BEFORE THE
Georgia Public Service Commission

In Re: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT	Docket No. 40161
Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan	Docket No. 40162

Direct Testimony of
Jeremy I. Fisher, PhD

On Behalf of
Sierra Club

PUBLIC DISCLOSURE

May 3, 2016

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues and policies for electricity sector issues, including fossil fuel power generation, efficiency, renewable energy, ratemaking and rate design, restructuring and market power issues, and environmental regulations.

Q Please summarize your work experience and educational background.

A I have worked at Synapse for nine years, evaluating and facilitating the creation of long-term electricity plans, performing planning on behalf of states and municipalities, and helping state regulators navigate Federal environmental regulations.

I have provided consulting services for a wide variety of public sector and public interest clients, including the U.S. Environmental Protection Agency (EPA), the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Utility Consumer Advocates (NASUCA), the National Rural Electric Cooperative Association (NRECA), the states of Alaska, Arkansas, Michigan, and Utah, the Commonwealth of Puerto Rico, Tennessee Valley Authority Office of Inspector General (TVA OIG), the California Division of Ratepayer Advocates (CADRA), the California Energy Commission (CEC), the Regulatory Assistance Project (RAP), the Western Grid Group, the Union of Concerned Scientists (UCS), Sierra Club, Earthjustice, Natural Resources Defense Council (NRDC), and other organizations.

I have provided testimony in electricity planning and general rate case dockets in Indiana, Louisiana, Kansas, Kentucky, Oklahoma, Oregon, Nevada, New Mexico, Utah, Washington, Wisconsin, and Wyoming.

I hold a doctorate in Geological Sciences from Brown University, and I received my bachelor degrees from University of Maryland in Geology and Geography.

My full curriculum vitae is attached as Exhibit JIF-1.

Q **On whose behalf are you testifying in this case?**

A I am testifying on behalf of Sierra Club.

Q **Have you testified in front of the Georgia Public Service Commission previously?**

A No, I have not.

Q **Please describe your experience in the review of integrated resource plans and in electric system planning in Georgia.**

A One of my primary roles at Synapse is the development, review, analysis, and critique of long-term energy plans for states, regions, and utilities. I have been involved in nineteen litigated resource planning efforts before twelve state utility commissions, including the assessment of integrated resource plans (IRP) and certificates for public convenience and necessity (CPCN). As part of my job, I track public IRPs across multiple states and retain a database of over 200 IRPs from thirty-eight states. I have helped regulators understand utility practices in resource planning, and developed a best practice guide for US EPA.[1]

In 2011 and 2013, I assisted in the review of Georgia Power Company's (GPC or the Company) IRP on behalf of Sierra Club.

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[1] US EPA, 2015. Energy and Environment Guide to Action. 7.1 Electricity Resource Planning and Procurement.

Q What is the purpose of your testimony?

A My testimony specifically focuses on the Unit Retirement Study (URS) conducted by the Company as part of the 2016 IRP. I examined in detail the mechanism, structure, assumptions, and outcomes of the URS. I focused on the Company's analysis and decisions regarding Plants McIntosh, Hammond, and Wansley. I also discuss the difficulties I encountered in conducting a reasonable review of the Company's analyses, a set of problems which are unique to Georgia Power Company.

Q What is the Unit Retirement Study?

A The Unit Retirement Study is a stand-alone, but critical, analysis that the Company has filed with IRPs since 2007.[2] The study is a plant-by-plant assessment of the economic benefit of continuing to operate each major fossil plant in the Company's portfolio. In the 2016 IRP, the Company assesses the net present value (NPV) of operating the plant through [redacted] against the cost of retiring the plant in [redacted] and building a new replacement thermal unit of the equivalent size in [redacted]. The operating costs of the existing plant and the replacement units are both evaluated in a production cost model (GenVal), assessed against a fixed system energy cost schedule. The GenVal model outputs are then put into a spreadsheet-based accounting framework, the Asset Valuation model. The Asset Valuation model adds the production cost benefit from the GenVal model to expected capital spending schedules and then makes an adjustment for fixed operations and maintenance (O&M) expenses and a capacity benefit. Each plant is tested against a range of natural gas and carbon dioxide (CO_2) emissions costs. The analysis does not test a range of coal prices for existing units independently or include any form of risk in coal pricing or availability.

Importantly, the URS is conducted completely outside of the Company's primary modeling framework, the Strategist capacity expansion and optimization model. Instead, the URS is conducted on an aggregated plant-by-plant basis in a separate

[2] See GPSC Docket 24505, 2007 GPC Integrated Resource Plan.

production cost model, and therefore lacks many of the features of a reasonable planning study, particularly with regards to resource options, portfolio replacement, and the appropriate use of risk valuation.

Q **What were the outcomes of the Company's unit retirement study?**

A The Company does not actually provide a narrative description of the results of the unit retirement study, or the decisions derived from the study, except in very broad terms. The URS states that "based on these economic evaluations (along with several other key factors), the Company recommends decertification of one coal-fired steam unit and four combustion turbines (CTs). For the remaining coal units, the Company recommends moving forward with compliance investments.[3] One can infer that the coal-fired steam unit recommended for decertification is Mitchell 3, yet the study does not specifically discuss how the Company draws this conclusion from the data presented. Indeed, an objective view of the data provided by the Company, before any adjustments, suggests that it is in ratepayers' interest to decertify at least two coal-fired plants ([redacted]‘), and very carefully evaluate at least one other coal-fired plant ([redacted]). Data provided by the Company as a supplement to the URS shows that [redacted]‘.[4]

Overall, the Company appears to draw its conclusions about plants' economic merits on the basis of runs with no carbon price or emissions restrictions, and an ostensibly "moderate" gas price, which I believe to be high given recent forecasts. The Company's threshold for choosing to retire a plant appears to be that the generator needs to perform much worse than a gas-fired alternative in exactly one low-risk scenario.

The table below summarizes the outcome of the Company's URS in four columns. Each column shows the net benefit (or liability) in millions of dollars net present value associated with each of the coal-fired units tested in the study.

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[3] Unit Retirement Study (2016), Public Disclosure. Page 1.
[4] Trade Secret response to STF 1-31 Attachment A & Attachment B. Results attached as Exhibit JIF-2.

The first column shows the results relied upon by the Company for decision-making in this IRP, from a scenario with zero CO_2 price and a “moderate” fuel price. The second column shows the simple average of all nine emissions and fuel scenarios tested by the Company in the URS. The third column shows the simple average of the six “low” and “moderate” fuel scenarios, which I believe are more indicative of a centroid for uncertainty based on current information. Finally, the last column shows my base case, or the case upon which I would make decisions from information known today, which uses a $10 CO_2 price and the Company's “low” fuel price forecast.

TS Table 1. Plant valuations from GPC Unit Retirement Study.[5]

	GPC Decision: Zero CO_2, “moderate” fuel	Simple average of all fuel and CO_2 scenarios	Simple average of “moderate” and “low” fuel scenarios	Synapse Base Case: $10 CO_2, “low” fuel
Bowen 1-4	[redacted]	[redacted]	[redacted]	[redacted]
Scherer 1-3	[redacted]	[redacted]	[redacted]	[redacted]
Wansley 1-2	[redacted]	[redacted]	[redacted]	[redacted]
Hammond 1-4	[redacted]	[redacted]	[redacted]	[redacted]
Hammond 4[6]	[redacted]	[redacted]	[redacted]	[redacted]
Hammond 1-3[7]	[redacted]	[redacted]	[redacted]	[redacted]
McIntosh 1	[redacted]	[redacted]	[redacted]	[redacted]
Mitchell 3	[redacted]	[redacted]	[redacted]	[redacted]

Shading applied to plants of interest in this assessment.

It is clear that the Company is assessing only the valuation of the plants from the URS under the zero CO_2 price, “moderate” fuel price results, and yet these results, even without any other adjustments or corrections, significantly overvalue the Company’s fleet. A reasonable range of up-to-date gas and CO_2 price forecasts would likely result in far poorer outcomes than those used by the Company.

[5] Source: TS Asset Valuation Models as provided in response to Staff 1-1, 1-2. Tab “Output Summary”
[6] Source: TS STF-1-31 Attachment B
[7] Source: TS STF-1-31 Attachment A

Q What are your concerns regarding the Company's unit retirement study?

A Overall, including the Company's choice of base fuel and emissions cost assumptions, I have a number of concerns with the Company's unit retirement study. I found seven critical problems with the Company's retirement analysis:

1. failed to seek an optimal replacement portfolio for retiring coal units;
2. inappropriately clustered substantially different coal units, blurring the line between marginal units and highly non-economic units;
3. utilized an outdated and high gas price forecast;
4. inappropriately weighed the risk of carbon regulation, assuming that there will be no reductions required over the next three decades;
5. erroneously assumed that the Company's obligation to pay fixed operations and maintenance (O&M) costs at coal-fired units will decrease substantially over time;
6. used unsupported and erroneously calculated forward capacity prices when the units are being replaced; and
7. assumed the units will provide useful capacity benefits to the system without replacement, even when idled for multiple spans of years, until 2045, when these units will be sixty to eighty years old.

Overall, the Company's unit retirement study is biased toward the continued operation of clearly high-risk, low-return plants. These plants pose a significant liability to Georgia ratepayers. I will demonstrate that the Company recognizes the liability posed by these plants, but has failed to recognize the extent of that liability in this IRP.

Q Where you able to correct the Company's model to address these concerns?

A I was able to address some of these concerns through adjustments and corrections, and estimate the magnitude of error associated with others. It is difficult to estimate the degree of error or bias caused by the Company's model choice, but I have made adjustments for errors in the Company's fixed O&M calculations and corrections for the Company's assessment of capacity prices. I will discuss the specific adjustments later in my testimony.

Q What are the results of your adjustment to the Company's model?

A Overall, the adjustments substantially reduce the benefit of maintaining the Company's coal fleet. For the three plants upon which I have focused my assessment (McIntosh 1, Hammond 1-4, and Wansley 1-2), the adjustments render two plants ([redacted]) definitively non-economic under even fairly conservative assumptions, and call into doubt the long-term viability of the third ([redacted]).

TS Table 2, below, shows the value of the three plants after adjustments. The last column shows my base case assessment of the Company's coal unit viability, under the likely future of long-term gas prices at a lower price point than assumed by the Company, and with a modest and realistic CO_2 price.

TS Table 2. GPC plant valuations (M$) with adjustments for O&M and capacity price.

	GPC Decision: Zero CO_2, "moderate" fuel	Zero CO_2, "low" fuel	**Synapse Base Case:** \$10 CO_2, "low" fuel
Wansley 1-2	[redacted]	[redacted]	[redacted]
Hammond 1-4	[redacted]	[redacted]	[redacted]
McIntosh	[redacted]	[redacted]	[redacted]

It is my assessment that both McIntosh and Hammond are significant ratepayer liabilities, and should be moved for decertification expeditiously.

Finally, Wansley 1 & 2 are not nearly as economically stable [redacted], and should be assessed carefully going forward.

2. McIntosh, Hammond, and Wansley are marginal today

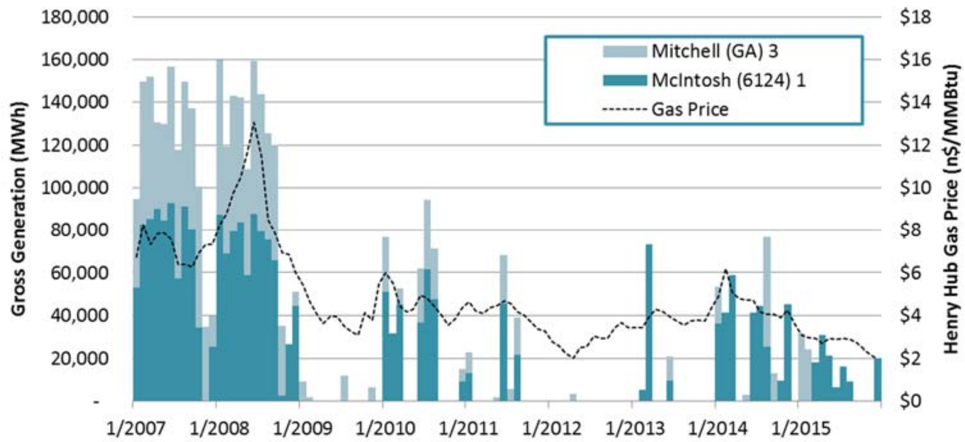
Q Please describe why you are assessing Plants McIntosh, Hammond, and Wansley in more detail.

A In addition to Mitchell 3, which the Company proposes to decertify in this proceeding, McIntosh 1, Hammond 1-4, and Wansley appear increasingly marginal today, as evidenced by their performance over the last three years. Since 2012, gas and energy prices have fallen and stayed low. As I will discuss later, long-term gas price forwards do not anticipate a significant increase in gas prices anytime soon, suggesting that plants that are having difficulty operating economically today are unlikely to provide customer benefits over the long term.

Generally, electricity market prices follow gas prices, and historically, gas-fired resources have set the marginal price of electricity. As gas prices have fallen, the benefits of running solid-fuel steam units (such as the Company's coal-fired fleet) have fallen substantially. In fact, as gas prices have fallen, the Company has reduced the dispatch of some of their more expensive units to prevent non-economic operation.

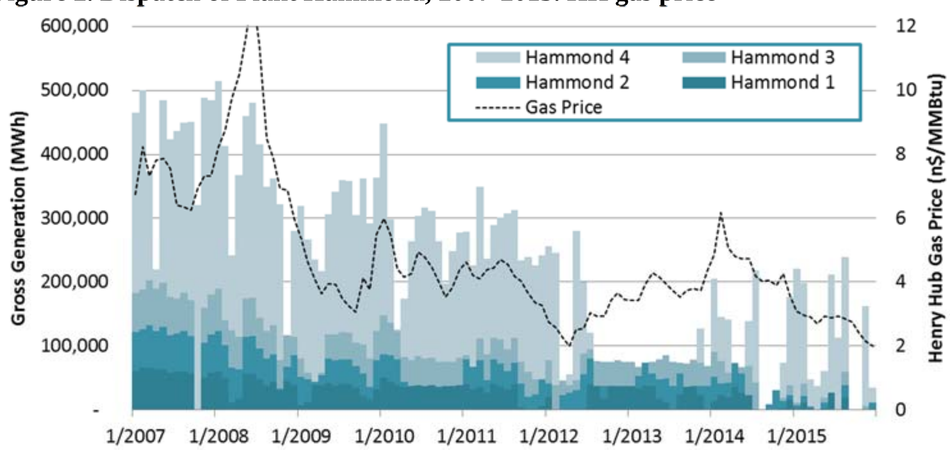
For example, as gas prices fell below $6 per MMBtu, both Mitchell 3 and McIntosh 1 reduced their output dramatically. Neither of these units have operated often since 2009, spending large portions of the year idled. Figure 1, below, shows how the units' dispatch has nearly halted with lower gas prices.

Figure 1. Dispatch of Mitchell 3 and McIntosh 1, 2007-2015. HH gas price.[8]



Similarly, as shown in Figure 2 and Figure 3, below, Plant Hammond and Plant Wansley have also reduced their dispatch with falling energy prices. In particular, while the smaller Hammond 1-3 units have reduced their output by nearly half through 2014 (and almost entirely in 2015), Hammond 4 simply did not commit (i.e., did not operate at all) in most months since mid-2012.

Figure 2. Dispatch of Plant Hammond, 2007-2015. HH gas price

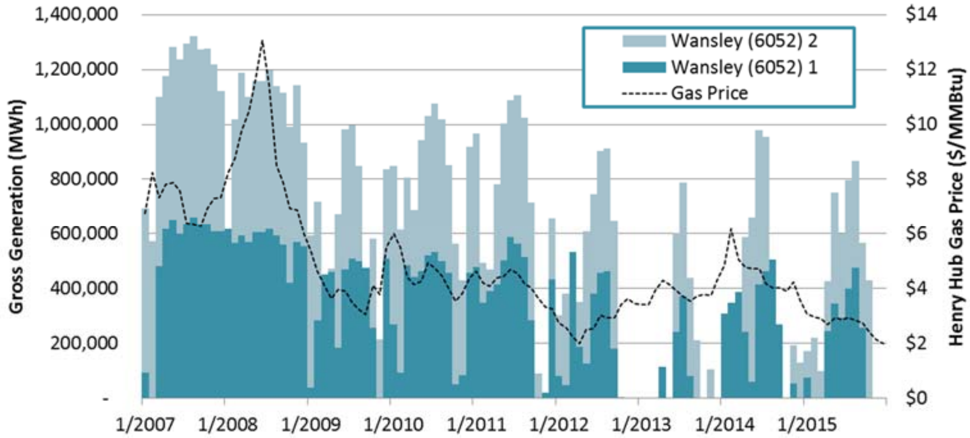


Plant Wansley has shifted from operating on a regular baseload schedule in 2007 and 2008 to providing service primarily during peak periods of the year. Since 2012, Wansley 1 & 2 have also had long periods of economic de-commitment,

[8] Unit output from EPA Clean Air Markets Division (CAMD) Air Markets Program Dataset (AMPD). Gas prices compiled from AEO short term energy outlook (January 2010, January 2013, March 2016). *Please note: graphs are* ***stacked*** *bar plots.*

during which the units simply could not make sufficient revenue to justify operation at all.

Figure 3. Dispatch of Plant Wansley, 2007-2015. HH gas price



It is difficult to envision, even without a sophisticated long-term energy model, that plants that cannot operate effectively under low energy prices have any real economic viability over the long run. In general, coal-fired units incur very high fixed operations and maintenance expenses, and require continuous capital investments to remain operational. Every year that these units sit idle, ratepayers pay to maintain them on the chance that gas and energy prices will rise again to levels that could sustain the plants and make them economic.

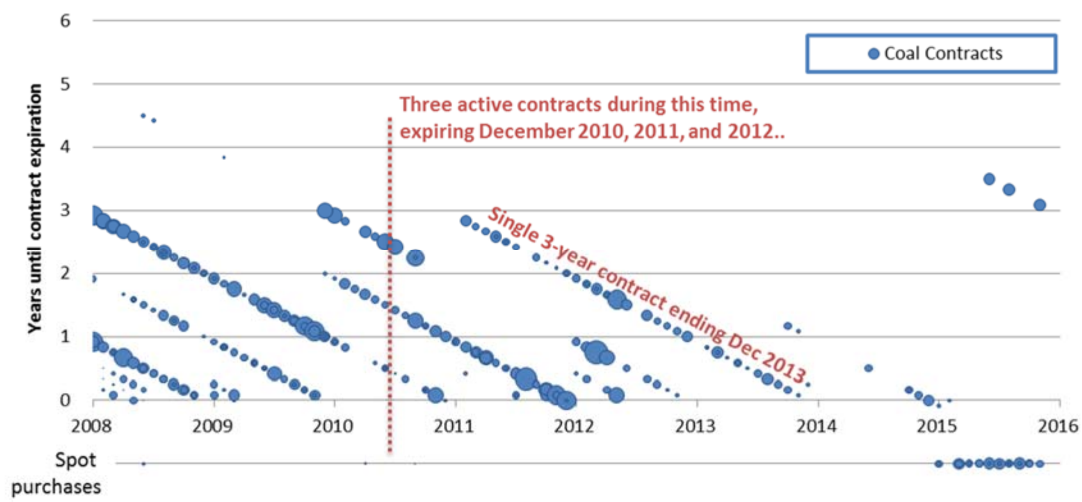
As I will demonstrate, the Company's unit retirement assessment does not indicate that these units have a highly economic future.

An examination of the Company's mid-term view of these units also indicates that Georgia Power Company is not convinced that they are viable over the long term. In Figure 4, I show all of the publicly reported coal contracts for fuel received at Plant Hammond.[9] Each dot represents a delivery on a certain date. The size indicates the total weight of the delivery (larger dots are larger deliveries) and the position on the y-axis indicates the amount of time until the expiration of the contract under which the coal was procured. Values below the 0 point indicate

[9] EIA Form 923. Fuel Receipts. (2008-2015, inclusive)

spot market coal purchases – i.e., no long-term contract. From 2008 to 2011, the Company laddered three- to five-year coal contracts, acquiring approximately one new contract each year.[10] As of 2012, the Company moved to one-year contracts, and as of 2015, the Company had let its contracts expire. Through 2015, the Company acquired primarily spot market coal for Hammond, signing one new contract that expires in 2018.

Figure 4. Hammond coal contracts through time (circle size by weight)[11]



We can surmise from this graph that Georgia Power Company is (appropriately) seeking optionality in coal contracts. Being locked into long-term contracts for coal that may not get used would be imprudent and wasteful. Thus, the Company appears to be anticipating the option of exiting Hammond, as evidenced through its decision to procure coal on an as-needed basis.

Similarly, the Company appears to be seeking optionality at Wansley (see Figure 5), also releasing long-term contracts in favor of shorter-term spot contracts with increased flexibility. In contrast, Figure 6 shows fuel procurement patterns at Bowen. While also taking advantage of low-cost spot market coal options, Bowen has not substantially reduced the acquisition of coal from long-term contracts and

[10] The annotations on the Hammond graph show that in mid-2010, the Company had three active long-term contracts for coal supply at Hammond, and indicate the trajectory of a single 3-year contract, ending in December 2013.
[11] Source: EIA Form 923. Fuel Receipts. (2008-2015, inclusive)

actively signed new contracts in 2013, 2014, and 2015. One can surmise that the Company has far greater confidence in the long-term viability of Bowen relative to Hammond and Wansley.

Figure 5. Wansley coal contracts through time (circle size by weight)

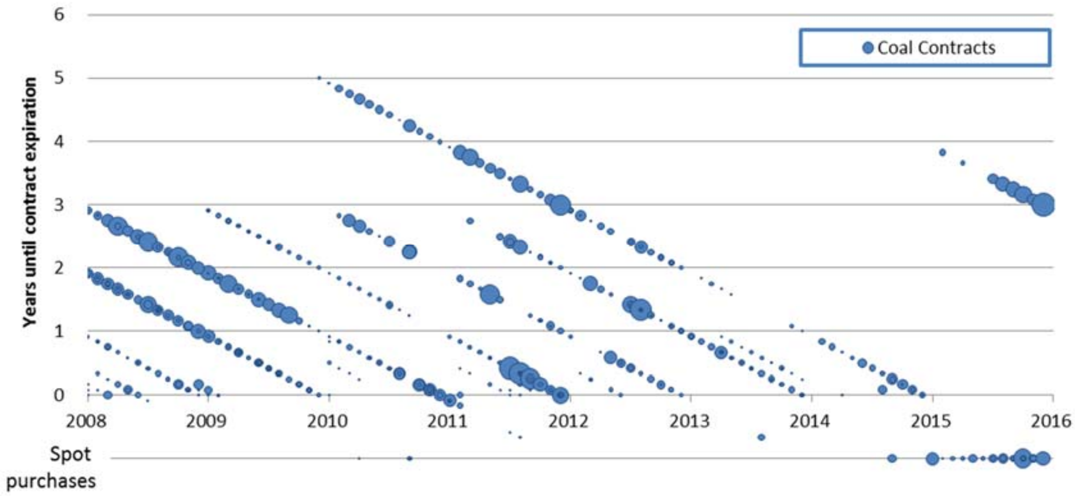
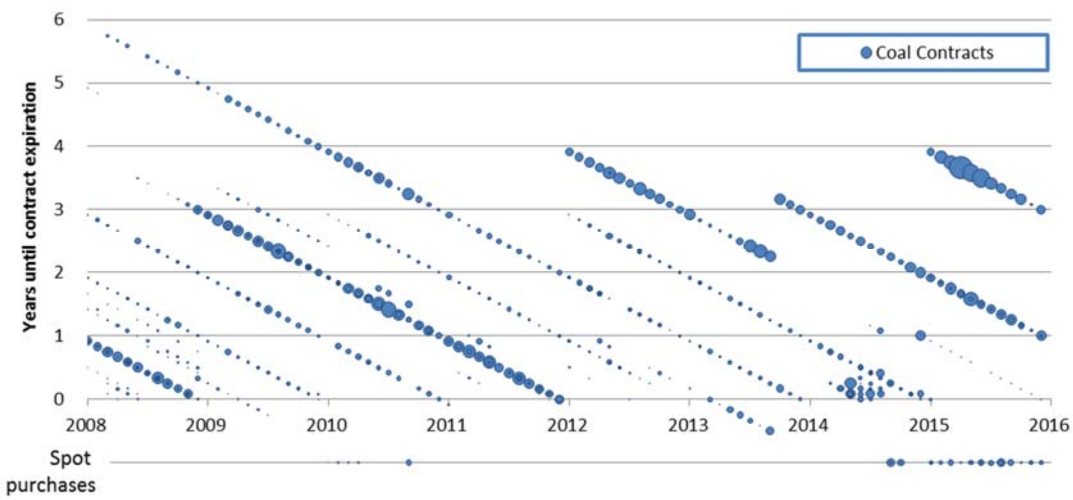


Figure 6. Bowen coal contracts through time (circle size by weight)



3. NON-OPTIMIZATION MODEL STRUCTURE FAILS TO ASSESS REAL REPLACEMENT VALUE

Q You stated a concern that the Company "failed to seek an optimal replacement portfolio for retiring coal units" in the unit retirement study. Please elaborate.

A For the unit retirement study, the Company relied on a production cost model (GenVal) and a spreadsheet-based asset valuation framework to compare the costs and benefits of existing units against equally-sized natural gas combined cycle (NGCC) units. The Company notably does not use the Strategist capacity expansion model in the unit retirement study.

The problem with the Company's evaluation framework is that it has no guarantee that it is seeking a least cost alternative solution for the coal plant replacement, and thus is not an appropriate ratepayer-based valuation for the plants. The value of the existing plants, from a ratepayer perspective, is the benefit provided by the plants above and beyond the next least cost long-term supply and/or demand-side option. The Company's model presupposes that the next least cost option is an NGCC unit, under all circumstances. By choosing this replacement resource outside of an optimization framework, the Company's model fails to find a portfolio replacement that might provide better benefits in light of customer needs. Such a portfolio could include a combination of new fossil units, new renewable energy, and demand-side management (DSM) options. In fact, by excluding accelerated DSM as a viable partial replacement option in the replacement timeframe (i.e., by 2021), the Company commits two errors: (a) failure to find a least cost alternative to the retiring units, and (b) failure to recognize the breadth of avoided capacity and energy benefits provided by incremental DSM. This later point is discussed in more depth by my colleague, Mr. Tim Woolf.

Q Is the Strategist model well-suited to the examination of existing unit retirements?

A In part, depending on how the platform is used. In the context of seeking one-off replacement capacity and energy for retiring coal units (as is under consideration by the Company in this IRP), it performs acceptably. Indeed, the configuration of the model to perform this analysis is fairly straightforward – the user simply indicates the retirement date of the existing asset and allows the model to find replacement capacity options. The analysis can (and should) have additional elements, including the examination of avoidable capital and O&M in the last years of a unit's life, and evaluation of DSM as a replacement option, but the fundamental analysis is readily executable.

Overall, Strategist should have been used to select an optimal replacement resource plan from a variety of options, including construction of new fossil generation; purchase power agreements (PPA) for energy and capacity; and energy efficiency, demand response, and renewable generating resources. This optimal replacement resource plan would then be compared against the cost of the plan in which the existing generator still exists: the value difference between the two plans indicates the ratepayer value of the existing generator.

Where Strategist fails as a model is the ability to find the most cost-effective time and circumstance to retire an existing asset, known as "endogenous retirement." One might imagine that, rather than testing each individual unit on a one-off basis, as is done by the Company, one could simply ask the model to find when various existing assets are non-economic under different commodity price assumptions, and retire them cost-effectively. The Strategist model is an increasingly outdated capacity expansion platform, but newer commercial linear programming models are able to perform this task with relative ease, including a model from ABB (the vendor of the Strategist model) called System Optimizer.

Ideally, the Company's entire IRP would include an assessment of cost-effective existing unit retirements in the fundamental model structure, rather than as a separate "unit retirement study." Such a model co-optimizes capacity expansion and retirement under various futures, and avoids the need to make many of the shortcut analysis assumptions made by the Company in the unit retirement study.

Q You also stated a concern that the Company "inappropriately clustered substantially different coal units, blurring the line between marginal units and highly non-economic units." Why is clustering units problematic in the coal retirement study?

A Evaluating the economics of a whole plant rather than individual units blurs the economic differences between fundamentally dissimilar units. In particular, when units are of different sizes, heat rates, or have substantially different capital requirements, a clustered plant-level analysis completely obscures important differences.

While good practice dictates that individual units are reviewed in all circumstances, the Company's clustering of Hammond units 1-3 with unit 4 in the same analysis is particularly egregious, and results in misleading outcomes. Hammond 1-3 were built in the mid-1950s and are all smaller (125 MW) units. Hammond 4 was built in 1970 and is larger than the three smaller units combined, at 578 MW. According to the Company's GenVal model inputs, [redacted][12]

Q Does clustering the units of a plant make a difference in the Company's analysis?

A Yes. The Company provided unit retirement studies for Hammond 1-3 and Hammond 4 separately in response to Staff 1-31. As I showed in TS Table 1, the relative economic value of Hammond 1-3 versus Hammond 4 are substantially different. [redacted]

[12] GenVal data inputs provided as [redacted]

[13] Does not include adjustments and corrections to O&M and capacity price, as discussed later in this testimony.

[redacted]

Q Why did the Company choose to cluster Hammond 1-4 if these units are so different?

A The Company's explanation for why Hammond 1-3 and Hammond 4 were clustered is vague. In response to Staff 6-29, the Company states that "the analyses submitted for the Unit Retirement Studies were performed on a plant level basis.[14] Consistent with the Company's past practice, units were logically grouped based on operational synergies and economies of scale." The "synergy" line is repeated with respect to Hammond's capacity price in Staff 6-4, which explained that "the methodology of assigning the earliest need year to the group of units analyzed was employed due to the operating synergies among these units."

Neither of these explanations appears consistent with the actual operations of Hammond 1-4, and simply remaining consistent with "past practice" is not "best practice." Reviewing operations in 2015 from publicly reported data, we can see that Hammond 4 operates on a regular basis without Hammond 1-3. In fact, the majority of the time that Hammond 4 is in operation, Hammond 1-3 are not.

[14] STF 6-29 attached as Exhibit JIF-3.

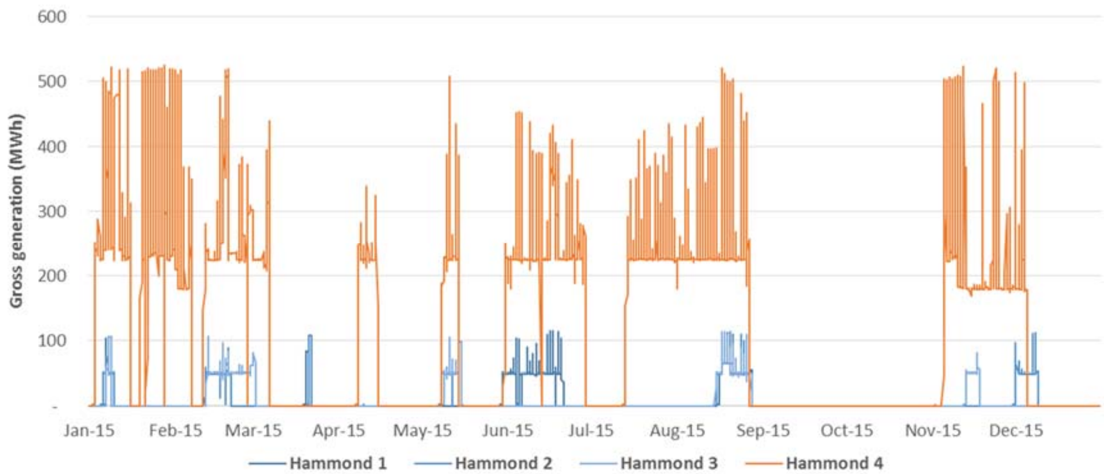


Figure 7. Gross generation from Hammond 1-4, 2015[15]

Overall, it would be correct to evaluate the long-term economics of Hammond 1-3 and Hammond 4 separately. In general, best practice is the separate evaluation of each and every unit in the Company's fleet.

4. <u>GAS PRICE ASSUMPTIONS ARE OUTDATED AND HIGH</u>

Q How does the Company's gas price forecast compare against recent estimates?

A Both recent natural gas prices and future expectations of natural gas prices have [redacted] markedly from the forecast provided for the Company by their fuel consultants. The Company's fuel price forecast methodology and outcome are described in the IRP Volume 1 Appendix H,[16] developed by Charles River Associates (CRA). According to Figure 13 therein, the Company's fundamental long-term fuel forecasts initially [redacted] price estimate in 2015 (2014$), with the "moderate" price forecast roughly [redacted]. However, by the time the paper (and this IRP) was published,

[15] U.S. EPA, Clean Air Markets Division. Air Markets Program Data. Pre-packaged data, hourly generation (2015).

[16] Georgia Power Company 2016 IRP. Volume 1, Appendix H. Scenario Fuel Forecast Documentation – Budget 2016. Prepared by Charles River Associates, December 2015.

it was known that the market price for natural gas was [redacted]. Indeed, Henry Hub natural gas prices averaged $2.63 per MMBtu in 2015, about [redacted] the 2015 estimate from CRA. In January and February of this year, those prices were $2.28 and $1.96, respectively, and on March 9th, Henry Hub prices reached "the lowest level in 20 years" at $1.57 per MMBtu.[17] NYMEX futures market expects prices to remain below $3 per MMBtu for 2016, 2017, and 2018.[18]

Since mid-2015, many analysts have realized that long-term gas prices are likely to remain very low, and reflect these trends in long-term utility projections. TS Figure 8 shows a comparison of the Company's forecasts (Henry Hub "low," "moderate," and "high"), short-term market-based futures, and other long-term forecasts from recent utility filings. The Company's forecasted prices [redacted] than actual and futures prices through [redacted]. After [redacted], the Company's forecasts begin to [redacted]. Then in [redacted], there is another [redacted] Company's forecast whereby the prices [redacted].

Starting in [redacted], the Company's "moderate" gas forecast is [redacted] than base cases developed by the Southwest Power Pool, PacifiCorp, and in the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) draft 2016 forecast. [redacted]

[17] EIA Natural Gas Weekly Update, March 10, 2016. Available at: http://www.eia.gov/naturalgas/weekly/archive/2016/03_10/index.cfm
[18] Henry Hub Futures: http://www.cmegroup.com/trading/energy/natural-gas, pulled on April 22, 2016

TS Figure 8. Georgia gas price forecast against other recent forecasts.[19]

Figure Redacted

[19] Source data:

a. GPC forecasts from Company response to TS Staff 1-37.
b. 2015 Henry Hub prices from EIA. Available online at https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.
c. 2016-2018 NYMEX futures extracted on April 22, 2016. Available online at http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.
d. EIA Annual Energy Outlook (AEO) 2016 draft reference case from February 9, 2016 presentation. Available online at https://www.eia.gov/forecasts/aeo/workinggroup/coal/pdf/AEO2016_Coal_Working_Group_020916a%20Presentation.pdf
e. Southwest Power Pool (SPP) data from 2017 ITP (Transmission Planning) summit on March 4, 2016. Page 7. Available online at http://www.spp.org/spp-documents-filings/?id=54277. Document 4 - 2017_ITP10_Overview.pdf (*Note: SPP forecast includes Central region basis differential*)
f. PacifiCorp December 2015 Official Forward Price Curve (Henry Hub), provided in PacifiCorp 2015 IRP Update, Figure 4.1 Available online at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015%20IRP%20Update/2015%20IRP%20Update_20160426.pdf
g. Indiana Michigan Power 2015 IRP, p.88 (November 2015). TCO delivered price for "No Carbon" case. Available at: https://www.indianamichiganpower.com/global/utilities/lib/docs/info/projects/IntegratedResourcePlan/2015%20I&M%20IRP.pdf
h. Source: Entergy New Orleans 2015 IRP, slide 2 (June 2015). Available at: http://www.entergy-neworleans.com/content/irp/Supplement_6-Supporting_Technical_Materials-Public.pdf
i. Southern Public Service Company 2015 IRP, p103 (July 2015) Available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/2015-SPS-NM-IRP-Final.pdf. *(Note: Includes basis differential from Henry Hub.)*

Q Should the Company's "high" gas price be considered?

A No. The "high" gas forecast is unreasonable and outdated, and should be disregarded for reasonable decision making. The Company's "moderate" price now serves as a reasonable high case, and there are other reputable entities that have clearly indicated that they believe gas prices will be [redacted], meaning that there is still room for a low forecast below the Company's outdated "low."

In all cases, however, the Company's forward gas prices have a [redacted]. This [redacted] would make the all-in cost of a gas replacement unit much higher at the start of its economic life, an important time period from the perspective of a discounted present value assessment.

Q Please explain the near-term [redacted] in the Company's gas price forecast.

A The upwards step is a function of blending low near-term forward prices derived from a commodities market and substantially higher long-term forecasts from the Company's fuel price forecast consultants.

According to Figure 13 in the IRP Volume 1 Appendix H,[20] the Company's fundamental long-term fuel forecasts initially [redacted] price estimate in 2015 (2014$), with the "moderate" price forecast roughly [redacted]. However, the prices projected in this document are not the same as are used in the unit retirement study. Instead, the Company appears to have realized, between the time that results were produced from its consultants on fuel prices and the time that the unit retirement study was produced, that market forwards for natural gas were substantially [redacted] long-term projections (at [redacted]/MMBtu, or nearly [redacted] estimates). Rather than re-visiting the fundamentals of the long-term forecast, the Company simply [redacted], retained [redacted]

[20] Georgia Power Company 2016 IRP. Volume 1, Appendix H. Scenario Fuel Forecast Documentation – Budget 2016. Prepared by Charles River Associates, December 2015.

[redacted], and interpolated [redacted]. This creates a distinct [redacted] [redacted] of anywhere from [redacted] ("low" forecast) to [redacted] ("high" forecast), implying a substantial recovery in the oil and gas markets in the very near term. NYMEX projections from April 2016 indicate that prices are projected to stay low through at least 2018 (after which point margins become too thin to be generally meaningful).

Overall, the Company's "low" case should serve as a rough proxy for a new "mid" estimate. In addition, it would be appropriate to add a new low below the Company's current "low."

Q Are the Company's coal plant valuations upwardly biased due to natural gas price assumptions?

A Yes. When making economic assessments of its fleet, the Company compares coal units to replacement natural gas units. Therefore, coal and natural gas generation are put in direct competition with one another. The Company's outdated and high natural gas prices bias the unit retirement study toward the selection of continued operation.

The Company's choice to assess its decisions to retire or maintain existing plants on the basis of a forecast which is now known to be high and outdated is imprudent. It is reasonable to reject (or marginalize) the Company's "high" forecast, re-brand the "moderate" forecast as a new high, and consider the "low" as a baseline estimate of forward-looking gas prices.

Under this revised assumption, Mitchell 3, [redacted] are all clearly non-economic, even without an assumption of a CO_2 price.

5. COMPANY'S DECISIONS ASSUME ZERO CARBON RISK

Q What CO_2 price is assumed by the Company for decision-making purposes?

A The Company assumes a zero CO_2 price in the unit retirement study for decision-making purposes.

Q But doesn't the Company assess a range of gas and CO_2 prices in the unit retirement study?

A Yes, the Company assesses the value of the existing fossil fuel plants under zero CO_2 price, a CO_2 price that starts at $10 per ton in 2020, and a CO_2 price that starts at $20 per ton in 2020. However, while the Company performs analyses with the CO_2 prices, the decisions about the retirement of units appear to be based exclusively on one run—the "moderate" gas price scenario with no CO_2 risk.

Q What is your evidence that the Company based its decisions only on a zero CO_2 price risk scenario?

First, the IRP Mix Study[21] identifies that the "[redacted]," and notes that relative to the base case, "[redacted]."

Second, had the Company assessed any other CO_2 price aside from zero, or even a simple average of all scenarios explored, [redacted] would have been shown to be clearly non-economic. Indeed, the Company's analysis shows that there is no circumstance, aside from an unreasonably [redacted] fares any better than having zero value. Therefore, I conclude that no read of the Company's analysis could have produced the decision [redacted] <u>except</u> to ignore all other runs aside from those with a zero CO_2 price.

Q Is it reasonable to assume no carbon risk over the Company's assessment period?

A No. It is not reasonable to assume that there will be no CO_2 price, real or implied, over the next three decades.[22] While the Clean Power Plan is currently under stay and legal consideration, there is certainly no guarantee that the rule will be overturned, and regardless, EPA is under a mandate to regulate CO_2 emissions from both new and existing power plants. Regardless of the disposition of the

[21] 2016 IRP, Volume 2 – Mix Study. "2 - TS 2016 Mix Study SCS – Final." Southern Company 2016 Integrated Resource Plan Resource Mix Study (January, 2016)
[22] The Company's analysis runs to 2045.

Clean Power Plan as a regulatory driver, there are multiple state and regional efforts to price CO_2, or displace emissions of CO_2 through complimentary policies. Indeed, Georgia Power states that "this IRP reflects a continuation of the Company's proactive efforts to position its system for a carbon constrained future," and goes on to describe that such positioning includes the "development of new nuclear resources and deployment of renewable resources."[23] Such a "proactive effort" clearly does not include making reasonable decisions for existing units on behalf of ratepayers.

Q The Georgia Attorney General and multiple other states are suing EPA over the implementation of the Clean Power Plan. If the state is opposed to the rule, why should Georgia Power assess the impacts of the regulation in its base case?

A The Georgia Attorney General's effort to halt or alter the Section 111(d) rulemaking process should not be the primary consideration for the Company's ratepayers. Legal challenges are typically filed in response to major EPA regulatory actions, but this does not excuse Georgia Power from its responsibility to comply with those regulations at the least cost, at a reasonable level of risk, for Georgia ratepayers. Forecasts are not appropriate venues for political outlooks.

Q Is the implementation of the CPP the only reason to include a real or hypothetical price on carbon emissions?

A No. My firm, Synapse Energy Economics, publishes a publicly available carbon regulation analysis and CO_2 price forecast on a regular basis. The study finds that utilities have (and continue to) plan on CO_2 emissions prices or reduction requirements regardless of the formal regulatory structure in place, including the CPP. The study states, in part:

> The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable. Such environmental

[23] GPC 2016 IRP, page 1-6.

> changes are expected to result in damages to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear, and policymakers have been responding accordingly. To make sound investment decisions, utilities must follow suit by considering existing, proposed, and expected future regulations.[24]

In addition, I have reviewed and mined data from dozens of public sector IRP published between 2008 and today. Over the last seven years, utilities have increasingly projected a future cost for CO_2 emissions, recognizing that this cost will, at some point, be internalized. This recognition did not fluctuate dramatically with the proposal or rejection of the 2008 American Clean Energy and Security Act, nor with the proposal, finalization or stay of the CPP.[25]

While the disposition of the finalized version of the CPP may impact near-term deadlines and prices, the idea that CO_2 emissions will remain unpriced for the next three decades is highly unlikely.

Q What would be your recommended CO_2 price for the purposes of the 2016 Georgia Power IRP?

A My firm, Synapse Energy Economics, publishes a publicly available carbon regulation analysis and CO_2 price forecast on a regular basis. As of March this year, we were projecting CO_2 prices starting between \$15 and \$25 per ton CO_2 in 2022, rising to between \$36 and \$110 per ton in 2050, allowance costs that were derived in part on the basis of mid-2015 projected gas prices.

At currently projected low natural gas prices (as discussed in Section 4), I would consider prices starting in the \$10 per ton range within reason. Coal-heavy states,

[24] Synapse Energy Economics. Spring 2016 National Carbon Dioxide Price Forecast. Updated March 16, 2016. Executive Summary. Available at http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast. Attached as Exhibit JIF-4.

[25] Fisher, JI. May 14, 2015. "Environmental Regulations in Integrated Resource Planning," presented at EUCI Conference *Utility Integrated Resource Planning*. Atlanta, Georgia. See pages 20-21. Available online at http://www.euci.com/energize/Fisher.pdf. Attached as Exhibit JIF-5.

if clustered together in trading regions, could see higher prices (i.e. the $20 per ton range) even at these lower gas prices.

At the Company's "moderate" gas prices, which I consider high, CO_2 prices would likely clear at higher dollar values to reach the same level of emissions reduction. I would expect a clearing price consistent with Synapse's most recent CO_2 price projection (i.e. at $20 per ton). Again, trading in clustered coal-heavy states could result in higher emissions costs (i.e. at a $30 per ton range, or above).

Therefore, I would expect the Company to evaluate a CO_2 price range from $0 per ton (as an unlikely sensitivity) to $30 per ton, with mid-cases at $10 and $20 per ton, depending on trading, stringency, and mitigation option assumptions.

It is my opinion that the combination of the Company's "low" gas price and $10 per ton CO_2 price trajectory are an appropriate base case for decision-making purposes by this Commission.

Q What is the impact of the $10 per ton CO_2 price on the Company's decisions to retire various units?

Substantial. At the Company's "moderate" gas prices (which again, are high and outdated), Mitchell 3, [redacted] are all clearly non-economic under a $10 per ton CO_2 price.

At my base case (equivalent to the Company's lower gas price point and a $10 per ton CO_2 price), Mitchell 3, [redacted] are non-economic. The valuation of [redacted] also drops by [redacted] from the Company's base perspective (see TS Table 1, first and fourth columns).

6. <u>UNIT RETIREMENT STUDY UNDERCOUNTS OPERATIONS AND MAINTENANCE (O&M) EXPENSES</u>

Q Earlier, you stated that the unit retirement study "erroneously assumed that the Company's obligation to pay fixed maintenance costs at coal-fired units

will decrease substantially over time." Please describe the nature of your concern.

A The Company's unit retirement assessment treats operation and maintenance (O&M) costs through a fairly *ad hoc* mechanism, which results in the absurd outcome that under most scenarios, the Company ceases paying fixed O&M expenses at coal-fired units well before the end of the analysis period. I understand the basis of the *ad hoc* mechanism, but the results are clearly erroneous, as I will describe shortly. Beyond simple error, the offhand mechanism has the effect of a significant bias in favor of maintaining the coal units, amounting to a substantial fraction of the benefit of maintaining the units.

Q What is fixed O&M, and how is it normally handled in long-term energy models?

A Fixed O&M (FOM) are expenses that are incurred on an annual basis regardless of the operation of the generator. These usually include most labor and administrative expenses, basic upkeep and maintenance, rents, fees, and property taxes.[26] In some cases, fixed charges for fuel supply (i.e., take-or-pay contracts or pipeline capacity payments) may also be included in the categorization of FOM in long-term models.

Production cost models (like GenVal) typically ignore all fixed costs, because they are focused on short-term dispatch considerations. Long-term capacity expansion models (like Strategist) may ignore FOM charges for existing generators because they do not impact dispatch decisions, and may be considered unavoidable if the model is not able to consider the retirement of existing generators. [redacted] On the other hand, since FOM is an important and expensive component of plant cost, and is eminently avoidable if a plant is retired, it was critical to include it in the

[26] See National Energy Technology Laboratory (NETL) September 2013. Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. Available online at https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/OE/BitBase_FinRep_Rev2a-3_20130919_1.pdf

unit retirement study. [redacted]

Q What is variable O&M, and how is it normally handled in long-term energy models?

A Variable O&M (VOM) are expenses that are incurred proportionately to the operation of a generator. Sorbent, catalysts, other environmental compliance chemicals, water, waste disposal, and byproducts are often included under the category of VOM.

Long-term capacity expansion models (like Strategist) and production cost models (like GenVal) both take VOM into account directly, because it is a key component of dispatch cost and hence the hour-to-hour profitability of an electric generator.

Q Were operations and maintenance expenses taken into account in the Company's Asset Valuation Models in the unit retirement study?

A Yes. The Asset Valuation Models include values for both VOM and FOM costs for every plant, [redacted] The manner in which these values are incorporated into the valuation of existing assets is rather opaque, however. Under normal circumstances, an asset valuation framework would compare explicit line items for fuel cost, VOM and emissions expenses (i.e., production costs), as well as FOM, capital expenses, and any other fixed charges against energy market revenues and equivalent capacity revenues, if applicable. The difference between these the costs and the revenues is the net margin. For a regulated utility, the plant may not actually make market revenues, but the calculation is the same as a merchant generator for the purposes of determining value.

The Company's model, however, skips a few steps when it comes to the existing units, which makes this particular error more difficult to assess. Instead of line items, the Company reports only a subset of terms normally used in a valuation framework [redacted].

Table 3. Typical and GPC Asset Valuation Model framework.

	Typical	Georgia Power Company
Production Costs	- Fuel Expense	[redacted] + ‘‘‘]
	- Variable O&M	[redacted]
	- Emissions (CO_2)	[redacted]
Production Revenue	+ Market Revenue	[redacted]
Fixed Expenses	- Fixed O&M	[redacted]
	- Capital Expenses	[redacted]
Fixed Revenue	+ Capacity Revenue	[redacted]
	= Net Margin	[redacted]

Q [redacted]**?**

A [redacted].

[redacted][28] [redacted]

[27] Gross margin: The difference between total production costs (fuel, variable O&M, and emissions) and energy market revenues. The gross margin does not include fixed costs.

[28] [redacted].

[redacted].[30]

This confusing and non-standard mechanism ends up leading to a substantial error for the existing units that would be blatantly obvious without the convoluted accounting.

Q Is this error present in the representation of costs for the Generic CC replacement unit?

A No. The asset valuation model clearly differentiates [redacted], although it also [redacted] into the gross margin calculation, rather than as a separate line item.

Q Did Staff ask for clarification with regards to the accounting measures in the Asset Valuation Model?

A Yes. In discovery request STF-14-2,[31] Staff asked eight detailed questions that would have shed light on the Company's Asset Valuation Model and non-standard accounting.

Q What was the Company's response to this request?

A In response to Staff's query, the Company simply replied that "the requested information was previously provided to Commission Staff." The response did not reference any other request or response.

As a result, I contacted Mr. Tom Newsome at the Georgia Public Service Commission (GPSC) to ask how this information had been provided to staff. Mr. Newsome indicated that the Company had contacted Staff or Staff's witness directly to provide clarification, a conversation corroborated by Company council.

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29 [redacted].

30 Notably, the Company's workbook actually appears to anticipate this need to keep matters clear and provides a separate line in which VOM costs could be taken out of the Budgeted O&M line to arrive at FOM. This line is not used, thus leading to substantial mislabeling in the Company's workbook.

31 PD STF-14-2 Attached as Exhibit JIF-6.

Neither I nor any other party were made privy to this conversation or its outcome, severely hindering my ability to assess this IRP and the Company's process.

Q You stated that the non-standard accounting led to a substantial error in the Company's accounting. What is the nature of that error?

A Simply stated, the Company removes too much [redacted]. Overall, it is clear that the model substantially undercounts required maintenance expenses due to this backwards bookkeeping.

Q [redacted]**?**

A [redacted].

[redacted],[32] the result of this machination is that [redacted] regardless of the annual operation of the plant.[33]

[redacted] total O&M drops markedly over the life of the plant.

[32] In modeling, the Company uses a nomenclature to identify gas and CO_2 pairings. Gas prices are denoted with LG, MG, and HG for "low gas," "moderate gas," and "high gas," respectively. CO_2 prices are denoted as 0, 10, and 20, marking the starting dollar cost for CO_2 in 2020. The Company's "moderate gas, zero CO_2 price scenario" is therefore marked "MG0," while a low gas case with a $20 CO_2 price is marked "LG20."

[33] In this particular case, the Company starts with total O&M (which inflates [redacted] per year), removes VOM from the MG0 scenario (specifically), and then adds back in the same VOM. On net, it results in simply increasing total O&M at [redacted] each year.

TS Figure 9 and TS Figure 10 below demonstrate the process and magnitude of the error.

TS Figure 9 shows total O&M at Hammond 1-4 as actually priced in the Asset Valuation Model for the MG0 scenario. As noted above, total O&M [redacted]

TS Figure 9. Total O&M at Hammond 1-4 from Company Asset Valuation Model (MG0 scenario).

Figure Redacted

Clearly, this pattern is absurd. [redacted] Absent liquidating the entire staff of the plant, there would not be any reason to believe [redacted].

TS Figure 10 illustrates the irrationality of this assumption in the LG10 scenario, my assumed base case. [redacted].

TS Figure 10. Total O&M at Hammond 1-4 from Company Asset Valuation Model (LG10 scenario).

Figure Redacted

As total VOM per case is an output of the Company's GenVal model, it should have been straightforward for the Company to execute its adjustment in a more rigorous fashion, make its assumption more explicit, and catch the error earlier. With the Company's current methodology, the Asset Valuation Models do not appropriately account for [redacted] in any circumstance, and significantly undercount the cost of maintaining the plant.

Q Where you able to correct this problem in the Company's analysis?

A Yes, to some extent.

I examined this problem specifically at Plants McIntosh, Hammond, and Wansley. [redacted] I was able to ensure that the plant accounted for total O&M costs over its entire lifetime.

Q [redacted]**?**

A For Hammond, Staff requested annual incurred FOM and VOM between 2010 and 2015, inclusive.[34] I adjusted these nominal values to constant 2016$, took the average (at [redacted]), and used this as my long-term assumed FOM, inflated annually at [redacted]. This calculation is likely conservative, [redacted].

TS Figure 11, below, shows the result of my [redacted] adjustment. [redacted] For Plant Hammond, it increases the cost of maintaining the plant by [redacted] (NPV 2016-2045).

[34] Response to Staff 6-5, Attachment A, tab G.

TS Figure 11. Total O&M at Hammond 1-4 <u>as adjusted</u> for consistent FOM (MG0 scenario).

Figure Redacted

The Company did not provide an historic breakdown of O&M at Plants McIntosh or Wansley, so I used data reported in Federal Energy Regulatory Commission ("FERC") Form 1 by Georgia Power Company. The form records several categories of O&M expense that are not readily separable into fixed and variable components. [redacted].

The results for McIntosh and Wansley are visually similar to the Hammond figures, if not more severe, as shown in Figure 12 and Figure 13 below. In McIntosh [redacted].[35]

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35 [redacted] By this logic, an abandoned, non-operational plant with no staff and no operations makes significant revenue just by existing.

Figure 12. Total O&M at McIntosh 1 implied from Company Asset Valuation Model (LG0 scenario).[36]

Figure Redacted

Figure 13. Total O&M at Wansley 1-2 from Company Asset Valuation Model (LG0 scenario).

Figure Redacted

Overall, my adjustment increases the cost of McIntosh by [redacted] and Wansley by [redacted] (NPV 2016-2045).

[36] "Budgeted O&M" from Company input.

7. UNIT RETIREMENT STUDY OVERVALUES CAPACITY BENEFIT OF EXISTING PLANTS

Q In your introduction, you stated that the Company's unit retirement study "used unsupported and erroneously calculated forward capacity prices when the units are being replaced." Can you explain further?

A Yes. The Company's unit retirement study (and underlying Asset Valuation Model) assigns a capacity value to both the existing fossil fuel resource, as well as the generic replacement NGCC. Since these resources are defined to have the same capacity, the capacity value is meaningless for every year in which both resources exist. However, in the replacement case, the coal unit is assumed to retire in [redacted] and the replacement unit is not built until [redacted], meaning that there is an implicit capacity replacement cost incurred for [redacted] while the new unit is under construction.

[redacted]

I will show that the derivation of the capacity price depends on a faulty assumption about the availability of capacity, and a poorly derived capacity price relationship.

Q If Georgia Power Company is not part of an open capacity market, why is there a capacity price in this analysis at all?

A In general, it is reasonable to assume that there is an intrinsic value to the ability to access capacity, although its value may be arguable and Georgia Power does not participate in a liquid capacity market as is otherwise available in PJM, New England, or even MISO. Therefore, I understand why the Company assesses a market value for capacity. However, the Company's calculations and assumptions for capacity prices are definitively incorrect.

Q What components are used in the formation of the Company's capacity price forecast?

A The capacity price forecast has two components, before and after a "year of need." The "year of need" represents a year in which the Company believes that it would need to pay [redacted] the capacity price forecast is the cost "associated with advancing a CT [by] one year."[37]

Q How was the capacity price prior to the year of need calculated?

A To calculate a base capacity price, the Company derived an exponential relationship between capacity price and reserve margin based on eleven ostensibly historical data points. That relationship was then applied to future expected reserve margins under a single scenario, and a capacity price generated.

Q Is the Company's calculation of capacity price prior to the year of need reasonable?

A No. Both the Company's methodology and the data it uses for this calculation are questionable. The Company's calculation relies on a methodologically-flawed regression analysis, as I will explain shortly, and the data is effectively unsourced. It consists of only eleven data points of reserve margin and capacity price, which are presented with scant and contradictory descriptions. [redacted] Without this background information,

[37] Reserve Margin Study, p23. i.e., the economic carrying charge (ECC) of a new CT.

it is impossible to tell whether or not these values are an appropriate dataset to be using for a predictive analysis such as a regression.

Q Is the Company's regression analysis an appropriate way to calculate capacity prices?

A No. The Company's regression analysis fails on two counts. First, the Company selected an [redacted] to describe the relationship between reserve margin and capacity price despite the fact that a [redacted] has a better goodness of fit (and thus is a better model). Second, the Company opted to use a more complicated and unsupported model when there is no directly known (or logical) [redacted] between capacity price and reserve margin. The ill-fitting regression analysis has very limited predictive value.

Q Is the Company's calculation of capacity price after the year of need reasonable?

A No. As I previously mentioned, the Company's capacity price forecast [redacted] to values representing the ECC of a new CT at the Company's predicted year of need, which is either [redacted] or [redacted] depending on the unit. For plants in which the year of need is predicted to be [redacted], the capacity price jumps to the carrying charge (ECC) of a CT immediately, and remains there until the replacement unit is built in [redacted]. [redacted]

Q How does the Company assess the "year of need"?

A The Company performed this analysis by incrementally removing relatively non-economic units to determine when the reserve margin sank below their expected requirement. According to Reponses to Staff 6-4, "the Company's approach was to assume all of these units were unavailable in [redacted] and then layer each unit back in-service in the order assigned while calculating the Company's reserve margin. The year the Company reflects a reserve margin deficit becomes the year of need.” [redacted]

There are multiple problems with this methodology. First, the Company's methodology links the fate of its assets to one another rather than examining the economics of each asset independently. While it may be appropriate to examine the capacity impacts of retiring multiple non-economic units simultaneously, the “year of need” assessment simply assumes that all less economic units have been retired, when in fact many of the units with a relatively low ranking are at low risk of imminent retirement.

Worse, the Company's execution of this analysis relies on outdated results from [redacted],[38] an assessment with substantially different economics and decisions than the present day. The Company's choice of [redacted] data for its year of need analysis causes the results to be nonsensical. [redacted]

Finally, the Company’s assessment of the “year of need” is inappropriately coarse and does not take into account the fact that in many cases, a much smaller segment of capacity would be required to keep the Company above reserve margins. Such a fine point could have theoretically been solved more readily in the Company’s Strategist model (i.e., the least expensive optimal capacity), but the Company opted not to use this model in the retirement study.

Q Where you able to correct the Company’s capacity price errors?

A In part, yes. Assuming that the Company’s historical capacity prices were accurate, if ill-sourced, I re-calculated [redacted]

[38] Refer to TS-STF-6-4 Attachment A, row 2. [redacted]

[redacted] For Plants [redacted], I assessed the capacity price with a "year of need" at [redacted], rather than [redacted]. I note that the adjustment to a [redacted] is a mathematically correct choice that favors the decision to maintain the coal plants.

Q What is the impact of your capacity price adjustment?

A By adjusting the year of need to [redacted] instead of [redacted], the value of maintaining Hammond 1-4 falls by [redacted] the value of Wansley 1-2 falls by [redacted]

Q What are the results of your adjustments to operations and maintenance costs and capacity prices?

A The table below shows the MG0[39] value that dictated the Company's decisions in this IRP (first column), my base case using the Company's LG10 scenario without any adjustments (second column),[40] the two values after my O&M and capacity price adjustments, as well as a column showing the outcome of the "low" gas price scenario (today's projections) without any carbon price.

TS Table 4. Plant valuations from GPC Unit Retirement Study and with Adjustments for O&M and capacity price

	Presented in 2016 IRP		**Adjusted for O&M and capacity price**		
	GPC Decision: Zero CO_2, "moderate" fuel	**Synapse Base Case:** \$10 CO_2, "low" fuel	**GPC Decision:** Zero CO_2, "moderate" fuel	Zero CO2, "low" fuel	**Synapse Base Case:** \$10 CO_2, "low" fuel
Wansley 1-2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hammond 1-4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
McIntosh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TS Table 4 shows the value of the three plants after adjustments in the last three columns. The first column shows the value from the Georgia Power's "moderate"

[39] MG0 = Moderate gas, zero CO_2 price
[40] LG10 = Low gas, \$10/ton CO_2 price

fuel, zero CO_2 price case ("MG0") upon which the Company appears to make its decisions. In this case, [redacted] moves from a marginal unit (at approximately [redacted] value) to a more certain liability, while [redacted] loses nearly [redacted] of its implied value (from [redacted] to [redacted]). As shown in the second adjusted column, with revised fuel prices (the Company's "low") closer to today's expected baseline forecasts, both [redacted] are distinctly non-economic. Finally, under even a modest CO_2 price scenario ($10 per ton), both [redacted] are clearly non-economic, with the value of [redacted]—from a net benefit in the Company's erroneous estimation to a substantial liability.

Overall, it is my assessment that both McIntosh and Hammond are significant ratepayer liabilities, and should be moved for decertification expeditiously.

Finally, Wansley 1 & 2 are not nearly as economically stable [redacted], and should be assessed carefully going forward. The Company finds [redacted] for maintaining these two units. However, under the new gas price regime, with the risk of even a low CO_2 price, and correcting capacity price and O&M errors, the [redacted], indicating that even relatively small capital costs at these units (or increased fueling costs) could change the economic outlook for these units.

Q Are there other problems with the Company's calculation of the capacity benefit of existing plants?

A Yes. The Company assumes that its existing coal-fired plants will provide an equivalent capacity value to a new CT through 2045, when these plants will be between 60 and 80 years old. This is an unrealistically optimistic assumption given the current and expected operation of these units, and it strongly overvalues the capacity benefits of the Company's existing plants as compared to new gas-fired generation.

Q **Why is the assumption that the Company's existing plants can provide the same capacity benefit as a CT unrealistic?**

A Capacity benefits depend on having near-immediate access to additional generation. The Company's comparison to existing units for capacity purposes is a combustion turbine, which is an appropriate choice given that CTs are able to respond rapidly (on the scale of minutes to an hour) to changes in demand. The Company's decision to ascribe the same per-kW capacity benefit to its existing units as would be provided by a new CT, however, is incorrect. Even when operating at less-than-full capacity, coal-fired plants generally have longer ramp rates (i.e., are slower to respond) than CTs. Coal-fired power plants have especially lengthy start-up times. Indeed, a brief survey of historical hourly generation data collected by EPA[41] suggests that Plants Hammond, McIntosh, and Wansley require at least three hours (and, in the case of Hammond 4, up to nine hours) to ramp from idle to generating at their full capacities.

Q **Does anything in the historical or expected future operation of the Company's existing units suggest that they have high capacity value?**

A No. As I described above, these units have been idle more and more in recent years. In several of the forecasted scenarios presented by the Company, its coal-fired units are idled for multi-year periods [redacted].

Despite these long periods of no operation, the Company continues to assume that these plants could provide a capacity benefit that is equivalent on a per-kW basis to a CT—even in years where the plant does not operate whatsoever. This generous assumption inflates the capacity benefit provided by these existing units.

While I believe that my concern with regard to the capacity value of the Company's idled coal units is valid, I did not make any adjustments or changes to the Company's assessment on the basis of this concern.

[41] EPA Clean Air Markets Program Database

8. RETIREMENT AND THE TREATMENT OF STRANDED COSTS

Q Which plants have you identified as not cost effective on a going-forward basis?

A Mitchell 3, McIntosh 1, and Hammond 1-4 are very likely non-economic on a going-forward basis. Wansley 1 & 2 may be marginally cost effective, but should be examined closely.

Q If the plants you've identified here all retire economically, wouldn't ratepayers incur a double cost in paying off both the existing plant balance as well as the costs of new replacement generation?

A No. The cost of paying off existing debts has already been factored into the analysis and the consideration of stranded costs guide the Company's assessment of a least-cost forward-going pathway. In addition, the Commission (not the Company) has leeway in selecting a treatment for stranded costs.

As a general principal, finding an optimal solution for ratepayers should disregard sunk costs, such as existing plant balance. The Company's investment in its existing plants is an important ratemaking issue but stands separately from the choice of a least-cost build and retirement plan. To conflate these two issues provides a distortionary incentive for the Company to maintain assets that are deeply underwater because pulling out risks losing a revenue stream from ratepayers. Instead, forward-looking analyses assume, implicitly, that the Company is made whole for sunk costs.[42] Compellingly, the analysis here shows that ratepayers are better off even if the Company is made whole for non-useful past investments.

[42] An analysis that assumes that the Company is not made whole for sunk capital investments would show a consistent massive ratepayer benefit in walking away from existing plant debts, and thus would almost always show a benefit in early retirement. This would be, on its face, a nonsensical analysis – akin to showing that buying a home and then walking away from the debt without penalty is a viable housing strategy.

Secondly, this Commission has full discretion with regards to the disposition of stranded costs for capital costs that have not yet been paid off. The Commission could choose several paths: (a) create a long-term (or short-term) regulatory asset from which the Company collects depreciation expenses and returns on past investments; (b) create a regulatory asset from which the Company collects only depreciation expenses; or (c) find that the retired coal plants are not economically useful, and thus are subject to a full or partial disallowance, compelling some form of division between ratepayers and the Company.

Q Aren't ratepayers on the hook for pending environmental compliance costs even if the plants retire?

A Generally no, although specific contracts held by the Company may have different terms, in which case this Commission will need to determine if those contracts were prudently incurred.

For Plants Hammond and McIntosh, the Company anticipates [redacted],[43] meaning that the plants can retire in that timeframe and not cause additional substantial stranded assets. At Plant Wansley, the Company is [redacted].[44] It is not clear if these projects are avoidable if the plant retires in the near future, and if so, what evidence the Company relied upon to determine that these environmental projects were cost effective. Overall, the Company is either required to [redacted] regardless of the disposition of the plant, or the Commission should assess the prudence of incurring this project's contract.

Ultimately, the retirement of McIntosh 1 and Hammond 1-4 would not leave this Commission with substantial incremental stranded costs above the existing plant balance. Should the Commission decide that Plant Wansley requires further

[43] See both TS STF-2-10, tab "CAPEX" and TS Asset Valuation Models for Hammond 1-4 and McIntosh, tab "Enviro Inputs."
[44] See TS STF-2-10, tab "CAPEX."

scrutiny, I recommend that the Company be required to disclose the analysis conducted to determine if the [redacted] were cost effective.

9. <u>ABILITY TO ACCESS KEY DATA IN A TIMELY FASHION</u>

Q Is your analysis informed by the full provision of timely information by the Company in this case?

A No. Our attempts to get full copies of the work papers upon which the Company bases its IRP and subsequent decisions has been substantially hampered by an arduous request process and the delayed and piecemeal provisioning of data. While the Company appears to have provided full and complete datasets to Staff, we were not able to access critical Company data until thirteen business days before this testimony was due. In addition, the Company appears to have provided substantial information to Staff outside of the discovery process, thereby making this data and information unavailable to intervenors.

Q When were you retained to provide testimony on this case?

A I was engaged by Sierra Club to provide testimony on this case in the beginning of February 2016, approximately a month and a half after the docket was opened.

Q When did you first request access to Trade Secret materials?

A Greenlaw, the attorney representing Sierra Club, first asked to be sent all Trade Secret materials that had been filed in this case (including but not limited to unredacted versions of the IRP and supporting documents, as well as Staff's requests for discovery and the Company's responses to these requests) in mid-March 2016.

Q Were you sent Trade Secret materials at this time?

A No. We were told that the Company required us to provide a specific, file-by-file list of the materials we were interested in. While this was possible for elements of the IRP filing and discovery record, this requirement left open the possibility that we had failed to request access to relevant files of whose existence we were unaware.

Q **When were you first provided with Trade Secret materials?**

A We first received Trade Secret materials on March 30, 2016, approximately a month before testimony was due.

Q **Were these materials complete?**

A No, not at all. First, we were not provided with the Company's more recent responses to discovery. More importantly, however, we were not provided with the Company's models and related input and output files. In Staff's first data request to the Company, Staff had requested all modeling materials. The Company responded that "the requested information was provided to Commission Staff on January 29, 2016, in accordance with the Commission's final order in the 2013 IRP in Docket No. 36498."[45]

In other words, <u>Staff was provided with this material outside of the discovery process</u>, and that data was not made immediately available to intervenors except through a separate request. When we asked the Company to provide copies of all data that had been sent to Staff, we were told that we needed to make our request more specific. We were unable to do so readily because the Company failed to disclose what data had been provided to Staff already. We were compelled to undertake an arduous and wasteful process of determining which files might be in Staff's possession in order to identify them to the Company. We then still waited a full week while the Company "processed" our request.

Q **Were you ultimately provided with the Company's models?**

A No, not a complete set by any means. After a lengthy back-and-forth between our counsel and the Company's legal staff, we were provided with copies of the

[45] Company response to PD STF 1-1. Attached as Exhibit JIF-7.

Company's excel-based models (including the Asset Valuation Model) and related materials on April 14, 2016—only 13 business days before testimony was due.

Q Which of the Company's data was not made available to you?

A The Company's primary IRP model is Strategist, a proprietary capacity expansion model used to determine a least-cost buildout given a set of generic resource options. The bulk of the planning decisions made by the Company are informed by this model, and fundamental Company assumptions are embedded in the Strategist model as inputs. Strategist is in common use for IRPs and other resource planning processes.

The Company provided us with proprietary-format Strategist input files, which can be neither read nor executed without a license for the Strategist model, a license which costs in excess of $20,000 for a limited use. Regardless of if we had the model and a licensure on hand, we would have had only two weeks to harness the model's capability.

Because of the Company's exacting specifications for our requests for information already provided to Staff, we asked explicitly for the specific output files that are produced by Strategist and are a standard part of Strategist production and review. These files would absolutely be in the Company's possession. The Company provided none of these files, meaning that we were unable to review the Company's fundamental IRP development mechanism, the Strategist model.

Q Do you, at this juncture, have a complete set of relevant Trade Secret information?

A No. We still do not have access to a complete discovery record, as we have been required to repeatedly submit requests for new material rather than being sent such materials as a matter of routine, as occurs in other jurisdictions.

In addition, as I noted previously in my testimony, the Company provided informal (i.e., oral) answers to multiple Staff requests, as well. Because intervenors are not granted discovery rights before this Commission, we had no way to examine the Company's response. Staff made multiple requests, many of which were critical to my analysis, to which the formal written response was "the requested information was previously provided to Commission Staff." Thus, by definition, this information was made <u>unavailable</u> to intervening parties.[46]

Q Has this process impeded your ability to perform a thorough and timely analysis of the Company's IRP?

Absolutely. The IRP is a complex document that relies on extensive modeling of different types. Ultimately, my team and I had <u>far less</u> time with key data than would have been appropriate and preferable for a case of this nature and import. While I believe the analyses presented above are correct and point to significant errors in the Company's consideration of its coal-fired assets, my comments have been limited to this area as I simply did not have enough time to perform a thorough analysis of other important aspects of the IRP. The inability of intervenors to submit discovery of their own or receive access to a complete record in a timely fashion prevents this proceeding from being a fully open and participatory one. As a result, the Commission has been prevented from receiving all of the contributing analyses and opinions which are its due, and which are intended to assist the Commission in making the best decisions for Georgia ratepayers.

As I described in my introduction, I have reviewed the core confidential data and models of utility plans in twelve states in nineteen litigated cases. This is the first case in which I have had no access to even the inputs and outputs, much less the fundamental model, by which the Company makes its decisions. The inability of intervenors to directly ask the Company for critical data and information severely

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[46] See specifically, STF-14-2, 14-3, 14-4, 14-5, 14-6, 14-7, 14-8, and 14-9. Response to Staff 14-2 attached as example. See Exhibit JIF-6.

impedes the ability of this Commission to render a fully informed opinion on the Company's analysis and planning.

10. CONCLUSION AND RECOMMENDATIONS

Q What have you concluded with regards to the Georgia Power Company's 2016 IRP unit retirement study?

A I was retained to review the Company's Unit Retirement Study and treatment of existing steam units. While my access to the Company's modeling has been hampered by the piecemeal and delayed withdrawal of information by the Company, I have found substantial concerns with the Company's unit retirement study and assumptions which, taken as a whole, dramatically change an objective assessment of the Company's existing fleet. Today, the Company requests the decertification of one existing coal-fired generator, Mitchell 3. It is my opinion that a rational planner would assess not only Mitchell 3, but both McIntosh 1 and all four Hammond 1-4 units as non-economically viable for continued operation. In addition Wansley 1 & 2 have substantially lower value to Georgia Power's customers than assessed by the Company.

If Georgia Power were to offer these eight generators to third-party buyers on an open market, they would receive no few, if any, positive value offers for the generators. Comparing the cost of these generators against the Company's narrowly defined best replacement option, all but Wansley 1 & 2 offer any ratepayer benefits, and the benefits offered by those two units are thin. Overall, ratepayers would see lower long-run costs if these units were retired and replaced by a least cost portfolio of options, including renewable energy, efficiency and demand response, power purchase agreements, and appropriately sized new thermal generation.

I found seven critical problems with the Company's unit retirement study:

1. It failed to seek an optimal replacement portfolio for retiring coal units, despite the fact that the Company maintains a basic capacity expansion model.
2. It clustered substantially different coal units for plant-wide analyses, which blurred the line between marginal units and highly non-economic units, even though the Company demonstrated the ability to provide outputs on a unit-specific basis.
3. It relied on an outdated and high gas price forecast, well outside of current utility forecasts, resulting in the erroneous impression that (a) replacement options are higher cost, and (b) market revenues for coal-fired assets will be higher than reasonable.
4. It failed to account for carbon regulation in the Company's actual decision-making, giving only lip service to the idea that any form of CO_2 reductions may be required over the next three decades.
5. It contained a critical accounting error that resulted in a dramatic and unrealistic reduction in the Company's operation and maintenance costs over the next three decades, implying that large steam generators can operate for multiple years with no budget and no staff, yet still provide significant capacity value.
6. It relied on unsupported and erroneously calculated forward capacity prices and used an outdated analysis to calculate when any capacity shortages may occur, falsely raising the hypothetical capacity value of existing generators over replacement options.
7. It assumed the existing coal units will provide capacity benefits to the system on par with new combustion turbines, even when idled for multiple spans of years, until these units are sixty to eighty years old.

I was able to correct some, but not all, of the errors and problematic assumptions on the part of the Company. I determined that, in addition to Mitchell 3, both McIntosh 1 and Hammond 1-4 are very likely non-economic on a going-forward basis. In addition, the net benefit of maintaining Wansley is likely substantially lower than determined by the Company, to the point that this plant is likely on the margin. Small changes in assumptions, known forward costs, or alternative replacement options could readily tip these units into a non-economic category.

In addition, I have shown that the Company has already taken steps to change their coal contracting methodology at both of these plants, possibly in anticipation of continued reduced output and near-term retirement. This analysis affirms that these plants should not be considered for continued operation.

I recommend that this Commission order the Company to, at a minimum, correct their analyses and re-file the Unit Retirement Study and action plan, or begin both the public and regulatory processes of moving not only Mitchell 3, but also McIntosh 1 and Hammond units 1-4 towards a near-term retirement schedule. In addition, the Commission should require that the Company reviewed Wansley 1 & 2 to ensure that ratepayers will benefit from the continued operations of that plant.

Finally, the process by which discovery and work papers were provided to intervenors in this IRP did not demonstrate a functional regulatory process with engaged intervenors. My analysis and testimony was hampered by the piecemeal and delayed provisioning of trade secret information by the Company. This prevented my meaningful intervention in the case, and denied this Commission the opportunity to hear viable and valuable alternatives or critical corrections to Company analyses.

I recommend that the Commission require that the Company provide timely and complete responses to discovery for all parties, and require that all data provided to staff also be provided, by default, to intervening parties with signed non-disclosure agreements.

In summation, the Company's Unit Retirement Study is incomplete and narrow, and fails to successfully identify non-economic units. Ratepayers will be saddled with higher costs and long-term risk than otherwise required.

Q **Does this conclude your testimony?**

A It does.