STATE OF GEORGIA

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:		
Georgia Power Company's	**)**	
2019 Integrated Resource Plan and	**)**	
Application for Certification of Capacity	**)**	**Docket No. 42310**
From Plant Scherer Unit 3 and Plant	**)**	
Goat Rock Units 9-12 and Application	**)**	
for Decertification of Plant Hammond	**)**	
Units 1-4, Plant McIntosh Unit 1, Plant	**)**	
Langdale Units 5-6, Plant Riverview	**)**	
Units 1-2, and Plant Estatoah Unit 1	**)**	

DIRECT TESTIMONY OF
PETER J. HUBBARD
GEORGIA CENTER FOR ENERGY SOLUTIONS

April 25, 2019

DIRECT TESTIMONY OF
PETER J. HUBBARD
GEORGIA CENTER FOR ENERGY SOLUTIONS

IN REGARD TO GEORGIA POWER COMPANY'S

2019 INTEGRATED RESOURCE PLAN AND APPLICATION FOR CERTIFICATION OF CAPACITY FROM PLANT SCHERER UNIT 3 AND PLANT GOAT ROCK UNITS 9-12 AND APPLICATION FOR DECERTIFICATION OF PLANT HAMMOND UNITS 1-4, PLANT MCINTOSH UNIT 1, PLANT LANGDALE UNITS 5-6, PLANT RIVERVIEW UNITS 1-2, AND PLANT ESTATOAH UNIT 1

GPSC DOCKET NO. 42310

I. INTRODUCTION

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

A. My name is Peter J. Hubbard. I am President of 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 promote the development of an economic and regulatory framework to transition Georgia's electric sector, transportation sector, and other sectors to a 100% clean energy (zero carbon) future in an equitable, reliable, resilient, sustainable, 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 from the University of Memphis and one Bachelor of Arts degree in French, also from the

University of Memphis. In addition, I 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 consulting focused primarily on integrated resource planning and natural gas markets but also strategic planning, power and natural gas market analysis and forecasting, utility portfolio risk analysis, future scenario development, and energy technology assessments. I have previously filed direct testimony related to integrated resource planning before the Indiana Utility Regulatory Commission.

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

A. No. This is my first time testifying before the Georgia Public Service Commission ("Commission").

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

A. Yes. I am sponsoring the following exhibit:

- Attachment GCES-1, Peter J. Hubbard's Curriculum Vitae

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 offer improvements on the 2019 Integrated Resource Plan ("IRP"), as presented by Georgia Power Company

("Company"), based on observations that fall into four topic areas. In addition, I wish to offer recommendations for additional commitments by the Company to be included in the 2019 IRP.

The four discussion points in this direct testimony, which serve as context for the subsequent recommendations, include the following: (1) A full-cost accounting of coal-fired generation is important in the decision-making processes of both the Company and the Commission; (2) The Company can and should move more quickly to incorporate renewable generation resources into its IRP process; (3) Grid reliability and resiliency can be improved with careful planning of renewables and storage; and (4) The Renewable Cost Benefit Framework ("RCB Framework") should evolve to incorporate the locational value of storage at the distribution level and the IRP process should evolve to evaluate solar+storage as a dispatchable generation resource.

The recommendations in this direct testimony for commitments by the Company to add to the 2019 IRP include the following: (1) Commit to triple the amount of utility-scale solar capacity, community solar capacity, and distributed rooftop residential and commercial solar capacity, committing to add 3,000 megawatts ("MW") by 2022 (up from 1,000 MW in this IRP); (2) Commit to increase support for Distributed Energy Resources ("DER") by developing Time-of-Use ("TOU") rates, preparing and publishing a distributed solar hosting capacity analysis, preparing and publishing a plan for Electric Vehicle ("EV") charging, and collaborating with the City of Atlanta on its recently launched Clean Energy Atlanta plan[1]; (3) Commit to rigorous improvements in the methodology for valuing storage and commit to include standalone storage in the Long-Term Capacity Expansion ("LTCE") plan(s) for the 2022 IRP; (4) Commit to evaluate solar+storage as a dispatchable resource in the 2022 IRP; and (5) Commit to

[1] http://www.100atl.com/

develop—by the 2022 IRP—a clearly articulated roadmap to achieve 100 percent zero carbon system operations by a reasonable but ambitious target date.

Q. DO YOU WISH TO PREFACE YOUR DISCUSSION OF THE FOUR TOPIC AREAS AND RECOMMENDED COMMITMENTS BY THE COMPANY TO BE INCLUDED IN THE 2019 IRP?

A. Yes. The Commission and the Company are to be commended for achieving an eighth-place state ranking in solar capacity buildout in the United States without the support from the state legislature in the form of tax credits or other subsidies, without a renewable portfolio standard, or without a net-metering law. Rather, the Commission used the IRP process to require the installation of hundreds of megawatts of solar generation capacity beginning in 2013. As a result, "energy is now being delivered to Georgia Power customers from more than 1.6 gigawatts ("GW") of renewable resources, with more than 1.5 GW of additional renewables projects under contract or development and anticipated to be online by the end of 2021."[2] The present direct testimony aims to continue that success.

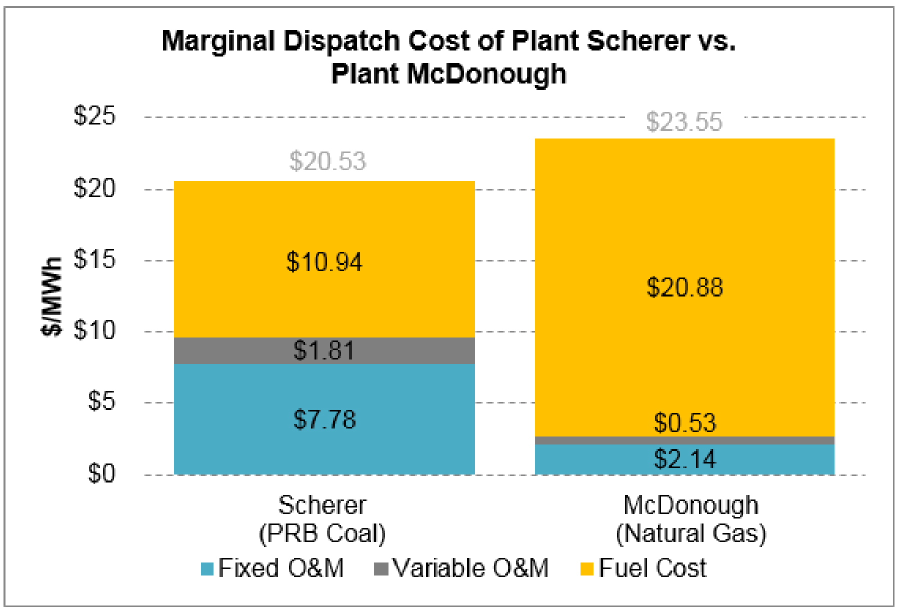
Q. IN WHAT WAYS IS A FULL-COST ACCOUNTING OF COAL-FIRED GENERATION IMPORTANT IN THE DECISION-MAKING PROCESSES OF BOTH THE COMPANY AND THE COMMISSION?

A. The Company and the Commission have to balance their own set of objectives in this IRP process. To provide context when interpreting IRP results, it is important to take into account the full costs and benefits of operating an asset. In particular, a coal-fired power plant is a relatively low-cost generation resource from the going-forward viewpoint of Marginal Cost of Energy ("MCOE"). For example, Plant Scherer is the largest coal-fired plant in the United States and one of the lower-cost resources in the Company's portfolio (albeit under partial ownership). According to S&P Global Market Intelligence[3], Plant Scherer is a 3,392 MW

[2] Georgia Power Company 2019 IRP, page 8-49

[3] With data collected from FERC Form 1, EIA Form 923, EPA CEMS, and company reports

(summer net capacity) four-unit coal-fired power plant with a heat rate of 10,700 Btu/kWh[4] and a weighted age of nearly 34 years, in which the Company retains a weighted 23.1 percent ownership share. By contrast, the relatively new and efficient Plant McDonough is a 2,722 MW (summer net capacity) nine-unit combined cycle natural gas-fired power plant with a heat rate of 6,960 Btu/kW[5], which has been online since 2011/2012 and is fully owned by the Company. Using an assumption of $18/ton delivered-to-Scherer Powder River Basin coal price and a $3/MMBtu delivered-to-McDonough natural gas price, as well as a five-year average (2014-2018) of the Fixed O&M[6] and Variable O&M[7] costs as reported by Velocity Suite Online, it follows that Plant Scherer has a dispatch cost of $20.53/MWh, which is $3/MWh less than Plant McDonough.



Source: GCES

[4] Average of reported data (see sources in footnote 2) from 2015-2018

[5] Ibid.

[6] Fixed O&M can include land, structures, equipment, rent, and prime mover expense.

[7] Variable O&M can include incremental maintenance cost, no-load costs during periods of operation, incremental labor cost, emission allowances/adders, VO&M adders, and a ten percent adder.

Compare this $20.53/MWh dispatch cost to retail electricity rates by sector in Georgia from 2015 to 2018. The average retail rates for the residential, commercial, industrial, and transport sectors in this timeframe were $115, $98, $59, and $53/MWh, respectively[8]. In this example, the MCOE from Plant Scherer is well below retail electricity rates and competitive with natural-gas fired resources, making it an ostensibly low-cost source of baseload dispatchable electricity generation on the basis of energy alone. Yet as competitive as this $20.53/MWh appears, a March 2019 joint study by Vibrant Clean Energy and Energy Innovation[9] found that the going-forward cost (*i.e.*, MCOE or marginal dispatch cost) of fully 211 GW of existing U.S. coal capacity (74 percent of the national fleet) is currently more expensive than the all-in costs or Levelized Cost of Energy ("LCOE") of new-build solar or wind projects. By 2025, the numbers rise to 246 GW or 86 percent of the fleet, including every operating coal plant in Georgia totaling nearly 10 GW out of the 246 GW. In other words, building a new solar or wind plant is now more economic than operating an existing coal plant across 74 percent of the U.S. coal fleet, growing to 86 percent in little more than five years.

In addition, the MCOE does not account for the estimated costs to close ash ponds and landfills, as well as the estimated costs during post closure care, in compliance with federal and state Coal Combustion Residuals ("CCR") regulations. To fulfill its CCR obligations to retire 29 ash pond assets at 11 coal-fired power plants across the state, Georgia Power reports in the 2019 IRP that it has spent $400 million through 2018 and expects to spend $7.1 billion more in the

[8] https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=0000000g&endsec=vg&linechart=ELEC.PRICE.GA-RES.M~ELEC.PRICE.GA-COM.M~ELEC.PRICE.GA-TRA.M~ELEC.PRICE.GA-IND.M&columnchart=ELEC.PRICE.GA-ALL.M&map=ELEC.PRICE.GA-ALL.M&freq=M&start=200101&end=201510&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0

[9] https://energyinnovation.org/wp-content/uploads/2019/03/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL.pdf

next decade and beyond. The substantial costs for remediation of past coal-fired generation send a clear signal of the true net cost to continue coal-fired generation.

In addition to the costs of CCR asset retirement obligations, there are two substantial costs (carbon costs and mortality/morbidity effects) that should inform the decision-making process to continue coal-fired generation. First, using a CO_2 emissions rate for Plant Scherer of 194.4 lbs/MMBtu, it follows that for every $1/ton increase in the cost of CO_2, there is an increase of approximately $1/MWh in the dispatch cost of the plant. Although a national market for CO_2 has not yet been enacted, the externality cost of emitting greenhouse gases has been established as a matter of public interest[10], prompting many states to act ahead of federal regulation. For example, nine states are members (with two states in the process of joining) of the Regional Greenhouse Gas Initiative ("RGGI"). RGGI's market clearing CO_2 price from 2014-2018 averaged $4.64/ton[11] and is indicative of the implicit subsidy that fossil-fuel generation receives in a market that has yet to internalize a CO_2 price. Yet despite a lack of a CO_2 price, simply by facing economic reality and yielding to customer pressure, two U.S. utilities—Xcel Energy[12] and Platte River Power Authority[13]—recently announced plans to eliminate 100 percent of carbon emissions from their power plants by 2050 and 2030, respectively. The Company would be well-served to prepare a similar plan to achieve carbon-free system operations.

Second, the U.S. Environmental Protection Agency issued analysis in August 2018 which found that the continuation of coal-fired generation under the proposed Affordable Clean Energy rule would result in a range of 246-1,740

[10] See Massachusetts v. EPA, 549 U.S. 497 (2007), https://supreme.justia.com/cases/federal/us/549/497/

[11] https://www.rggi.org/index.php/auctions/auction-results/prices-volumes

[12] https://www.xcelenergy.com/staticfiles/xe/PDF/Xcel%20Energy%20Carbon%20Report%20-%20Mar%202019.pdf

[13] https://www.prpa.org/wp-content/uploads/2018/12/12.06.2018-Resource-Diversification-Policy.pdf

premature deaths among U.S. adults in 2030.[14] Assuming Georgia's 2030 population is 3.3 percent of the total U.S. population and the state holds a similar share of coal-fired generation as it does today, between 8 and 57 premature deaths could be expected in 2030 among Georgia adults (as well as several morbidity effects) as a result of keeping the current level of coal-fired generation in the Company's portfolio and in the state. It has been argued that such societal costs "represent an externality for which benefits do not accrue to the electric utility by avoiding them and, therefore, there is no benefit to be passed on to utility customers."[15] Yet the IRP document shows recognition of positive externalities when we read on page 9-63, "The hydro fleet also provides other unique benefits to the state of Georgia, including recreational opportunities, fish and wildlife enhancements, and local economic development." Perhaps more to the point, continued coal-fired operations could expose the Company to large financial liabilities and other unforeseen risks, as demonstrated by the ongoing lawsuit against Orlando Utilities Commission and its coal-fired Stanton Energy Center.[16]

These economic realities should figure into the full-cost accounting and risk analysis that the Company and the Commission use when making decisions about the long-term affordability and viability of coal-fired generation assets. Moreover, given an average Georgia Power coal fleet age of 45 years, which is sufficient time to allow for full depreciation outside of recent environmental compliance upgrades, the Company and the Commission should evaluate the viability of retiring coal assets with innovative regulatory and financing constructs or, for example, transitioning the steam turbines into synchronous condensers coupled with advanced power electronics and Flexible Alternating Current Transmission Systems ("FACTS") to provide ancillary grid services that may be needed as renewables penetration increases.

[14] See Table 4-6, https://www.epa.gov/sites/production/files/2018-08/documents/utilities_ria_proposed_ace_2018-08.pdf

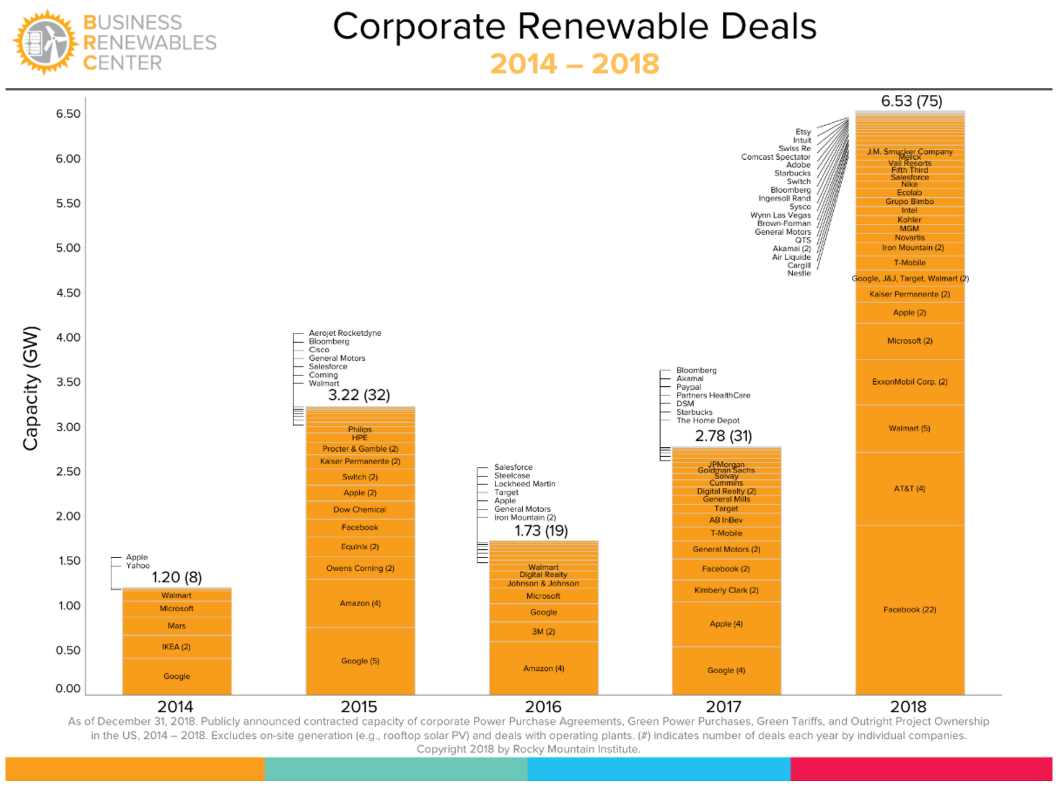
[15] A Framework for Determining The Costs and Benefits of Renewable Resources in Georgia, p. 10

[16] https://www.orlandosentinel.com/news/os-ne-ouc-coal-class-action-suit-20181218-story.html

Q. PLEASE ELABORATE ON YOUR ASSERTION THAT THE COMPANY CAN AND SHOULD MOVE MORE QUICKLY TO INCORPORATE RENEWABLE GENERATION RESOURCES INTO ITS PLANNING.

A. In its response to Data Request STF-L&A-1-36, the Company states that they plan to retire just 475 MW of their coal capacity between 2024-2034 (5.5 percent of a total of 8.6 GW). It will then take another decade to reach 6.1 GW (70 percent) of coal retirements by 2044. The last coal unit, Plant Scherer Unit 3, is planned to operate until 2052. Contrast this with the strong and growing trend of industrial and technology firms demanding ever more renewable Power Purchase Agreements ("PPA"). To this end, the newly launched Renewable Energy Buyers Alliance aims to grow the marketplace for U.S. corporate renewable deals from nearly 16 GW through the end of 2018 to 60 GW by 2025. The technology firm Facebook, which inked 22 deals in 2018 for 2 GW of corporate PPA contracted capacity[17], is investing $750 million in a data center in Stanton Springs, Georgia opening in 2020, which highlights the importance of accelerating competitive renewable energy offerings to attract new business into the state and to maintain Georgia's No. 1 position (five years running) as the Top State for Doing Business.

[17] https://businessrenewables.org/corporate-transactions/



Source: Business Renewables Center

A second reason for fast-tracking renewables development is to take advantage of the federal Investment Tax Credit ("ITC") for solar generation. The ITC allows for a dollar-for-dollar reduction in corporate income taxes equal to 30 percent of the investment in eligible solar property which has begun construction in 2019. The ITC declines to 26 percent for projects that begin construction in 2020, 22 percent for projects that begin construction in 2021, and only 10 percent for commercial and utility-scale projects that begin construction in 2022 (while the ITC for residential distributed solar generation goes away completely in 2022). By accelerating the buildout of solar capacity on its system, the Company can realize 20-30 percent lower construction costs compared to solar projects that commence in 2022 and beyond.

A third reason to accelerate renewables deployment is a recognition of rapidly changing economics that favor solar and wind buildout. As mentioned in the foregoing testimony and in the direct testimony of Dr. Rhodes, 74 percent of the national coal fleet is currently more expensive than the all-in costs of new-build solar or wind projects. By 2025, 86 percent of the U.S. coal fleet will be at risk, including every plant in Georgia. While replacing coal plants with new solar or wind capacity is more complex in practice, this is a strong signal that the Company's efforts to embrace renewable generation can and should be accelerated. Such a move would not be unprecedented. Northern Indiana Public Service Company, a utility with a 40-year-old 2,094 MW coal fleet (73 percent of the utility's total capacity), recently laid out a plan in its 2018 IRP[18] to become entirely coal-free by 2028, with most retirements occurring by 2023.

A rapid expansion of renewable generation resources requires careful planning as well as the application of lessons learned from successful models. For example, the Public Utility Commission of Texas designated Competitive Renewable Energy Zones ("CREZ") and collaboratively developed a transmission plan to deliver renewable power from CREZ to customers, while maintaining system reliability and favorable economics. Texas' approach provides a model showing how transmission investments can directly enable a rapid, low-cost, and reliable transition to a generation portfolio with much higher levels of renewable energy. The implementation of CREZ has enabled the addition of more than 18 GW of wind capacity to Texas' power system, which is on track to build 70 percent more wind capacity than initially planned. The economic benefits speak for themselves: annual electricity production cost savings of $1.7 billion per year plus another $5 billion in incremental economic development. With a service life of 30 to 50 years, the benefits of CREZ lines will return their construction cost of $7 billion many times over. Furthermore, CREZ lines are now enabling a utility-scale solar boom in Texas that was never part of the original plan. With more than 2,900

[18] https://www.nipsco.com/docs/default-source/about-nipsco-docs/nipsco-irp-public-advisory-meeting-october-18-2018-presentation.pdf

MW of utility-scale solar capacity already installed, Texas expects to add another 7,000 MW over the next five years.[19]

Q. HOW CAN GRID RELIABILITY AND RESILIENCY BE IMPROVED WITH CAREFUL PLANNING OF RENEWABLES AND STORAGE?

A. The North American Electric Reliability Corporation ("NERC") issued its most recent long-term reliability assessment in December 2018.[20] On pages 111-115 of the document, NERC finds that from 2019 to 2028 the SERC-SE anticipated planning reserve margin falls between 30.58 and 34.15 percent, well over the proposed winter target reserve margin of 26 percent. The assessment also finds that in SERC-SE in 2020 there is zero loss of load hours per year and zero expected unserved energy. Finally, the assessment notes that variable solar energy resources can be assigned a 32 percent solar capacity credit (which could potentially be improved with greater geographic distribution of solar resources and definitely improved when coupled with storage). Granted, this assessment does not account for the requested changes in the present IRP, but it does suggest that there is room to incorporate more renewables (particularly utility-scale solar) and storage than is being proposed by the Company without sacrificing reliability.

In SERC-SE, the NERC assessment notes that DERs are not explicitly modeled as generators but are instead modeled as a reduction in bus load, netting the actual bus load and the online DER generation. NERC reports that the Company has been actively establishing processes and collecting data to explicitly model the bus load and DER generation independently to better represent, model, and plan for DERs. Sufficient evidence should now be available from the Company's own research activities and from the increasing number of case studies involving DER integration to affirm the NERC finding that, "From a technological perspective,

[19] https://www.seia.org/state-solar-policy/texas-solar

[20] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

modern DER units will be capable of providing essential reliability services, such as frequency and voltage support."

A sister analysis performed by the Eastern Interconnection Planning Collaborative (dated February 27, 2019 but released in April)[21] examined the forward-looking frequency response measures on the Eastern Interconnection ("EI"). The assessment examined concerns that planned retirements of synchronous resources and continued additions of asynchronous generation (*i.e.*, variable solar generation resources) will affect the continued ability of large interconnections to maintain frequency by reducing the amount of automatic frequency response, known as system inertia. The main conclusion and results of the assessment "demonstrate the EI has sufficient system inertia over the next five years with planned resource retirements and non-synchronous resource additions." We can conclude that any technical challenges presented from the rapid and high penetration of renewables are surmountable.

In the 2019 IRP and its April 8-9, 2019 testimony before the Commission, the Company states its plans to continue the operation of coal units such as Plant Bowen Units 1-2 (representing 1,448 MW of capacity), acknowledging the challenging economics of these units in certain scenarios but pointing to significant winter reliability risks and transmission system upgrades associated with generation capacity shortfall linked to the retirement of these units. The Company also cites the penetration of solar resources as a driver of increased winter reliability risks. This echoes arguments that coal resources are critical for maintaining grid reliability and/or resiliency, particularly during extreme weather events such as the Polar Vortex of 2014 and the Bomb Cyclone of 2018. However, in the PJM market, 13.7 GW of coal capacity was forced offline during the Polar Vortex of 2014, which equated to 7.5 percent of total capacity in that

[21] https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5ca541769b747a55f8444c03/1554334072121/EIPC_FRTF_2018_Final_Report_Public_Version_EC_Approved_2019-02-27.pdf

market at that time.[22] In January 2019, forced coal generation outages in PJM reached 7,739 MW or 3.8% of total PJM capacity,[23] to pick just two weather events. In fact, an analysis of the causes of major electricity disturbances in the United States from 2012-2016 found that severe weather caused 96.2 percent of customer-hour disruptions.[24] The 2018 State of the Market Report for PJM demonstrated that in 2018, after accounting for planned, maintenance, and forced outages, coal capacity had an equivalent availability factor of only 71.4 percent (see Table 5-30).[25] Moreover, the typically large capacity size of coal units and the instantaneous and abrupt nature of failures means that commensurately large-capacity backup units are needed to maintain reliability during times when coal capacity is unavailable. The conclusion is that coal-fired generation is not always a consistent source of reliability or resiliency, particularly as extreme weather events occur with greater frequency and severity (and which are increasingly exacerbated by CO_2 emissions from coal-fired generation).

In contrast, unexpected failures are far rarer for solar (and wind) resources. Solar panels have few moving parts and are easily maintained, making their forced outage rate close to zero.[26] Output varies with the availability of the sun (and wind), but grid operators and system planners have significantly improved their ability to accurately predict the output from renewable resources and manage their variability, which can also be improved with greater geographic diversity as mentioned previously. Pairing storage with intermittent renewables would also improve the variability issue and allow for resources like utility-scale solar facilities to become dispatchable, contributing to grid stability and reliability. Given these observations, it follows that careful planning of renewables and

[22] https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx

[23] https://www.rtoinsider.com/pjm-polar-vortex-cold-weather-alerts-110358/

[24] https://rhg.com/research/the-real-electricity-reliability-crisis-doe-nopr/

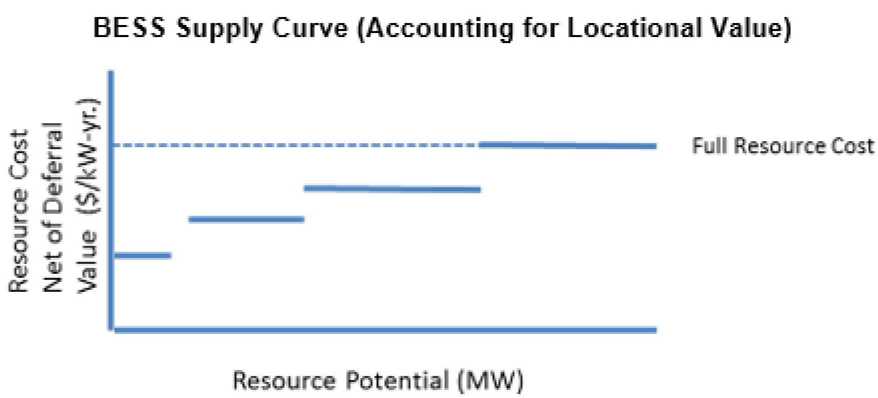
[25] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf

[26] https://rmi.org/fuel-hand-make-coal-nuclear-power-plants-valuable/

storage can lead to improved reliability and resiliency metrics for the bulk electric system.

Q. IN WHAT WAYS SHOULD THE RCB FRAMEWORK AND THE IRP PROCESS BE IMPROVED?

A. The RCB Framework would benefit from, among other things, the inclusion of the residual value of storage based on its location at the distribution level. Once identified and quantified using system planning software, the locational value benefits of storage can be subtracted from the full cost of distribution-connected storage to provide a residual cost of storage (subject to the capacity already deployed) that is considered for the LTCE process. The LTCE plan(s) would continue to consider secondary benefits from storage such as energy arbitrage, ancillary service contribution, and system-wide capacity contribution prior to identifying storage as part of the least cost resource solution. Such an approach would create a more level playing field with transmission-connected storage or traditional generation resources which may have lower capital costs but can only provide wholesale services. It would also help to optimize the storage requirements from a generation and distribution standpoint. An illustrative construct of this concept for Battery Energy Storage Systems ("BESS") is shown below.



Source: GCES

The IRP process would benefit from the inclusion of solar+storage as a dispatchable generation resource. Attachment B of the 2019 IRP includes a technology screening. While five types of storage were retained from the preliminary screening and used as inputs for the secondary screening, Table B-4 indicates that only three technology options were retained from the secondary screening for use as inputs into the LTCE process, none of which include storage. With the proper valuation of BESS technologies such as lithium-ion batteries and advanced lead acid batteries, whether installed independently from or in conjunction with renewables, they could potentially pass the cost test of what is acceptable to the Company. This valuation technique would improve the IRP process and this would lead to a more optimized portfolio outcome.

Q. BASED ON YOUR ANALYSIS OF THE 2019 IRP AND THE DISCUSSION ABOVE , WOULD YOU RECOMMEND ADDITIONAL COMMITMENTS FROM THE COMPANY IN THIS IRP?

A. Yes. I would suggest adding five commitments by the Company for inclusion in the 2019 IRP. First, the Company should commit to triple the amount of utility-scale solar capacity, community solar capacity, and distributed rooftop residential and commercial solar capacity, committing to add 3,000 MW by 2022 (up from 1,000 MW in this IRP). As demonstrated in the foregoing analysis, the Company should be able—from a technical perspective—to increase significantly in the short-term the amount of utility-scale solar capacity, community solar capacity, and solar rooftop DER capacity interconnecting into its system. From an economic and social perspective, the Company should be able to reduce system costs and reduce loss of life by rapidly scaling up solar capacity to replace coal. The Company should commit to 3,000 MW by the next IRP while conducting programs to encourage Commercial and Industrial ("C&I") as well as residential and community customers to take advantage of solar energy offerings.

Second, the Company should commit to increase support for DERs by developing TOU rates, by publishing a distributed solar hosting capacity analysis, by preparing a public plan for EV charging, and by collaborating with the City of Atlanta on its Clean Energy Atlanta plan. Properly designed and deployed TOU rates help customers to save money by shifting their use away from high-priced time periods; they can help utilities reduce their expenditures by lowering the highest demand they must meet; and they often move customer demand toward periods when low cost renewables are in greater supply on the system, which saves costs for customers and utilities. Over 60 pilot programs[27] and ongoing implementation among utilities will help guide the Company toward a prudent TOU rate design. In particular, the California Public Utilities Commission required the state's three investor-owned utilities to offer TOU rates. San Diego Gas & Electric began moving its customers in March 2019 while Southern California Edison and Pacific Gas & Electric have until October 2020 to implement their TOU billing systems. The Company's Nights & Weekends residential rate is a good start but can be improved, while the Company's Time of Use – Supplier Choice and other Marginally Priced Rates for C&I customers could be made available as widely as possible. A distributed solar hosting capacity analysis, such as the one Xcel Energy developed for Minnesota[28], would allow for better planning and implementation of distributed rooftop solar in particular. An EV charging plan would help the City of Atlanta, which is experiencing rapid population growth, C&I customers, and other cities and locations throughout the state to more proactively plan for the increasing electrification of the transportation sector. And collaboration with the City of Atlanta on its new Clean Energy Atlanta plan is vital for maintaining Georgia's competitive business edge, its livability, and its sustainability.

[27] http://files.brattle.com/files/12658_the_national_landscape_of_residential_tou_rates_a_preliminary_summary.pdf

[28] https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map

Third, the Company should commit to rigorous improvements in the methodology for valuing storage in the context of the RCB Framework as well as the IRP process, as discussed in the foregoing testimony. The Company also should commit to include storage in the LTCE plan(s) for the 2022 IRP.

Fourth, the Company should commit to evaluate solar+storage as a dispatchable resource in the 2022 IRP. In the 2019 IRP, the Company extols the unique operating characteristics of its hydro fleet (*e.g.*, quick start capability, high ramp rates) as a complement to intermittent renewables. To an even greater extent, BESS have such operating characteristics, while also providing other ancillary services to maintain grid stability. The Company can prudently evaluate the economics of including storage and solar+storage in the 2022 IRP LTCE plan(s) while also assessing and monitoring the possibility of a federal ITC for storage.

Fifth, the Company should commit to develop, by the 2022 IRP, a clearly articulated roadmap to achieve 100 percent zero carbon system operations by a reasonable but ambitious target date. Prudent environmental and social stewardship as well as the fiduciary responsibility to ratepayers and shareholders should encourage the Company to develop and publish a clear technical, economic, and achievable roadmap to achieving zero carbon on its system and for its customers. Such analysis should be developed in the context of other utilities within the EI also moving toward zero carbon in the same timeframe.

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

A. In this direct testimony, I have provided information that I hope is useful in adding color to four key discussion points, including full-cost accounting of coal-fired generation, the feasibility of rapidly building out renewable generation resources, the reliability and resiliency of renewables compared to coal, and suggested improvements to the RCB Framework and IRP process. I then provided five recommended actions to which the Company should commit in the 2019 IRP, including adding 3,000 MW of solar (utility-scale, community, and rooftop) capacity by 2022; increasing support for DER in four ways (TOU rates, a distributed solar hosting capacity analysis, an EV charging plan, and support for the Clean Energy Atlanta plan); improving the methodology for valuing storage and including storage in the LTCE plan(s) for the 2022 IRP; evaluating solar+storage as a dispatchable resource; and developing by the 2022 IRP a clearly articulated roadmap to achieve 100 percent zero carbon system operations by a reasonable but ambitious target date.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

VERIFICATION

The undersigned, Peter J. Hubbard, affirms under the penalties of perjury that the answers in the foregoing Direct Testimony in Docket No. 42310 before the Georgia Public Service Commission are true to the best of his knowledge, information, and belief.

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Peter J. Hubbard
Georgia Center for Energy Solutions

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing Georgia Center for Energy Solutions' Direct Testimony of Peter J. Hubbard in Docket No. 42310 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

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This 25th day of March 2019.

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