STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

<table>
<tr><td>Georgia Power Company's 2022
Integrated Resource Plan and Application
for Decertification of Plant Wansley Units
1 -2 & 5A, Plant Boulevard Unit 1, Plant
Bowen Units 1-2, Plant Gaston Units 1-4
& A, and Plant Scherer Unit 3; and
Application for Certification of the Power
Purchase Agreements from Plant Harris
Unit 2, Plant Wansley Unit 7, Plant
Dahlberg Units 1, 3, & 5, Plant Dahlberg
Units 2 & 6, Plant Dahlberg Units 8-10,
and Plant Monroe Units 1 & 2; and
Application for Certification of Capacity
from Blocks 2 -4 and Blocks 5 & 6; and
Application for the Certification,
Decertification, and Amended Demand-
Side Management Plan</td><td>)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)</td><td>Docket No. 44160 &
Docket No. 44161</td></tr>
</table>

DIRECT TESTIMONY OF
PETER HUBBARD
GEORGIA CENTER FOR ENERGY SOLUTIONS

May 5, 2022

DIRECT TESTIMONY OF
PETER HUBBARD
ON THE 2022 INTEGRATED RESOURCE PLAN

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Peter Hubbard. I am a Clean Energy Advocate with the Georgia Center for Energy Solutions, Inc. ("GCES"). My business address is 55 Leslie Street SE, Atlanta, Georgia 30317.

Q. PLEASE DESCRIBE YOUR ORGANIZATION.

A. GCES seeks to develop an economic and regulatory framework to transition Georgia's electric, transportation, buildings, and agriculture sectors to a 100% clean energy (zero-carbon) future in an equitable, reliable, resilient, sustainable, rapid, and economically efficient manner and in furtherance of the public benefit.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I hold two Bachelor of Science degrees in Physics and Mathematics and one Bachelor of Arts degree in French from the University of Memphis. I also hold one Master of Arts degree from the Johns Hopkins University School of Advanced International Studies in International Affairs with two Concentrations in International Economics and Energy, Resources, and Environment and one Specialization in Quantitative Methods and Economic Theory.

My professional experience is in energy management consulting focused on electric utility Integrated Resource Plan ("IRP") project management, organized power market analysis in North America, global gas market analysis, commodity price projections, stochastic risk analysis, future scenario development, strategic management consulting, capacity expansion modeling, production cost modeling, new technology assessment, and general economic feasibility of clean energy systems. I have 13 years of professional experience in the energy sector.

Q. MR. HUBBARD, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?

A. I have previously filed direct testimony and given an oral summary of my direct testimony related to Georgia Power Company's 2019 Integrated Resource Plan before the Georgia Public Service Commission ("Commission") in Docket No. 42310.

Q. **ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?**

A. Yes. I am sponsoring the following exhibits:

- Exhibit GCES-01, Peter Hubbard's Curriculum Vitae
- Exhibit GCES-02, Record High Percentage of Renewable Generation
- Exhibit GCES-03, Total System Costs by Scenario
- Exhibit GCES-04, Annual Fuel Costs Comparison
- Exhibit GCES-05, Map of Proposed Gas PPAs
- Exhibit GCES-06, Company Affiliations
- Exhibit GCES-07, Purchased Power Cost Comparison
- Exhibit GCES-08, Uneconomic unit commitment
- Exhibit GCES-09, Rate Impact by Scenario
- Exhibit GCES-10, Company Reliability Metrics
- Exhibit GCES-11, Reserve Margin Comparison
- Exhibit GCES-12, System Exports
- Exhibit GCES-13, Coal Unit Underinvestment
- Exhibit GCES-14, AEO Price Outlooks
- Exhibit GCES-15, Gas Pipeline OFOs

- Exhibit GCES-16, ELCC and LCOE Comparison
- Exhibit GCES-17, States Mentioned in Oral Hearings

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

A. I am testifying on behalf of the Georgia Center for Energy Solutions.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is to lay out my findings from a detailed review of the 2022 IRP and demonstrate that Georgia Power Company's (the "Company") 2022 IRP fails to adequately demonstrate the economic, environmental, and other benefits to the state and to customers of the utility, as required by the Official Code of Georgia Annotated (O.C.G.A.) § 46-3A-2. In addition, the 2022 IRP fails to meet the requirements of Commission Rule 515-3-4-.05, which states that a Base Case IRP be "based on the most economic and reliable combination of demand and supply-side resources" while "minimizing customer bills, minimizing overall rates and maximizing net societal benefit." I present my findings in the form of a listing of fatal flaws and red flags that I have identified along with comments on what is in the best interests of Georgia and Customers of the Company. Given these findings, it is my recommendation that the Commission require the Company to produce a new IRP (and related studies that are specifically identified in this direct testimony) that fully meets the requirements of Georgia law and the Commission's rules, and which adequately addresses the concerns raised in this direct testimony.

Q. ARE THE RENEWABLE INTEGRATION PLAN AND FLEET TRANSITION PLAN PROPOSED IN THE 2022 IRP ACTION PLAN IN THE BEST INTERESTS OF GEORGIA AND CUSTOMERS OF THE COMPANY?

A. No, they are not. The Company is proposing to add 2,100 MW of utility scale solar to be online by 2029 (IRP 1-14), with a similar tranche in the next IRP to be online by 2032, and so on, with a total of 6,000 MW incremental renewable capacity by 2035. This very long deployment schedule results in a higher-cost Proposed Portfolio through continued uneconomic coal plant operations. The lagged schedule also subjects Customers to significant and avoidable fuel commodity cost and price volatility risk from a fossil-heavy portfolio. It subjects the System to correlated fuel shortage risks. It continues to grow the $8.99 billion and rising liability for Coal Combustion Residuals Asset Retirement Obligation ("CCR ARO") that the Company is asking to recover from Customers. And it puts upward pressure on Customer rates. Rather, it is in the interests of Georgia and Customers of the Company to accelerate the transition to the lowest cost generation resource, which is utility-scale and distributed solar photovoltaics, as well as batteries, solar+storage (also called Battery Energy Storage System + Charging Solar or "BESS+CS"), energy efficiency, demand side management, and other resource options that will put downward pressure on Customer rates.

Q. IS IT POSSIBLE TO ACCELERATE RENEWABLE ENERGY INTEGRATION ON THE SYSTEM EVEN FASTER THAN PROPOSED BY THE COMPANY?

A. Yes, it is possible to accelerate the integration of renewable energy on the System ("System") (the Integrated Transmission System or tight electricity pool to which Georgia belongs) without sacrificing reliability and, in fact, likely improving currently poor reliability. Georgia Power Company and its Operating Company affiliates have a low renewable penetration rate compared to most other organized power markets in the United States and they have a similar poor ranking in terms of record renewable generation in an hour (GCES Exhibit 02). This same exhibit also demonstrates that it is technically feasible for renewable penetration rates to reach 100% on the System, as was very recently reported in California. The barriers to faster renewable energy integration are not technical. The barriers are embedded in the 2022 IRP that the Company has put forward seeking approval.

Q. IS THE COMPANY'S PROPOSED PORTFOLIO IN THE BEST INTERESTS OF GEORGIA AND CUSTOMERS OF THE COMPANY?

A. No, it is not. The Company is proposing the Moderate Gas, $0 Carbon ("MG0") case as its Base Case, which serves as the basis for the Proposed Portfolio. The Proposed Portfolio includes the Chapter 19 Action Plan and all the requested approvals in the Conclusion of Chapter 1. However, the Company acknowledges that "continuing to invest in these [coal and oil] units for the long-term increases the risk of new environmental compliance costs" (IRP 1-5). Gas units are subject to many of the same cost risks that coal and oil units are subject to, including fuel price volatility and carbon pricing. Gas units are subject to additional risks like upstream methane leakage accounting that could exceed the cost risk to coal and oil units. This conclusion is reached by the Company's own modeling which shows significant upside risk to Total System Cost from high gas prices and any carbon price (GCES Exhibit 03). These are risks that renewable capacity does not face (GCES Exhibit 04).

Q. WHAT ARE THE FATAL FLAWS AND RED FLAGS YOU'VE IDENTIFIED IN THE 2022 IRP?

A. I have identified at least five (5) fatal flaws and six (6) red flags in the 2022 IRP document and appurtenant documentation. The first fatal flaw is embedded in the Renewable Integration Study, which artificially inflates the required level of operating reserves to meet the full intermittency of renewable energy, rather than selecting for less expensive options than increased operating reserves. This results in large mitigation costs that create an economic hurdle for renewables to be selected in any model. First, the only mitigation option the Company uses to address swings in net demand from solar is an increase in operating reserves. Instead, operational curtailment of excess renewable generation could avoid the direct cost of increased operating reserves. Second, economic curtailment of solar generation is counted as a direct cost rather than an opportunity cost. This is done by increasing operating reserves until pre-curtailment levels are reached, converting an opportunity cost into a direct cost. Third, the Renewable Integration Study fails to account for geographic diversity of solar (and wind) that would smooth out swings in net demand, which further increases operating reserves and thus mitigation costs. These three increases in 'required' operating reserves creates a more costly Proposed Portfolio.

The second fatal flaw is that the long-term capacity expansion plan modeled in AURORA was constrained to only allow for generic capacity expansion beginning in the year of capacity need, which in this IRP is 2029. Capacity for the period of 2022-2028 comes from the 2022-2028 Capacity RFP ("Capacity RFP" or "RFP"), which very plainly excluded and disadvantaged many lower-cost and lower-risk resources, while advantaging gas-fired units (see following Q&A on the Capacity RFP). The RFP resulted in 85% of the winning gas Power Purchase Agreement ("PPA") capacity contracts belonging to a direct affiliate of Georgia Power Company (GCES Exhibit 05 and Exhibit 06). It is also true that Purchased Power is up to 2.3 times as costly as power that the Company provides from its owned units (GCES Exhibit 07). Accordingly, the Capacity RFP did not result in a market-based outcome and is not in the best interests of Georgia and Customers of the Company.

The third fatal flaw is the failure to address uneconomic unit commitment. The Company states that the System operates according to economic dispatch, which seeks to minimize the total System production cost (IRP G-164). Although security constrained economic dispatch is subject to operational constraints and reliability considerations, the lowest cost generation assets are not being dispatched by the Company to ensure that the lowest cost energy is produced every hour. This issue was examined by Synapse in their November 2021 report "Georgia Power's Uneconomic Coal Practices Cost Customers Millions" using publicly available Company-reported data (GCES Exhibit 08). Synapse determined that the Company's uneconomic unit commitment practices resulted in $232 million in excess costs for Customers from 2017 to 2020. The Proposed Portfolio does not address the issue of uneconomic unit commitment and will continue the practice. Accordingly, the 2022 IRP fails to adequately demonstrate the economic benefits to Georgia and to Customers of the Company as required by O.C.G.A. § 46-3A-2.

The fourth fatal flaw is the continued overreliance on a non-diverse, gas-heavy portfolio. The Company's own scenario modeling shows that there is significant upside risk that Total System Costs could be much higher than the Base Case. This creates upward rate pressure risk from any level of carbon pricing and from high gas prices. The Base Case is six (6) times riskier than a low gas future if each scenario is equally likely as the Company claims, which it is not (GCES Exhibit 09). This is not an acceptable risk when existing, commercial technologies like solar+storage can provide all the energy, capacity, and ancillary services that gas-fired units can provide, except at lower cost and lower risk than gas.

The fifth fatal flaw is the plan for an additional 6,000 MW of new renewables resources by 2035. This number is unjustifiably low and does not come out of any of the analysis or modeling presented in the 2022 IRP. Rather, it is based on the Company's judgment. This very slow transition to replace higher cost coal and gas units with utility-scale and distributed solar photovoltaics, batteries, solar+storage, energy efficiency, demand side management, and other resource options results in upward pressure on Customer rates. The Company is already moving too slowly to procure the required renewable capacity stipulated in the last IRP, having issued the second Renewable RFP only 10 days before this 2022 IRP was filed. The McGrau Ford battery will not come online until 2027. The Company claims it cannot expand the monthly net metering cap of 5,000 Customers until all systems are interconnected, one full year passes, and a study is performed on the resulting performance data. Meanwhile, the RFP Framework shows five (5) benefits and one (1) cost to distributed generation. These delays put upward pressure on Customer rates.

The first red flag is that reliability is talked about extensively in the IRP and the Company invests significant capital expenditure on reliability, but actual Company performance is demonstrably poor. According to self-reported data from EIA Form 861, Georgia Power Company ranks near the bottom among investor-owned utilities for two common reliability metrics (GCES Exhibit 10).

The second red flag is that the System reserve margin is too high because the generation capacity of Georgia Power Company and the other Operating Companies in the pool is overbuilt, beyond what is recommended in the company's economic Target Reserve Margin (GCES Exhibit 11). Furthermore, there are significant historical energy exports to neighboring Balancing Authorities, which is a strong signal of excess capacity, uneconomic unit commitment, or both (GCES Exhibit 12). Overbuilt capacity is a significant cost that is not in the interests of Georgia and Customers of the Company.

The third red flag is the underinvestment in Bowen Units 1-4 and Scherer Unit 3. This reduction in spending was ordered by the Commission in the 2019 IRP. However, there is a non-negligible risk that this underinvestment will impact System reliability, which is already poor (GCES Exhibit 13).

The fourth red flag is the inconsistent use of models and swapping of data between models, which results in a sub-optimal and uneconomic Proposed Portfolio. For example, production costing is modeled in the Strategic Energy and Risk Valuation Model ("SERVM") (IRP C-148), a legacy Southern Company-developed model that is also used for the Reserve Margin Study and Renewable Integration Study and that includes support from a legacy Southern Company consultant, Astrapé. Production costing is also modeled in AURORA to determine marginal energy cost for use in the Profitability Reliability Incremental Cost Evaluation Model ("PRICEM") and RCB Framework (IRP C-151). Finally, production costing is modeled in the Strategist model for the 2022-2028 Capacity RFP (IRP K-182). This inconsistent use of three different production cost models creates discontinuities in the IRP analysis and results in a higher cost portfolio.

The fifth red flag is that transmission planning was conducted independently of the generation planning in the AURORA model and is only planned out 10 years, half the time horizon as generation planning. Generation and transmission planning analysis can be performed together at a high level using the AURORA model, which provides internal consistency to the modeling and increased confidence in results, after which more detailed transmission analysis (voltage, frequency, thermal violations, etc.) can be conducted. This is another discontinuity that likely results in a suboptimal Proposed Portfolio.

The sixth red flag was the Company's admission (Witnesses Phillips and Valle, Day 2 at approximately 1 hour and 5 minutes into the hearing) that they dismissed the conclusion of the Georgia DSM Working Group to use the AURORA model to allow demand-side resources to compete head-to-head with supply-side resources. However, the Company concluded that because it is a complex process to model demand-side resources in AURORA, their current methodology is the most appropriate. The Company can simply reach out to Energy Exemplar, the licensor of the AURORA model, and they will provide guidance on implementing demand-side resources.

Q. WHAT ARE THE CONCERNS YOU'VE INDENTIFIED IN THE RENEWABLE INTEGRATION STUDY?

A. The Company is asking for approval of the Company's use of the Renewable Integration Study for planning purposes (IRP 1-14). However, the study demonstrates many fatal flaws and red flags that artificially inflate the required renewable integration costs. As a result, use of the Renewable Integration Study in the 2022 IRP results in a Proposed Portfolio that is economically sub-optimal and puts upward pressure on Customer rates.

The first fatal flaw is that the Renewable Integration Study does not consider less costly solutions. The Company states, “the intermittent nature of solar resources creates unexpected swings in the momentary net demand on the system, which must be met using the inherent flexibility of the system, including the flexibility associated with available operating reserves.” The sole solution proposed in the Renewable Integration Study to mitigate swings in net demand is to increase operating reserves, which is among the most expensive mitigation costs. The Company did not consider that the solar resources themselves can provide the needed flexibility by curtailing excess solar energy with Automatic Generation Control (“AGC”) and using behind-the-meter batteries to shave peaks and fill troughs to provide firm energy and reduce unexpected swings in net demand. AGC is affordable, as affirmed by Witness Mallard who estimates AGC has a price of $50k that is borne by the developer. Moreover, the Company admits that a flexibility violation, “does not likely represent an actual loss of load.” In sum, the Company is proposing an expensive option for a problem that may or may not occur, when less expensive alternatives are available.

The second fatal flaw is that the Renewable Integration Study falsely considers solar generation curtailment as a direct cost rather than an opportunity cost to displace more expensive generation or to generate revenues via off-system sales. The Company states, “The increase between the pre- and post-mitigation curtailment should be considered an additional integration cost.” This adds even more expensive operating reserves beyond what is needed to meet swings in net demand, as discussed above. The so-called ‘overgeneration’ can simply be curtailed with AGC and does not require an increase in operating reserves. Furthermore, the Renewable Integration Study does not consider the impact of off-system sales of surplus solar energy.

The third fatal flaw is that the Renewable Integration Study fails to account for geographic diversity of solar resources across the System. It is well-documented that the broader the geographic distribution of solar resources, the less volatile the aggregate generation swings of solar resources. The Renewable Integration Study does not take this effect into account, which would reduce the required level of operating reserves and reduce mitigation costs.

The first red flag is that the Renewable Integration Study uses one-hour blocks to determine the level of additional spinning reserves required to manage the change in load from hour to hour. Spinning reserves are ready to dispatch at a moment's notice. While a sub-hourly analysis of intrahour load changes was conducted, the use of one-hour block requirements for additional spinning reserves likely inflates the true requirement.

The second red flag is that the Renewable Integration Study does not include a scenario to account for the Southeastern Energy Exchange Market ("SEEM"), and as a result does not reflect the now certain future.

A third red flag is the reliance on the traditional Loss of Load Expectation ("LOLE") metric as the sole reliability target. The North American Electric Reliability Corporation ("NERC") issued a report ("Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning" or "2011 NERC Study"), which the Company references and uses in the 2022 IRP, acknowledges that planning based on LOLE alone may be inadequate to accurately measure a resource's reliability. The NERC report was issued 11 years ago and does not capture the learnings on resource adequacy metrics of the last decade. Accordingly, the Renewable Integration Study needs more diverse and inclusive reliability metrics.

Q. WHAT ARE THE CONCERNS YOU'VE INDENTIFIED IN THE RESOURCE MIX STUDY?

A. The Resource Mix Study demonstrates numerous fatal flaws and red flags that result in the exclusion or disadvantaging of resources that, if included or evaluated properly, would result in a more economically optimal portfolio. Its use in the 2022 IRP is an additional factor as to why the Proposed Portfolio is not in the best interests of Georgia and Customers of the Company.

The first fatal flaw is that BESS+CS is excluded as a generic candidate expansion resource. Solar and storage are available separately, but the generic expansion plan should have offered the same resources as the Capacity RFP. Ostensibly, BESS+CS could have been a resource option prior to the first year of capacity need (2029), but it was greatly disadvantaged in the Capacity RFP and thus excluded from 2022 to 2028. Batteries, firm wind, compressed air energy storage, capacity in neighboring Balancing Authorities, and other resources were also excluded from the Capacity RFP.

The second fatal flaw is that CT additions only include the cost of contracting for firm summer only natural gas delivery (page 12), whereas the larger and growing larger reliability risk to the Company is in the winter when gas pipelines are the most constrained. Furthermore, it should be noted that Witness Grubb testified to the following: Daniel Walsh (Day 1 at approximately 1 hour 2 minutes into the hearing): "In obtaining a firm gas transportation contract, did the Company assume that it would be necessary to have a firm gas contract every day of the year?" Witness Grubb responded, "Yes, we did." This inconsistency and failure to account for the full cost of year-round firm transportation in the Resource Mix Study biases the model toward selection of CTs at the expense of other resources.

The third fatal flaw is that the Base Case is based upon the Annual Energy Outlook ("AEO") 2021 Reference Case, which is historically a poor predictor of future gas prices, as all AEO forecasts are (GCES Exhibit 14) (note: the AEO includes multiple scenarios to address this issue). This topic is discussed in detail in another Q&A of this testimony.

The fourth fatal flaw is that unabated gas-fired resources are available for expansion through 2039 in the case of Combined Cycle units and 2034 in the case of CTs. These gas units will have a book value of 20 years or more, which is inconsistent with the 2050 Net Zero Carbon target from Georgia Power's parent company. This creates a stranded asset risk for these late-addition gas resources, which is a risk that will be borne by Georgia and Customers of the Company. It will be very expensive to retrofit unabated gas units for Carbon Capture and Sequestration or to repower/re-engineer for hydrogen firing, so these are not economic options. The latest that unabated gas should be allowed to be added to the System is 2030, to remain consistent with the 2050 Net Zero Carbon target. The Company is proposing gas PPAs in another Operating Company's service territory. Accordingly, the System-wide 2050 Net Zero Carbon target should also be integrated into the 2020 IRP Resource Mix Study.

The red flag is that all expansion units were sized to 300 MW blocks for the sake of modeling expediency. However, there is no reason to have equal sizes of capacity blocks for different technologies, and this assumption biases selection toward large, centralized units rather than smaller, more distributed assets.

Q. IS THE 2022-2028 CAPACITY RFP IN THE BEST INTERESTS OF GEORGIA AND CUSTOMERS OF THE COMPANY?

A. No, it is not. The Capacity RFP is a critical element of the 2022 IRP Action Plan but demonstrated serious technical flaws that arbitrarily excluded or constrained market-based solutions, as well as financial, risk, and procedural flaws. These flaws include, but are not limited to, the following:

Technical:

(1) the RFP excluded most resources less than 100 MW from participating in any manner in the RFP, including a notable gap between 30-100 MW. This arbitrary cut-off excluded many medium-sized projects that could provide additional value that small- and large-sized projects cannot deliver;

(2) the RFP created barriers that disadvantaged or excluded certain technology offerings that can provide capacity, notably including compressed air energy storage and all demand-side resources. This is contrary to the Company's statement, "This [IRP] process provides for an orderly and reasoned framework through which both demand- and supply-side resources are compared on an equitable basis to develop a plan that provides for reliable and economical electric energy to serve customers' needs over the planning horizon" (IRP 4-22). Excluding resources is not an equitable basis for soliciting capacity in order to meet reliability and resource adequacy requirements;

(3) the RFP required that any resource offering capacity must provide one full cycle in a 24-hour period in order to qualify for participation, without providing justification for this requirement, which disadvantaged BESS+CS resources;

(4) the Company states that renewable resources are weather-limited, drawing a contrast to gas resources. However, gas resources are not only weather-limited but face correlated fuel scarcity risk, which the RFP minimizes or ignores as a risk for gas resources. The Company acknowledges such weather-related limitations for gas resources, "These units operate primarily on natural gas while maintaining limited coal backup per the requirement of the Mercury and Air Toxics Standards rule to ensure reliable operation during periods when natural gas pipelines are constrained, such as during cold winter days." Most of the gas resources in the PPAs do not have coal backup, and not all expensive have Firm Transportation. As a result, gas resources were advantaged in the RFP;

(5) the Company did not accurately or fairly address the value of real-time operational flexibility provided by renewable resources (with Automatic Generation Control), the reduction in congestion costs from small- and medium-

sized resources that are distributed rather than resources that are centralized in blocks of capacity 100 MW or larger, or the transmission and distribution capital expenditure deferrals from small- and medium-sized resources in the RFP, all of which disadvantaged renewable resources;

(6) the gas resources were advantaged in the RFP by ignoring permit condition limitations. For example, Plant Monroe (Doyle Energy Facility) Units 1 & 2 are limited to 1,550 hours each per consecutive 12-month period in order to limit carbon monoxide emissions;

(7) the RFP ignored the symbiotic relationship of BESS+CS, which can make a significant contribution to reliability of the System. Using a loss of load probability model to estimate the capacity credit of solar resources and battery resources under increasing penetrations of both technologies, in isolation and in tandem, North Carolina State University researchers have demonstrated that as much as 40% more of the combined capacity can be counted on during peak demand hours compared to scenarios where the two technologies are deployed separately.

Financial:

(8) while BESS+CS and gas Combined Cycle ("CC") resources were treated exactly equally in terms of Buy Down Payment penalties for capacity reduction, despite nominally different products (Designated Storage Capacity vs. Designated Capacity, respectively) that are functionally equivalent, BESS+CS resources were treated unequally in the RFP and were disadvantaged in at least two ways by not being allowed to designate Nominal Supplemental Capability ("NSC") on top of a designation of Nominal Base Capability ("NBC")" (IRP 11-74) like CC resources were allowed to do with duct-firing and with an option for multiple tiers of NSC;

(9) the calculation of Contracted Capacity Cap in the RFP requires 102.5% of the NBC, where 100% of capacity and energy generated by the unit must be sold to the Company, with restrictions on NBC, but any shortfall of capacity below 92% triggers a rapid 10-day Cure Period after which significant liquidated damages are triggered, which disadvantaged BESS+CS resources;

(10) the BESS+CS resources were disadvantaged by the calculation of replacement costs using Seasonal Availability Percentage compared to gas resources that calculate replacement costs based on a Monthly Availability Percentage, which can lead to higher performance hurdles and higher replacement costs on Undelivered Scheduled Energy vs. Undelivered Energy;

(11) the BESS+CS resources were disadvantaged by the application of the reductive Seasonal Availability Adjustment to the Monthly Capacity Payment, which did not apply to gas resources;

(12) Certification of the PPAs arbitrarily and unfairly shifts fuel costs to non-participating customers of the Company, including customers who fully subscribe to the Company's solar programs such that they offset all their energy consumption and capacity needs via solar resources. This is a cross-subsidization of gas resources via the PPAs by non-participating customers of the Company.

Risk:

(13) the gas resources were advantaged in the RFP by ignoring the risks, which are currently present and growing into the future, from federal regulation in multiple matters presently before the Supreme Court of the United States (e.g., West Virginia v. EPA), which are risks not faced by BESS+CS resources;

(14) the gas resources were advantaged in the RFP by ignoring the substantial risks born presently by gas resources from fuel price volatility and correlated fuel scarcity due to heavy dependence on interruptible transportation during winter months on the Southern Natural Gas pipeline system, which experienced 41 days of Critical Notice Operational Flow Orders ("OFO") from November 11, 2021 to March 15, 2022, including two days of the highest OFO Type 6 in which daily shipper imbalances threaten system integrity (GCES Exhibit 15). This risk is inherent to gas-fired generation and follows from a dependence on vulnerable pipeline infrastructure, and which are risks that BESS+CS resources do not face at all;

(15) the gas resources were advantaged in the RFP by ignoring the risks of financial impairment for gas-fired generation. These financial impairment risks are derivative of the regulatory risk, climate risk, fuel price volatility risk, and correlated fuel scarcity risk that gas resources face presently, which are risks that BESS+CS resources do not face at all or in equal measure.

Procedural:

(16) the process was concluded without obtaining Post Evaluation Standard of Conduct Agreements for five members of the RFP Evaluation Team, including notably the Financial Analysis and Planning Manager and the Bulk Power Operations Compliance Assurance Manager;

(17) the relationship between Southern Company's unregulated subsidiary, Southern Power Company, and Southern Company's regulated subsidiary, the Company, is unmonitored and unregulated, which can lead to conflicts of interest between the Affiliates with substantial business before each other via the PPAs;

(18) the justification for the capacity required for Reliability and Resource Adequacy that is solicited in the RFP is called into question by the 2021 Long-Term Reliability Assessment issued in December by the North American Electric Reliability Corporation ("NERC"), which demonstrates that the region in which the Company, its affiliates, and merchant capacity operate (SERC-SE) is anticipated to have a summer Reserve Margin as high as 46.8% in 2028 vs. the Company's Target Reserve Margin of between 14.78% and 16.25% for summer periods or Economic Reserve Margin of 20.5%.

Q. WHAT ARE THE CONCERNS YOU'VE INDENTIFIED IN THE STUDY OF RENEWABLE CAPACITY VALUES USING THE ELCC METHODOLOGY IN THE SOUTHERN COMPANY SYSTEM?

A. The Effective Load Carrying Capability ("ELCC") is the capacity value assigned to energy-limited or non-dispatchable resources and is examined in the Study of Renewable Capacity Values using the ELCC Methodology ("ELCC Study"). The

ELCC methodology is compared to the Company's current use of an Incremental Capacity Equivalence ("ICE") Factor and the ELCC Study concludes that they are equivalent. However, both methodologies discussed in the ELCC Study demonstrate red flags.

The first red flag is that the ICE Factor methodology assumes a gas-fired combustion turbine ("CT") is a fully dispatchable resource. (GCES Exhibit 16). CTs experience forced outages. CTs have emissions and operations limitations. CTs that lack dual-fuel capability can experience restricted energy supply during critical periods of grid operation, such as during winter weather when constraints on natural gas pipeline transportation are frequently seen (GCES Exhibit 15). This fuel risk is augmented by its correlation among gas resources, as there are just two pipelines serving all the Georgia Power gas fleet.

The second red flag is that the ICE Factor shows utility scale solar at 10% winter and 35% summer (rooftop solar is 5% and 25%, respectively), meaning solar has year-round capacity value. However, solar received a 0% capacity credit in the Capacity RFP, and BESS+CS was significantly disadvantaged vis-à-vis gas resources.

The third red flag is that the ICE Factor does not account for increasing resource penetration levels or geographic diversity, which limits its usefulness, whereas the ELCC methodology is dynamic and adapts to an increasing penetration level of renewables that are dispersed across varying locations.

The fourth red flag is that the ICE Factor yields a non-winter capacity credit of 20% whereas the ELCC method gives 40%, a major difference that will significantly impact the long-term capacity expansion planning process and level of wind recommended in the Resource Mix Study. Notably, wind received a 0% capacity credit in the Capacity RFP because it was excluded.

Q. WHAT ARE THE CONCERNS YOU'VE INDENTIFIED IN THE ECONOMIC AND RELIABILITY STUDY OF THE TARGET RESERVE MARGIN FOR THE SOUTHERN COMPANY SYSTEM?

A. The Target Reserve Margin Study ("TRM Study") uses a probabilistic approach to randomly select unit availability and performance, weather year, and load to determine what level of reserve capacity is needed to reliably and economically meet Customer load. However, the TRM Study demonstrates red flags.

The first red flag is that the TRM Study recommends a Summer TRM of 16.25% whereas Base Case summer reserve margin for the Company reaches 30.6% in 2027, with an even higher 35% in 2021 for the System. The surplus capacity is a cost that is being borne by Customers, but the modeling shows it is not needed (GCES Exhibit 11).

The second red flag is the assumption that unit performance and availability are less correlated than is implied by the Unplanned Outage Probability shown in Figure I.8. Georgia Power's gas fleet relies on two pipelines only that are subject to fuel scarcity risk, operational restrictions, cyberattack, and so on. The Company states, "there have been occasions in the last ten years when more than 10% of the capacity of the system has been in a forced outage state concurrently." In addition, the use of historical weather years minimizes the correlation. Using weather patterns from 1962 through 2019 dilutes the recent acceleration of weather pattern change and ignores the expected acceleration of weather pattern changes over the 2022 IRP planning horizon.

The third red flag is that the TRM Study ignores and does not include in its reliability assessment a metric for forced unserved energy from Customer shutoffs.

Q. WHAT ARE THE CONCERNS YOU'VE INDENTIFIED IN THE UNIT RETIREMENT STUDY?

A. The Unit Retirement Study demonstrates fatal flaws and red flags that result in a flawed assessment of optimal unit retirement dates. The first fatal flaw is that the results of Capacity RFP were uses as actionable information in this Unit Retirement Study. However, the Capacity RFP excluded and disadvantaged many lower-cost and lower-risk resources, which resulted in 85% of the proposed gas PPA capacity offered by a Georgia Power Company direct affiliate and this purchased power will be more expensive than self-generation (GCES Exhibit 07). The Unit Retirement Study only evaluated the winning Capacity RFP resources in its replacement capacity cost analysis through November 2039, rather than looking at lower-cost resources like solar+storage that were excluded from the Capacity RFP to be evaluated for their replacement capacity cost or benefit prior to the end of November 2039.

The second fatal flaw is the use of a Pre-Retirement Avoided Energy Cost ("PAEC") that assumes all coal units remain online through 2041 to calculate hourly marginal cost. This PAEC is then used to derive the energy benefit for each unit in isolation. This is a sub-optimal use of the AURORA model. The model has a Long-Term Capacity Expansion module that evaluates unit retirements in an integrated manner on a level playing field, allowing for head-to-head competition among all resources—both supply-side and demand-side.

The first red flag is that Asset Retirement Obligations ("ARO") are not included in the Unit Retirement Study, on the grounds that existing AROs are a sunk cost. However, continued operation of coal units through 2030 and beyond will create incremental and expanded AROs that should be included in the assessment of unit retirement.

The second red flag is that the CO_2 price from $0 to $50 per ton is not reflective of the full social cost of carbon, which advantages fossil fueled generation units in this Unit Retirement Study.

Q. WHAT ARE THE CONCERNS YOU'VE INDENTIFIED IN THE BATTERY STORAGE COST-BENEFIT ANALYSIS?

A. The Battery Storage Cost-Benefit Analysis demonstrates that a battery is a cost-effective proposal for Customers of the Company in all scenarios. All six of the key observations show very positive benefits provided by batteries. The concern with the results of this analysis is that the results are largely being ignored. Standalone batteries were not allowed in the Capacity RFP and BESS+CS were disadvantaged in the Capacity RFP, excluding them from AURORA model selection until 2029 at the earliest. Instead, the Company selects a round number of 1,000 MW by 2030 of Energy Storage System capacity, which is based on the Company's pre-selected level of renewable capacity on the system in that year. The 1,000 MW of battery capacity is not based on economic modeling and is not optimized to be in the best interests of Georgia and Customers of the Company.

Q. WHAT ARE THE CONCERNS YOU'VE INDENTIFIED IN THE RCB FRAMEWORK?

A. It is clear from Table 1 in the Public Disclosure Renewable Cost-Benefit Framework ("RCB Framework") analysis, as updated for the 2022 IRP, that distributed generation offers multiple benefits with only integration costs to net out some of the benefit. The Company must realize that Customers can simply defect from the System with their own distributed generation and monetize all those benefits to achieve lower electricity costs for the now ex-Customer. The Company's position on monthly net metering—that it cannot recommend an action until it first interconnects the initial 5,000 customers, waits a full year, performs an assessment, and then puts a proposal in front of the Commission—this is a major impediment to deploying more distributed generation, whereas the net benefits are clear in the RCB Framework. The chief concern for the Commission is that, due to the upward rate pressure from defections, the Customers left behind on the System will see their rates rise even faster than they otherwise would.

Q. HOW DOES A FLEET THAT CONSISTS OF 45% GAS GENERATING CAPACITY PUT UPWARD PRESSURE ON CUSTOMER RATES?

A. Georgia Power Company currently has a non-diverse fleet that consists of 66% fossil generation capacity, including 45% gas-fired. Gas-fired assets cost more to own and operate—whether they are existing or new units—compared to utility-scale solar+storage. Growth in load and replacement capacity should be met with solar capacity, energy efficiency, demand side management, and other lower cost options. The failure to move rapidly away from gas-fired generation capacity to lower cost options like solar+storage puts upward pressure on Customer rates.

The 2022 IRP Base Case is based on a low (sub-$4) natural gas price outlook to 2041 and beyond. Natural gas prices were historically low in the past decade but are now moving higher based on long-term fundamentals. The Company does not capture this market shift in its Base Case (GCES Exhibit 14). On the fundamentals, the past decade of low-cost capital allowed companies to pursue ever more drilling to grow production from hydraulically fractured wells that have very steep decline rates. However, interest rates are now rising, which is itself a reaction to current high inflation. Further, the U.S. natural gas market is now more closely linked to global markets via Liquefied Natural Gas ("LNG"), including Elba Island LNG near Savannah, putting upward pressure on natural gas prices in the United States. In fact, Europe saw skyrocketing gas prices even before the Russia-Ukraine war, due to short supply. As gas prices move higher and given Georgia Power Company's heavy dependence on gas-fired generation, there will be upward pressure on Customer rates as a result.

In addition to fuel commodity costs moving higher, gas-fired generation carries substantial risk from fuel price volatility. Gas prices are very volatile and while this risk can be partially mitigated, the hedging program itself adds to overall cost. Gas-fired units also face risk from correlated fuel scarcity. Georgia Power Company relies on just two pipelines to supply natural gas, which frequently experience Critical Notice Operational Flow Orders that, in some cases, threaten system integrity (GCES Exhibit 15). Even firm gas transportation is subject to operational restrictions and susceptible to cyberattacks.

These risks are all inherent to gas-fired generation and follow from a dependence on a volatile, scarce commodity (natural gas) and vulnerable infrastructure (pipelines), which are risks that BESS+CS resources do not face at all. As a result, the failure to transition away from 45% gas generating capacity—including the requested certifications for gas PPAs—toward low-cost alternatives puts upward pressure on Customer rates.

Q. DID GEORGIA POWER COMPANY AND THE COMMISSION FOLLOW ANY RECOMMENDATIONS IN YOUR TESTIMONY IN THE 2019 IRP?

A. In my 2019 testimony I made several recommendations, including: (1) increase solar procurement to 3,000 MW from 1,000 MW; (2) publish a distributed solar hosting capacity map; (3) commit to evaluate solar+storage as a dispatchable resource; and (4) commit to develop a clearly articulated roadmap to achieve a 100 percent zero carbon system by 2050 at latest. The Company did not pose any questions in cross examination but has proposed a hosting capacity analysis in the 2022 IRP. The Commission stipulated more than doubling solar capacity procurement in the 2019 IRP. The Company minimally complied with this stipulation by issuing its second utility-scale solar Request for Proposals ("RFP") 10 days before the present 2022 IRP was filed. This demonstrates an inability to execute on required obligations in a timely manner and a lack of respect for the Commission's stipulation. The Company failed to adequately evaluate solar+storage in both its 2022-2028 Capacity RFP and the 2022 IRP. Finally, the Company does not address in the 2022 IRP the 2050 Net Zero Carbon target set by its parent company, despite the Company modelling out to the year 2056.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS?

A. Yes. Florida and California were brought up in oral hearings. On Florida, the Commission noted that the state, through their legislature, rolled back net monthly netting. On April 27, 2022, Governor DeSantis vetoed CS/CS/HB 741 Net Metering bill, which authorized public utilities to impose an Additional Sum to recover lost revenues resulting from residential solar generation that exceeds the public utility's estimate. Gov. DeSantis states, "The amount that may be recovered under this provision is speculative and would be borne by all customers." In California, there are brief times when the 35 GW of solar capacity drives down daytime marginal energy costs to $0. Prices can go negative with transmission constraints and to account for lost revenues from Renewable Energy Credit. However, Georgia is years from this problem. Georgia has 1/8 the solar capacity and 1/4 the population of California. Careful planning and market reform can mitigate this risk (GCES Exhibit 17).

Q. PLEASE PROVIDE A CONCLUDING SUMMARY OF YOUR DIRECT TESTIMONY.

A. In my direct testimony, I have provided numerous examples of the fatal flaws and red flags I discovered during my detailed review of the 2022 IRP and accompanying studies, documents, and witness testimony provided by the Company. It is clear from the public disclosure information and my analysis that the Company's Proposed Portfolio was developed using flawed methodologies, arbitrary constraints, and limiting assumptions. This resulted in some resources being advantaged at the expense of other resources, with the ultimate result being a sub-optimal portfolio that fails to adequately demonstrate the economic, environmental, and other benefits to the state and to customers of the utility, as required by

O.C.G.A. § 46-3A-2. Specifically, the Preferred Portfolio is costlier than it should be, which puts upward pressure on Customer rates. It is my recommendation that the Commission require the Company to produce a new IRP that fully meets the requirements of Georgia law and the Commission's rules, and which adequately addresses the concerns raised in this testimony.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

VERIFICATION

The undersigned, Peter Hubbard, affirms under the penalties of perjury that the answers in the foregoing Direct Testimony in Docket Nos. 44160 & 44161 before the Georgia Public Service Commission are true to the best of his knowledge, information, and belief.

Peter Hubbard
Georgia Center for Energy Solutions

ALEXIS GRAHAM
NOTARY PUBLIC
DEKALB COUNTY, GEORGIA
My Commission Expires
03-22-2026

GCES Exhibit 01

Peter Hubbard

55 Leslie St SE ● Atlanta, GA 30317 ● peter@georgia-ces.org ● 404.226.4448

Summary

Peter Hubbard is a Clean Energy Advocate working to create a 100% clean energy economy in Georgia and the U.S. Southeast via his nonprofit the Georgia Center for Energy Solutions. He is currently running for office in the Georgia General Assembly House District 90 in order to legislate this energy transition. Mr. Hubbard has 13+ years of experience in U.S. and global energy consulting and is a Subject Matter Expert in U.S. electricity markets, utility Integrated Resource Plan (IRP) analysis, natural gas markets, transaction due diligence, economic modelling, regulatory compliance, expert witness testimony.

Experience

Advocacy and Regulatory

- Founded the Georgia Center for Energy Solutions (www.georgia-ces.org)
- Provided expert witness testimony before the Georgia Public Service Commission in response to Georgia Power Company's 2019 and 2022 Integrated Resource Plans

Transactions

- Performed commercial and technical due diligence on multiple transactions, the largest of which was a $2.4 billion buy-side transaction of Canadian district energy firm Enwave by IFM Investors

Utility Integrated Resource Plans

- Managed multi-year IRP efforts for major utilities including Vectren Energy in Indiana, Orlando Utilities Commission in Florida, the Puerto Rico Electric Power Authority, and many others

Public Service

- Two years representing the United States of America as a health volunteer in the U.S. Peace Corps
- Two-time volunteer for Remote Area Medical (RAM) clinics in rural Appalachia
- Five-time healthy volunteer for National Institutes of Health vaccines, including HIV/AIDS

Employment

- **Clean Energy Advocate,** Georgia Center for Energy Solutions (2019 – 2022; Atlanta, GA)
- **Principal Consultant,** AFRY Management Consulting (2020 – 2021; Atlanta, GA)
- **Manager,** Siemens Energy Business Advisory (2018 – 2020; Atlanta, GA)
- **Project Manager,** Siemens Energy Business Advisory (2016 – 2017; Atlanta, GA)
- **Senior Consultant,** Pace Global, a Siemens Business (2014 – 2015; Fairfax, VA; Atlanta, GA)
- **Consultant,** Pace Global, a Siemens Business (2012 – 2013; Fairfax, VA)
- **Project Analyst,** U.S. Trade and Development Agency (2009 – 2012; Arlington, VA)
- **Environmental Consultant,** Council for Scientific and Industrial Research (2008 – 2009; South Africa)
- **Development Intern,** German Marshall Fund of the United States (2008; Washington, D.C.)
- **Congressional Press Intern,** Office of U.S. Senator Lamar Alexander, U.S. Senate (2007)
- **Peace Corps Volunteer,** U.S. Peace Corps, Morocco (2004 – 2006)

Education

Johns Hopkins University, School of Advanced International Studies, Bologna, Italy; Washington, D.C.

- *M.A. in International Relations and International Economics, Master's degree conferred 2009*
- *Concentration: International Energy & Environmental Policy; Specialization: Quantitative Methods*

University of Memphis, Memphis, TN

- *B.S. in Physics; B.S. in Mathematical Sciences; B.A. in French Language and Literature*
- *Bachelor's degrees conferred 2002*