiCorp	Special contract for industrial consumer
2002/ 2003	U-25888	LA	Louisiana Public Service Commission	Entergy	Investigation of retail issues related to the System Agreement
2003	U-27136 Subdocket A	LA	Louisiana Public Service Commission Staff	Entergy	Aging gas steam-fired retirement study
07/03	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy	Rough production cost equalization proceeding
05/04	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Development of a large QF avoided cost methodology
06/04	18687-U 18688-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	2004 Integrated Resource Planning Studies
08/04	ER03-583-000	FERC	Louisiana Public Service Commission	Entergy	Affiliate power purchase agreements
11/04	03-035-19	UT	Utah Committee for Consumer Services	PacifiCorp	Industrial customer's request for a special economic development tariff
11/04	03-035-38	UT	Utah Committee for Consumer Services	PacifiCorp	Large QF proceeding.
03/05	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Concerning PacifiCorp's Schedule 38 avoided cost tariff and remaining unsubscribed capacity
07/05	03-035-14	UT	Utah Committee for Consumer	PacifiCorp	Concerning PacifiCorp's Schedule 38 avoided cost proceeding

Date	Case	Jurisdict	Party	Utility	Subject
			Services		
12/05	04-035-42	UT	Utah Committee for Consumer Services	PacifiCorp	Net power costs in General Rate Case
04/06	05-035-54	UT	Utah Committee for Consumer Services	PacifiCorp	Certification request to expand Blundell Geothermal Power Station. Related to Mid-American Energy Holding's Acquisition of PacifiCorp
05/06	22403-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	March 2006 fuel cost recovery filing
2006	06-35-01	UT	Utah Committee for Consumer Services	PacifiCorp	2006 rate case, net power costs
08/06	U-21453	LA	Louisiana Public Service Commission Staff	Entergy Gulf States	Jurisdictional separation.
11/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Fuel adjustment clause filings
01/07	23540-U	GA	Georgia Public Service Commission Staff	Georgia Power	November 2005 fuel cost recovery filing
04/07	07-035-93	UT	Utah Committee for Consumer Services	PacifiCorp	General Rate Case
06/07	24505-U	GA	Georgia Public Service Commission Staff	Georgia Power	2007 Integrated Resource Planning
10/07	U-30334	LA	Louisiana Public Service Commission Staff	Cleco Power	2008 Short-Term RFP
04/08	26794-U (FCR-20)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
2008	6630-CE-299	WI	Wisconsin Industrial Energy Group, Inc.	WEPCO	Certification Proceeding for environmental upgrades at Oak Creek power plant
07/08	ER07-956	FERC	Louisiana Public Service Commission	Entergy	2006 rough production cost equalization compliance filing in the System Agreement case
09/08	6680-CE-180	WI	Wisconsin Industrial Energy	Wisconsin Power and Light	Certification proceeding concerning Nelson-Dewey coal-fired generating unit

Date	Case	Jurisdict	Party	Utility	Subject
			Group, Inc.		
11/08	08-1511-E-GI	WV	West Virginia Energy Users Group	Allegheny Power	Fuel cost recovery filing
12/08	27800-U	GA	Georgia Public Service Commission Staff	Georgia Power	Vogtle 3 and 4 nuclear unit certification proceeding
2008	08-035-35	UT	Utah Committee for Consumer Services	PacifiCorp	Chehalis Combine Cycle Power Plant based on a waiver of the RFP solicitation process certification proceeding
07/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy	2007 rough production cost equalization compliance filing in the System Agreement case
07/09	U-30975	LA	Louisiana Public Service Commission Staff	SWEPCO and Cleco	Application to acquire the Oxbow Mine to supply Dolet Hills Power Station certification proceeding
09/09	E015/PA-09-526	MN	Large Power Intervenors	Minnesota Power	Request for approval to purchase Square Butte's 500 kV DC transmission line, restructure a coal based power purchase agreement
09/09	09-035-23 Direct	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
10/09	09A-415E	CO	Public Utilities Commission of Colorado	Black Hills/Colorado	CPCN application to construct two LMS 100 natural gas combustion turbine units
10/09	09-035-23 Surrebuttal	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
12/09	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	First Semi-Annual Vogtle Construction Monitoring Report
12/09	ER08-1224	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
2009	09-2035-01	UT	Utah Office of Consumer Services	PacifiCorp	2008 IRP
01/10	28945-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
2010	EL09-61	FERC	Louisiana Public Service Commission	Entergy	System Agreement, individual operating company sales

Date	Case	Jurisdict	Party	Utility	Subject
06/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Second Semi-Annual Vogtle Construction Monitoring Report
12/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Third Semi-Annual Vogtle Construction Monitoring Report
01/11	ER09-1350 Direct	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
02/11	ER09-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
04/11	33302-U (FCR-22)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
06/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fourth Semi-Annual Vogtle Construction Monitoring Report
09/11	U-31892	LA	Louisiana Public Service Commission Staff	Cleco Power	Settlement agreement, CPCN to upgrade Madison 3 coal unit to accommodate biomass fuel
11/11	26550-U	GA	Georgia Public Service Commission Staff	Georgia Power	Reacquisition of wholesale block capacity
11/11	34218-U	GA	Georgia Public Service Commission Staff	Georgia Power	Decertification of two aging coal units, acquire PPA resources, approve IRP update
12/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifth Semi-Annual Vogtle Construction Monitoring Report
03/12	U-32148	LA	Louisiana Public Service Commission Staff	Entergy	Change of Control Proceeding to move to Midwest ISO
2012	20000-EA-400-11	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power	Certification of environmental upgrades at Naughton 3
05/12	35277-U (FCR-23)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
05/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixth Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Environmental upgrades in compliance with MATS and CSAPR
09/12	U-32275	LA	Louisiana Public Service Commission Staff	Dixie Electric Member Cooperative	Ten year power supply acquisition certification proceeding
12/12	EL09-61-002 Direct	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement
12/12	U-32557	LA	Louisiana Public Service Commission Staff	Entergy	Certification of 28 MW PPA for renewable energy capacity (RAIN waste heat) in accordance with LPSC's Renewable Energy Pilot
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy	Retail proceeding regarding termination of cross-PPAs
12/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Seventh Semi-Annual Vogtle Construction Monitoring Report
03/13	EL09-61-002 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Mitchell Certificate of Public Convenience and Necessity
05/13	36498-U	GA	Georgia Public Service Commission Staff	Georgia Power	2013 IRP and request to decertify over 2,000 MW of coal-fired capacity
07/13	U-32785	LA	Louisiana Public Service Commission Staff	Entergy	8.5 MW PPA for renewable energy capacity (Agrilectric rice hull) in accordance with LPSC's Renewable Energy Pilot
08/13	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighth Semi-Annual Vogtle Construction Monitoring Report
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Base rate case
05/14	13-035-184	UT	Utah Office of Consumer Services	PacifiCorp	2014 General Rate Case, net power cost
06/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Ninth/Tenth Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
07/14	20000-446-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 General Rate Case, net power cost
08/14	2000-447-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 Energy Cost Adjustment Mechanism application
08/14	14-035-31	UT	Utah Office of Consumer Services	PacifiCorp	2014 Energy Balancing Adjustment application
09/14	ER13-432	FERC	Louisiana Public Service Commission	Entergy	Allocation of Union Pacific Settlement Agreement benefits
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power	Kentucky Power Company's Fuel Adjustment Clause
12/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eleventh Semi-Annual Vogtle Construction Monitoring Report
05/15	14-035-140	UT	Utah Office of Consumer Services	PacifiCorp	Solar and wind capacity contribution avoided cost proceeding.
06/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twelfth Semi-Annual Vogtle Construction Monitoring Report
08/15	15-035-03	UT	Utah Office of Consumer Services	PacifiCorp	2015 Energy Balancing Adjustment application
09/15	14-035-114	UT	Utah Office of Consumer Services	PacifiCorp	Cost and Benefits of PacifiCorp's Net Metering Program
11/15	39638-U	GA	Georgia Public Service Commission Staff	Georgia Power	FCR-24 Fuel Cost Recovery Proceeding
11/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Thirteenth Semi-Annual Vogtle Construction Monitoring Report
5/16	40161	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power Company's 2016 IRP and Application for Decertification of Plant Mitchell Units 3, 4A, and 4B, Kraft Unit 1 CT, and Intercession City CT
6/16	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Fourteenth Semi-Annual Vogtle Construction Monitoring Report
8/16	16-035-27	UT	Utah Office of Consumer Services	PacifiCorp	Renewable Energy Services Contract between Rocky Mountain Power and Facebook, Inc

Date	Case	Jurisdict	Party	Utility	Subject
8/16	16-035-01	UT	Utah Office of Consumer Services	PacifiCorp	2016 Energy Balancing Adjustment application
9/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Direct Testimony
11/16	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifteenth Semi-Annual Vogtle Construction Monitoring Report
11/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Rebuttal Testimony
11/16	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Direct
3/17	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Rebuttal
6/17	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixteenth Semi-Annual Vogtle Construction Monitoring Report
9/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Direct
11/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Surrebuttal
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Response
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Rebuttal to Response
12/17	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Direct
1/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Rebuttal
4/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Second Rebuttal
6/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighteenth Semi-Annual Vogtle Construction Monitoring Report
8/18	Cause 45052	IN	Indiana Coal Council	Vectren Energy Delivery of Indiana	Request for Approval of an 850 MW CCGT Plant

Date	Case	Jurisdict	Party	Utility	Subject
9/18	U-34836	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Authorization to Participate in a 50 MW Solar PPA
11/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Nineteenth Semi-Annual Vogtle Construction Monitoring Report
1/19	U-35019	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Authorization to Make Available Experimental Renewable Option and Rate Schedule RTO
4/19	42310-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2019 IRP Proceeding
11/19	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty/Twenty-First Semi-Annual Vogtle Construction Monitoring Report
5/20	43011-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power Fuel Cost Recovery Application (FCR-25)
6/20	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Second Semi-Annual Vogtle Construction Monitoring Report
7/20	17-035-61	UT	Utah Office of Consumer Services	Rocky Mountain Power	Approval of an Export Credit Rate for Customer Generators (Primarily Rooftop Solar)
9/20	20-035-04	UT	Utah Office of Consumer Services	Rocky Mountain Power	Utah Rate Case
10/20	2019-226-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina	Review of DESC's 2020 IRP
10/20	2019-227-E	SC	South Carolina Office of Regulatory Services	Lockhart Power Company	Review of Lockhart Power Company's 2020 IRP
11/20	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Third Semi-Annual Vogtle Construction Monitoring Report
12/20	20-035-01	UT	Utah Office of Consumer Services	Rocky Mountain Power	Application for Approval of the 2020 Energy Balancing Account

Date	Case	Jurisdict	Party	Utility	Subject
2/21	2019-224 and 225-E	SC	South Carolina Office of Regulatory Services	Duke Energy Carolinas and Duke Energy Progress	Review of Duke Energy's 2020 IRP
6/21	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Fourth Semi-Annual Vogtle Construction Monitoring Report
9/21	U-35927	LA	Louisiana Public Service Commission	1803 Electric Cooperative	Compliance with MBM Order in Conducting RFP and Acquiring Resources
12/21	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Fifth Semi-Annual Vogtle Construction Monitoring Report
5/22	44160-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2022 IRP Proceeding
6/22	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Sixth Semi-Annual Vogtle Construction Monitoring Report
12/22	22-035-01	UT	Utah Office of Consumer Services	Rocky Mountain Power	Application for Approval of the 2022 Energy Balancing Account
12/22	2022-259-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina, Inc.	Mid-Period Adjustment to Increase Base Rates for the Recovery of Electric Fuel Costs
1/23	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Seventh Semi-Annual Vogtle Construction Monitoring Report
06/23	2023-9-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina, Inc.	Review of DESC's 2023 IRP
7/23	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Eighth Semi-Annual Vogtle Construction Monitoring Report
09/23	2023-154-E	SC	South Carolina Office of Regulatory Services	South Carolina Public Service Authority	Review of Santee Cooper's 2023 IRP
11/23	23-0735-E	WV	West Virginia Energy Users Group	Mon Power and Potomac Edison	Expanded Net Energy Cost proceeding.

Date	Case	Jurisdict	Party	Utility	Subject
12/23	U-36974	LA	Louisiana Public Service Commission Staff	1803	Calpine Capacity PPA Certification Proceeding.
2/24	55378	GA	Georgia Public Service Commission Staff	Georgia Power	2023 Integrated Resource Plan Update
6/24	U-37134	LA	Louisiana Public Service Commission Staff	1803	Transmission Asset Transfer
7/24	2023-8-E and 2023-10-E	LA	South Carolina Office of Regulatory Services	Duke Energy Progress and Duke Energy Carolinas	Review of Triennial Integrated Resource Plan
12/24	2024-00285	KY	Kentucky Attorney General's Office	Duke Energy Progress and Duke Energy Carolinas	Duke Energy Kentucky desire to convert from an FRR entity to an RPM entity
1/25	24-035-01	UT	Utah Office of Consumer Services	PacifiCorp	Application for Approval of the 2023 Energy Balancing Account
2/25	2024-00195	VA	Old Dominion Committee for Fair Utility Rates	APCO	2024 Fuel Factor Proceeding

ADDITIONAL JUDICIAL PROCEEDINGS AND OTHER PROJECT INFORMATION

- 1995 – 2000 - Modeled the Singapore Power Electricity System and analyzed the benefits of dispatching a new oil-fired unit within the system, BHP Power
- 1995 – 2000 - Modeled the Australian National Energy Market to develop market based energy price forecasts on behalf of an Independent Power Producer in Australia, BHP Power
- 1995 – 2000 - Analyzed the benefit of purchasing existing gas-fired steam turbine units within the Australian market, BHP Power
- 1995 – 2000 Developed market price forecasts for South Australia as part of the evaluation of a new gas fired combined cycle unit, BHP Power
- 1995 – 2000 - Modeled the Vietnam Electricity System as part of a project to develop Least Cost Expansion plans for Vietnam, EVN State Utility
- 1995 – 2000 - Assisted in the evaluation of Phu My CCGT power plant in Vietnam, BHP Power
- 1995 – 2000 - Assisted in the development of Market Price Forecasts in several regions of the US. These forecasts were used as the basis for stranded cost

estimates, which were filed in testimony in a number of jurisdictions across the country.

- 1995 – 2000 - Conducted research regarding ISO Tariffs and Operations for the PJM Power Pool, the California ISO, and the Midwest ISO on behalf of a Japanese Research.
- 1995 – 2000 - Performed research on numerous electric utility issues for 3 Japanese research organizations. This was primarily related to deregulation issues in the US in anticipation of deregulation being introduced in Japan.
- 1995 – 2000 - Critiqued the IRP filings of 5 utilities in South Carolina on behalf of the South Carolina State Energy Office
- 1999 - Helped to analyze the rate structure and develop an electricity price forecast for the Metropolitan Atlanta Rapid Transit Authority (MARTA) in Atlanta, Georgia
- August 2002 – Expert Report, Civil Action No. 1:00-cv-1262 in the United Stated District Court for the Middle District of North Carolina, United States v. Duke Energy Corporation, Department of Justice
- 2002 - Worked on behalf of the Utah Committee of Consumer Services to provide guidance and assist in the analysis of PacifiCorp's 2002 Integrated Resource Plan.
- July 2003 - Worked on behalf of the Oregon Public Utility Commission to Audit PacifiCorp's Net Power Costs per a Settlement Agreement accepted by the Public Utility Commission of Oregon in its Order No. 01-787. Audit report in Docket No. UE-116 filed July 2003.
- 2003 - Regulatory support to the Utah Committee of Consumer Services regarding PacifiCorp's 2003 Utah General Rate Case Docket # 03-2035-02.
- 2004 – Assistance to the Utah Committee of Consumer Services to analyze a series of power purchase agreements and special contracts between PacifiCorp and several of its industrial customers.
- 2005 - Worked on behalf of the Utah Committee of Consumer Services to help analyze PacifiCorp's restructuring proposals.
- 2005 - Assisted the Utah Committee of Consumer Services by evaluating PacifiCorp's 2005 IRP and assisted in writing comments that were filed with the Commission.
- 2007 - Assisted the Utah Committee of Consumer Services to evaluate PacifiCorp's 2007 IRP.
- 2007 - Conducted an investigation of the Southern Company interchange accounting and fuel accounting practices on behalf of the Georgia Public Service Commission Staff (Docket 21162-U).
- 2008 - Assisted the Louisiana Public Service Commission Staff with the review and evaluation of Cleco Power's 2008 Short Term RFP and its 2010 Long-Term

RFP.

- 2008 - Assisted the Utah Committee of Consumer Services by participating in a collaborative process to develop an avoided cost tariff for large QFs.
- 2008 - Assisted the Louisiana Public Service Commission Staff with a rulemaking for the opportunity to implement a Renewable Portfolio Standard in Louisiana. (Docket No. R-28271 Sub-Docket B)
- April 2011 – Initial Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States v.Detroit Edison
- June 2011 – Rebuttal Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States Detroit Edison
- 2011 - Assisted the Georgia Public Service Commission Staff to investigate the acquisition of additional coal and combustion turbine capacity currently wholesale capacity (Docket 26550).
- 2012 - Assisted the Louisiana Public Service Commission Staff with a rulemaking to design Integrated Resource Planning ("IRP") rules. (Docket No. R-30021)
- December 2013 – Expert Report, Civil action no. 4:11-cv-00077-RWS, on behalf of the Department of Justice in US District Court, United States v. Ameren Missouri.

PUBLICATIONS AND PRESENTATIONS

Co-authored "Review of EPA's Section 111 May 23, 2023 Proposed Rule for the State of South Carolina", on behalf of South Carolina Office of Regulatory Staff, August 2023.

Co-authored "Review of EPA's Section 111(d) CO_2 Emission Rate Goals for the State of Montana, on behalf of the Montana Large Customer Group, October 2014.

Authored "Singapore's Developing Power Market", which appeared in the July/August 1999 edition of Power Value Magazine

Co-authored "The New Energy Services Industry – Part 1", which appeared in the January/February 1999 edition of Power Value Magazine.

Co-authored and Presented "Evaluation of a Large Number of Demand-Side Measures in the IRP Process: Florida Power Corporation's Experience", Presented at the 3rd International Energy and DSM Conference, Vancouver British Columbia, November 1994

Co-authored "Impact of DSM Program on Delmarva's Integrated Resource Plan", Published in the 4th International Energy and DSM Conference Proceedings, held in Berlin, Germany, 1995

Presentation – Law Seminars International, Electric Utility Rate Cases, Case Study of the

Louisiana Public Service Commission's Quick Start Energy Efficiency Program, March 2015.

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EXHIBIT

PENGAD 800-631-6989

STF-PIA-13

EXHIBIT

STF-NHSW-3 - Anthony Sandonato Resume

Anthony Sandonato, Sandonato Utility Regulatory Specialists, Inc., Outside Consultant to J. Kennedy and Associates, Inc.

EDUCATION

B.S., Nuclear Engineering, North Carolina State University, 2011

EXPERIENCE

Since receiving his undergraduate degree in nuclear engineering in 2012, Mr. Sandonato has worked in the electric utility industry in the areas of energy policy, utility regulation, renewable resource evaluation, integrated resource planning, electrification, and energy efficiency program design and implementation. Mr. Sandonato started his career at ICF and worked on behalf of utilities administering both residential and commercial energy efficiency programs satisfying multiple state legislative and regulatory requirements. After that, he worked for approximately 7 years at the South Carolina Office of Regulatory Staff, starting as a Regulatory Analyst participating in water, wastewater, natural gas and electric rate proceedings and annual filings. Ultimately, He served as Deputy Director for Energy Planning and Emerging Technology, where he prepared testimony and functioned as an expert witness before the Public Service Commission of SC on matters such as annual fuel recovery, base rate cases, and integrated resource planning. Mr. Sandonato was on the Board of the Low-Level Radioactive Waste Forum and assisted the Atlantic Compact Commission ensuring compliance with federal and state laws. Mr. Sandonato spent almost two years at Laurence Berkeley National Lab where he conducted research and presented his findings on state energy efficiency policy, electrification, distribution system planning and cost recovery. During his time at the Lab he also helped administer the National Community Solar Partnership, which offered technical assistance and education to solar developers, state local and tribal government entities, NGOs, and community-based organizations. Mr. Sandonato began work as an Outside Consultant for J. Kennedy and Associates in February 2025 and provides analytical support to clients in the areas of utility resource planning, energy efficiency, electrification, cost recovery and grid modernization.

2025 to Present: J. Kennedy and Associates, Inc.
Outside Consultant (February 2025 – Present)

Performs analysis and prepares expert witness testimony on utility planning studies and economic evaluations in review of electric utility regulatory filings. Clients include State Public Service Commissions, Industrial Users Groups, and Consumer Advocacy Groups.

2023 to 2025: Laurence Berkeley National Laboratory
Energy Policy Researcher: (July 2023 - February 2025)

Supported the National Community Solar Partnership, through the development of tools and curricula to advance and implement community solar programs in various regulatory jurisdictions. Conducted research and presented findings on energy efficiency, grid modernization, utility planning, electrification, decarbonization, and energy policy.

2016 to 2023: South Carolina Office of Regulatory Staff
Deputy Director – Energy Planning and Emerging Technology (December 2021 – July 2023)
Senior Regulatory Manager – Energy Operations (October 2019 – December 2021)
Regulatory Analyst (September 2016 – October 2019)

Prepared and assisted in the preparation of testimony and exhibits for formal regulatory proceedings before the Public Service Commission of South Carolina. Functioned as an expert witness before the Commission on a range of electric proceedings, including annual fuel recovery, base rate cases, integrated resource planning (encompassing integrated system operations planning), transmission and facility siting, battery energy storage systems, electric vehicles, and distributed energy resources. Validated capacity expansion and production cost modeling software for utilities' integrated resource planning and evaluating energy efficiency and demand-side management programs proposed by electric utilities. Managed the Radioactive Waste program to continue compliance with the SC Atlantic Implementation Act and Atlantic Compact Law and interface with the Atlantic Compact Commission on behalf of the state of SC.

2012 to 2016: ICF
Smart Energy in Offices Engagement Lead (July 2015 – September 2016)
Analyst (February 2014 – July 2015)
Account Manager (May 2012 – July 2013)

Developed and implemented energy efficiency programs, including building operator challenges to increase building efficiency and comfort, leveraging partnerships with universities for data analysis and facilitating operator interaction. Engaged property managers and tenants in energy-saving initiatives. Managed field engagement teams conducted commercial and industrial field inspections and developed energy savings estimates. Verified technical information and savings for projects, stayed current on building and energy codes, and provided technical training to contractors. Developed training materials and techniques for energy simulation software, trained contractors on its use, and advised them on business and sales strategies related to high-efficiency HVAC and weatherization.

2013 to 2014: South Carolina Energy Office
Technical Assistance Manager

Helped develop the Technical Assistance Program for the State Energy Office by offering Energy Assessments to Government entities outlining areas. Evaluated energy savings calculations for State grants and loans.

CLIENTS SERVED

Georgia Public Service Commission Staff
Kentucky Industrial Utility Customers, Inc.
Louisiana Public Service Commission Staff
South Carolina Office of Regulatory Staff

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
04/18	2016-384-E	SC	South Carolina Office of Regulatory Staff	Moore Sewer	Adjustment of Rates and Charges and Modification to Certain Terms and Conditions for the Provision of Collection-Only Sewer Service
08/18	2018-197-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas Company	Certificate of Environmental Compatibility and Public Convenience and Necessity
10/18	2018-5-G	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas Company	Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies
02/19	2018-319-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, LLC	Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order
03/19	2018-318-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Progress, LLC	Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order
03/19	2019-2-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas Company	Annual Review of Base Rates for Fuel Costs
10/19	2019-5-G	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc. f/k/a South Carolina Electric & Gas	Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies

Date	Case	Jurisdict	Party	Utility Company	Subject
01/20	2019-290-WS	SC	South Carolina Office of Regulatory Staff	Blue Granite Water Company	Approval to Adjust Rate Schedules and Increase Rates
03/20	2020-2-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	Annual Review of Base Rates for Fuel Costs
05/20	2020-1-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Progress, LLC	Annual Review of Base Rates for Fuel Costs
07/20	2019-226-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	2020 Integrated Resource Plan
08/20	2020-3-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, LLC	Annual Review of Base Rates for Fuel Costs
10/20	2019-227-E	SC	South Carolina Office of Regulatory Staff	Lockhart Power Company	2020 Integrated Resource Plan
10/20	2020-5-G	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies
11/20	2020-125-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	Adjustments of Rates and Charges
03/21	2019-224-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, Inc	2020 Integrated Resource Plan
03/21	2019-225-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Progress, Inc	2020 Integrated Resource Plan
09/21	2021-3-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, LLC	Annual Review of Base Rates for Fuel Costs
06/22	2022-93-E	SC	South Carolina Office of Regulatory Staff	SR Lambert I, LLC	Certificate of Environmental Compatibility and Public Convenience and Necessity
06/22	2022-97-E	SC	South Carolina Office of Regulatory Staff	SR Lambert II, LLC	Certificate of Environmental Compatibility and Public Convenience and Necessity
12/22	2022-254-E	SC	South Carolina Office of	Duke Energy Progress, LLC	Application for an Increase in Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and Request for

Date	Case	Jurisdict	Party	Utility	Subject
			Regulatory Staff		an Accounting Order
02/23	2022-239-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, LLC	Determinations Regarding Balancing Area Competitive Procurement of Renewable Energy Framework and 2022 Solar Procurement Program
02/23	2022-240-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Progress, LLC	Determinations Regarding Balancing Area Competitive Procurement of Renewable Energy Framework and 2022 Solar Procurement Program
05/23	2021-93-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	Request for "Like Facility" Determinations Pursuant to S.C. Code Ann. § 58-33-110(1) and Waiver of Certain Requirements of Commission Order No. 2007-626
05/23	2022-158-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	Electric Vehicle Make Ready Credit Program
05/23	2022-159-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	Electric Vehicle Supply Equipment Program

REPORTS AND INDUSTRY PUBLICATIONS

Date	Title	Author(s)
07/20	Review of Dominion Energy South Carolina, Inc.'s 2020 Integrated Resource Plan Docket No. 2019-226-E	South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc.
10/20	Review of Lockhart Power Company's 2020 Integrated Resource Plan Docket No. 2019-227-E	South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc.
03/21	Review of Duke Energy Carolinas, Inc.'s 2020 Integrated Resource Plan Docket No. 2019-224-E	South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc.
03/21	Review of Duke Energy Progress Inc.'s 2020 Integrated Resource Plan Docket No. 2019-225-E	South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc.

Date	Title	Author(s)
06/24	Community Solar for Opportunity States: An exploration of development models for community solar projects in states that lack explicit enabling policies	LBNL - Sandonato, Anthony, Bentham Paulos, Greg Leventis
01/25	Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments	LBNL - Pereira, Guillermo, Jeff Deason, Anthony Sandonato
01/25	Reimagining Energy Efficiency Resource Standards	LBNL - Frick, Natalie Mims, Angela Long, Grace Relf, Anthony Sandonato

PRESENTATIONS

- Sandonato, A and Frick, N.M. "Updating Energy Efficiency Resource Standards." Presented at ACEEE conference, October 2023
- Sandonato, A "The National Community Solar Partnership." Presented to NASUCA, November 2023
- Sandonato, A and Schwartz, L. "Regulator challenges with cost recovery for grid modernization." Presented at IEEE Power & Energy Society Innovative Smart Grid Technologies Conference, February 2024
- Sandonato, A and Schwartz, L. "Regulator challenges with cost recovery for grid modernization." Presented to NARUC Electric Vehicle States Working Group, May 2024

OTHER EXPERIENCE

Dates	Case	Jurisdict	Party	Utility	Subject
1/24	R-31106	LA	Louisiana Public Service Commission Staff	Various	Approval of Phase II Energy Efficiency Rule and Implementation of Statewide Program (Transition)

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EXHIBIT
PENGAD 800-631-6989
STF-PIA-14

EXHIBIT

STF-NHSW-4 - Leah Wellborn Resume

EDUCATION

M.S. Operations Research, Georgia Institute of Technology, 2017
B.S. Mathematics, Georgia Southern University, 2012

PROFESSIONAL AFFILIATIONS

Women's Energy Network, Greater Atlanta Chapter – Board Member (2019 – 2023)
Women's Energy Network, Greater Atlanta Chapter – Member (2016 – Present)

EXPERIENCE

Ms. Wellborn has been working in regulated energy markets since early 2013. She has an undergraduate degree in mathematics and graduate degree in operations research. She started her career working at J. Kennedy and Associates, Inc., and sub-contracting to Hayet Power Systems Consulting. For these companies, she provided critical support in the areas of production cost modeling and data analysis through 2018. Ms. Wellborn then spent nearly 3 years at Accenture, supporting its global regulated energy team within the procurement practice, helping large commercial and industrial clients manage their energy spend and energy related initiatives, as they related to regulated utility tariffs, economic dispatch, planning, and market risk (energy efficiency, green tariffs, PPA/VPPA, etc.). Ms. Wellborn rejoined J. Kennedy and Associates in late 2021, and currently provides analytical support to clients in the areas of utility resource planning and market modeling.

2021 to Present:

J. Kennedy and Associates, Inc.
Manager, Consulting (October 2021 – Present)

Performs analysis and prepares expert witness testimony on utility planning studies and economic evaluations in review of electric utility regulatory filings. Clients include State Public Service Commissions, Industrial Users Groups, and Consumer Advocacy Groups.

2019 to 2021:

Accenture, LLP
Associate Manager, Global Team, Regulated (March 2021 - October 2021)
Sourcing Specialist, International Teams Lead (March 2020 - March 2021)
Senior Analyst, Regulated Energy Procurement (January 2019 - March 2020)

As a part of Accenture Operations' Energy Management and Procurement practice, the Regulated Energy team helps clients identify opportunities for electricity and natural gas cost savings through data analysis and deep industry experience. Clients include large industrial and commercial end-use customers with locations spread across multiple geographies and utility service territories.

• Conducts tariff optimization analysis and ad hoc economic decision analysis for clients with operations and energy spend in areas served by regulated electricity and natural gas distribution utilities.

• Leads cross functional international delivery team of 10, providing career counseling and project oversight. Supports international energy procurement functions as they relate to regulated utilities/energy markets of Australia, Southeast Asia, and Latin America.
• Manages project assessments and economic studies as they relate to resource planning or capacity/energy market risk and dispatch pricing (renewables, time-of-use tariffs, real-time-pricing/avoided cost, PPA, VPPA, etc.)
• Collaborates with all energy management work streams - including utility bill management, renewable energy procurement, deregulated markets competitive sourcing, market intelligence, and project management/technology development initiatives to manage customer spend end to end.

2013 to 2019: **J. Kennedy and Associates, Inc.**
Senior Consultant (January 2016 – January 2019)
Consultant (March 2013 – December 2015)

Responsible for conducting research, performing data analysis, developing production-cost model input assumptions and running production-cost studies, analyzing model output, and conducting related economic studies.

CERTIFICATIONS

Energy Exemplar – Aurora Core Certification Course (March 2022)
Energy Exemplar – PLEXOS Power Core Certification Course (June 2023)

CLIENTS SERVED

Georgia Public Service Commission Staff
Kentucky Industrial Utility Customers, Inc.
Kentucky Office of the Attorney General
Louisiana Public Service Commission Staff
Ohio Energy Group
South Carolina Office of Regulatory Staff
Utah Office of Consumer Services
West Virginia Energy Users Group
Wisconsin Industrial Energy Group

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
06/18	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Eighteenth Semi-Annual Vogtle Construction Monitoring Report
11/18	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Nineteenth Semi-Annual Vogtle Construction Monitoring Report
5/22	44160	GA	Georgia Public Service Commission Staff	Georgia Power	2022 Integrated Resource Plan (Supply Side Resource Plan, Aurora)
10/22	44280	GA	Georgia Public Service Commission Staff	Georgia Power	2022 Rate Case (Revenue Forecast)
8/23	2023-9-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	2023 Integrated Resource Plan
12/23	2023-154-E	SC	South Carolina Office of Regulatory Staff	South Carolina Public Service Authority (Santee Cooper)	2023 Integrated Resource Plan
12/23	U-36974	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Certification of a Capacity Purchase Agreement
2/24	55378	GA	Georgia Public Service Commission Staff	Georgia Power	2023 Integrated Resource Plan Update (Supply Side Resource Plan, Aurora)
7/24	2023-8-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Progress, LLC	2023 Integrated Resource Plan
7/24	2023-10-E	SC	South Carolina Office of Regulatory Staff	Duke Energy Carolinas, LLC	2023 Integrated Resource Plan
8/24	24-0508-EL-ATA	OH	Ohio Energy Group	Ohio Power Company	Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers
11/24	2024-00243	KY	Office of the Attorney General & Kentucky Industrial Utility Customers	Kentucky Power Company	Renewable Energy Purchase Agreement

Date	Case	Jurisdict	Party	Utility	Subject
12/24	24-0611-E-T-PW	WV	West Virginia Energy Users Group	Appalachian Power Co. / Wheeling Power Co.	Application for Approval of Revisions to Schedules LCP and IP (Data Centers)

REPORTS AND INDUSTRY PUBLICATIONS

Date	Title	Author(s)
8/23	Review of EPA's Section 111 May 23, 2023 Proposed Rule for the State of South Carolina	J. Kennedy and Associates, Inc. (On behalf of the South Carolina Office of Regulatory Staff)
7/24	Review of Dominion Energy South Carolina, Inc.'s 2024 Integrated Resource Plan Update Docket No. 2024-9-E	South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc.
1/25	Review of Santee Cooper's 2024 Integrated Resource Plan Update Docket No. 2024-18-E	South Carolina Office of Regulatory Staff and J. Kennedy and Associates, Inc.

OTHER EXPERIENCE

Dates	Case	Jurisdict	Party	Utility	Subject
1/24	R-31106	LA	Louisiana Public Service Commission Staff	Various	Approval of Phase II Energy Efficiency Rule and Implementation of Statewide Program (Transition)
3/25	2024-00326	KY	Kentucky Industrial Utility Customers	Kentucky Utilities / Louisville Gas & Electric	2024 Joint Integrated Resource Plan (Comments)

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EXHIBIT
PENGAD 800-631-6989
STF-PIA-15

STF-NHSW-5 - Reserve Margin Tables

Case 1 MG0 - GPC Starting Position
GPC Load, 26% TRM, Not Accounting for 2023 IRP Update BESS RFP 500 MW

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Georgia Power Peak Demand (MW)	*	16,264	16,892	18,334	20,320	22,168	23,612	24,469	24,900	25,213	25,451	25,653	25,768	25,987	26,216	26,605	26,917
Existing and Approved Gen Cap		14,306	15,164	16,545	16,801	16,265	16,266	16,266	16,266	16,266	16,266	16,266	12,759	12,759	12,759	12,110	12,110
Scherer 1 - 2 Extension beyond 2035													-	-	-	-	-
Scherer 3 Extension beyond 2028						-	-	-	-	-	-	-	-	-	-	-	-
Bowen 1 - 4 Extension beyond 2035													0	0	0	0	0
Gaston 1-4 Extension beyond 2028						-	-	-	-	-	-	0	0	0	0	0	0
Gaston A (CT) Extension beyond 2028						-	-	-	-	-	-	0	0	0	0	0	0
SUM OF EXIST AND APPROVED CAP	A	14,306	15,164	16,545	16,801	16,265	16,266	16,266	16,266	16,266	16,266	16,266	12,759	12,759	12,759	12,110	12,110
Scherer 3 Wholesale-To-Retail		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
McIntosh CT Uprates (1-8)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
McIntosh CC Uprates (10-11)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hatch 1-2 Uprates		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle 1-2 Uprate		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Goat Rock 3-6 Hydro Inc. Cap		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF 2025 INC RESOURCE REQUESTS	B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF GENERIC RESOURCE ADDITIONS	C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OWNED GENERATING CAPACITY	D = A+B+C	**14,306**	**15,164**	**16,545**	**16,801**	**16,265**	**16,266**	**16,266**	**16,266**	**16,266**	**16,266**	**16,266**	**12,759**	**12,759**	**12,759**	**12,110**	**12,110**
Purchased Generating Capacity (MW)		5,913	6,012	6,242	6,503	5,223	5,330	3,287	3,287	3,232	3,229	1,912	1,330	1,263	914	914	554
2022 IRP Planned ESS		0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500
2023 IRP UPDATE BESS RFP		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF PURCH GEN CAP (MW)	E**	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**
Existing Programs (CVR, DPEC, RTP, TempCheck)		649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720
DER Customer Program		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Staff Assumed Additional Demand Response		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM DISPATCHABLE DSOs (MW)	F***	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**
TOTAL CAPACITY (MW)	G = D+E+F	**20,868**	**21,829**	**23,443**	**23,960**	**22,647**	**22,757**	**20,719**	**20,721**	**20,668**	**20,668**	**19,353**	**15,265**	**15,203**	**14,875**	**14,235**	**13,884**
GPC TRM		24.6%	24.6%	24.6%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%
Cap Required to Meet GPC Target (MW)	****	(602)	(781)	(598)	1,467	5,093	6,790	9,900	10,438	10,881	11,180	12,747	16,980	17,316	17,930	19,057	19,799
2029-2031 RFP TARGET (Take through 2033)					1,467	5,093	6,790	9,900	10,438	10,881	10,881	10,881	10,881	10,881	10,881	10,881	10,881
2032-2033 RFP TARGET									0	0	0	0	0	0	0	0	0
2033+ NEEDS											299	1,866	6,099	6,435	7,049	8,176	8,918
GPC Reserve Margin (%)		28.3%	29.2%	27.9%	17.9%	2.2%	-3.6%	-15.3%	-16.8%	-18.0%	-18.8%	-24.6%	-40.8%	-41.5%	-43.3%	-46.5%	-48.4%

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

Case 2 MG0 - GPC with Near Term Resources

GPC Load, 26% TRM, 2025 IRP Requests, Extensions, Not Accounting for 2023 IRP Update BESS RFP 500 MW or Thermostat DR

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Georgia Power Peak Demand (MW)	*	16,264	16,892	18,334	20,320	22,168	23,612	24,469	24,900	25,213	25,451	25,653	25,768	25,987	26,216	26,605	26,917
Existing and Approved Gen Cap		14,306	15,164	16,545	16,801	16,265	16,266	16,266	16,266	16,266	16,266	16,266	12,759	12,759	12,759	12,110	12,110
Scherer 1 - 2 Extension beyond 2035													-	-	-	-	-
Scherer 3 Extension beyond 2028						537	537	482	458	458	458	458	-	-	-	-	-
Bowen 1 - 4 Extension beyond 2035													0	0	0	0	0
Gaston 1-4 Extension beyond 2028						460	460	460	460	460	460	0	0	0	0	0	0
Gaston A (CT) Extension beyond 2028						10	10	10	10	10	10	0	0	0	0	0	0
SUM OF EXIST AND APPROVED CAP	**A**	14,306	15,164	16,545	16,801	17,272	17,273	17,218	17,194	17,194	17,194	16,724	12,759	12,759	12,759	12,110	12,110
Scherer 3 Wholesale-To-Retail		0	52	52	52	52	107	162	187	187	187	187	187	187	187	0	0
McIntosh CT Uprates (1-8)		0	0	0	0	28	37	47	56	65	74	74	74	74	74	74	74
McIntosh CC Uprates (10-11)		0	0	0	0	194	194	194	194	194	194	194	194	194	194	194	194
Hatch 1-2 Uprates		0	0	0	0	0	28	58	58	58	58	58	58	58	58	58	58
Vogtle 1-2 Uprate		0	0	0	0	7	14	34	54	54	54	54	54	54	54	54	54
Goat Rock 3-6 Hydro Inc. Cap		0	0	0	0	4	13	22	26	26	26	26	26	26	26	26	26
SUM OF 2025 INC RESOURCE REQUESTS	**B**	0	52	52	52	285	394	517	575	584	594	594	594	594	594	407	407
SUM OF GENERIC RESOURCE ADDITIONS	**C**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OWNED GENERATING CAPACITY	**D = A+B+C**	**14,306**	**15,216**	**16,597**	**16,853**	**17,557**	**17,667**	**17,735**	**17,769**	**17,778**	**17,787**	**17,318**	**13,352**	**13,352**	**13,352**	**12,517**	**12,517**
Purchased Generating Capacity (MW)		5,913	6,012	6,242	6,503	5,223	5,330	3,287	3,287	3,232	3,229	1,912	1,330	1,263	914	914	554
2022 IRP Planned ESS		0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500
2023 IRP UPDATE BESS RFP		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF PURCH GEN CAP (MW)	**E****	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**
Existing Programs (CVR, DPEC, RTP, TempCheck)		649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720
DER Customer Program		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Staff Assumed Additional Demand Response		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM DISPATCHABLE DSOs (MW)	**F *****	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**
TOTAL CAPACITY (MW)	**G = D+E+F**	**20,868**	**21,881**	**23,495**	**24,012**	**23,939**	**24,158**	**22,188**	**22,223**	**22,180**	**22,189**	**20,404**	**15,859**	**15,797**	**15,469**	**14,642**	**14,290**
GPC TRM		24.6%	24.6%	24.6%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%
Cap Required to Meet GPC Target (MW)	****	(602)	(833)	(650)	1,415	3,801	5,389	8,431	8,936	9,369	9,659	11,696	16,386	16,722	17,336	18,650	19,392
2029-2031 RFP TARGET (Take through 2033)					1,415	3,801	5,389	8,431	8,936	9,369	9,369	9,369	9,369	9,369	9,369	9,369	9,369
2032-2033 RFP TARGET									0	0	0	0	0	0	0	0	0
2033+ NEEDS											289	2,327	7,017	7,353	7,967	9,280	10,023
GPC Reserve Margin (%)		28.3%	29.5%	28.2%	18.2%	8.0%	2.3%	-9.3%	-10.8%	-12.0%	-12.8%	-20.5%	-38.5%	-39.2%	-41.0%	-45.0%	-46.9%

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update,
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

Exhibit STF-NHSW-5
Reserve Margin Tables

Case 3 111-MG0 - GPC with Near Term Resources
GPC Load, 26% TRM, 2025 IRP Requests, Extensions, Not Accounting for 2023 IRP Update BESS RFP 500 MW or Thermostat DR

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Georgia Power Peak Demand (MW)	*	16,264	16,892	18,334	20,320	22,168	23,612	24,469	24,900	25,213	25,451	25,653	25,768	25,987	26,216	26,605	26,917
Existing and Approved Gen Cap		14,306	15,164	16,545	16,801	16,265	16,266	16,266	16,266	16,266	16,266	16,266	12,759	12,759	12,759	12,110	12,110
Scherer 1 - 2 Extension beyond 2035													147	147	147	-	-
Scherer 3 Extension beyond 2028						537	537	482	458	458	458	458	458	458	458	-	-
Bowen 1 - 4 Extension beyond 2035													3,360	3,360	3,360	0	0
Gaston 1-4 Extension beyond 2028						460	460	460	460	460	460	0	0	0	0	0	0
Gaston A (CT) Extension beyond 2028						10	10	10	10	10	10	0	0	0	0	0	0
SUM OF EXIST AND APPROVED CAP	**A**	14,306	15,164	16,545	16,801	17,272	17,273	17,218	17,194	17,194	17,194	16,724	16,724	16,724	16,724	12,110	12,110
Scherer 3 Wholesale-To-Retail		0	52	52	52	52	107	162	187	187	187	187	187	187	187	0	0
McIntosh CT Uprates (1-8)		0	0	0	0	28	37	47	56	65	74	74	74	74	74	74	74
McIntosh CC Uprates (10-11)		0	0	0	0	194	194	194	194	194	194	194	194	194	194	194	194
Hatch 1-2 Uprates		0	0	0	0	0	28	58	58	58	58	58	58	58	58	58	58
Vogtle 1-2 Uprate		0	0	0	0	7	14	34	54	54	54	54	54	54	54	54	54
Goat Rock 3-6 Hydro Inc. Cap		0	0	0	0	4	13	22	26	26	26	26	26	26	26	26	26
SUM OF 2025 INC RESOURCE REQUESTS	**B**	0	52	52	52	285	394	517	575	584	594	594	594	594	594	407	407
SUM OF GENERIC RESOURCE ADDITIONS	**C**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OWNED GENERATING CAPACITY	**D = A+B+C**	**14,306**	**15,216**	**16,597**	**16,853**	**17,557**	**17,667**	**17,735**	**17,769**	**17,778**	**17,787**	**17,318**	**17,317**	**17,317**	**17,317**	**12,517**	**12,517**
Purchased Generating Capacity (MW)		5,913	6,012	6,242	6,503	5,223	5,330	3,287	3,287	3,232	3,229	1,912	1,330	1,263	914	914	554
2022 IRP Planned ESS		0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500
2023 IRP UPDATE BESS RFP		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF PURCH GEN CAP (MW)	**E****	**5,913**	**6,012**	**6,242**	**6,503**	**5,723**	**5,830**	**3,787**	**3,787**	**3,732**	**3,729**	**2,412**	**1,830**	**1,763**	**1,414**	**1,414**	**1,054**
Existing Programs (CVR, DPEC, RTP, TempCheck)		649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720
DER Customer Program		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Staff Assumed Additional Demand Response		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM DISPATCHABLE DSOs (MW)	**F*****	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**
TOTAL CAPACITY (MW)	**G = D+E+F**	**20,868**	**21,881**	**23,495**	**24,012**	**23,939**	**24,158**	**22,188**	**22,223**	**22,180**	**22,189**	**20,404**	**19,824**	**19,762**	**19,434**	**14,642**	**14,290**
GPC TRM		24.6%	24.6%	24.6%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%	25.1%
Cap Required to Meet GPC Target (MW)	****	(602)	(833)	(650)	1,415	3,801	5,389	8,431	8,936	9,369	9,659	11,696	12,421	12,757	13,371	18,650	19,392
2029-2031 RFP TARGET (Take through 2033)					1,415	3,801	5,389	8,431	8,936	9,369	9,369	9,369	9,369	9,369	9,369	9,369	9,369
2032-2033 RFP TARGET									0	0	0	0	0	0	0	0	0
2033+ NEEDS											289	2,327	3,052	3,388	4,002	9,280	10,023
GPC Reserve Margin (%)		28.3%	29.5%	28.2%	18.2%	8.0%	2.3%	-9.3%	-10.8%	-12.0%	-12.8%	-20.5%	-23.1%	-24.0%	-25.9%	-45.0%	-46.9%

*Territorial Load requirements less non-dispatchable DSOs

**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.

*** Values stated in combustion turbine equivalence terms

****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

Case 4 MG0 - Staff Starting Position
Staff 1 LRM Uniform Load, 24.5% TRM, With 2023 IRP Update BESS RFP 500 MW

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Staff Uniform Peak Demand Case (MW)	*	16,176	16,614	17,659	19,157	20,574	21,743	22,459	22,826	23,093	23,297	23,474	23,585	23,799	24,024	24,406	24,718
Existing and Approved Gen Cap		14,306	15,164	16,545	16,801	16,265	16,266	16,266	16,266	16,266	16,266	16,266	12,759	12,759	12,759	12,110	12,110
Scherer 1 - 2 Extension beyond 2035													-	-	-	-	-
Scherer 3 Extension beyond 2028						-	-	-	-	-	-	-	-	-	-	-	-
Bowen 1 - 4 Extension beyond 2035													0	0	0	0	0
Gaston 1-4 Extension beyond 2028						-	-	-	-	-	-	0	0	0	0	0	0
Gaston A (CT) Extension beyond 2028						-	-	-	-	-	-	0	0	0	0	0	0
SUM OF EXIST AND APPROVED CAP	**A**	14,306	15,164	16,545	16,801	16,265	16,266	16,266	16,266	16,266	16,266	16,266	12,759	12,759	12,759	12,110	12,110
Scherer 3 Wholesale-To-Retail		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
McIntosh CT Uprates (1-8)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
McIntosh CC Uprates (10-11)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hatch 1-2 Uprates		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vogtle 1-2 Uprate		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Goat Rock 3-6 Hydro Inc. Cap		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF 2025 INC RESOURCE REQUESTS	**B**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF GENERIC RESOURCE ADDITIONS	**C**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OWNED GENERATING CAPACITY	**D = A+B+C**	**14,306**	**15,164**	**16,545**	**16,801**	**16,265**	**16,266**	**16,266**	**16,266**	**16,266**	**16,266**	**16,266**	**12,759**	**12,759**	**12,759**	**12,110**	**12,110**
Purchased Generating Capacity (MW)		5,913	6,012	6,242	6,503	5,223	5,330	3,287	3,287	3,232	3,229	1,912	1,330	1,263	914	914	554
2022 IRP Planned ESS		0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500
2023 IRP UPDATE BESS RFP		0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500
SUM OF PURCH GEN CAP (MW)	**E****	**5,913**	**6,012**	**6,742**	**7,003**	**6,223**	**6,330**	**4,287**	**4,287**	**4,232**	**4,229**	**2,912**	**2,330**	**2,263**	**1,914**	**1,914**	**1,554**
Existing Programs (CVR, DPEC, RTP, TempCheck)		649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720
DER Customer Program		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Staff Assumed Additional Demand Response		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM DISPATCHABLE DSOs (MW)	**F*****	**649**	**652**	**656**	**656**	**659**	**661**	**665**	**667**	**670**	**673**	**675**	**676**	**681**	**703**	**711**	**720**
TOTAL CAPACITY (MW)	**G = D+E+F**	**20,868**	**21,829**	**23,943**	**24,460**	**23,147**	**23,257**	**21,219**	**21,221**	**21,168**	**21,168**	**19,853**	**15,765**	**15,703**	**15,375**	**14,735**	**14,384**
STF TRM		23.1%	23.1%	23.1%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%
Cap Required to Meet GPC Target (MW)	********	(952)	(1,374)	(2,201)	(773)	2,292	3,628	6,551	7,004	7,386	7,639	9,173	13,398	13,724	14,330	15,443	16,180
2029-2031 RFP TARGET (Take through 2033)					(773)	2,292	3,628	6,551	7,004	7,386	7,386	7,386	7,386	7,386	7,386	7,386	7,386
2032-2033 RFP TARGET									0	0	0	0	0	0	0	0	0
2033+ NEEDS											252	1,786	6,012	6,338	6,944	8,057	8,794
GPC Reserve Margin (%)		29.0%	31.4%	35.6%	27.7%	12.5%	7.0%	-5.5%	-7.0%	-8.3%	-9.1%	-15.4%	-33.2%	-34.0%	-36.0%	-39.6%	-41.8%

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

Case 5 MG0 - Staff with Near Term Resources

Staff 1 LRM Uniform Load, 24.5% TRM, Staff Recommendations, With 2023 IRP Update BESS RFP 500 MW and Thermostat DR

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Staff Uniform Peak Demand Case (MW)	*	16,176	16,614	17,659	19,157	20,574	21,743	22,459	22,826	23,093	23,297	23,474	23,585	23,799	24,024	24,406	24,718
Existing and Approved Gen Cap		14,306	15,164	16,545	16,801	16,265	16,266	16,266	16,266	16,266	16,266	16,266	12,759	12,759	12,759	12,110	12,110
Scherer 1 - 2 Extension beyond 2035													147	147	147	147	147
Scherer 3 Extension beyond 2028						537	537	482	458	458	458	458	458	458	458	458	458
Bowen 1 - 4 Extension beyond 2035													3,360	3,360	3,360	3,360	3,360
Gaston 1-4 Extension beyond 2028						460	460	460	460	460	460	0	0	0	0	0	0
Gaston A (CT) Extension beyond 2028						10	10	10	10	10	10	0	0	0	0	0	0
SUM OF EXIST AND APPROVED CAP	A	14,306	15,164	16,545	16,801	17,272	17,273	17,218	17,194	17,194	17,194	16,724	16,724	16,724	16,724	16,076	16,076
Scherer 3 Wholesale-To-Retail		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
McIntosh CT Uprates (1-8)		0	0	0	0	28	37	47	56	65	74	74	74	74	74	74	74
McIntosh CC Uprates (10-11)		0	0	0	0	194	194	194	194	194	194	194	194	194	194	194	194
Hatch 1-2 Uprates		0	0	0	0	0	0	0	28	58	58	58	58	58	58	58	58
Vogtle 1-2 Uprate		0	0	0	0	7	14	34	54	54	54	54	54	54	54	54	54
Goat Rock 3-6 Hydro Inc. Cap		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUM OF 2025 INC RESOURCE REQUESTS	B	0	0	0	0	229	245	275	332	371	381	381	381	381	381	381	381
SUM OF GENERIC RESOURCE ADDITIONS	C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OWNED GENERATING CAPACITY	D = A+B+C	**14,306**	**15,164**	**16,545**	**16,801**	**17,501**	**17,519**	**17,493**	**17,526**	**17,565**	**17,574**	**17,105**	**17,105**	**17,105**	**17,105**	**16,456**	**16,456**
Purchased Generating Capacity (MW)		5,913	6,012	6,242	6,503	5,223	5,330	3,287	3,287	3,232	3,229	1,912	1,330	1,263	914	914	554
2022 IRP Planned ESS		0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500
2023 IRP UPDATE BESS RFP		0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500
SUM OF PURCH GEN CAP (MW)	E**	**5,913**	**6,012**	**6,742**	**7,003**	**6,223**	**6,330**	**4,287**	**4,287**	**4,232**	**4,229**	**2,912**	**2,330**	**2,263**	**1,914**	**1,914**	**1,554**
Existing Programs (CVR, DPEC, RTP, TempCheck)		649	652	656	656	659	661	665	667	670	673	675	676	681	703	711	720
DER Customer Program		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Staff Assumed Additional Demand Response		0	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
SUM DISPATCHABLE DSOs (MW)	F***	**649**	**750**	**754**	**754**	**757**	**759**	**763**	**765**	**768**	**771**	**773**	**774**	**779**	**801**	**809**	**818**
TOTAL CAPACITY (MW)	G = D+E+F	**20,868**	**21,927**	**24,041**	**24,558**	**24,481**	**24,608**	**22,544**	**22,578**	**22,565**	**22,574**	**20,789**	**20,209**	**20,147**	**19,819**	**19,179**	**18,828**
STF TRM		23.1%	23.1%	23.1%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%	23.7%
Cap Required to Meet GPC Target (MW)	****	(952)	(1,472)	(2,299)	(871)	958	2,278	5,226	5,646	5,989	6,233	8,236	8,954	9,280	9,886	10,999	11,736
2029-2031 RFP TARGET (Take through 2033)					(871)	958	2,278	5,226	5,646	5,989	5,989	5,989	5,989	5,989	5,989	5,989	5,989
2032-2033 RFP TARGET									0	0	0	0	0	0	0	0	0
2033+ NEEDS											243	2,247	2,964	3,291	3,897	5,010	5,746
GPC Reserve Margin (%)		29.0%	32.0%	36.1%	28.2%	19.0%	13.2%	0.4%	-1.1%	-2.3%	-3.1%	-11.4%	-14.3%	-15.3%	-17.5%	-21.4%	-23.8%

*Territorial Load requirements less non-dispatchable DSOs
**Includes territorial and imported power purchases. Capacity does include the Winter 2027/2028 BESS Request for Proposals (RFP) approved in the 2023 Integrated Resource Plan (IRP) Update.
*** Values stated in combustion turbine equivalence terms
****Reflects Staff's view of GPC TRM resulting from the system TRM of 24% (2025-2027) and 24.5% (2028 and beyond).

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EXHIBIT
PENGAD 800-631-6989
STF-PIA-16

STF-NHSW-6 - Generic Resource Comparison

Exhibit STF-NHSW-6
Generic Resource Costs[139]

Certain Information considered confidential to the utility has been omitted from STF-NHSW-6 tables where cells are intentionally left blank. Staff escalated other utilities and public sources to 2030$ using a 2.3% escalation rate.

Combustion Turbine												
	GPC 2025 IRP	GPC 2023 IRP Update	LG&E/KU 2024 IRP	Santee Cooper 2024 IRP Update	DESC 2025 IRP Update	DESC 2025 IRP Update	EIA AEO 2025	NREL ATB 2024 Mod	Entergy NOLA 2024 IRP	Ind. Mich. Pwr Comp. 2024 IRP	TVA Draft 2025 IRP	Duke Energy Indiana 2024 IRP
	CT w SCR	CT w SCR		H-Class	1x0 Adv. Greenfield Frame CT	2x0 Greenfield F Class	Industrial Frame	F Class	Frame CT	F Class	Frame CT	
Year Availability	2029		2030	2031			2026			2030	2029	2031
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)	856	691	258	402	450	402	419	233	408	240	884	425
Capital Cost ($/kW)	1,128	1,276	1,636	1,919	1,494	1,650	907	1,311	1,330	1,500	853	1,146-1,375
Fixed O&M ($/kW-yr.)	11.84	12.10	6.90	5.85			7.99	31.19	7.93	9.31	6.30	
Variable O&M ($/MWh)	8.88	5.84		11.23			4.64	8.32	10.14	5.98		
Average Heat Rate (MBTU/MWh)	9,105	9,662	9,500	9,386			9,142	9,717	9,450	9,910	10,087	

[139] Sources used for the following tables: Entergy NOLA 2024 IRP, EIA AEO 2025 Preliminary Results, DESC 2024 IRP Update, NREL 2024 ATB, Lazard LCOE 2024, Santee Cooper 2024 IRP Update, Duke Supplemental Planning Analysis ("SPA") 2023 IRP, TVA Draft 2025 IRP, 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, and Indiana Michigan power Company Stakeholder Meeting #2.

Exhibit STF-NHSW-6
Generic Resource Comparison
TRADE SECRET

Combined Cycle																
	GPC 2025 IRP	GPC 2023 IRP Update	LG&E/KU 2024 IRP	LG&E/KU CPCN	LG&E/KU CPCN	Santee Cooper 2024 IRP Update		DESC 2025 IRP Update	EIA AEO 2025	Lazard 2024 LCOE	Lazard 2024 LCOE	NREL ATB 2024	Entergy NOLA 2024 IRP	Ind. Mich. Pwr Comp. 2024 IRP	Duke Energy Indiana 2024 IRP	Duke Indiana CPCN
	NGCC 1x1		NGCC	Brown 12	Mill Creek 6	1x1 H Class	1x1 F Class	1x1 Greenfield	Single-Shaft	(Low) (New Build)	(High) (New Build)	H Frame				Cayuga CC
Year Availability			2030	2030	2031	2031	2031		2027					2031	2030	
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)	762	731	660	660	660	630	357	665	627	550	550	649	729	420	719	1,476
Capital Cost ($/kW)	1,257	1,205	2,121	2,120	2,138	1,949	3,010	2,337	1,003	974	1,490	1,752	1,520	1,955	1,662-1,777	2,597
Fixed O&M ($/kW-yr.)	9.67	12.01	7.80	7.80	7.10	8.91	13.47		18.05	11.46	29.23	46.78	14.75	19		
Variable O&M ($/MWh)	1.54	1.25	0.23	0.23	0.23	3.27	3.78		3.89	3.15	5.73	3.00	5.83	3		
Average Heat Rate (MBTU/MWh)	6,250	6,306	6,300	6,300	6,300	6,136	6,668		6,226	6,750	7,500	6,068	6,759	6,430		

Combined Cycle with CCS						
	GPC 2025 IRP		GPC 2023 IRP Update	TVA 2025 IRP Draft	Ind. Mich. Pwr Comp. 2024 IRP	Duke Energy Indiana 2024 IRP
	Local CCS	Distant CCS				
Year Availability	2037	2037		2033	2035	2035
Dollar Year	2030	2030	2030	2030	2030	2030
Capacity (MW)	663	663	635	1,430	380	1,215
Capital Cost ($/kW)	3,719	6,312	3,049	3,458	3,838	4,298
Fixed O&M ($/kW-yr.)	9.67	9.67	10.03	107.75	36	
Variable O&M ($/MWh)	4.38	4.38	3.52	5.73	8	
Average Heat Rate (MBTU/MWh)	7,200	7,200	7,300	7,832	7,120	

On-Shore Wind										
	GPC 2025 IRP	GPC 2023 IRP Update	Santee Cooper 2024 IRP Update	Duke Energy Indiana 2024 IRP	EIA AEO 2025	NREL ATB 2024 (Mod)	Entergy NOLA 2024 IRP	Lazard 2024 LCOE (Low)	Lazard 2024 LCOE (High)	Indiana Michigan Power Company 2024 IRP
Year Availability	2033	2032	2029	2028	2027					2028
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)	150	150	50	50	200	200	100-200	250	250	200
Capital Cost ($/kW)	2,221	2,093	2,236	2,350	1,864	1,776	2,357	1,490	2,178	3,140
Fixed O&M ($/kW-yr.)	59.19	59.23	55.41		38.45	38.38	49.99	28.08	45.85	10.04

Solar													
	GPC 2025 IRP	GPC 2023 IRP Update	Santee Cooper 2024 IRP Update	Duke Energy Indiana 2024 IRP	DESC 2025 IRP Update	EIA AEO 2025	NREL ATB 2024 (Mod)	Entergy NOLA 2024 IRP	Lazard 2024 LCOE (Low)	Lazard 2024 LCOE (High)	TVA Draft 2025 IRP	LG&E/KU Utility-Scale Solar 2024 IRP	Indiana Michigan Power Company 2024 IRP
Year Availability	2028	2027	2026	2027		2026					2027		2028
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)	200	200	50	50	100	150	100	100	150	150	50	100	150
Capital Cost ($/kW)	1,813	1,703	1,781	2,120	1,826	1,581	1,654	2,188	974	1,605	1,490	1,902	2,616
Fixed O&M ($/kW-yr.)	12.81	11.51	27.30			26.26	26.39	15.36	12.61	16.05		17.00	10.04

Battery Storage (4 Hour)												
	GPC 2025 IRP	GPC 2023 IRP Update	Santee Cooper 2024 IRP Update (4 Hour)	Duke Energy Indiana 2024 IRP (4 Hour)	DESC 2025 IRP Update (4 Hour)	EIA AEO 2025 (4 Hour)	NREL ATB 2024 (Mod) (4 Hour)	Entergy NOLA 2024 IRP (4 Hour)	TVA Draft 2025 IRP	LG&E/KU 2024 IRP (4 Hour)	Indiana Michigan Power Company 2024 IRP (4 Hour)
Year Availability	2028		2026	2028		2025			2029	2028	2028
Dollar Year	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030	2030
Capacity (MW)	300	300	50	50	100	150	60	50/200	50	100+	50
Capital Cost ($/kW)	1,963	2,034	2,132	2,636	2,281	1,811	2,123	2,734	1,656	2,049	2,093
Fixed O&M ($/kW-yr.)	12.49	11.49	53.29			46.56	52.78	17.34	53.42	25.00	54.57

Battery Storage (MDESS)		
	GPC 2025 IRP	GPC 2023 IRP Update
Year Availability	2033	2033
Dollar Year	2030	2030
Capacity (MW)	480	300
Capital Cost ($/kW)	3,045	2,911
Fixed O&M ($/kW-yr.)	21.78	11.73

Nuclear (AP-1000)		
	GPC 2025 IRP Nuclear (AP-1000)	TVA 2025 IRP Draft Adv. Pressurized Water Reactor
Year Availability	2037	2038
Dollar Year	2030	2030
Capacity (MW)	2,248	1,150
Capital Cost ($/kW)	10,486	14,818
Fixed O&M ($/kW-yr)	147	146.60
Variable O&M ($/MWh)		1.51
Average Heat Rate (MBTU/MWh)		10,132

EXHIBIT
STF-PIA-18

DAYMARK®
ENERGY ADVISORS

Douglas A. Smith

Vice President and Principal Consultant

Doug provides clients with strategic insights and customized analysis of the impacts of market dynamics and policy choices on infrastructure development. He advises project developers, utilities, and regulators who are navigating through new business opportunities and market environments. He has extensive experience forecasting wholesale electricity prices, leading market and power system analyses, and directing integrated resource planning processes and evaluations. Doug has appeared as an expert before U.S. state and Canadian provincial regulatory agencies.

SELECTED PROFESSIONAL EXPERIENCE

Power System Planning

- For a national not-for-profit, advised on the state of state, regional and national transmission development conditions, including barriers to development, efforts to change processes, and methods for engagement with key stakeholders. Produced multiple reports and presentations to staff and senior decision makers. Reviewed and assisted in the development of an engagement strategy.
- For Central Maine Power, led a team that provided analysis, advisory services, and testimony in support of the New England Clean Energy Connect (NECEC); provided market analytical modeling and analysis to assess cost implications, benefits, and risks to customer and the client; led presentations of results to internal and external parties. The effort led to filed reports with the Federal Energy Regulatory Commission and the Maine Public Utilities Commission as well as multiple rounds of oral and written testimony.
- For Central Maine Power, managed the analysis of a combined proposal for wind energy and transmission in northern New England; assisted team members in understanding the impacts of various quantities of wind energy and the respective transmission needed to deliver wind energy and crafted scenario analysis to quantify the range of potential benefits, all of which resulted in multiple public reports as components of the client's response to the 2016 Clean Energy RFP by Massachusetts, Connecticut and Rhode Island and the 2018 Section 83D RFP by Massachusetts.
- Led a team providing transmission planning and development advisory and analytical services to a confidential developer. Work spans multiple regions and involves consideration of multiple projects, alternatives, and integration with potential renewable generation developers.
- For multiple confidential developers, leads teams to provide electric market analytical modeling and analysis supporting the development of multiple bids into state procurement processes seeking renewable generation. Teams deliver reports detailing the economic benefits to the region of several separate portfolios of generating assets.
- For the Maryland Office of Peoples' Counsel (MD OPC), provided advisory evaluation services regarding a certificate of public convenience and necessity related to a proposed competitive transmission project in Maryland. Assisted the MD OPC through review of the regulatory record and consideration of potential testimony options. Resulted in multiple rounds of written and oral

testimony outlining the results of the review and potential alternative approaches to the transmission solution identified.

- Managed a team to advise a confidential transmission developer's business development team regarding a bid into a regional request for proposal. The work included advising the client on various financial and transmission tariff related matters to ensure the client could properly account for regulated transmission requirements when bidding into a competitive solicitation.
- Provided advisory services to a confidential distribution utility regarding a regional transmission constraint and potential solutions to that constraint. Designed key aspects of the benefit-cost screening tools used to evaluate the options identified. Advised the client on use of the screening tools and considerations important to their review of potential solutions. The effort resulted in utility action to champion support for several transmission upgrade projects.
- For NRG Energy Inc, analyzed the regional benefits of the proposed Canal 3 peaker plant; advised and managed the Daymark team regarding emissions impact scenarios, with the plant operating as either an energy unit or a reserve unit; investigated state emissions policies and their potential impact on plant operations.
- For a confidential client, led the creation of a proof of concept model of the Southern Company balancing authority and surrounding areas, including benchmarking to available public data and forecasting of potential future capacity expansion outcomes.
- As an input to several economic studies for NYSERDA, provided review and critical analysis of a third-party, long-term forecast of growth and pricing in New York's energy and capacity markets.
- Managed the review of a large generation owner's internal electric market price forecasting process relied upon to evaluate business decisions; provided recommendations for (1) process improvements designed to more-closely align forecasting efforts to better address internal requirements, (2) updated and extended the client's New York modeling capabilities using the AURORA production cost model, and (3) recommended key benchmarking tools that should be used to evaluate specific forecasting results.

Non-Transmission Alternative Assessments

- Assisted in evaluating non-transmission alternatives (NTAs) as compared to a set of proposed transmission upgrades in Vermont; assisted in the development of an economic scorecard designed to facilitate the comparison of transmission and non-transmission solutions on equal footing and compared potential rate impacts of the proposed solutions.
- Assisted in evaluating non-transmission alternatives (NTAs) as compared to a set of proposed transmission upgrades in Maine; evaluated the economics of transmission and non-transmission solutions and leveraged market simulation models to estimate the impact of solutions on energy clearing prices in Maine and in New England.
- On behalf of Vermont-based utility, developed and analyzed non-transmission alternatives (NTAs) to a set of proposed transmission upgrades that would impact the distribution-level supply system; developed an economic tool to evaluate the cost of operating "pre-contingency" generation options.

Clean Energy

- For a confidential developer, led a team that produced an offshore wind siting feasibility study related to a potential investment in offshore leasing. Investigated the project's interconnection and market risks and opportunities.

Asset Valuation'

- For a confidential client, led a valuation of storage as a transmission asset designed to enhance transfer capability. Advised on potential operational outcomes and method for valuing impact on regional energy and capacity markets.
- For a confidential client, led a valuation of a hydropower asset in consideration of a potential sale. Evaluated the asset considering multiple potential ownership structures and reported the range of valuation.
- For Calpine Corporation, led a team that assessed the financial condition and cashflows of several nuclear plants located in New Jersey, Ohio, and Pennsylvania in light of the stranded cost payments determined at the time of the initial stranded cost determinations in 1999 and 2001 and compared them to the financial conditions as estimated based on actual market outcomes.
- For multiple clients, advised on and assisted with the creation of financial models of natural gas and hydro-electric facilities for tax valuation.

Competitive Procurement

- Oversaw development of and currently managing the quantitative evaluation for a procurement process for SaskPower to procure low-carbon energy for delivery over an expanded transmission line between SPP and Saskatchewan. (Ongoing)
- Advisor to Southwest Louisiana Electric Membership Corporation (SLEMCO), Pointe Coupee Electric, and Concordia Electric Cooperative for an appropriate long-term contracting plan for energy and capacity by developing, documenting, and recommending a planning process and the resulting steps needed to acquire its next sources of power supply. Prepared the quantitative review for the responses to a Request for Proposal (RFP) to solicit diverse offerings to meet load. Prepared and delivered multiple rounds of testimony.
- For a confidential developer, led multiple investigations into potential competitive bid requests for proposal to assess client's likely competitive position relative to the market. This effort included assessment of RFP conditions, potential solutions, cost evaluation, evaluation of net benefits and advising on potential competition. The outcome of each effort was a bid / no bid decision in part based on the overall team recommendation.

Regulatory Economics

- For the Georgia PSC Public Interest Advocacy Staff, reviewed and provided testimony regarding transmission and interconnection issues regarding the Georgia Power 2023 IRP Update filing. Reviewed the Company's methodology and results. Oversaw a team of transmission planners who reviewed and tested the Company's results. Provided recommendations regarding the analysis and results of the Company's transmission plan for new generation requested in the IRP Update.
- Served as an Independent Expert Consultant to the Manitoba Public Utilities Board to provide an independent expert opinion of Manitoba Hydro's export revenue forecast as part of the utility's 2017/18 & 2018/19 General Rate Application (GRA) and the 2023/24 GRA. Directed the review of

Manitoba Hydro's long-term market price forecast, its projection of surplus energy, existing contracts, the markets fundamentals, and a comprehensive review of the economics and decision-making behind one power sale and transmission construction project. Reviewed utility's hedge trading and risk policies and its performance during drought. Thess accuracy and reasonableness reviews culminated in public and confidential independent expert reports and oral testimony that together were key inputs to regulators' consideration of the utility's rate increase request.

- For the Arkansas Public Service Commission Staff, led the review of a utility's proposal to use a tax equity partner in the acquisition of wind power plants. Analyzed the risks and benefits of the proposal to utility customers and reviewed potential alternative financing options. The analysis led to the provision of written testimony before the Arkansas Public Service Commission.
- Assisted in the assessment of a request to the Arkansas Public Service Commission for a declaratory order; the request sought a finding that installation of environmental controls at the Flint Creek power plant was in the public interest.
- For the Interconnection Rights Holders (IRH) Management Committee (IMC) of an HVDC transmission facility between HQ and ISO-NE, led a team to prepare a cost-benefits study to assess the merits of extending the agreement for a period of up to twenty years. The purpose of the study was to measure both ratepayer and shareholder impacts by isolating the net benefits that would potentially accrue to the contract holders. Project resulted in a comprehensive report documenting the cost and benefit analysis approach, assumptions, results, and conclusions.
- For the Southern Environmental Law Center (SELC), led a team that reviewed the Integrated Resource Planning (IRP) performed by Duke Energy Carolinas and Duke Energy Progress and identified, modeled, and compiled results of alternative resource plans that illustrated the benefits of a more aggressive renewable generation focus. Provided a report that was relied upon by SELC to craft testimony for submission in the docketed case.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc.	Worcester, MA
Principal Consultant	2021 – Present
Treasurer	2016 – Present
Managing Consultant	2017 – 2021
Various consulting positions	2004 – 2017
The Sports Authority	Ft. Lauderdale, FL
Senior POS/EDP Programmer/Analyst	2002 – 2004
SHL USA Inc.	Boulder, CO
Software Engineer	2000 – 2001
Strategic Technologies Group	Boulder, CO
Senior Consultant	1995 – 2000

EDUCATION

Syracuse University	Syracuse, NY
B.S., Accounting, Summa Cum Laude	1991

PUBLICATIONS & TESTIMONY

Invited Speaker

- *Webinar on Northeast transmission*

Publications

- *Independent Expert Consultant Report: SaskPower Contract-Economic Review;* Confidential Report prepared for the Manitoba Public Utilities Board regarding Manitoba Hydro's 20-year power contract with SaskPower and associated transmission, December 15, 2017. Contributing Author.

- *Independent Expert Consultant Report: Export Pricing and Revenues Review;* Confidential Report prepared for the Manitoba Public Utilities Board regarding Manitoba Hydro's 20-year forecast of its export revenues submitted in its 2017/18 and 2018/19 General Rate Application, November 16, 2017. Contributing Author.

- *MCPC Project Benefits; Quantitative and Qualitative Benefits,* Confidential Report prepared for Central Maine Power regarding the benefits of the Maine Clean Power Connection, a 345-kV transmission expansion accompanied by 1100 MW of wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Contributing Author.

- *NECEC Project Benefits; Quantitative and Qualitative Benefits,* Confidential Report prepared for Central Maine Power and H.Q. Energy Services regarding the benefits of the New England Clean Energy Connection, 1200 MW HVDC transmission expansion accompanied by 1090 MW of hydropower and wind energy project development offered in the Massachusetts RFP for Clean Energy Resources, July 27, 2017. Contributing Author.

- *MREI Project Benefits; Direct, Indirect, Qualitative and Other Benefits,* prepared for Central Maine Power Company and Emera Maine regarding the benefits of the Maine Renewable Energy Initiative, a 345 kV transmission expansion accompanied by 1200 MW of wind energy project development, January 28, 2016. Contributing Author.

- *MCPC Project Benefits; Direct, Indirect, Qualitative and Other Benefits",* prepared for Central Maine Power Company regarding the benefits of the Maine Clean Power Connection, a 345-kV transmission expansion accompanied by nearly 600 MW of wind energy project development, January 28, 2016. Contributing Author.

- *Maine Power Connection: Analysis of Benefits in Maine and New England,* Report for Central Maine Power. September 5, 2014. Contributing Author.

Expert Testimony

FORUM	ON BEHALF OF	MATTER
Georgia Public Service Commission	Georgia PSC Public Interest Advocacy Staff	Prefiled Direct testimony regarding the Georgia Power Company's Application for Certification of The Robins, Moody, Hammond, and McGrau Ford Phase I and II Battery Energy Storage Systems. Docket No. 55378.
Georgia Public Service Commission	Georgia PSC Public Interest Advocacy Staff	Prefiled Direct testimony and expert witnessing regarding the transmission and interconnection analyses and results from the Georgia Power 2023 Integrated Resource Plan Update. Docket 5538
The Louisiana Public Service Commission	Southwest Louisiana Membership Corporation (SLEMCO), Concordia Electric Cooperative (Concordia), and Point Coupee Electric Cooperative (PC Electric)	Prefiled Direct and Surrebuttal testimony and expert witnessing regarding the Application of SLEMCO, Concordia, and PC Electric to enter into contracts for full requirements power services and solar PPAs. Docket No. U-36514, U-36515, and U-36516. August 2022, May 2023.
The Public Utilities Board of Manitoba	Daymark Energy Advisors *(independent expert consultant, under contract to the Public Utilities Board)*	Manitoba Hydro 2023/24 General Rate Application - independent expert for the review of specific issues regarding Manitoba Hydro's forecast of export revenues, review of MH power contracts, evaluation of utility hedging and risk policies and review of utility performance during drought. Testimony addressed reasonableness of forecast methods and results. May 2023
Rhode Island Division of Public Utilities and Carriers	Rhode Island Division of Public Utilities and Carriers (RIDPUC Staff)	Prefiled Direct testimony in the form of a report to the RIDPUC and brief accompanying testimony. Testimony related to utility's filing for approval to join a revolving credit facility and evaluation of potential impacts to ratepayers. Docket No. D-22-13 January 2023
The Maryland Public Service Commission	The Maryland Office of Consumer Advocates	Prefiled Direct and Surrebuttal testimony and expert witnessing regarding the Application of Transource Maryland, LLC for a CPCN to construct new transmission lines in Maryland. Testimony related to proposed settlement and stipulation and addressed applicant's forecasted economic impacts of proposed transmission. Docket No. 9471. April 2019, May 2019, June 2019, December 2019, February 2020
The Arkansas Public Service Commission	The General Staff of the Arkansas Public Service Commission	Application of the Empire District Electric Company for Approval to Acquire Renewable Wind Generation Facilities and to Establish a Regulatory Asset. Testimony addressed reasonableness of applicant's proposal to use tax equity financing. Docket No. 17-61-U. February 2018

FORUM	ON BEHALF OF	MATTER
The Arkansas Public Service Commission	The General Staff of the Arkansas Public Service Commission	Application of the Empire District Electric Company for Approval to Acquire Renewable Wind Generation Facilities and to Establish a Regulatory Asset. Testimony addressed reasonableness of applicant's proposal to use tax equity financing. Docket No. 17-61-U. February 2018
The Public Utilities Board of Manitoba	Daymark Energy Advisors *(independent expert consultant, under contract to the Public Utilities Board)*	Manitoba Hydro 2017/18 & 2018/19 General Rate Application - independent expert for the review of specific issues regarding Manitoba Hydro's forecast of export revenues and review of MH power contracts. Testimony addressed reasonableness of forecast methods and results. January 2018
Maine Public Utilities Commission	Central Maine Power	Witness in support of CMP's request for approval of a certificate of finding of public convenience and necessity for the New England Clean Energy Connect construction of a 1,200 MW HVDC transmission line from the Quebec-Maine border to Lewiston, Maine. Testimony addressed the economic benefits associated with interregional transmission connection and associated clean energy development benefits. Docket No. 2017-00232. December 2017, April 2018, August 2018, November 2018, January 2019
Maine Public Utilities Commission	Central Maine Power	Emera Maine's application for approval of the Maine Power Connection Transmission project. Testimony addressed the economic benefits associated with interregional transmission connection and associated wind energy development benefits. Docket No. 2014-00048. September 2014

EXHIBIT

STF-PIA-19

DAYMARK® ENERGY ADVISORS

AREAS OF EXPERTISE

Transmission planning

Power system modeling

Interconnection studies

BACKGROUND

Daymark Energy Advisors
2024-Present

ISO New England
2015-2024

EDUCATION

M.S., Electrical and Computer Engineering
Clemson University

B.E., Electrical and Electronics Engineering
Anna University

Sasikumar Kannan

Lead Engineer

Sashi works with power system developers and transmission owners to advance generation and transmission projects. Previously with ISO New England, he has an extensive understanding of New England's bulk power system and the greater northeast region, including long-term planning, compliance standards, and dynamics modeling. He is experienced in transmission planning and power system modeling, including case builds, dynamic data management and validation, system stability studies, and generator interconnection stability studies.

SELECTED EXPERIENCE

- As a *Power System Engineer with ISO New England*, engineered and led the implementation of a strategic, company-wide dynamics model development process, optimizing system planning and validation to comply with NERC standards. Spearheaded the adoption of automated tools and databases, significantly enhancing the efficiency and reliability of power system models.
- Innovated a Python-based tool and a text database for dynamic data management, revolutionizing the dynamics case build process for New England-wide PSS/E dynamics case files.
- Chaired and actively contributed to several high-impact working groups, including internal stability, dynamics data validation, and northeast regional dynamics modeling (SS-37 and MMWG), improving collaborative efforts and knowledge transfer across operational, planning, and compliance teams.
- Developed and maintained a comprehensive Stability Case Library consisting of up to 22 cases, each stressed to different parameters. This library served as a crucial resource for Operations, Planning, Transmission System Services, and Transmission Owners (TOs), supporting their diverse analytical needs and ensuring optimal system performance under various scenarios.
- Directed the overhaul of existing case build processes, achieving substantial time savings and increased model accuracy for cluster studies, transmission planning, and operational studies.
- Provided expert technical support and training to internal and external stakeholders, improving model management practices and fostering a culture of continuous improvement and compliance with industry standards.
- Spearheaded the design and ongoing maintenance of advanced transmission models for the New England Bulk Power System, enhancing system reliability and supporting extensive generation and transmission

expansion projects within the New England Power Pool (NEPOOL) system using SIEMENS MOD.

- Led the periodic updates of the ISO-NE PSS/E basecase and developed specialized models for ISO-NE and Transmission Owners (TOs), ensuring optimal operational efficiency and compliance with regional standards.
- Systematically collected, modified, and reviewed a comprehensive range of electric transmission system parameters, including equipment ratings, impedances, contingency sets, and system topologies, to uphold system integrity and performance.
- Implemented Siemens Power Technologies International's (PTI) Model on Demand (MOD), significantly enhancing infrastructure and streamlining processes for project-based long-term planning and model management.
- Contributed to product development initiatives with PTI, including beta testing SIEMENS Power system programs such as PSS/E, MOD File Builder, MOD Web interface, and PSS/E GIC tool. These collaborations facilitated key enhancements to simulation and model management platforms, improving operational readiness.
- Developed internal powerflow cases, chaired inter-departmental meetings, and conducted case building tutorials; updated contingency decks, optimized economic dispatch, and conducted fault analysis to maintain system resilience.
- Innovated and refined internal tools and scripts to improve efficiency and accuracy, including:
    - Developed the Field Data Bridge Utility (FDBU) program to seamlessly integrate data between EMS and steady state models, ensuring data consistency.
    - Created the GNET Cleaner program in Python to automate the removal of duplicate entries in dynamic files, enhancing data integrity.
    - Engineered the DYR Merger program in Python, automating the process of searching and merging hundreds of dynamics IDV files from subfolders, significantly speeding up model integration tasks.

EXHIBIT
STF-PIA-20

Exhibit MG-1: Michael S. Goggin Background and Qualifications

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis "Is it Time for a Change? Science, Policy, and Climate Change"

Experience:

Grid Strategies — Vice President — February 2018-present

- Serve as a consultant on electricity transmission, grid integration, reliability, market, and public policy issues for consumer, grid operator, non-profit, and industry clients
- Have testified before FERC and in over 25 state regulatory commission cases

AWEA — Senior Director of Research, other titles — February 2008-February 2018

- Led team responsible for all American Wind Energy Association (now American Clean Power Association) analysis
- Served as primary technical and economic expert for market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (ISO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases)
- Directed economic and power sector modeling to inform AWEA's policy strategy and support advocacy positions

- Communicated with the press and policy makers about wind energy
- Authored reports to promote AWEA's policy agenda, rebut misconceptions about wind energy, and explain complex energy topics to lay audiences
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. Research Analyst October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE's renewable energy R&D funding decisions

Union of Concerned Scientists Clean Energy Intern May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups Policy Analyst August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

EXHIBIT
STF-PIA-21

Exhibit MG-2: Georgia Power's response to data request STF-GS-1-1 in the 2023 IRP Update (Docket No. 55378)

STF-GS-1-1

Question:

Has the Company evaluated the use of Battery Energy Storage Systems (BESS) to reduce, defer, or eliminate the need for the transmission upgrades identified in the Updated IRP? If so, please provide that evaluation and explain why BESS were not selected. If the Company has not conducted that evaluation, please explain why not.

Response:

Please refer to the Company's response to STF-DEA-4-15.

The Company did not study Battery Energy Storage Systems ("BESS") as options to reduce, defer, or eliminate the transmission upgrades identified in the 2023 IRP Update to facilitate the delivery of power from the proposed Plant Yates combustion turbines.

Exhibit MG-3: Georgia Power's response to data request STF-GDS-4-7.e. in the 2022 IRP (Docket No. 44160)

e. Alternative solutions such as energy storage or distributed energy resources have not been considered yet for various reasons. Some projects such as the Klondike switch replacement, are relatively inexpensive and easy to accomplish, so no such alternative is needed. For the identified strategic projects (second Heard County – Tenaska 500 kV line and the new Lagrange – North Opelika 230 kV line), the magnitude of storage or DER that would be needed makes those options untenable. The solutions for the other identified constraints are still under review. Other strategic solutions may replace some of the listed projects, and energy storage, DER, and operating guides will be considered in due time, before the listed projects are approved and budgeted.

Exhibit MG-4: Georgia Power's responses to data requests STF-GS-1-8 and STF-GS-1-9 in the 2023 IRP Update (Docket No. 55378)

STF-GS-1-8

Question:

As a follow-up to the STF-JKA-4-5 question about discussing non-firm, interruptible, or lower service quality options with new customers, has the Company evaluated demand response programs that would compensate those customers for curtailing their load, particularly during the generation or transmission system contingency events that triggered a need for upgrades in the Transmission Screening Analysis? If so, please discuss that evaluation. If not, please explain why the Company has not conducted that analysis.

Response:

The Company is proposing a new Curtailable Load program, which will compensate customers for curtailing load during periods of extreme supply and demand conditions. The customer payment will be directly linked to the capacity value provided by the potential demand reduction.

STF-GS-1-9

Question:

As a follow-up to the STF-JKA-4-5 question about evaluating non-firm, interruptible, or lower service quality options with new customers, has the Company spoken with new customers about an option for potential reductions in interconnection costs or rates from deploying customer-sited battery storage or demand response resources? If so, please describe those discussions. If not, please explain why the Company has not offered that option.

Response:

Yes, the Company makes potential customers aware of rate options and programs available to them, including the Real Time Pricing rate. The Company also has current demand response programs and is proposing three new DER and DR customer programs as part of this IRP Update to enable both new and existing customers to receive credit for providing system value from customer-sited resources.

Qualifications of Robert R. Stephens

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Southern Illinois University at Carbondale in 1984 with a Bachelor of Science degree in Engineering. During college, I was employed by Central Illinois Public Service Company in the Gas Department. Upon graduation, I accepted a position as a Mechanical Engineer at the Illinois Department of Energy and Natural Resources. In the summer of 1986, I accepted a position as Energy Planner with City Water, Light and Power, a municipal electric and water utility in Springfield, Illinois. My duties centered on integrated resource planning and the design and administration of load management programs.

From July 1989 to June 1994, I was employed as a Senior Economic Analyst in the Planning and Operations Department of the Staff of the Illinois Commerce Commission. In this position, I reviewed utility filings and prepared various reports and testimony for use by the Commission. From June 1994 to August 1997, I worked as an advisor to one of the Commissioners. In this role, I provided technical and policy analyses on a broad spectrum of issues related to the electric, gas, telecommunications and water utility industries.

In May 1996, I graduated from the University of Illinois at Springfield with a Master of Business Administration degree.

In August 1997, I joined Brubaker & Associates, Inc. as a Consultant. Since that time, I have participated in the analysis of various utility rate and restructuring matters in several states and the evaluation of power supply proposals for clients. Over time, I advanced to my current position.

The firm of Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients, including large industrial and institutional customers, some utilities, and on occasion, state regulatory agencies. More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate, feasibility, economic and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services; and provide technical support to legislative activities.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-BAI Data Request Set No. 1

STF-BAI-1-5

Question:

Please provide any revenue impact estimates prepared by the Company resulting from the Company's standard load growth sensitivity scenario (see page 19 of 2025 IRP Main Document for definition).

Response:

The Company has not prepared revenue impact estimates for any of the scenarios.

Contact: Jeff Grubb

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

GEORGIA POWER COMPANY
DOCKET NO. 55378

Data Request No. STF-DEA-3-6

BASIS FOR THE ASSERTION THAT THE INFORMATION SUBMITTED IS A TRADE SECRET

As part of Georgia Power Company's 2023 Integrated Resource Plan Update filed in Docket No. 55378 ("2023 IRP Update"), Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission its response to STF-DEA-3-6 ("Response"). In the Response, the Company has provided forward-looking estimates of revenues, loads, and costs for specific capacity projects. All of such information (the "Information") constitutes trade secret information of Southern Company, Georgia Power, and its affiliates and is therefore protected from public disclosure under Commission Rule 515-3-1-.11.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains detailed data related to the Company's load and revenue forecast in addition to the estimated costs for capacity, financing, capital costs, unit, and operation assumptions. Disclosure of the Information would provide extensive insight into the Company's projected unit operations. If revealed to the public, a generation wholesaler, power marketer, or original equipment manufacturer could use the Information to arbitrarily tailor proposals with the intention of pricing products and services according to the Company's expected costs, which could undermine the Company's ability to procure the best cost products and services for customers. Such disclosure could unfairly allow competitors to artificially manipulate the wholesale market and ultimately harm the Company. Lastly, the Company's competitors are generally not required to file similar forecast information and to require the Company to do so would put it at an economic disadvantage.

The Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company Services personnel are granted access to the Information. Those personnel receive access only on a "need to know" basis. Parties outside the Company who have been granted access to the Information, if any, have been required to sign confidentiality agreements with respect to the Information.

Docket No. 55378
Georgia Power Company's 2023 Integrated Resource Plan Update
STF-DEA Data Request Set Number 3

STF-DEA-3-6

Question:

Provide a forecast of upcoming price increases as a result of the inclusion of Plant Vogtle Units 3 and 4 into rate base as well as the new load acquisitions necessary to serve major new load growth.

Response:

Per Commission approval of the Stipulation in Georgia Power's Application to Adjust Rates to Include Reasonable and Prudent Plant Vogtle Units 3 and 4 Costs in Docket No. 29849, the base rate change will result in an increase of approximately 5% for the average retail customer, which translates to $8.95 per month for a typical residential customer using an average of 1,000 kWh/month. This base rate change will occur the month following the commercial operation date ("COD") of Plant Vogtle Unit 4. Based on the current schedule, rates would change April 1, 2024.

All else being equal, the Company expects that the projected revenues associated with incremental load from known new customer projects, which necessitate the additional capacity requested in the 2023 IRP Update, will fully offset the costs of those resources requested in the 2023 IRP Update and put downward pressure on overall retail rates. Please note, the projected revenues provided are preliminary estimates at this point in time and may differ from future revenues. See TS STF-DEA-3-6 Attachments A-I for additional information.

Contact: Jeff Grubb

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-BAI Data Request Set No. 1

STF-BAI-1-8

Question:

Please explain if the Company anticipates that the increased revenue requirement resulting from resource additions included in the MG0 scenario will be less than increases in revenue resulting from the Company's load growth in the Company's MG0 scenario. If the answer is in the affirmative, please provide any calculations or workpapers prepared by the Company supporting this assertion in Excel format with all formulae and links intact.

Response:

The Company does not have an analysis comparing the revenue requirements for the generic generation resource additions in the MG0 scenario to the revenue forecast associated with the MG0 scenario load growth. For large load customers, the Company is following the direction of the Commission's Order Approving Revisions to Georgia Power Company's Rules and Regulations and does anticipate that incremental revenue requirements associated with serving large load customers will be covered by the revenues collected from those customers.

Contact: Jeff Grubb

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-BAI Data Request Set No. 1

STF-BAI-1-6

Question:

Please provide any presentations prepared by either Georgia Power or its parent company, Southern Company, since January 1, 2023, comparing its billing rates to other investor-owned utilities.

Response:

Please see STF-BAI-1-6 Attachment A TRADE SECRET, STF-BAI-1-6 Attachment B, and STF-BAI-1-6 Attachment C TRADE SECRET. These attachments reflect Georgia Power's data only.

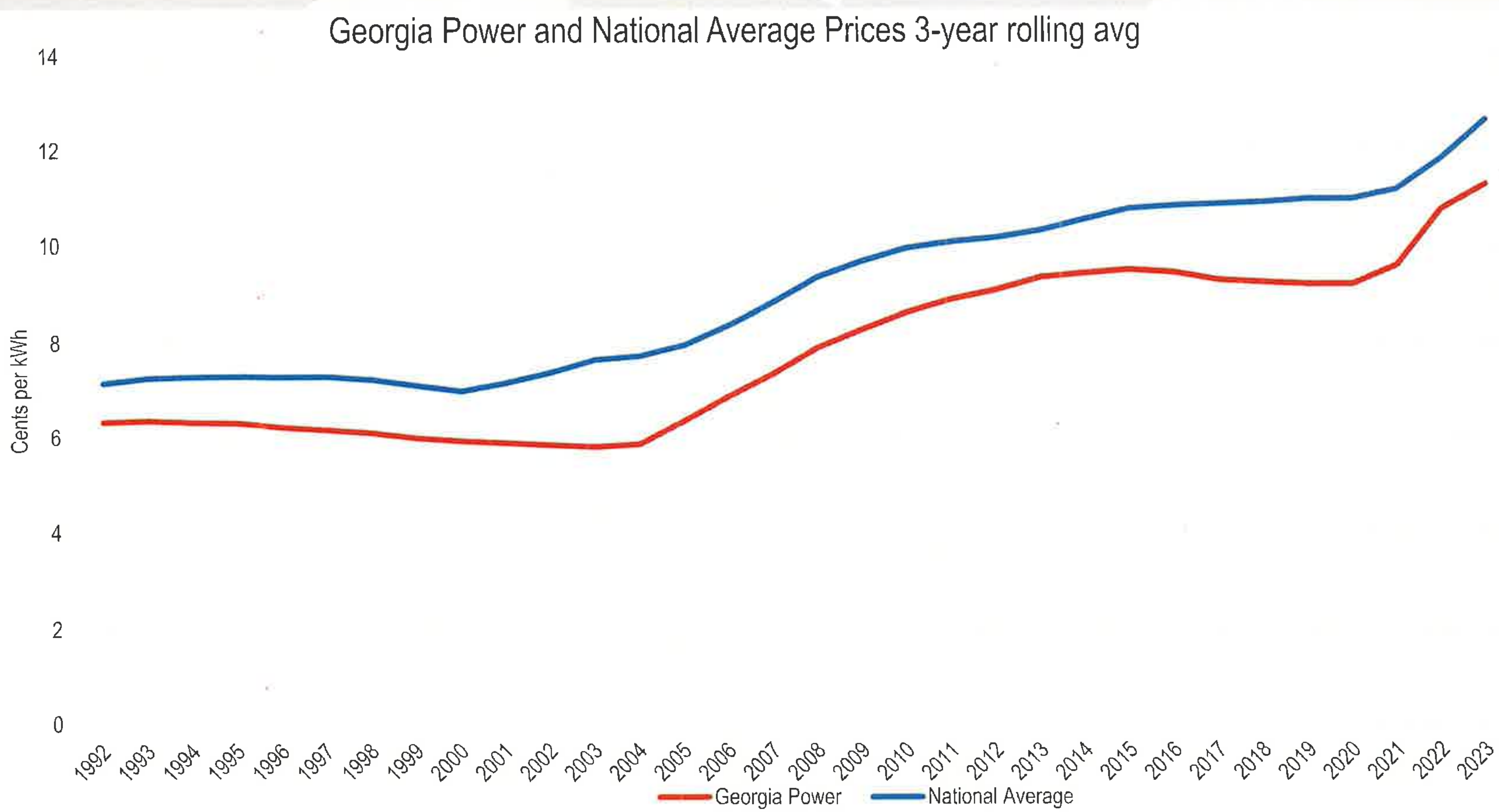
STF-BAI-1-6 Attachment B

Southern Company

Georgia Power Price Trends

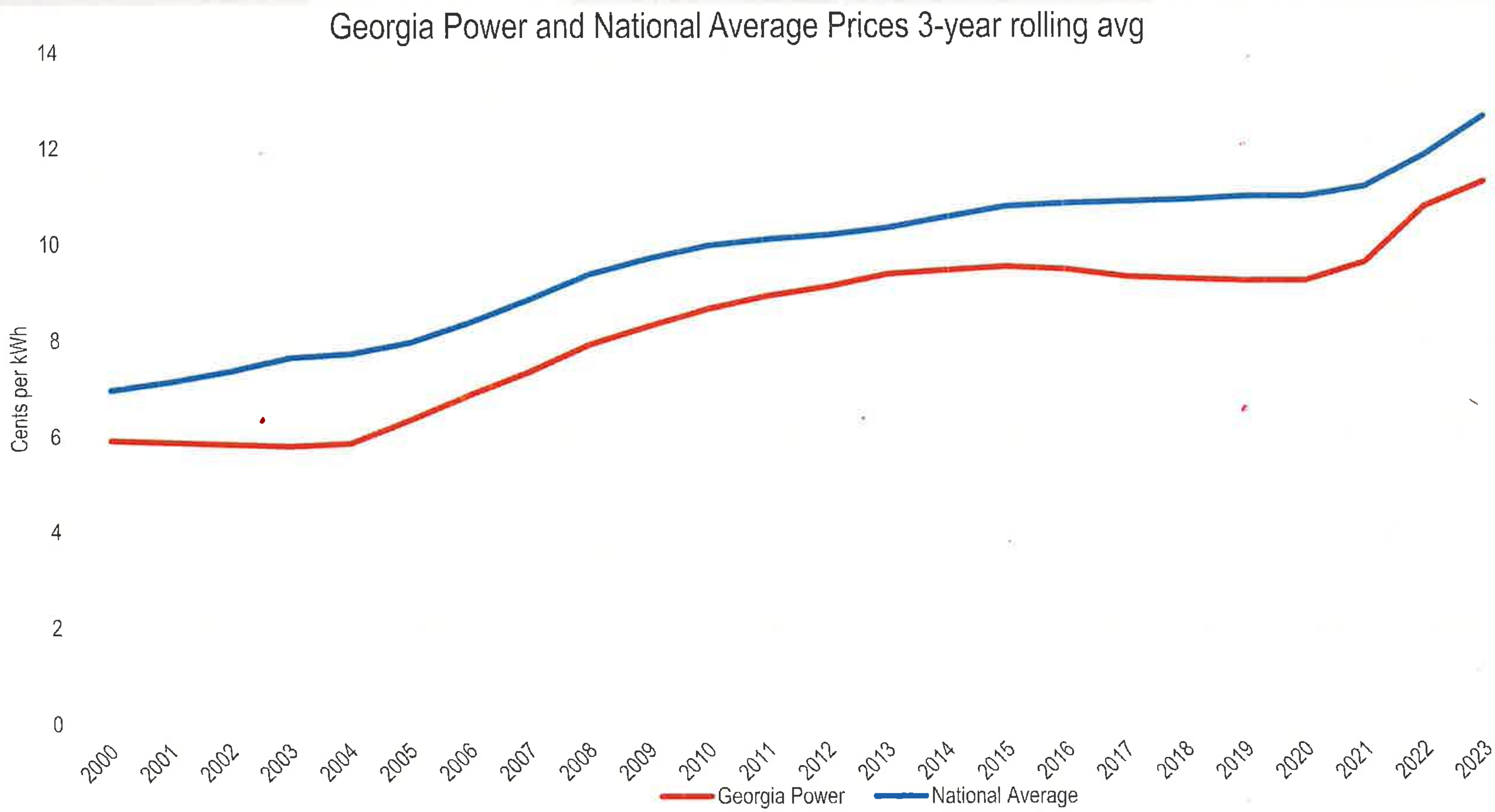
STF-BAI-1-6 Attachment B

Georgia Power has Maintained Prices Below the National Average



STF-BAI-1-6 Attachment B

Georgia Power has Maintained Prices Below the National Average



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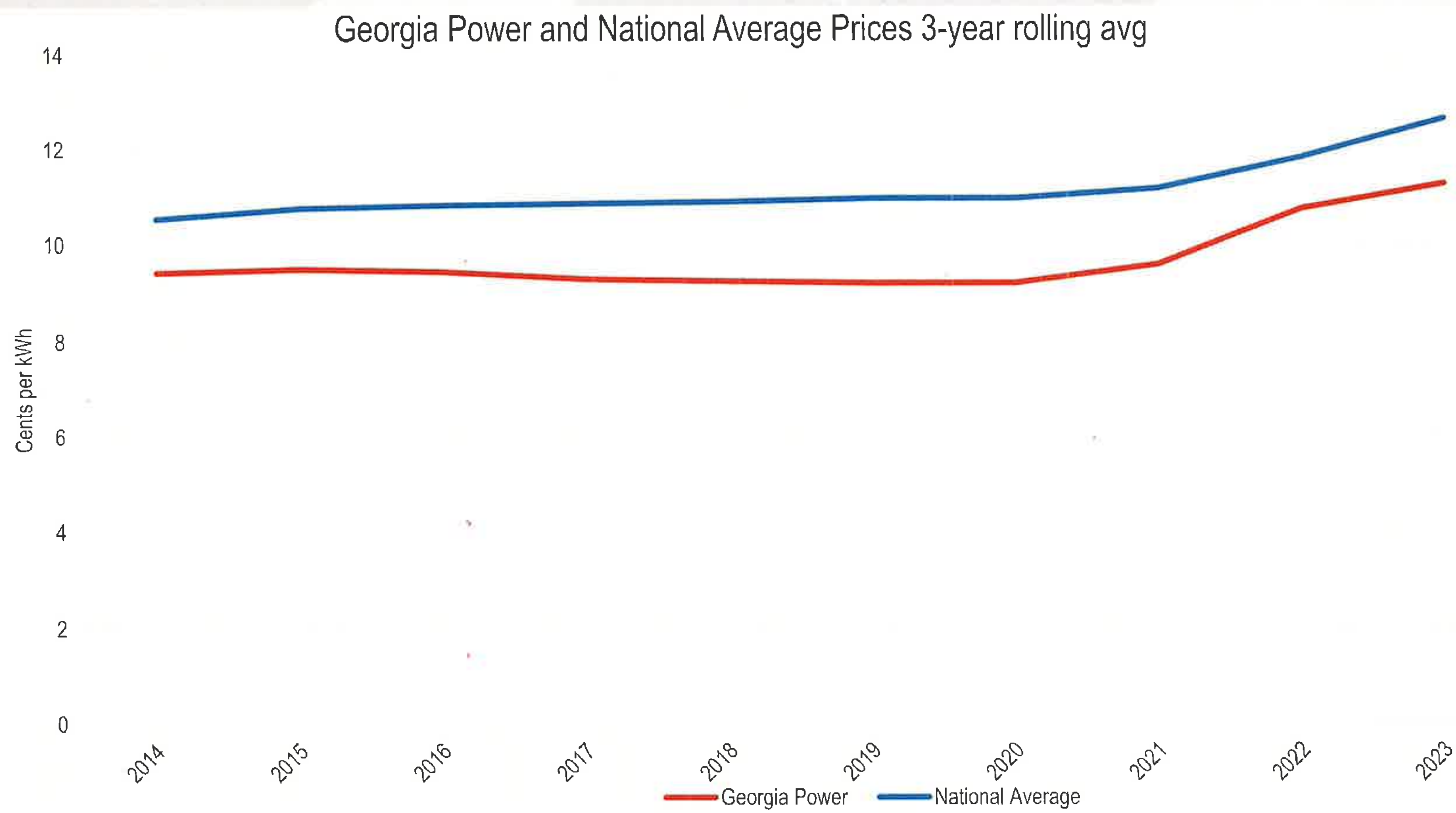
Georgia Power has Maintained Prices Below the National Average



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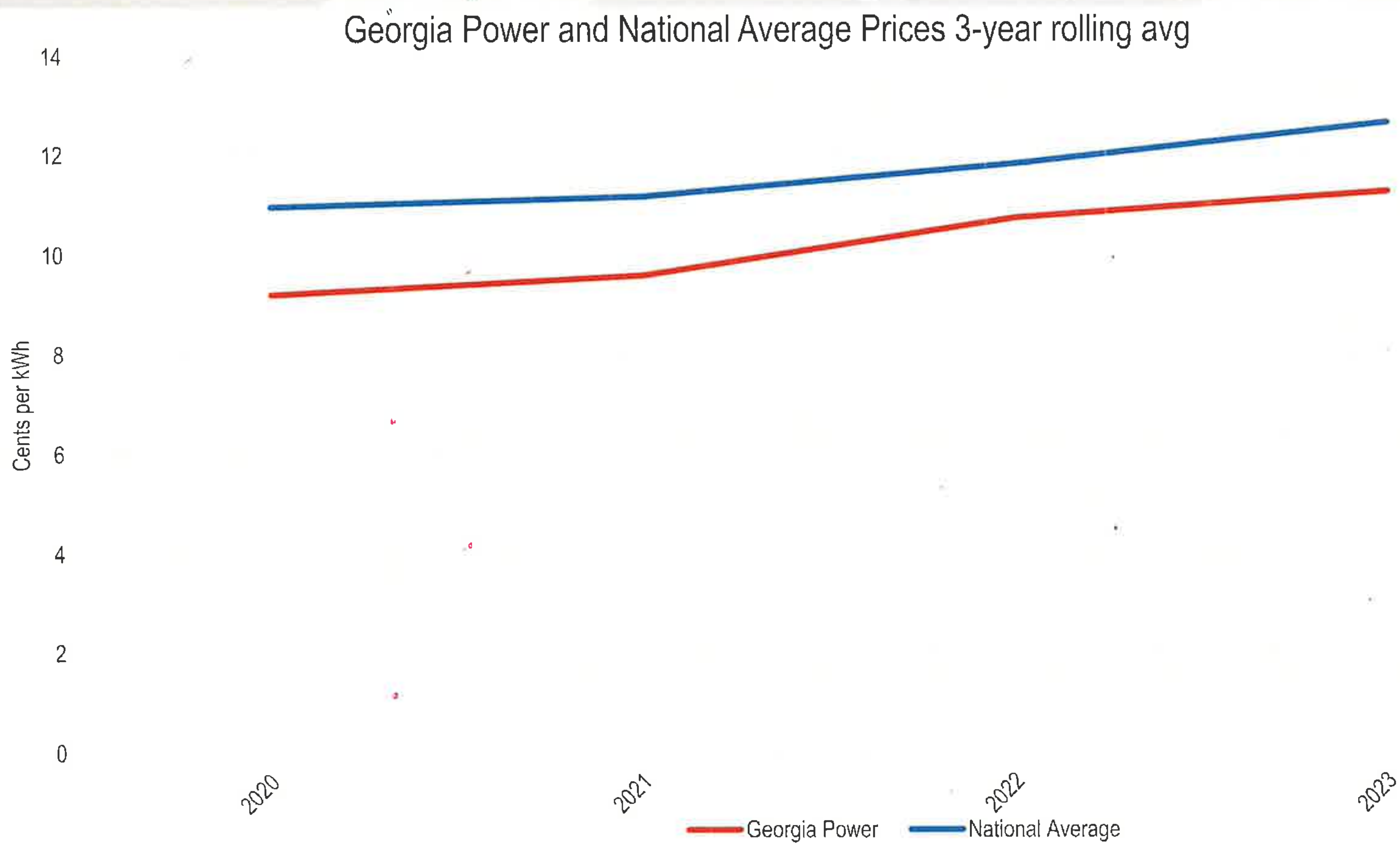
Georgia Power has Maintained Prices Below the National Average



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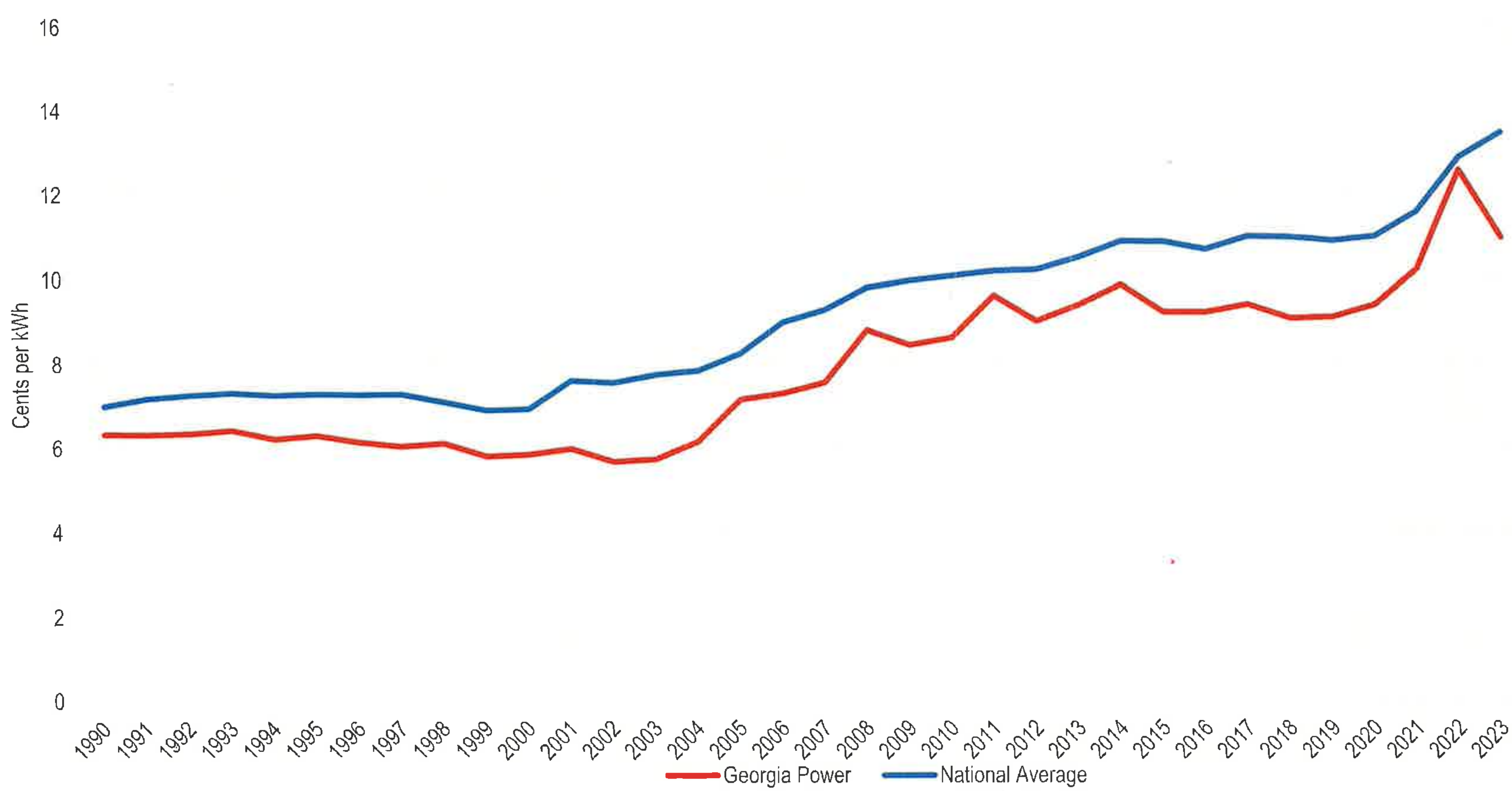
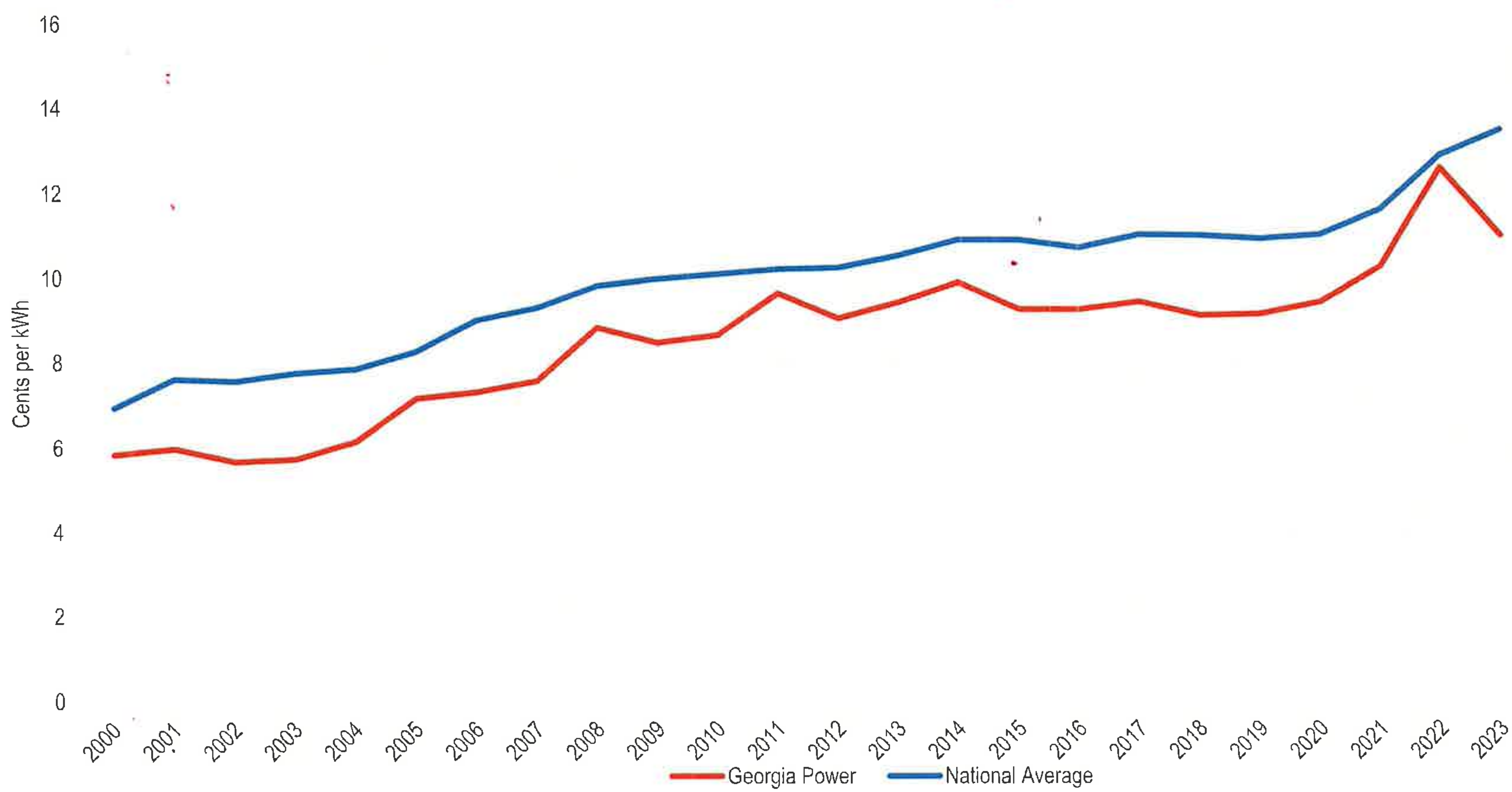


Available to share externally

STF-BAI-1-6 Attachment B

Georgia Power has Maintained Prices Below the National Average



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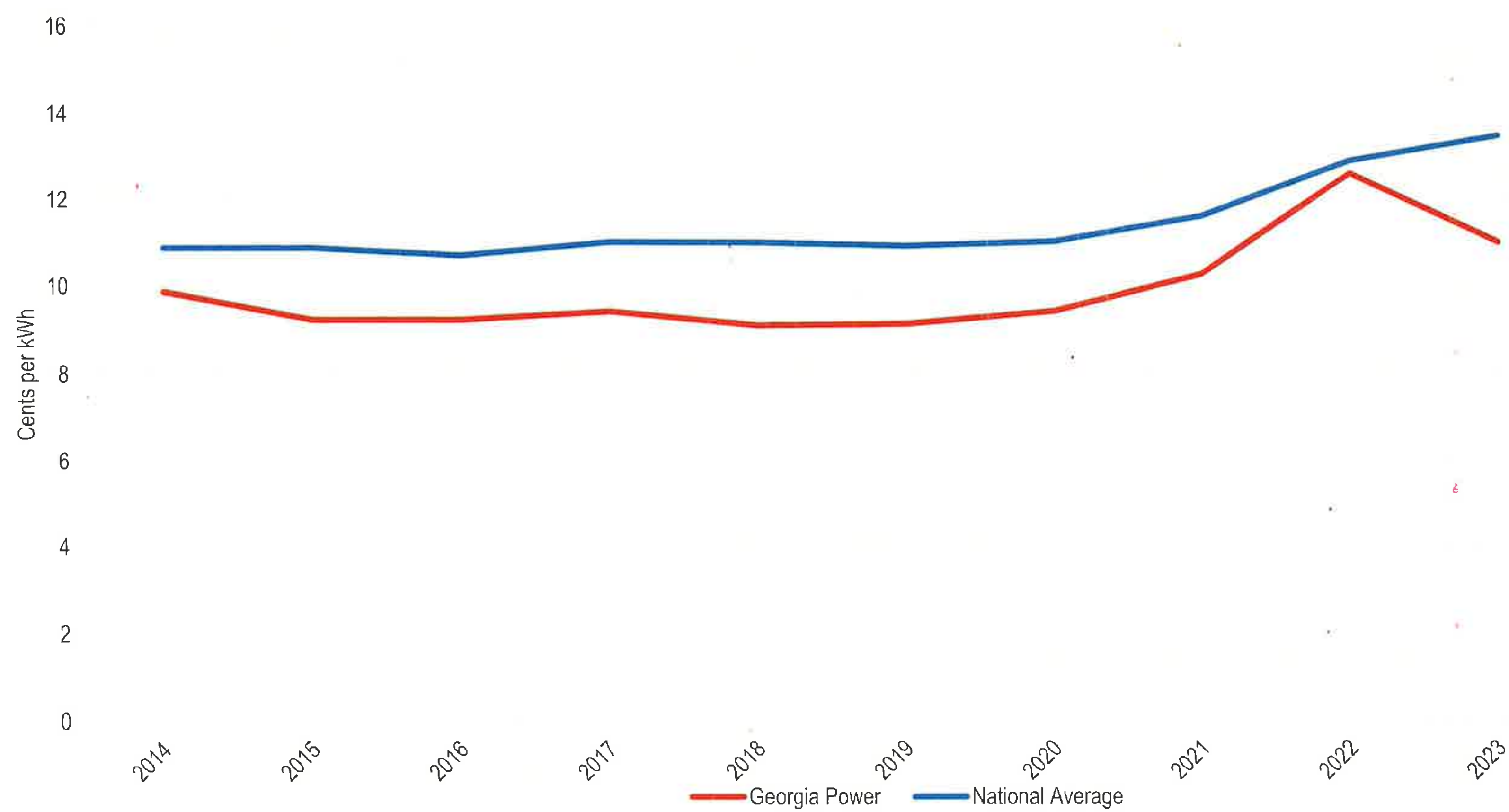

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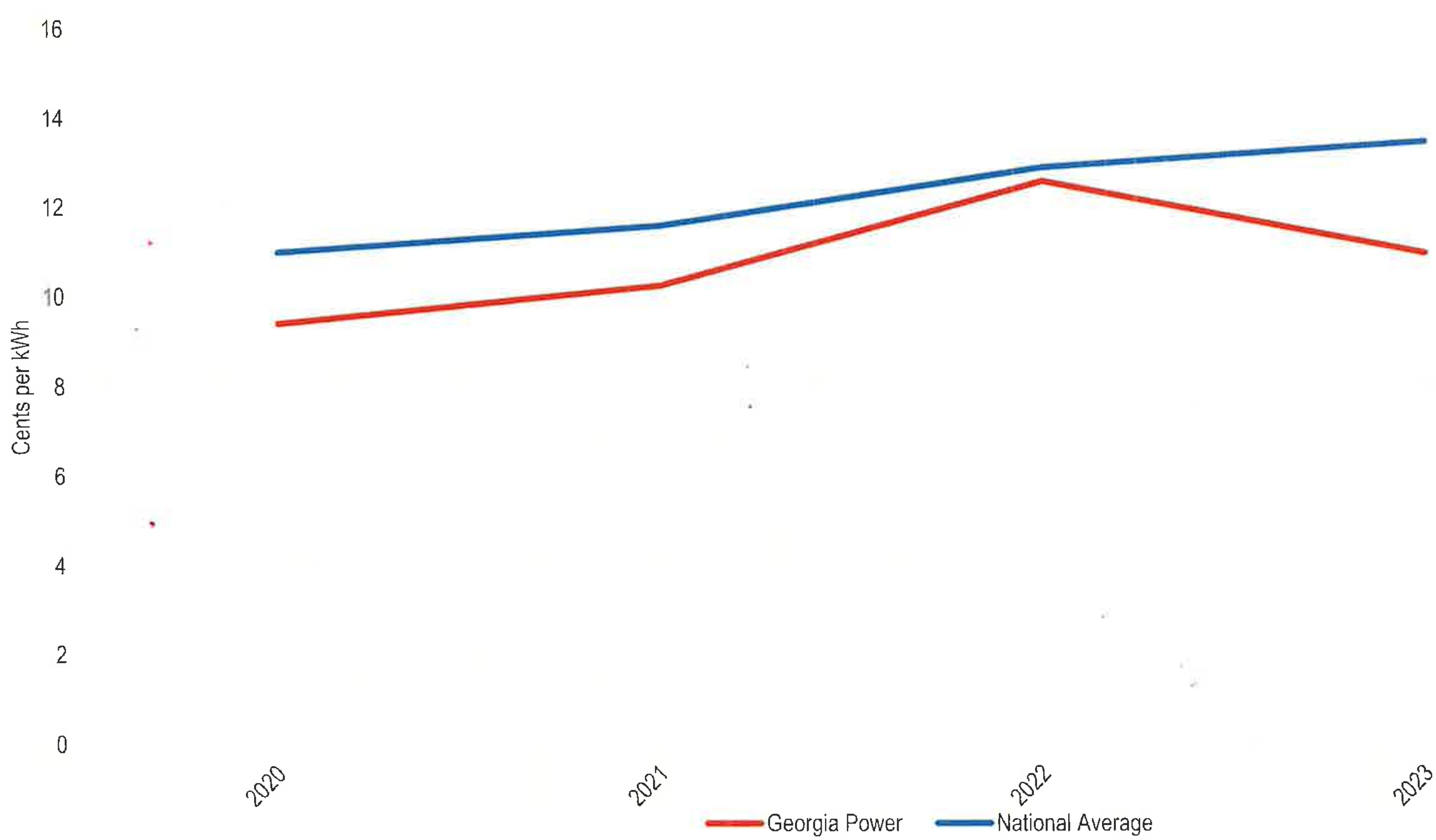

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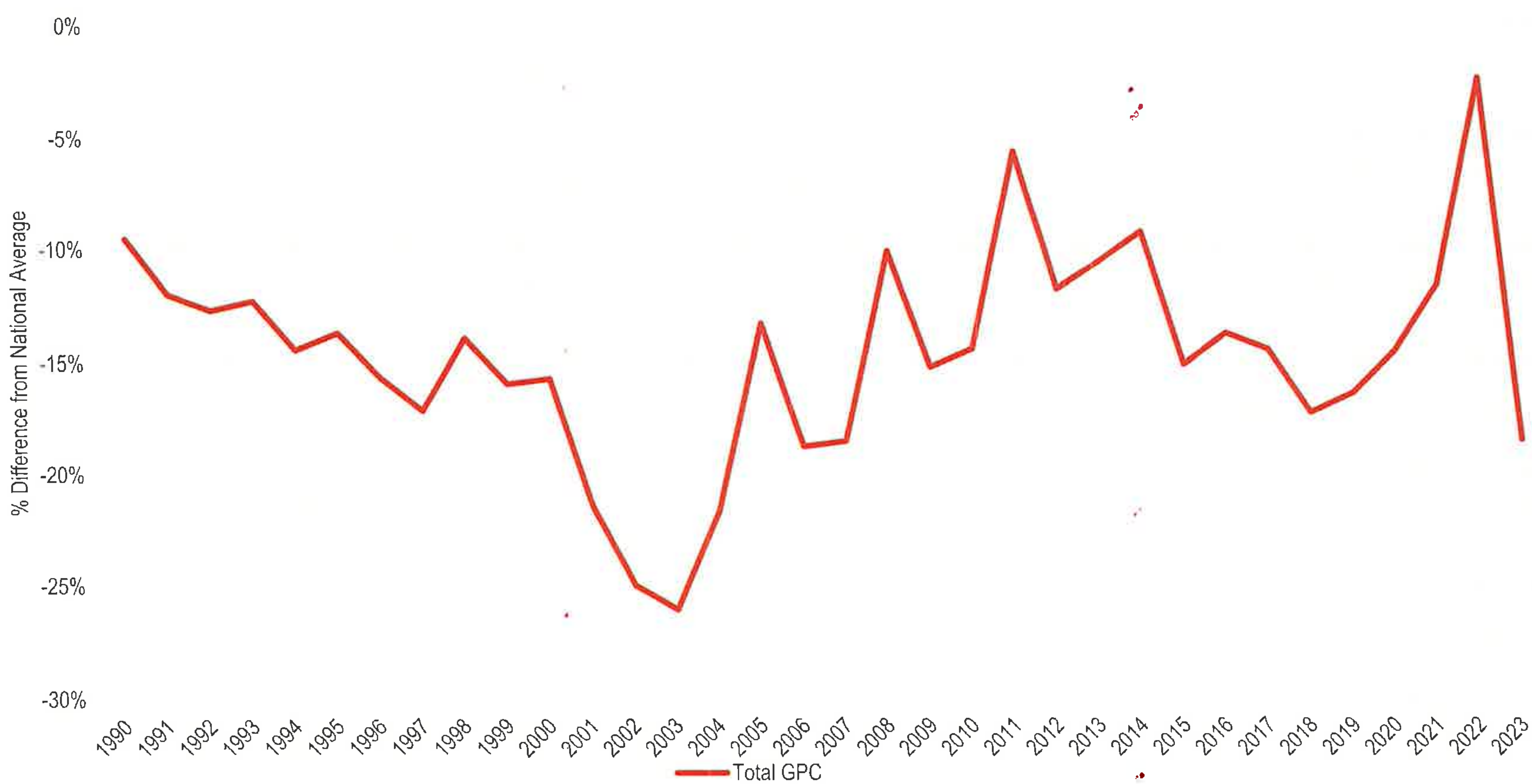
Georgia Power has Maintained Prices Below the National Average



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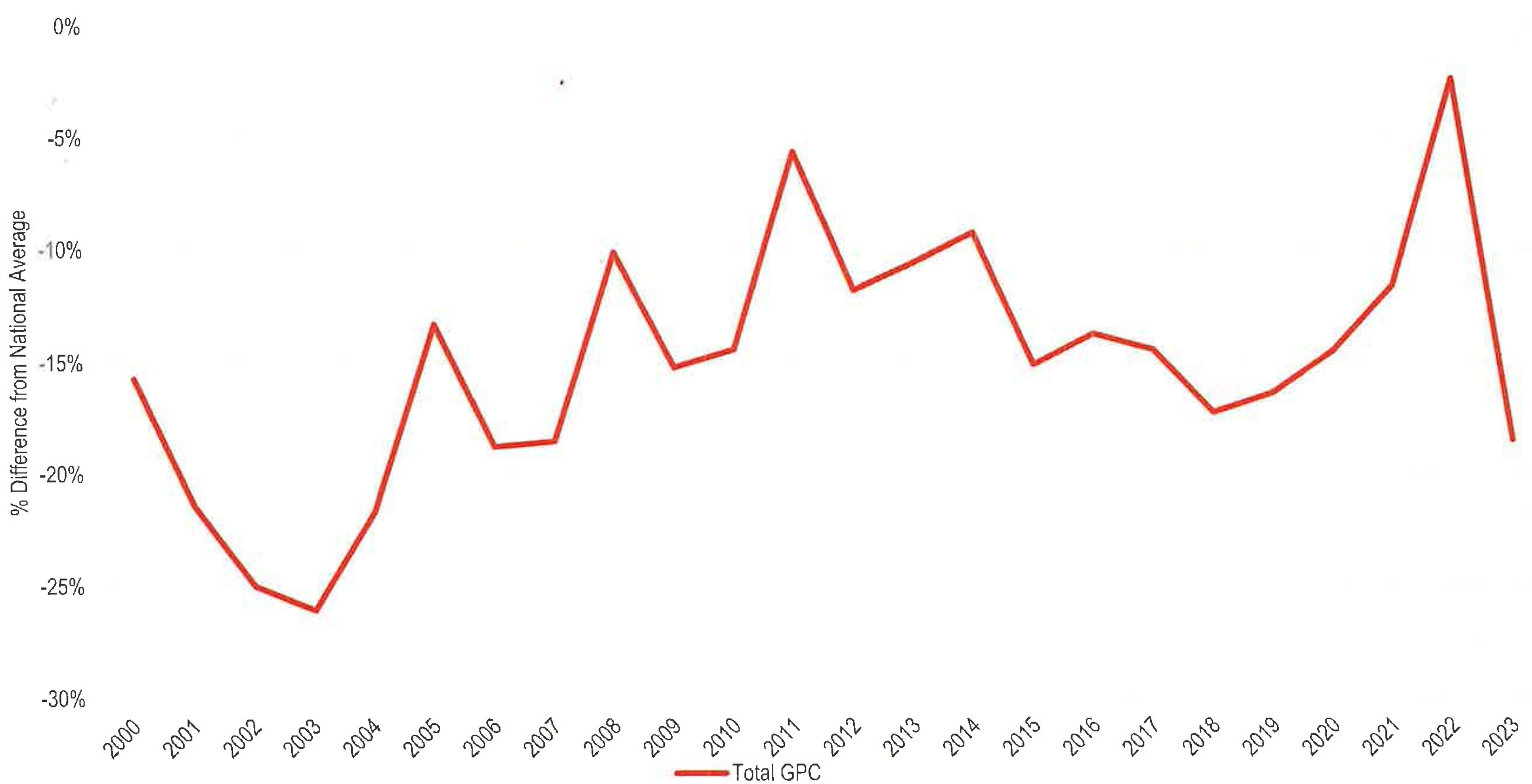
Georgia Power has Maintained Prices Below the National Average



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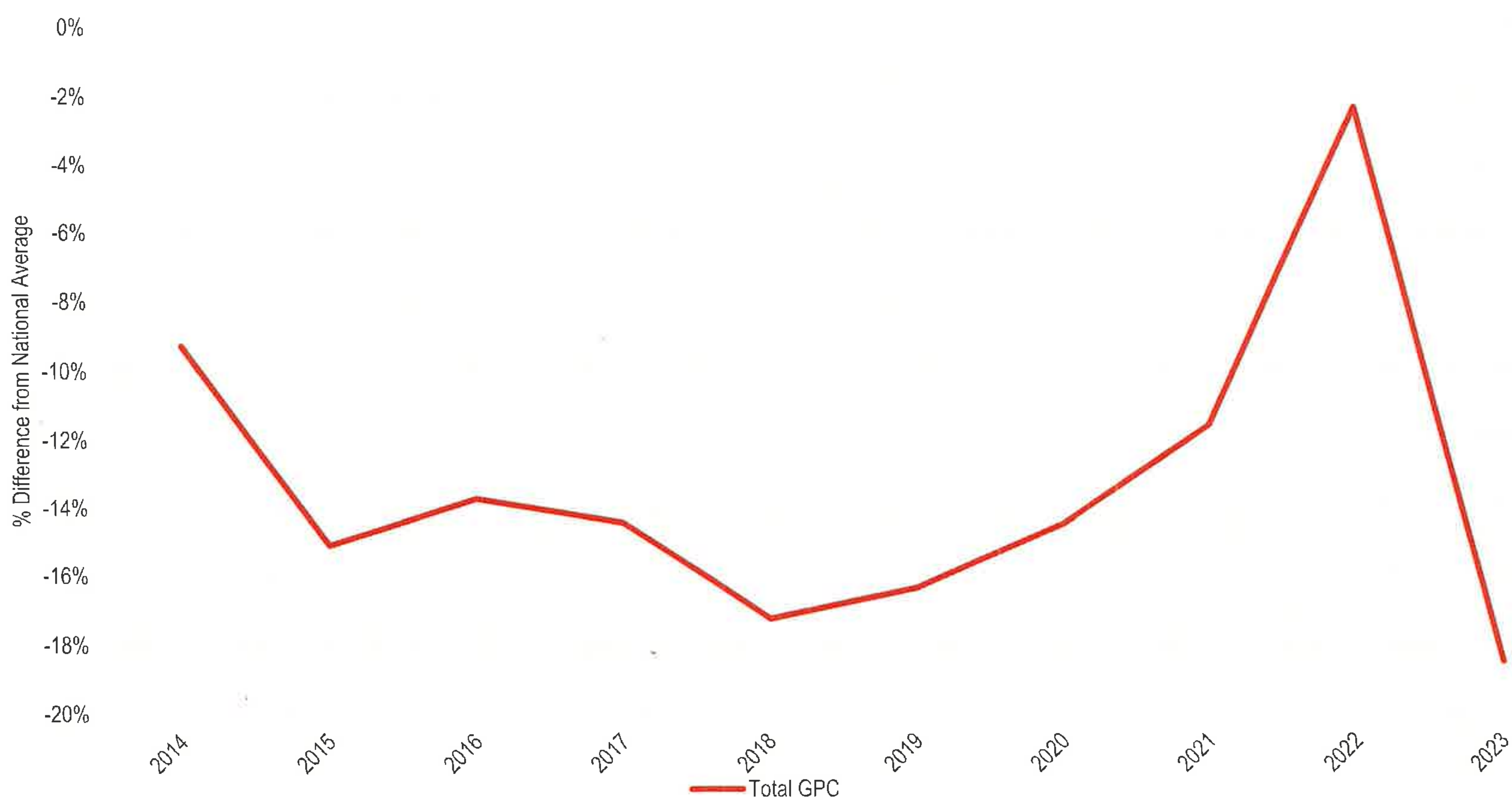
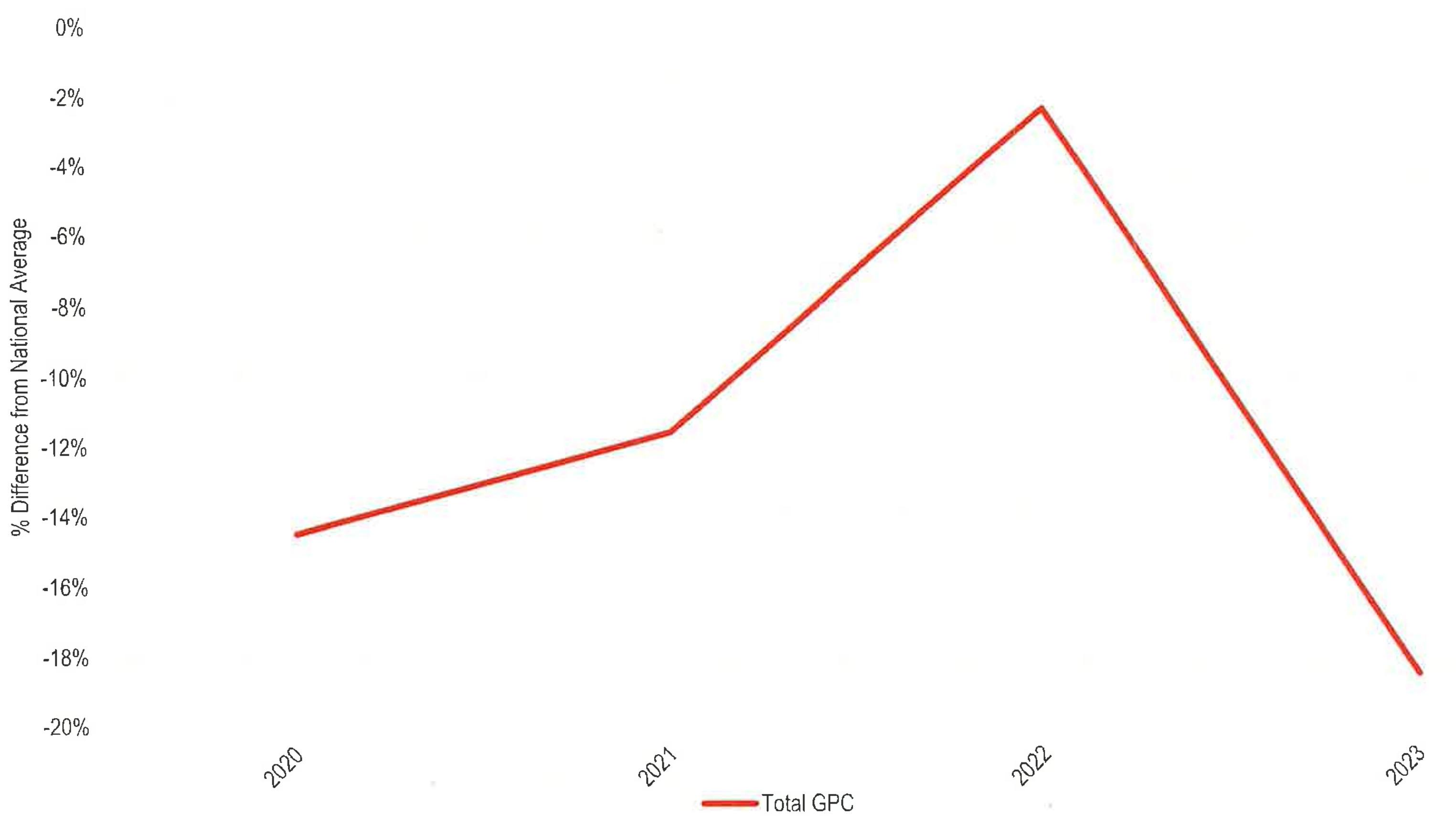
Georgia Power has Maintained Prices Below the National Average



STF-BAI-1-6 Attachment B

Georgia Power has Maintained Prices Below the National Average



STF-BAI-1-6 Attachment B

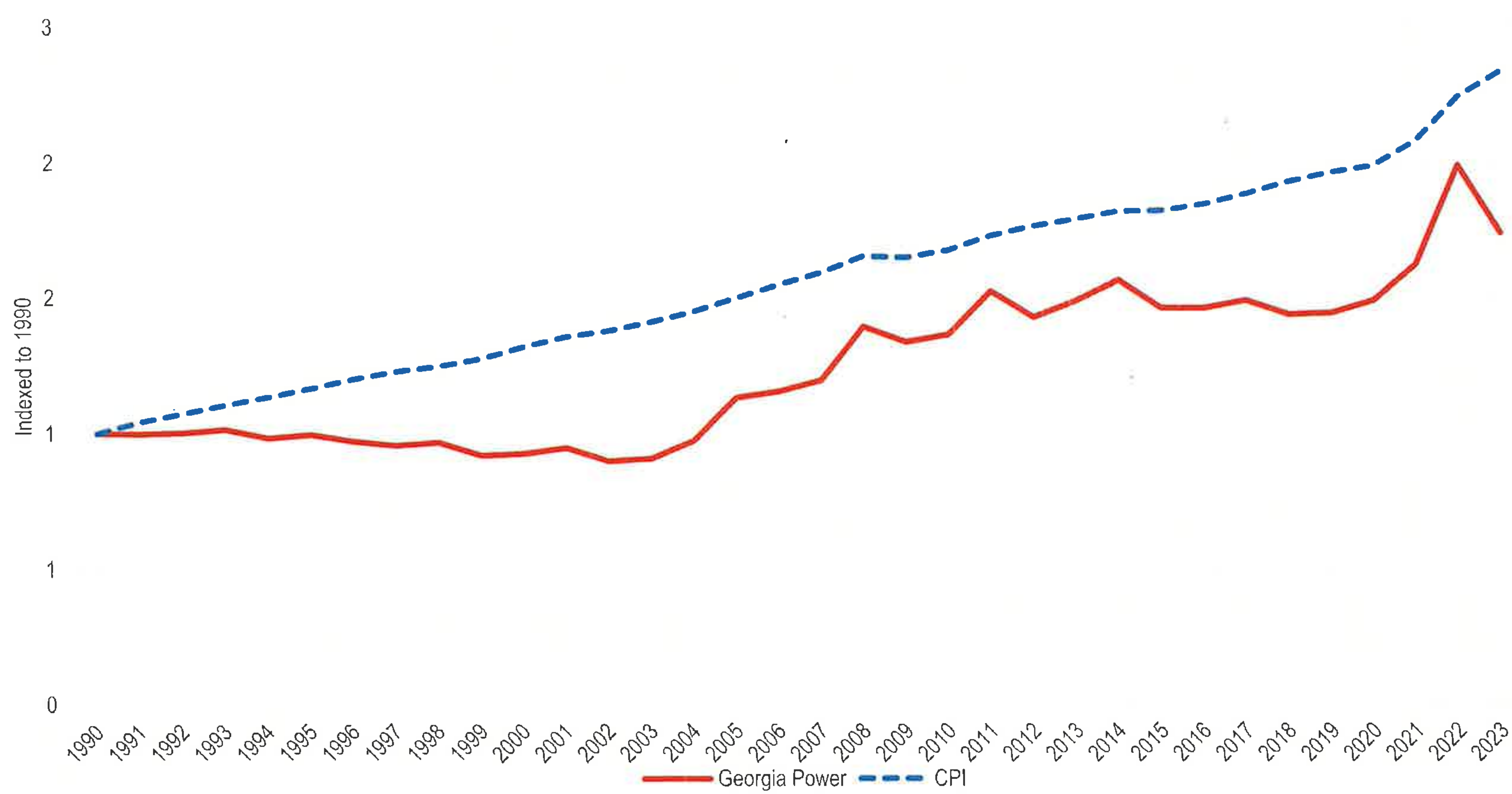
Southern Company

Retail Price vs. Inflation Trends

STF-BAI-1-6 Attachment B

Historical Residential Price vs. Consumer Price Index

Georgia Power prices are EIA 861 data (revenue / KWh) vs the Bureau of Labor Statistics' consumer price index



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Historical Residential Price vs. Consumer Price Index

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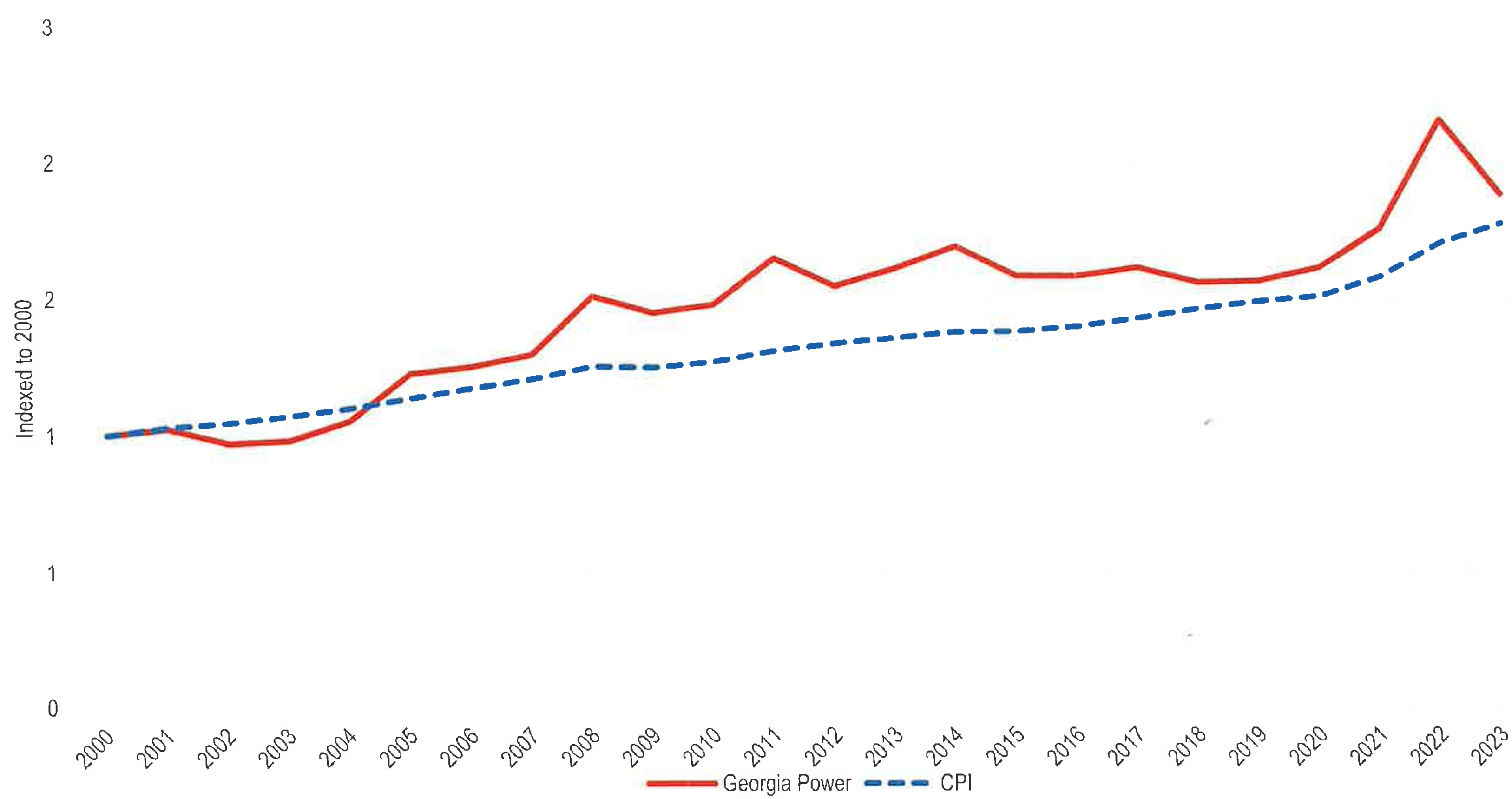
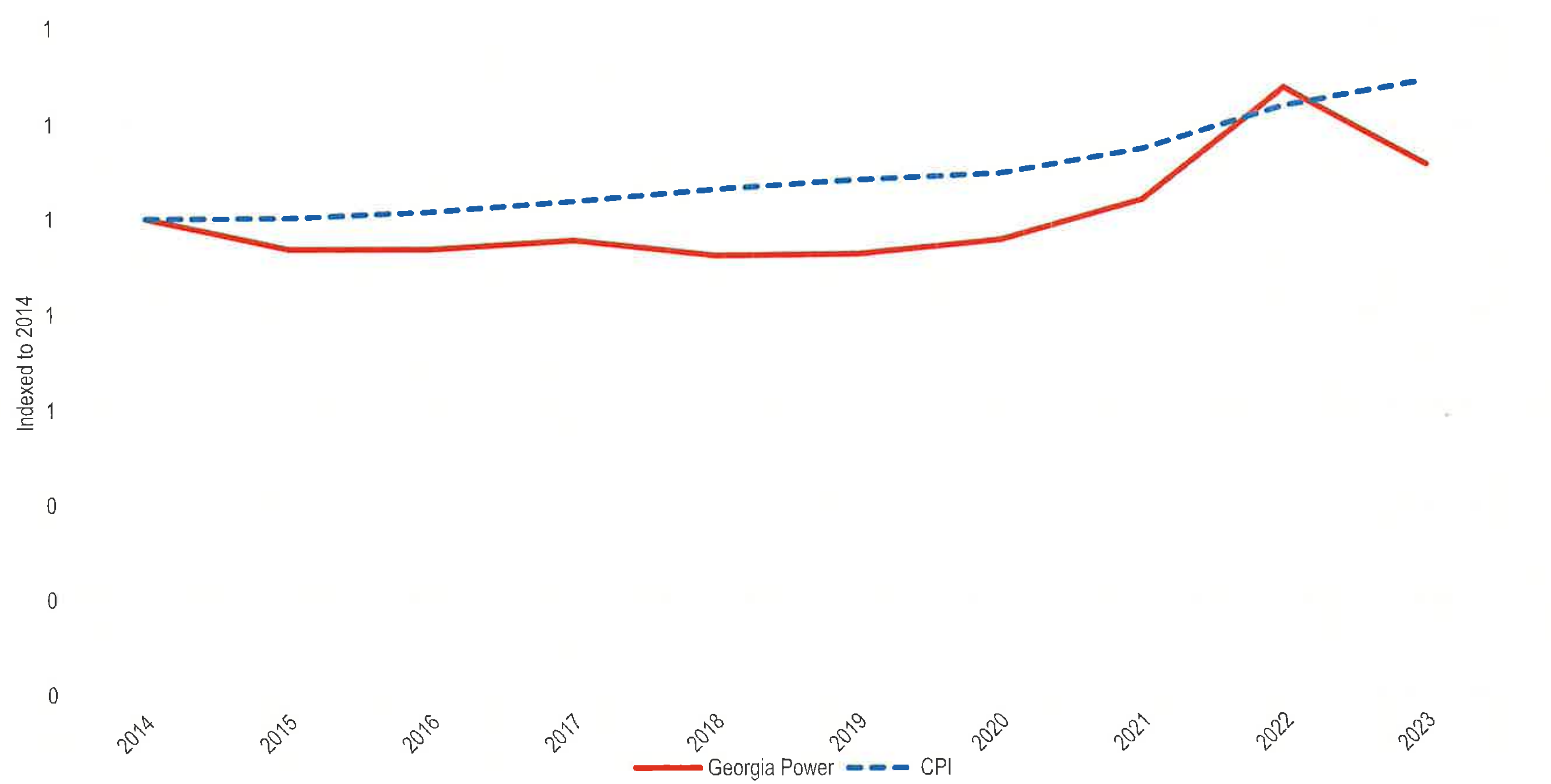


STF-BAI-1-6 Attachment B

Historical Residential Price vs. Consumer Price Index

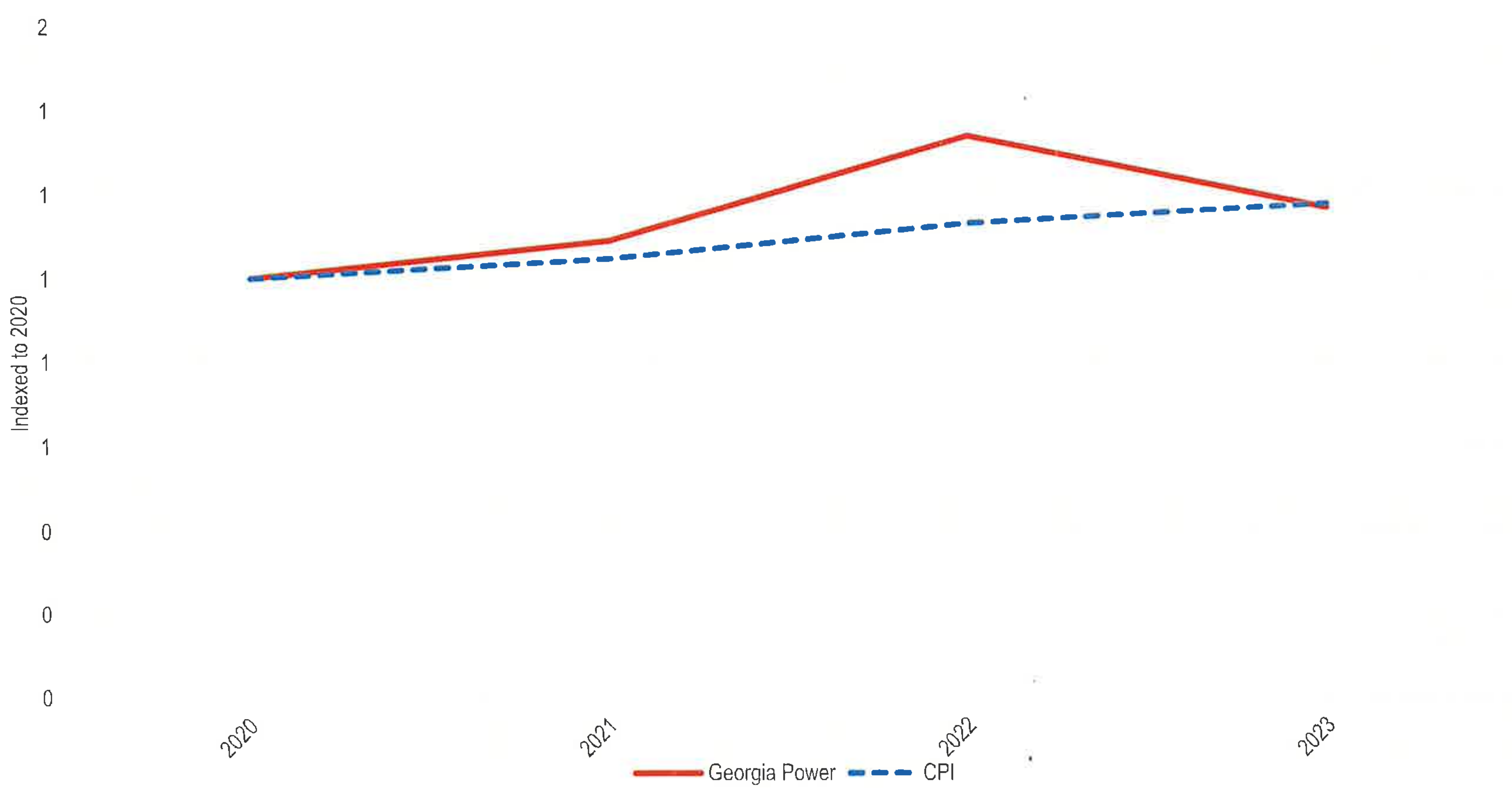
Georgia Power prices are EIA 861 data (revenue / KWh) vs the Bureau of Labor Statistics' consumer price index



STF-BAI-1-6 Attachment B

Historical Residential Price vs. Consumer Price Index

Georgia Power prices are EIA 861 data (revenue / KWh) vs the Bureau of Labor Statistics' consumer price index



Southern Company

2023 EIA Relative Price Position

Executive Summary

- **Based on EIA data, Southern Company's electric price position improved relative to the National and Southeast averages from 2022 to 2023. However, Southern's residential prices remained higher than our Southeast peers for calendar year 2023.**
  - ➢ Southern's average total retail price was 16% below the National average[1] for 2023, compared to 4.4% below in 2022.
  - ➢ Southern's average total retail price was 1.3% below the Southeast regional average[2] for 2023, compared to 13.5% above in 2022. Southern Company's Residential prices were 4.9% above our Southeast peers for calendar year 2023.
- **EIA data does not necessarily equate to the price customers are seeing on their bills.**
  - ➢ For example, there are timing discrepancies between when fuel costs are incurred and when they show up on a customer's bill.
- **The 2023 year-end results return Southern's relative price to historical trends after a volatile 2022 fuel environment.**
  - ➢ In 2022, Southern Company experienced rapid fuel expense increases leading to a sharp degradation in Southern's relative price position.
  - ➢ In 2023, fuel costs declined causing our relative price position to improve and yielding results in line with historical trends.

[1]National Comparison is based on peer IOUs reported on by US Energy information Administration.
[2]Southeast region is based on Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Florida Power & Light, Gulf Power, Tampa Electric, and Virginia Electric & Power.
National and Southeast region peer groups exclude Southern Company.

2023 Relative Price Position – Southern Company and OpCos

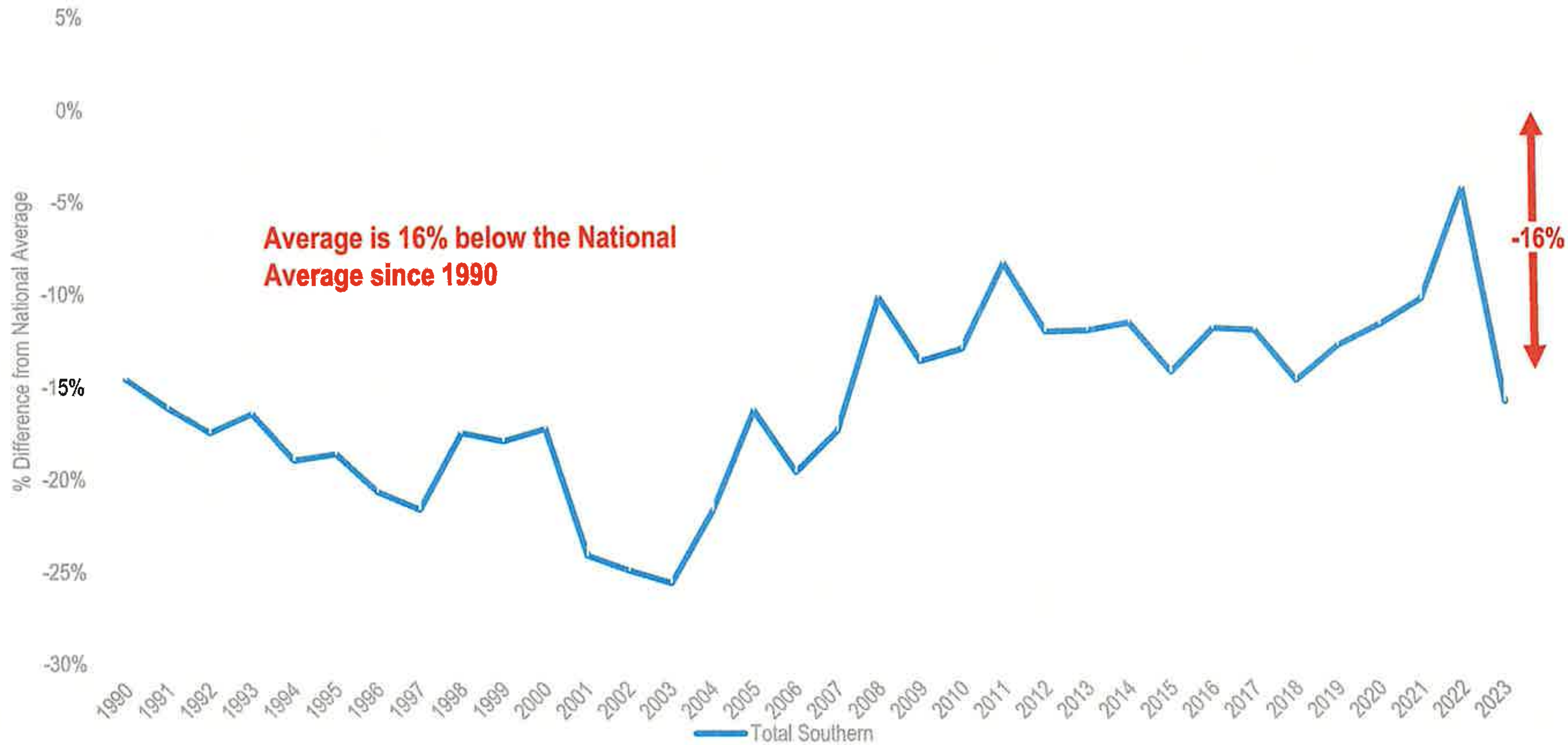
- Southern Company's relative price position for calendar year 2023 was 16% below the National average and 1.3% below Southeast regional peers.
- However, Southern Company's Residential prices were 4.9% above our Southeast peers for calendar year 2023.
- Shown in the table at right are Southern Company's retail prices by customer class and total retail price as reported by EIA for the 12 months ending December 2023.
- The below table shows total retail and R,C, & I prices and relative price position for each electric OpCo.

12-months ending December 2023	Benchmark - Average Prices, ¢/kWh		Total Southern 12-months ending December 2023		
	National Average	Southeast Average	¢/kWh	Difference from National Average	Difference from select Southeast Peers
Residential Price	16.63	14.38	15.09	-9.3%	4.9%
Commercial Price	12.77	10.50	11.87	-7.0%	13.0%
Industrial Price	8.46	6.89	7.08	-16.3%	2.7%
Total Retail Price[1]	13.45	11.45	11.31	-16.0%	-1.3%

12-months ending December 2023	REDACTED			Georgia Power			REDACTED		
	REDACTED	REDACTED	REDACTED	¢/kWh	Difference from National Average	Difference from select Southeast Peers	REDACTED	REDACTED	REDACTED
Residential Price	REDACTED	REDACTED	REDACTED	14.62	-12.1%	1.7%	REDACTED	REDACTED	REDACTED
Commercial Price	REDACTED	REDACTED	REDACTED	11.05	-13.5%	5.2%	REDACTED	REDACTED	REDACTED
Industrial Price	REDACTED	REDACTED	REDACTED	6.54	-22.7%	-5.1%	REDACTED	REDACTED	REDACTED
Total Retail Price[1]	REDACTED	REDACTED	REDACTED	10.96	-18.5%	-4.3%	REDACTED	REDACTED	REDACTED

[1]Total Southern Retail Price represents total revenues ($) for listed customer classes divided by total sales (kWh) for listed customer classes.

Southern Company Continues to Offer Prices Below the National Average



Southern Company

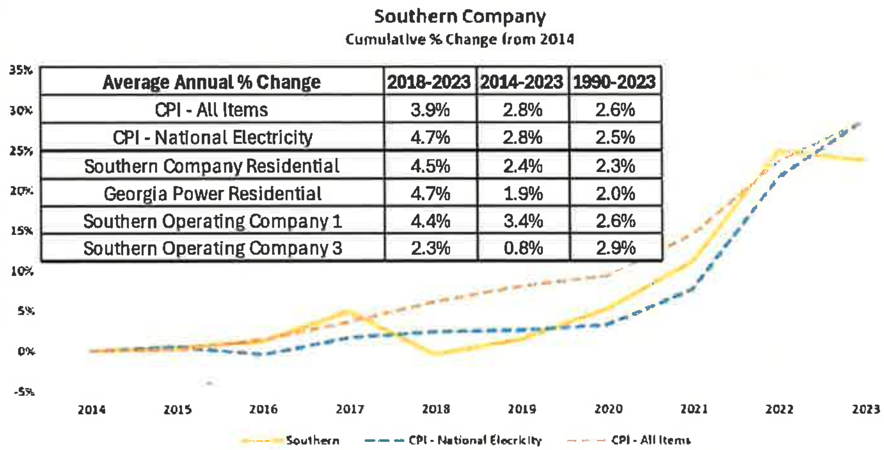
Retail Price vs. Inflation Trends

PUBLIC DISCLOSURE

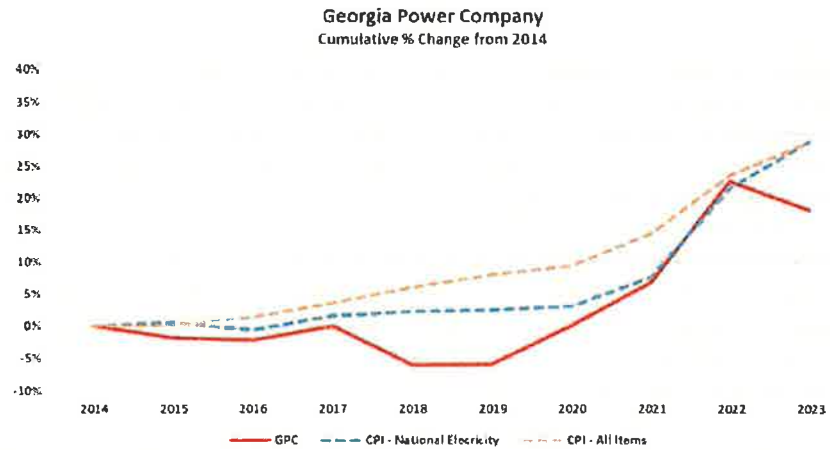
STE-BA-1-6 Attachment A PUBLIC DISCLOSURE

Historical Residential Price vs. Consumer Price Index

Southern prices are EIA 861 data (revenue / kWh) vs the Bureau of Labor Statistics' consumer price index



Average Annual % Change	2018-2023	2014-2023	1990-2023
CPI - All Items	3.9%	2.8%	2.6%
CPI - National Electricity	4.7%	2.8%	2.5%
Southern Company Residential	4.5%	2.4%	2.3%
Georgia Power Residential	4.7%	1.9%	2.0%
Southern Operating Company 1	4.4%	3.4%	2.6%
Southern Operating Company 3	2.3%	0.8%	2.9%



REDACTED

REDACTED

PUBLIC DISCLOSURE

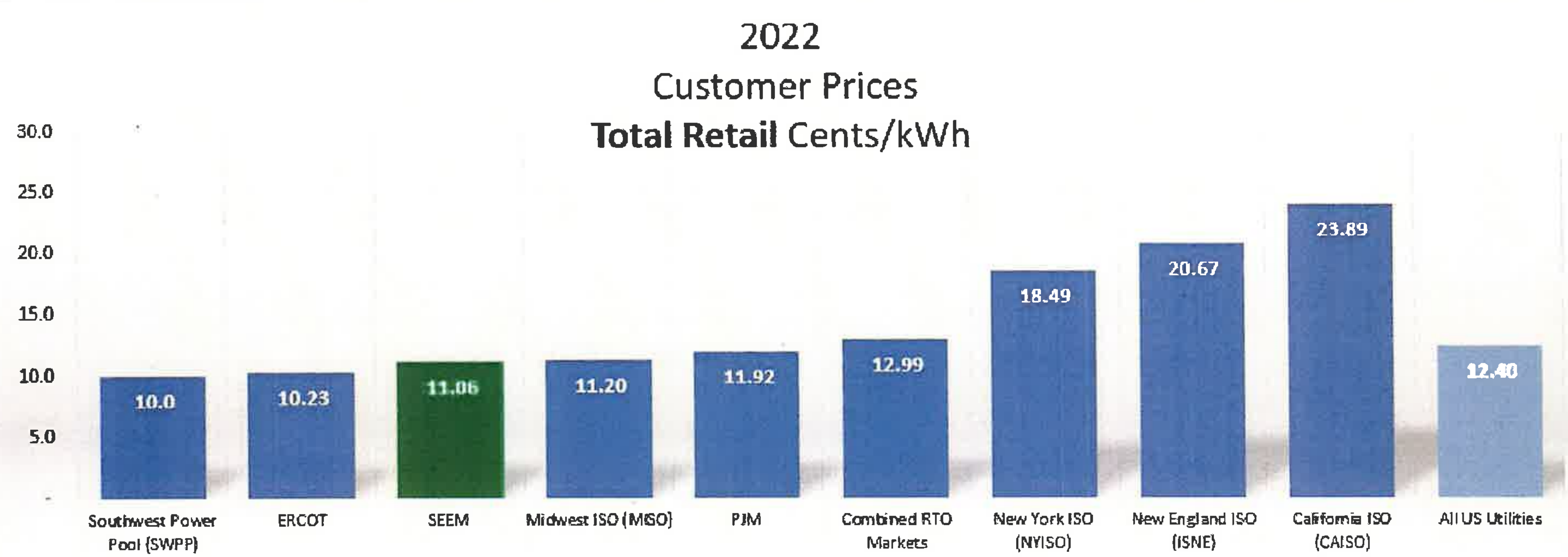
Southern Company

Southeast Energy Exchange Market (SEEM)

PUBLIC DISCLOSURE

STF-BAI-1-6 Attachment A PUBLIC DISCLOSURE

2022 SEEM comparison



Source: DOE EIA Form 861

2023 results will be available in Q42024

PUBLIC DISCLOSURE

Southern Company

Affordability

Source: Customer Service, Customer Experience, System Customer Council

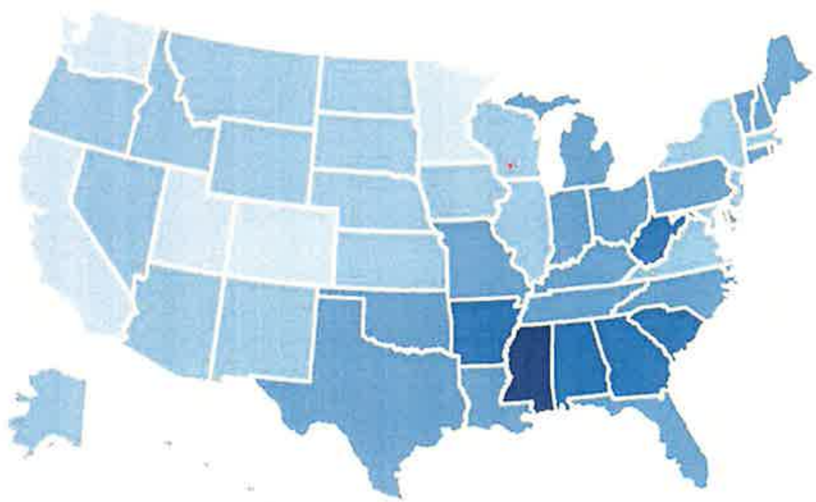
PUBLIC DISCLOSURE

STF-BAI-1-6 Attachment A PUBLIC DISCLOSURE

Combined Electric Demographics

Low Income Cost of Energy as % of Household Income

4%–6% 6%–8% 8%–10% 10%–12% 12%–14%



U.S. Department of Energy - 2018

United States

- Median household income is $74,580
- 12.6% of households fall below the poverty level
- 34% of households have income < $50,000

REDACTED

Georgia

- Georgia's median household income is $72,860
- 12.7% of households fall below the poverty level
- REDACTED REDACTED REDACTED

REDACTED

Source: Energy Assistance Overview Presentation – Customer Service, 2022 Census Data, S&P Global

Bill Affordability Remains a Challenge for LMI Customers

REDACTED

Source: Energy Affordability Update Presentation March 2024 – System Customer Council, JD Power

PUBLIC DISCLOSURE

Strategic Approach

STF-BAI-1-6 Attachment A PUBLIC DISCLOSURE

Affordability
Help alleviate the strain that customers are facing with limited financial resources, causing them to be unable to afford their basic standard of living.

Awareness
Ensure that stakeholders are well informed of Energy Assistance resources and programs that can help.

Accessibility
Enable the sharing of resources with partners to expand access to additional funding.

Assistance
Successfully match LMI customers to assistance to help prevent financial hardship.

Source: Energy Affordability Update Presentation March 2024 – System Customer Council

PUBLIC DISCLOSURE

Southern Company

Appendix

Impact of Fuel on 2022 and 2023 Relative Price Position

- In 2022, Southern Company experienced rapid fuel expense increases leading to a sharp degradation in Southern's relative price position.
  - Beginning in 2021, numerous variables drove an increase in the cost of fuel used for power generation such as geopolitical unrest, global supply chain constraints, which included slower-than-expected gas production coming out of the COVID-19 pandemic, higher than expected domestic demand for natural gas, and an increased demand for LNG-exports. These variables not only drove the cost of natural gas to levels not seen since 2008, but also increased the cost of coal, as its supply (influenced in part by transportation constraints) did not keep pace with increased demand.
  - Weather volatility exacerbated these cost pressures. Higher temperatures in the summer, coupled with lower temperatures in the winter, increased demand for electricity,
- In 2023, fuel costs declined causing our relative price position to improve and yielding results in line with historical trends.
- The accounting for fuel revenues and fuel expense did cause some changes in relative price position between Southern and the National Average in 2022 and 2023 as demonstrated below.

EIA Relative Price Position

Total Revenue →

÷ Total kWh sales

= c/kWh

Southern Company

Fuel Revenue is set to match Fuel Expense on the income statement. (any over/under recovery falls to the balance sheet) Therefore, in 2022, rapid fuel expenses impacted our total revenue (and EIA relative price position) greatly and in 2023 we saw that trend reverse. →

Some Peer Utilities

Fuel Revenue is set to match Fuel Collection (via fuel cost recovery tariffs) on the income statement. (any over/under recovery falls to balance sheet) Therefore, in 2022, rapid fuel expenses had less of an impact on total revenue (and EIA relative price position) for some peers. By 2023, as these costs were being passed through via rates some of our peers' relative price were going up as Southern was coming down.

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-BAI Data Request Set No. 1

STF-BAI-1-2

Question:

Please provide Georgia Power's historical marginal energy cost on an hourly basis for the period 2019-2024.

Response:

Please see STF-BAI-1-2 Attachment for the Southern Company associated interchange energy rate ("AIER") on an hourly basis for 2019-2024. Southern Company AIER represents the marginal energy cost for the electric Operating Companies, including Georgia Power, in the Southern Company Pool.

Contact: Randy Hubbert

Georgia Power Company
Docket Nos. 56002 & 56003
2025 Integrated Resource Plan and 2025 Demand-Side Management Application
STF-BAI Data Request Set No. 1

STF-BAI-1-3

Question:

Please provide the marginal energy cost output derived from the Aurora model for the Company's MG0 scenario (see page 19 of 2025 IRP Main Document for definition) on an hourly basis for the period 2025-2030.

Response:

See STF-BAI-1-3 Attachment TRADE SECRET.