BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER'S FUEL COST RECOVERY (FCR-27) APPLICATION	)))	**Docket No. 56765**

PUBLIC DISCLOSURE

DIRECT TESTIMONY

AND EXHIBITS

OF

MICHAEL S. GOGGIN

On Behalf of the

Southern Alliance for Clean Energy,
Sierra Club,
and Natural Resources Defense Council

April 9, 2026

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1. Introduction

Q. PLEASE STATE YOUR NAME AND JOB TITLE.

A. My name is Michael S. Goggin, and I am the Executive Vice President at Grid Strategies, LLC, a consulting firm based in the Washington, DC, area.

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

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

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am testifying on behalf of the Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION OR OTHER UTILITY REGULATORY BODIES?

A. Yes. I have testified before the Georgia Public Service Commission ("GPSC" or "Commission") in the last five Georgia Power Integrated Resource Plan ("IRP") cases, which were the 2025 full IRP, 2023 IRP Update, and the full IRP filings in 2022, 2019, and 2016. I have also testified before state utility commissions in Arizona, Colorado, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, before the Federal Energy Regulatory Commission ("FERC"), and before the U.S. House Energy and Commerce Committee's Subcommitee on Energy.

Q. CAN YOU PLEASE OUTLINE YOUR TESTIMONY?

My testimony first provides background on how economic dispatch efficiently determines which power plant units operate by dispatching the lowest-cost resources first. That section also explains how uneconomic dispatch, either due to designating higher-cost generators as "must-run" resources or simply using inputs that excessively dispatch higher-cost resources, results in excessive costs for Georgia Power ("the Company") ratepayers.

The bulk of my testimony then presents analysis that identifies $[redacted] million of ratepayer net losses to date (through the end of February 2026) during the three-year historical period for which Georgia Power seeks recovery in this case, June 1, 2023 to May 31, 2026, due to uneconomic dispatch of the Bowen and Scherer coal power plants. These losses occurred because the Company uneconomically dispatched these units, even though the Company's own data show lower-cost resources were available. These total ratepayer losses represent net losses, after factoring in startup costs and other costs in the counterfactual case wherein the unit was shut down and then restarted once system marginal costs were high enough to economically justify its operation, instead of remaining online.

The next section of my testimony then reviews a variety of factors that could result in uneconomic dispatch and recommends solutions to reduce or eliminate these causes of uneconomic dispatch.

Finally, I review how the Company increasing its dependence on gas generation exposes its ratepayers to excessive costs and risks. As a notable example, ratepayers incurred more than $[redacted] million in gas fuel costs for the Company's combined cycle generators alone during the two weeks of Winter Storm Fern, January 23-February 6, 2026. I recommend solutions that would better protect ratepayers from those costs and risks than the Company's proposal to expand financial hedges.

Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?

A. I respectfully recommend that the Commission disallow recovery of the $[redacted] million in net losses that occurred because of imprudent dispatch decisions for the Company's coal fleet. This will protect ratepayers from shouldering these imprudently incurred costs, and more importantly will incentivize the Company to avoid uneconomic dispatch going forward.

To reduce uneconomic dispatch going forward, the Commission should direct the Company to remove persistent biases in inputs into the Company's commitment and dispatch software that result in suboptimal dispatch. I also recommend that the Commission direct the Company to not negotiate coal supply and transportation contracts that include penalties for failing to meet minimum fuel delivery requirements. As explained below, those contract terms can cause the Company to run those plants even when they are not economic, resulting in their excessive and costly operation. In future fuel cost recovery cases, the Commission should also review new or extended fuel supply or transportation contracts to ensure they do not include penalties associated with minimum fuel delivery requirements.

Finally, I recommend that the Commission implement a fuel cost sharing mechanism to incentivize the Company to more effectively manage gas price risk, and account for the risks of gas price volatility and uncertainty when weighing the prudence of the Company increasing its dependence on gas generation.

Q. ARE YOU SPONSORING ANY EXHIBITS FOR YOUR TESTIMONY?

A. Yes, I am sponsoring the following list of exhibits.

Exhibit	**Name**	**Confidentiality**
MG-1	Michael S. Goggin background and qualifications	Public
MG-2	Georgia Power's response to data request STF-PIA-2-3 - Attachment A	Trade Secret
MG-3	Georgia Power's response to data request STF-PIA-2-2 - Attachment	Trade Secret
MG-4	Georgia Power's response to data request STF-PIA-2-6 - Attachment	Trade Secret
MG-5	Georgia Power's response to data request STF-PIA-2-3 - Attachment C	Trade Secret
MG-6	Georgia Power's response to data request STF-PIA-1-13	Public
MG-7	Georgia Power's response to data request STF-PIA-1-3	Public

2. Background on economic dispatch

Q. HOW DO UTILITIES TYPICALLY CHOOSE WHICH POWER PLANTS TO OPERATE?

A. Utility generation dispatch is designed to ensure that a generating facility with the lowest incremental cost of producing an additional megawatt-hour (MWh) of electricity, also referred to as marginal cost or marginal production cost, is used first before a higher-cost resource like a coal plant is dispatched, which minimizes ratepayer costs. Incrementally more expensive generation is then dispatched until generation supply meets demand. A power plant's marginal production cost includes its fuel cost and other variable operations and maintenance ("O&M") costs that increase in proportion to the MWh generated at the plant. Capital and other fixed costs do not factor into the decision about which power plants are selected because those sunk costs are incurred regardless of whether the power plant operates. As a result, wind and solar resources that have no fuel cost and minimal variable O&M costs are typically dispatched first, generally followed by other resources with low marginal production costs like hydropower and nuclear, and then the grid operator progresses through the remaining available resources in order of increasing marginal production cost. While coal units are increasingly expensive to maintain and operate, whether a specific coal unit is the highest marginal cost resource in a given hour depends upon the specific variable costs associated with running that unit relative to other resources' variable costs. As noted above, the variable costs to dispatch a unit depends upon its variable O&M costs, its efficiency or heat rate, and the price of fuel, which for gas and to a lesser extent coal is driven by real-time supply and demand factors. Accordingly, some natural gas combined cycle generators have a lower marginal production cost than some coal plants, while gas combustion turbines are less efficient and therefore generally have a higher marginal production cost.

Q. HOW DOES UNECONOMIC DISPATCH SPECIFICALLY HARM RATEPAYERS?

A. My analysis indicates that the Company's coal units are routinely operating at a loss, reflecting that their marginal cost of producing electricity is greater than that of other resources that were available . This indicates that the cost for the coal unit to produce that electricity is greater than the value of that electricity. Said another way, the Company ratepayers would have saved money if the Company replaced the coal generation with energy generated by another resource. This excess cost is passed on to the Company ratepayers through the fuel rider, which is determined in this proceeding. This uneconomic dispatch of coal also displaces generation from lower-cost resources like solar and hydropower, and in some cases from lower-cost natural gas combined cycle generation. The costs for ratepayers are particularly high when uneconomic dispatch results in the curtailment of renewable generation, replacing a non-emitting and zero-marginal-cost resource with costly coal generation. For solar resources under Power Purchase Agreements with the Company, depending on the terms of those contracts, renewable curtailment can even result in the Company having to compensate renewable power producers for lost revenue, further increasing the cost of uneconomic dispatch to the Company ratepayers. By displacing lower-cost and lower-emitting generation, uneconomic coal dispatch also increases emissions of pollutants that harm public health and the environment.

Q. ARE VERTICALLY-INTEGRATED UTILITIES MORE LIKELY TO UNECONOMICALLY DISPATCH THEIR GENERATION?

A. Yes. In contrast to merchant generators whose profits are reduced by uneconomic generation, fuel costs do not affect the profits of vertically integrated utilities like the Company, which pass their fuel costs through to their ratepayers in proceedings such as this one. Many analysts have found that vertically integrated utilities are much more likely to uneconomically dispatch their coal plants than merchant plant owners because it does not affect their profits.[1] Vertically integrated utilities' economic indifference to fuel costs requires diligent regulation from state utility commissioners to protect ratepayers from

[1] *See* Catherine Morehouse, *MISO Integrated Utilities Lost $492M From 2016-2019 Via Uneconomic Coal Dispatch: Market Monitor*, UTILITY DIVE (Oct. 9, 2020), https://www.utilitydive.com/news/miso-integrated-utilities-lost-492m-from-2016-2019-via-uneconomic-coal-dis/586714/ (last visited July 15, 2025); JOE DANIEL ET AL., UNION OF CONCERNED SCIENTISTS, USED, BUT HOW USEFUL?: HOW ELECTRIC UTILITIES EXPLOIT LOOPHOLES, FORCING CUSTOMERS TO BAIL OUT UNECONOMIC COAL-FIRED POWER PLANTS (2020), https://www.ucsusa.org/sites/default/files/2020-05/Used%20but%20How%20Useful%20May%202020.pdf; RMI, *Economic Dispatch Dashboard*, UTILITY TRANSITION HUB, https://utilitytransitionhub.rmi.org/economic-dispatch/ (last visited July 15, 2025).

imprudent commitment and dispatch decisions.

Q. WHAT IS A MUST-RUN DESIGNATION?

A. One form of uneconomic dispatch is a must-run designation. When a utility designates a unit as must-run, it elects to operate the unit regardless of economics. As a result, the unit will run even if it has a higher cost than the marginal resource that was selected through economic dispatch, which results in costs for ratepayers. There can be legitimate reasons for using a must-run designation, such as completing generator testing that requires a unit to operate, though in other cases must-run designations are not justified. As explained in the following section, our analysis conservatively excludes net ratepayer costs that were incurred during must-run designations, as the Company did not provide sufficient information to assess the prudency of those must-run designations.

3. Analysis Method and Results

Q. WHAT METHOD DID YOU USE FOR YOUR ANALYSIS?

A. For each hour to date in the three-year historical period for which Georgia Power is requesting rate recovery in this proceeding, June 1, 2023 to May 31, 2026, I assessed whether the marginal production cost of an operating coal unit[2] exceeded the Company's day-ahead forecast for system-wide marginal production cost, a metric that is also known as system "lambda."[3] System lambda measures the marginal cost of the highest cost unit dispatched across the Company's system to meet electricity demand in an hour. The Company's coal units include four units totaling 3,498.6 MW nameplate capacity at Plant Bowen, and three units totaling 2,673 MW at Plant Scherer, for a total of 6,171.6 MW.[4] The Company provided data through the end of February 2026 in response to discovery, so the analysis covers the period June 2023-February 2026, or approximately 2 and ¾

[2] *See* Company's Trade Secret Response to STF-PIA-2-3 Attachment A (providing hourly marginal production costs for the coal units).

[3] *See* Company's Trade Secret Response to STF-PIA-2-2 Attachment.

[4] Nameplate capacity taken from EIA, *Preliminary Monthly Electric Generator Inventory: January 2026*, https://www.eia.gov/electricity/data/eia860m/.

years.

In conducting this analysis, I used the Company's day-ahead forecast for system lambdas, which varied depending on the incremental fuel costs and other incremental variable costs of the resources the Company dispatched during those specific hours. If an operating coal unit's marginal production cost exceeded the system lambda, this indicates that the unit was uneconomic relative to other available resources, and thus the Company incurred a loss by operating the unit in that hour. To calculate the net cost of the Company keeping a coal unit online, for each must-run event, I also factored in the startup and shutdown costs for the unit to calculate the cost of the alternative case of the unit shutting down and then restarting once power prices were high enough for it to profitably operate.[5] Put simply, this counterfactual was intended to assess whether the costs associated with shutting off and restarting a high marginal cost coal unit outweigh the value of power provided by a lower marginal cost alternative resource. As a result, time periods in which a coal unit was unprofitable, but shutting it down and restarting it would have resulted in higher net costs to ratepayers, were not counted in our analysis as they did not impose a net cost on ratepayers. I also incorporated the Company's reported coal unit operating constraints, including startup time, minimum uptime, and minimum downtime when designing this counterfactual.[6] Accounting for these start up and shutdown costs and other operating constraints reduced the number of periods that resulted in a net cost for purposes of this case, as those dispatch decisions were arguably prudent for the Company's existing generating fleet. However, the Commission should recognize that transitioning to a fleet with more flexible resources, like battery storage, will reduce the need to unprofitably operate inflexible coal resources.

[5] *See* Company's Trade Secret Response to STF-PIA-2-6 Attachment.

[6] *Id.*

Q. WHY DID YOU COMPARE THE COAL UNIT'S COST AGAINST SYSTEM LAMBDA?

A. Because system lambda reflects the marginal cost of the highest cost unit dispatched across the Company's system to meet electricity demand in that hour, it is the best metric of the marginal cost of producing electricity in that hour. If the coal unit's cost is higher than system lambda, this indicates that the lower-cost generator setting the system-wide lambda, and in many cases other resources like imports, could have more economically provided that generation than the coal unit.

Q. WHY DID YOUR ANALYSIS USE THE DAY-AHEAD FORECAST FOR LAMBDA INSTEAD OF REAL-TIME LAMBDA?

A. In the day-ahead timeframe, the utility selects which resources are "committed" to operate the next day, so the power plant operators can make any necessary preparations, like starting up their units (for coal units) or procuring fuel (for gas units). Because coal plants take a long time to start up and have limited flexibility, our analysis exclusively focused on the day-ahead forecast for system lambda. This metric accurately reflects the supply and demand balance and generator economics in the day-ahead timeframe when the Company decided which power plants to commit to operate so that long startup time coal units could be online by the next day. This makes our analysis conservative, as it does not penalize the Company when there were unexpected drops in electricity demand or increases in supply after the day-ahead timeframe when it committed the coal units. Said another way, this ensures the analysis is not "Monday morning quarterbacking" with the advantage of perfect hindsight, and instead is only judging the Company's commitment decisions based on the information that was available to the Company at the time it made those decisions.

Georgia Power is the operator for all units at Scherer,[7] even though the units are jointly owned with other utilities, so Georgia Power is responsible for commitment and dispatch

[7] For example, see Oglethorpe Power Corporation, *SEC Form 10-K for 2024* at 5,

decisions for these units. The results presented below allocate total net costs from uneconomic dispatch to Georgia Power in proportion to Georgia Power's ownership of each unit, so the results below accurately reflect the costs that are passed through to Georgia Power ratepayers.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS?

A. The charts and table below report all uneconomic dispatch events that resulted in a net cost to ratepayers. Figure 1 sums the total net cost of uneconomic dispatch by unit, breaking out the share of uneconomic dispatch costs that occurred in periods with must-run designations versus other factors, while Table 1 reports the same information in tabular form. These net costs total $[redacted] million over the period June 2023-February 2026, of which $[redacted] million were incurred during time periods that included must-run designations. For reference, the Company's filing shows $[redacted] billion in total costs for coal generation over the 2 year and 7 month period of June 2023-December 2025.[8] The $[redacted] million in imprudently incurred costs over the 2 year 9 month period of our analysis were around [redacted]% of the Company's total coal fuel costs over the reported 2 year 7 month period (the percentage would be slightly lower than [redacted]% if the additional two months of total fuel costs were added to the denominator).

https://www.sec.gov/Archives/edgar/data/788816/000162828025015552/opc-20241231 htm; Deloitte, *Independent Auditors Report: Gulf Power*, at 12 (59 in pdf) https://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/fixed-income-investors/download-library/gulf-power/gulf-taxexemp-oct2019.pdf.

[8] Workpaper MFRH-2 TS.xlsx provided with Georgia Power's filing.

Figure/Table 1: Net cost of uneconomic dispatch June 2023-February 2026, by unit

[redacted]

	Uneconomic Dispatch	Must-run	Total
Bowen 1	[redacted]	[redacted]	[redacted]
Bowen 2	[redacted]	[redacted]	[redacted]
Bowen 3	[redacted]	[redacted]	[redacted]
Bowen 4	[redacted]	[redacted]	[redacted]
Scherer 1	[redacted]	[redacted]	[redacted]
Scherer 2	[redacted]	[redacted]	[redacted]
Scherer 3	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

The Company's coal units operated at a net loss more than [redacted]% of the time, with Bowen Units 3 and 4 and Scherer Unit 3 operating uneconomically [redacted] of the time, as shown in Table 2 below. This is calculated as a percent of the total hours when they were available for economic dispatch (*e.g.* not on outage or under a must-run designation) during the analysis period. If periods of uneconomic dispatch under must-run designations were included, these percentages would be even higher.

Table 2: Percent of total available hours during June 2023-February 2026 in which each unit operated at a net loss

Unit	% of available hours in which unit operated at a net loss
Bowen 1	[redacted]
Bowen 2	[redacted]
Bowen 3	[redacted]
Bowen 4	[redacted]
Scherer 1	[redacted]
Scherer 2	[redacted]
Scherer 3	[redacted]
Average	[redacted]

Q. WHAT FACTORS DID THE COMPANY CITE FOR CAUSING ITS USE OF MUST-RUN DESIGNATIONS?

A. In response to discovery, the Company indicated days when each coal unit was designated as a must-run unit, as well as the Company's stated reason for making that designation.[9] The Company's stated reason for all must-run designations was [redacted]. The Company's pre-filed direct testimony also explains that the "FCR-27 budget includes must-run requirements for Plant Bowen to address system constraints and ensure operational reliability."[10]

[9] *See* Company's Trade Secret Response to STF-PIA-2-3 Attachment C.

[10] Direct Testimony of Mr. Houston and Mr. Berrigan, at 17.

Q. WERE THESE USES OF MUST-RUN DESIGNATIONS JUSTIFIED AND PRUDENT?

A. It is not clear. The Company did not provide adequate information about its commitment and dispatch model processes and results to assess the extent to which the must-run commitments of coal units were prudent. To be conservative, we have excluded uneconomic dispatch costs incurred during must-run designations from our analysis. As a result, the recommended disallowance is $[redacted] million. If net costs incurred during must-run designations were included, the recommended total disallowance would increase by $[redacted] million to $[redacted] million, as shown in Figure 1 and Table 1 above.

Q. DO THESE MUST-RUN COMMITMENTS INDICATE OTHER SOLUTIONS ARE NEEDED TO REDUCE THEIR USE GOING FORWARD?

A. Yes. Because the Company claims the must-run commitments were due to [redacted]. As I have explained in the Company's IRP proceedings, ratepayers would benefit from a proactive multi-value transmission planning process that uses tools like production cost modeling to account for the economic value of transmission reducing congestion.[11] [redacted]

Q. HOW DO FUEL COSTS AFFECT UNECONOMIC DISPATCH?

A. Fuel costs are the largest component of total marginal production costs, with plant variable O&M costs generally being much smaller. Energy Information Administration data show

[11] For example, see the Direct Testimony of Michael Goggin in Docket No. 56002, Georgia Power Company's 2025 Integrated Resource Plan, https://services.psc.ga.gov/api/v1/External/Public/Get/Document/DownloadFile/222515/103630, at 14-38.

that Plant Bowen has an average coal price that is significantly higher than Plant Scherer's, and the national average. Specifically, Plant Bowen's average coal price in 2025 was $3.96 per million British thermal units ("MMBtu"), while Scherer's was $3.02 per MMBtu,[12] and the national average coal price was $2.55 per MMBtu in 2024.[13] Plant Bowen is fueled by Appalachian and Illinois Basin coal, which is significantly more expensive to produce than the Powder River Basin coal used by most coal power plants. In response to discovery, Georgia Power indicates that:

> The Company explored switching Plant Bowen over the years and the various studies have shown that converting the coal units at Plant Bowen to be able to burn PRB [Powder River Basin] coals would require a large amount of capital investment. In addition, even though the PRB coal is cheaper than Appalachian and IB [Illinois Basin] coal on average per ton basis, there is a capacity reduction associated with PRB in comparison due to lower coal quality of subbituminous coal. Given the significant capital investment required and the lower expected capacity output with PRB coal, the switching of Plant Bowen to PRB coal would be uneconomic for customers.[14]

The fuel cost figures for Bowen and Scherer in the preceding paragraph are presented in $/MMBtu, so they account for differences in the energy content of different types of coal. The Company did not provide any studies in this docket supporting the conclusion that retrofit costs would outweigh fuel cost savings. In separate proceedings, the Company and the Commission should assess whether Bowen should be retired due to its high fuel costs and other factors.

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[12] EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920): 2025*, https://www.eia.gov/electricity/data/eia923/xls/f923_2025.zip, page 5, multiplying price times quantity for each coal purchase, and then summing the total cost and dividing by the total quantity for all purchases.

[13] Electric Power Annual 2024, Table 7.5, https://www.eia.gov/electricity/annual/pdf/epa.pdf. During the first nine months of 2025, generators paid an average of $2.43/MMBtu for coal, per *U.S. coal-fired generators reprieved by higher gas prices,* https://jkempenergy.com/2025/12/11/u-s-coal-fired-generators-reprieved-by-higher-gas-prices/.

[14] Company response to STF-PIA-1-13.

In this proceeding, however, the Commission can disallow costs that were imprudently incurred from the excessive operation of Plant Bowen. The results above indicate that the Company routinely committed and operated Plant Bowen when its generation was not needed and lower-cost sources of generation were available.

4. Dissecting the factors that drive uneconomic dispatch

Q. WHAT FACTORS CAN CAUSE UNECONOMIC DISPATCH?

A. As shown in Table 1 above, factors that cause uneconomic dispatch can generally be grouped into a utility designating a unit as must-run, and other factors that result in a flawed and uneconomic dispatch outcome. These other factors can include flaws in the generator commitment and dispatch process, including systemic biases in forecasts used in that process, inefficient fuel contract structures, and other factors. This section reviews those factors in more detail and develops recommendations for the Commission to address these problems.

Q. ARE THERE FLAWS IN GEORGIA POWER'S COMMITMENT PROCESS?

A. Yes. Persistent biases or other flaws in the inputs into the generator commitment process can increase ratepayer costs by inefficiently overcommitting generators. In response to discovery, the Company provided[15] data allowing a comparison between its actual load data and its day-ahead load forecast, and between actual solar output and its day-ahead solar forecast. Over the three year period, the day-ahead load forecast [redacted]. The Company's solar forecast [redacted] MW on average. Taken together, these persistent biases result in a [redacted] of the need for conventional generation. A statistical t-test[16] confirms that an over-forecasting bias of this size exceeds the deviation expected due to normal forecast error by many orders of magnitude. This persistent and significant overestimate of need contributes to the overcommitment of coal units, which results in uneconomic dispatch of

[15] *See* Company's Trade Secret Response to STF-PIA-2-2 Attachment.

[16] A statistical t-test compares the averages between two sampled groups to determine whether the variance in those averages is statistically significant.

those coal units to the detriment of ratepayers. The Commission should also recognize that transitioning to a fleet with more flexible resources that can quickly start up and respond to changes in supply and demand, like battery storage, will eliminate costs caused by day-ahead forecast errors.

Q. WHAT OTHER FACTORS CAN CAUSE UNECONOMIC DISPATCH?

A. Utilities can also uneconomically over-dispatch coal plants to use up surplus coal supplies to avoid penalties associated with minimum delivery requirements in coal transportation contracts. This factor was not accounted for in our analysis, as our analysis conservatively used the marginal fuel costs as provided by the Company in discovery without questioning their accuracy or reasonableness. As a result, our analysis likely significantly understates the full ratepayer costs of uneconomic dispatch.

The Company explains that it reduces the assumed marginal fuel cost for coal generators in its generator commitment and dispatch decisions to account for these penalties, if the Company is falling below the minimum delivery requirement:

> If the applicable transportation contract contains minimum-volume / take-or-pay provisions with liquidated damages (or similar shortfall charges), the marginal replacement cost of transportation component reflects those provisions only to the extent they affect the incremental cost of additional deliveries based on the timing of need:
>
> *i.* When forecast deliveries are below the contractual minimum, the component of transportation costs covered by the shortfall/liquidated damages is treated as fixed and excluded from the marginal replacement cost for incremental deliveries up to the minimum;… [17]

By reducing the fuel cost that is the primary component of the marginal production cost for coal generators, accounting for these penalties makes it much more likely for coal units

[17] *See* Company's Response to STF-PIA-1-3.

to operate. While this is the economically rational response to avoid those penalties, which is why our analysis conservatively does not contest the Company's assumed fuel costs, contracts that include those penalties are economically inefficient as they incentivize Georgia Power to excessively operate coal plants to consume more coal. The Commission can ensure that this type of uneconomic dispatch does not occur in the future by requiring the Company to move to more efficiently structured contracts for coal transportation that do not include such penalties as new fuel contracts are signed or existing contracts come up for renewal. The Commission should also recognize that transitioning to a fleet that is less dependent on inflexible fuel contracts will reduce the cost of these penalties.

Q. WHAT STRUCTURE DOES AN ECONOMICALLY EFFICIENT FUEL CONTRACT USE INSTEAD OF PENALTIES FOR FAILING TO MEET MINIMUM DELIVERY QUANTITIES?

A. In an economically efficient fuel contract, the price the Company pays for each ton of delivered coal should only include the marginal cost of extracting and delivering that fuel. While the coal mine operator or railroad does have fixed costs associated with building and operating the infrastructure necessary to produce and deliver the coal, those fixed costs should be recovered separately from the variable per-unit price of the fuel. Capital and other fixed costs associated with that infrastructure should be recovered as fixed costs in the fuel supply contract, such as through a one-time payment or a fixed cost per year. Fuel contracts that use minimum delivery requirements and penalties to recover fixed costs are inherently inefficient as these fixed costs should not affect the marginal cost of the fuel.

<u>5. Gas price risk</u>

Q. Is gas price volatility a major risk for the Company ratepayers?

A. Yes. Henry Hub natural gas prices have increased by around 50% over the last year and a half.[18] Natural gas prices are volatile and uncertain on both a day-to-day basis due to

[18] EIA, *Henry Hub Natural Gas Spot Price (Dollars per Million Btu),* https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

weather, and on a longer-term basis due to economic and geopolitical factors. Increased U.S. exports of Liquefied Natural Gas (LNG) have increasingly tethered domestic gas prices to the global price for gas, which is higher and heavily affected by geopolitical volatility and uncertainty. For example, Russia's invasion of Ukraine and the ongoing closure of the Strait of Hormuz have caused global natural gas prices to increase dramatically, and to display greater volatility and uncertainty. The linkage between domestic and global natural gas prices is likely to increase as the U.S. is expected to roughly double its LNG export capacity by 2029, after increasing from essentially nothing to 15.4 billion cubic feet per day (bcf/day) over the last decade,[19] an amount that is comparable to nearly 17% of U.S. gas consumption in 2025.[20]

Moreover, ongoing consolidation in the gas supply and transportation industries may result in higher and more volatile gas prices. Ernst and Young reports that oil and gas industry "[m]erger and acquisition expenditures increased 331% in 2024, from US$47.9 billion in 2023, to US$206.6 billion in 2024."[21] For example, the largest gas producer in the Appalachian basin has recently completed acquisitions and announced plans to increase prices by reducing production.[22]

Q. HOW HAVE EXTREME COLD WEATHER EVENTS AFFECTED GAS PRICES?

A. Delivered gas prices also show major volatility and uncertainty on a short-term basis,

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[19] EIA, *North America's LNG export capacity could more than double by 2029*, (October 16, 2025), https://www.eia.gov/todayinenergy/detail.php?id=66384.

[20] EIA, *U.S. natural gas consumption set a monthly and yearly record in 2025*, (March 18, 2026) https://www.eia.gov/todayinenergy/detail.php?id=67365#.

[21] Ernst and Young, *US oil and gas reserves, production and ESG benchmarking study*, https://www.ey.com/content/dam/ey-unified-site/ey-com/en-us/industries/oil-gas/documents/ey-us-oil-and-gas-reserves-production-esg-study-2025-final.pdf at 6.

[22] For example, see EQT, *EQT Announces Strategic Production Curtailment*, (March 2024) https://ir.eqt.com/investor-relations/news/news-release-details/2024/EQT-Announces-Strategic-Production-Curtailment/default.aspx; N. Cano, *EQT's Q2 Call Highlights Strategic Shift Toward Demand-Linked Growth*, (July 2025) https://aegis-hedging.com/insights/eqts-q2-call-highlights-strategic-shift-toward-demand-linked-growth; Reuters, *EQT to buy Olympus Energy assets for $1.8 bln to boost Marcellus presence*, (April 2025) https://www.reuters.com/business/energy/eqt-acquire-upstream-midstream-assets-olympus-energy-18-billion-2025-04-22/.

primarily due to weather events that increase demand and/or affect supply. Cold weather events have the largest impact because they cause a spike in natural gas use for building heating, just as demand for electricity generation also increases. Because of the strong positive correlation between gas demand for building heating and electricity generation during winter, there are likely to be larger price spikes during extreme cold as more gas is used for electricity generation, including Georgia Power's ongoing and proposed expansion of gas generation.

Extreme cold events can also disrupt supplies of gas by causing gas wellheads to freeze, just as gas demand peaks. Pipeline constraints during periods of high demand can also cause price spikes or even shortages. Winter Storms Uri, Elliott, and Fern caused dramatic spikes in the price of natural gas in the Eastern U.S due to wellhead freezeoffs. For example, PJM notes that during Winter Storm Fern, there was a 10 billion cubic feet/day drop in natural gas production nationally due to frozen gas wells.[23] This is smaller than the well freeze-offs during both Uri and Elliott, when gas production dropped by around 20 percent nationally, or 20 billion cubic feet/day.[24] While gas supply interruptions during Fern were not large enough to repeat the rolling blackouts that occurred during Uri and Elliott, ratepayers were not spared an economic hit. PJM notes that "Spot gas prices through this event reached historic levels throughout the eastern U.S. with many hubs trading well over $100/mmbtu with prices in NY and New England approaching $300/mmbtu."[25]

Shortfalls in gas supply due to wellhead freezeoffs, along with generator equipment failures and pipelines equipment outages and constraints, contributed to widespread correlated outages of gas generators during recent extreme cold weather events. FERC and NERC reports and regional analyses have documented that forced outages and derates of gas

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[23] PJM, *January Cold Weather Operations*, https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update.pdf, at 38.

[24] *Id.* at 40.

[25] *Id.* at 38.

generators were the primary cause of electric reliability problems during recent extreme cold weather events, including Winter Storm Elliott,[26] Winter Storm Uri,[27] the 2018 Bomb Cyclone,[28] the 2018 South Central Cold Snap,[29] and the 2014 Polar Vortex.[30] In particular, gas accounted for 63% of unplanned outages and derates during Winter Storm Elliott, and 55% during Winter Storm Uri and the 2014 Polar Vortex, while coal accounted for a large share of the remainder.

Q. HOW DID THE SPIKE IN GAS PRICES DURING WINTER STORM FERN AFFECT GEORGIA POWER'S RATEPAYERS?

A. [redacted]. Georgia Power's response to STF-PIA 2-3 Attachment A Trade Secret shows $[redacted] million in fuel expenditures for Georgia Power's gas combined cycle generators alone over the two week period from January 23-February 6, 2026. This translates into an average fuel cost of $[redacted]/MWh , which for the average heat rate for the McDonough and McIntosh combined cycle generators in January 2025 of 6.920 MMBtu/MWh[31] reflects a gas fuel cost of $[redacted]/MMBtu, or [redacted] times the $3.52 Henry Hub average in 2025.[32] The fuel cost

[26] FERC and NERC, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations*, (September 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott, at 5.

[27] FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States (2021)*, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 16.

[28] U.S. Energy Info. Admin., *January's Cold Weather Affects Electricity Generation Mix in Northeast, Mid-Atlantic (Jan. 23, 2018)*, https://www.eia.gov/todayinenergy/detail.php?id=34632.

[29] FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf, at 57-58, 96-97.

[30] NERC, *Polar Vortex Review iii (Sept. 2014)*, https://www.nerc.com/globalassets/our-work/reports/event-reports/polar_vortex_review_29_sept_2014_final.pdf, at 13.

[31] EIA, *Form EIA-923 detailed data with previous form data: 2025*, https://www.eia.gov/electricity/data/eia923/xls/f923_2025.zip page 5 (dividing total MMBtu of fuel consumed by MWh generated for those two plants for January 2025).

[32] EIA, *Henry Hub Natural Gas Spot Price*, https://www.eia.gov/dnav/ng/hist/rngwhhdA htm.

identified above only accounts for combined cycle generation, which includes 4,141.4 MW of owned capacity and the 230 MW Santa Rosa PPA for a total of 4,371 MW. Georgia Power also owns 1,618.4 MW of other gas generating capacity, which have a significantly worse average heat rate, so we can roughly estimate that the total gas fuel cost for Georgia Power ratepayers during Winter Storm Fern exceeded $[redacted] million. For reference, the fuel cost for the 4,141.4 MW of combined cycle generators owned by Georgia Power over the 2 year 7 month period covered in the Company's filing totaled $[redacted], so the $[redacted] million cost during the two week period of Winter Storm Fern was more than [redacted]% of the cost incurred over the preceding 134 weeks.[33]

Q. ARE THE COMPANY'S PROPOSALS TO EXPAND ITS USE OF FINANCIAL HEDGING ADEQUATE TO MITIGATE THIS RISK.

A. No. First, the Company has not proposed to fully cover its gas needs via hedges or long-term contracts. More importantly, it is difficult for financial institutions to hedge their price risk for commodities like natural gas, which has large and widespread price volatility and uncertainty due to the factors discussed above, including highly correlated risks in gas supply and transportation. A financial institution is willing to sell me health insurance or homeowners insurance at a reasonable price because the odds of me becoming ill or my house burning down are not highly positively correlated with the risk of those things happening to other people at the same. However, gas deliveries regionally and even nationally are dependent on a small number of supply fields and pipelines, which as documented above are prone to disruption, particularly during extreme cold events that also cause gas demand to spike. As a result, a counterparty offering Georgia Power a hedge cannot adequately hedge that risk itself. The result is that financial hedging products will come at a significant price premium or will not adequately cover risks, and those costs and risk will be passed on to Georgia Power ratepayers. For example, Georgia Power's filing in this proceeding shows $[redacted] million in net costs for

[33] Workpaper MFRH-2 TS.xlsx provided with Georgia Power's filing.

natural gas hedges over the period 2023-2025, or more than $[redacted] million per year on average.[34]

Q. HOW CAN THE COMMISSION REDUCE RATEPAYERS' EXPOSURE TO THAT RISK?

A. As an initial step, the Commission should require the Company to adopt a fuel cost sharing mechanism. Fuel cost sharing mechanisms incentivize utilities to reduce their exposure to gas price volatility, in turn reducing ratepayers' exposure to that risk. Fuel cost sharing mechanisms are particularly important for incentivizing Georgia Power to make prudent decisions regarding meeting new load with new fuel-based generation or non-fuel-based resources.

Fuel cost sharing mechanisms address a type of market failure economists term a "moral hazard," namely the principal-agent problem. There is a market failure because the Company does not bear the cost or risk of the decisions it makes regarding whether to increase its dependence on gas generation and what physical mechanisms to use to reduce that risk, which can significantly increase costs for ratepayers. Said another way, the Company is the agent who makes the decision, but the ratepayer is the principal who pays the cost of that decision. The solution to a principal-agent problem is to internalize the cost and risk of a decision to the agent making the decision, which in this case is the Company.

Q. WHAT CAN THE COMPANY DO TO MITIGATE GAS PRICE RISK?

A. Several things. In situations like this where financial hedges are unable to adequately mitigate correlated risks, a primary solution is for Georgia Power and the Commission to make generation mix choices that create a physical hedge. A fuel cost sharing mechanism will incentivize Georgia Power to account for the price risk of natural gas when making decisions about the optimal generation mix should. The Company can also pay for steps that somewhat improve the availability of gas, like increasing access to gas storage or

[34] *Id.*

buying firm transportation. However, these steps do not fully mitigate the economic or reliability risk of gas generation. For example, firm transportation does not fully address the risks from supply freezeoff events discussed above. Firm transportation customers are still subject to *force majeure* declarations by the pipeline in the event of pipeline failures or constraints due to supply shortfalls. Gas storage is also subject to failures itself, deliveries of gas from storage can be affected by pipeline interruptions or constraints, and the gas storage must be refilled using the same risky sources of supply.

The most resilient solution to a range of economic and reliability risks is diversifying the Company's generation mix by adding resources like renewable and battery resources that do not rely on volatily-priced fuel deliveries that can be interrupted by extreme weather or other unexpected events. The Commission should thoroughly weigh the economic and reliability risks for ratepayers from the Company increasing its dependence on gas generation and fuel-based generation in general. Adding renewable, storage, and demand-side resources builds a more diverse generation mix that reduces ratepayer risk and increases resilience. Each resource type has distinct outage risks, so a diverse mix reduces the economic and reliability risk to ratepayers. As the age-old aphorism explains, putting all of your eggs in one basket is not a resilient strategy.

<u>6. Conclusion</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I respectfully recommend that the Commission disallow recovery of the $152 million in net ratepayer losses that occurred over the period June 2023-February 2026 as a result of uneconomic coal unit dispatch. This represents about [redacted]% of the $[redacted] billion in total fuel costs over the period June 2023-December 2025 for which the Company is seeking recovery. This will protect ratepayers from shouldering these imprudently incurred costs, and more importantly will incentivize the Company to not imprudently dispatch resources going forward.

To that end, I further recommend that the Commission direct the Company to take prudent and cost-effective steps to minimize or eliminate uneconomic dispatch going forward. Specifically, the Commission should direct the Company to remove inefficient penalty provisions from coal transportation contracts as existing contracts come up for renewal or new contracts are signed and [redacted] and other flaws in the economically optimized generator commitment and dispatch process that result in suboptimal dispatch that increases ratepayer costs. The Commission should also thoroughly weigh the net benefits of replacing uneconomic and inflexible coal resources with more cost-effective modern resources, particularly renewable resources without fuel price risk and flexible battery storage.

Finally, the Commission should require the Company to effectively manage gas price risk through a fuel cost sharing mechanism. This will incentivize the Company to thoroughly weigh the risks for ratepayers from increasing its dependence on gas generation relative to renewable and battery resources that are not subject to volatile fuel prices.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MG-1: Michael S. Goggin background and qualifications

Michael Goggin

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 Executive Vice President February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and policy issues for non-profit, grid operator, state regulator, and industry clients
- Have testified before FERC and in dozens of state regulatory commission cases
- Actively engaged in NERC Standards development processes related to renewable and storage resources

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

- Led team responsible for all American Wind Energy Association analysis
- Served as primary technical and economic expert on market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (RTO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- 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
- 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, hydrogen, 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

Publications available at https://gridstrategiesllc.com/reports/

MG-2: Georgia Power's response to data request STF-PIA-2-3 - Attachment A

Exhibit has been redacted in its entirety.

MG-3: Georgia Power’s response to data request STF-PIA-2-2 - Attachment.

Exhibit has been redacted in its entirety.

MG-4: Georgia Power's response to data request STF-PIA-2-6 - Attachment

Exhibit has been redacted in its entirety.

MG-5: Georgia Power's response to data request STF-PIA-2-3 - Attachment C

Exhibit has been redacted in its entirety.

MG-6: Georgia Power's response to data request STF-PIA-1-13

STF-PIA-1-13

Question:

Please explain why Bowen is primarily fueled from Appalachian and Illinois Basin coal mines instead of lower-cost Powder River Basin coal mines.

Response:

The coal units at Plant Bowen became operational from 1971 to 1975 and were designed for Bituminous coals primarily sourced from Appalachian and Illinois Basin ("IB") coal mines. The use of Powder River Basin (PRB) coal was very limited in the 1970's and didn't really become widespread in the Southeast until the 80's and 90's with the western railroad expansion and 1990 Clean Air Act Amendments. The Company explored switching Plant Bowen over the years and the various studies have shown that converting the coal units at Plant Bowen to be able to burn PRB coals would require a large amount of capital investment. In addition, even though the PRB coal is cheaper than Appalachian and IB coal on average per ton basis, there is a capacity reduction associated with PRB in comparison due to lower coal quality of subbituminous coal. Given the significant capital investment required and the lower expected capacity output with PRB coal, the switching of Plant Bowen to PRB coal would be uneconomic for customers.

MG-7: Georgia Power's response to data request STF-PIA-1-3

Georgia Power Company
Docket No. 56765
Fuel Cost Recovery (FCR-27) Application
STF-PIA Data Request Set No. 1

STF-PIA-1-3

Question:

Please explain how the Company calculates the fuel cost used in determining the marginal cost of generation (item 2c above). Please explain whether this calculation is based on the contractual cost of fuel supply and transportation, the spot market price of fuel at that time, or other factors. If the coal supply or transportation contracts include any provisions for liquidated damages or other penalties for failing to meet minimum delivery quantities, take-or-pay provisions, or similar mechanisms, please explain if and how those provisions are accounted for in the fuel cost used in determining the marginal cost of generation from each coal unit.

Response:

Please see MFRP-13.5 submitted in the Company's initial filing submitted February 17, 2026 for an overview of how marginal cost of fuel was determined for the projected test period.

The marginal replacement costs for each gas-fired unit are typically updated once each gas trading day. These costs include the best estimate of the next day's gas prices based on Intercontinental Exchange ("ICE") average index pricing for the generating unit's supply plus any pipeline fuel, transportation, and fuel use tax adders.

The marginal replacement costs for each oil-fired unit are typically updated once each gas trading day. These costs include the best estimate of the next day's fuel oil prices based on the Oil Price Information Services ("OPIS") 10 AM rack average index pricing for the generating unit's supply terminal plus a transportation adder to have oil delivered to the unit based on the current fuel oil supply agreement.

Transportation for uncommitted coal is reflected in marginal replacement cost using the applicable active contract rate or recent carrier quote for the relevant origin/destination and time period. If the applicable transportation contract contains minimum-volume / take-or-pay provisions with liquidated damages (or similar shortfall charges), the marginal replacement cost of transportation component reflects those provisions only to the extent they affect the incremental cost of additional deliveries based on the timing of need:

i. When forecast deliveries are below the contractual minimum, the component of transportation costs covered by the shortfall/liquidated damages is treated as fixed and excluded from the marginal replacement cost for incremental deliveries up to the minimum; and

ii. Once forecast deliveries are at or above the contractual minimum, marginal replacement cost reflects the full applicable transportation rate for additional deliveries.

BEFORE

THE GEORGIA PUBLIC SERVICE COMMISSION OF

DOCKET NO. 56765

In re: Georgia Power Company's Fuel Cost Recovery (FCR-27)	**CERTIFICATE OF SERVICE**

I hereby certify that a true and correct copy of the Direct Testimony of Michael Goggin (Public Disclosure) on behalf of Sierra Club, NRDC, and SACE has been furnished by electronic mail on this 9th day of April, to the following:

Sallie Tanner
Executive Secretary
Georgia Public Service Comm.
244 Washington Street, SW
Atlanta, GA 30334
stanner@psc.state.ga.us

Jeffry C. Pollock
J. Pollock Incorporated
14323 South Outer 40 Road,
Suite 206 N
Town and Country, Missouri 63017-5734
jcp@pollockinc.com

Jeremiah Haswell
Kyle Leach
Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374
jhaswell@southernco.com
kleach@southernco.com

Robert Trokey
Justin Pawluk
Chris Collado
Tom Newsome
Jamie Barber
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334
rtrokey@psc.ga.gov
jpawluk@psc.ga.gov
ccollado@psc.ga.gov
tnewsome@psc.ga.gov
jamieb@psc.ga.gov

Jennifer Whitfield
Amitav Kamani
Bob Sherrier
Alyssa Krantz
Southern Environmental Law Center
Ten 10th Street, NW, Suite 1050
Atlanta, GA 30309
jwhitfield@selc.org
akamani@selc.org
bsherrier@selc.org
akrantz@selc.org

Brandon F. Marzo
Steven Hewitson
Allison W. Pryor
Troutman Pepper Hamilton Sanders LLP
600 Peachtree Street NE, Suite 3000
Atlanta, GA 30308-2216
brandon.marzo@troutmansanders.com
steven.hewitson@troutman.com
allison.pryor@troutman.com

Charles B. Jones, III
Jim Kelleher
Georgia Association of Manufacturers 75
Fifth Street, NW
Suite 3412
Atlanta, GA 30308
cjones@gamfg.org
jkelleher@gamfg.org

Robert B. Baker
Robert B. Baker, PC
2480 Briarcliff Road, NE, Suite 6
Atlanta, Georgia 30329-3008
bobby@robertbbaker.com

/s/ Caden Koontz
Caden Koontz
Sierra Club
50 F St. NW, Eighth Floor
Washington, DC 20001
(202) 650-6075
caden.koontz@sierraclub.org