2022 INTEGRATED RESOURCE PLAN

Docket No. 44160

GEORGIA POWER COMPANY'S
2022 INTEGRATED RESOURCE PLAN
DOCKET NO. 44160

- 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
- 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
- Application for Certification of Capacity from Blocks 2-4 and Blocks 5&6

Applicant name, address, and principal place of business:

Georgia Power Company
241 Ralph McGill Blvd NE
Atlanta, Georgia 30308

Authorized person to receive notices or communications with respect to application:

Marc Vinson
Regulatory Affairs, BIN 10230
Georgia Power Company
241 Ralph McGill Blvd NE
Atlanta, Georgia 30308
Voice: 404-506-2687
Fax: 404-506-7253

Location for public inspection:

Georgia Power Company
241 Ralph McGill Blvd NE
Atlanta, Georgia 30308

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CHAPTER 1. EXECUTIVE SUMMARY

The 2022 Integrated Resource Plan ("IRP") is filed by Georgia Power Company ("Georgia Power" or the "Company") pursuant to the planning process established by the Integrated Resource Planning Act of 1991 (the "IRP Act")[1] and overseen by the Georgia Public Service Commission (the "Commission"). In this IRP, the Company continues to chart a course supporting Georgia's energy future, taking proactive steps to address current market and regulatory conditions while positioning itself to respond to future developments and the evolving energy landscape, all for the benefit of customers. The Company developed the 2022 IRP through an extensive planning process that focuses on meeting the energy needs of its customers and the communities it serves in an economical and reliable manner. As such, the Company presents a comprehensive plan with a balanced portfolio of energy resources that will provide customers with clean, safe, reliable, and affordable electric service for years to come, even as customer preferences, society's energy needs, technology, and the energy landscape continue to evolve.

As further discussed below, the Company continues to leverage a diverse mix of resources, a comprehensive environmental compliance strategy ("ECS"), enhanced reliability and resilience planning and initiatives, and state-of-the art technology to provide industry leading service and forward-looking energy solutions that will meet the needs of its customers and the communities it serves in a wide variety of future economic and regulatory scenarios.

The 2022 IRP follows Georgia's constructive regulatory process, with Commission guidance and oversight, and proactively identifies the critical steps needed to address the evolving conditions facing Georgia Power and the electric utility industry. Key considerations within this plan include, among others, the continued economic challenges facing the Company's coal-fired generation fleet, increasing policy and regulatory pressure related to carbon and environmental standards, the significant increase in customer expectations for renewable and other low or no carbon solutions, and the availability of valuable supply-side market options resulting from the successful 2022-2028 Capacity Request for Proposals ("RFP") completed by the Company. To best position the state's energy system to meet customers' needs, the Company's IRP provides for efficient and effective transformation of the generating fleet, while ensuring the reliability and resiliency of the grid. To achieve these critical objectives, the Company must take appropriate and proactive

[1] O.C.G.A. § 46-3A-1 et seq.

steps to successfully execute on the numerous and long-lead time activities required to support the plan.

As a result, this IRP seeks to continue the transition of the generating fleet through additional retirements within the coal fleet, allowing the Company to seize what may be a limited opportunity to procure cost-effective market resources from the recent Capacity RFP, and continue growing its renewable portfolio. To prepare for and support these changes, the Company has planned for transmission system improvements, investments in distributed energy resources ("DER") and energy efficiency, and investments in other technologies including battery energy storage. This strategic and comprehensive portfolio of energy solutions, combined with innovative customer programs, will provide a strong foundation for Georgia Power to reliably and economically meet the needs of its customers.

Georgia Power is proud to serve Georgia's communities across the state, and the Company's commitment to its customers remains the cornerstone of its business model. Through the 2022 IRP process, the Company will continue to work constructively with the Commission to invest in Georgia's energy future and provide industry-leading energy solutions that will benefit customers and Georgia's communities for future generations.

1.1. RELIABILITY AND SEASONAL PLANNING

Consistent with the use of seasonal planning approved in the 2019 IRP, the Company will continue to use seasonal planning to address weather-related reliability risks during summer and winter periods. The continued use of seasonal planning is supported by the Company's 2021 Reserve Margin Study, provided in Technical Appendix Volume 1, which identifies the generation capacity required above the forecasted peak demand (the "Target Reserve Margin") to account for uncertainties associated with the demand for electricity and the reliability of available resources. The importance of seasonal planning has been reinforced by the reliability events seen around the country since the 2019 IRP. For long-term planning purposes, the Company continues to use a Target Reserve Margin of 16.25% for summer periods and 26% for winter periods for the Southern Company System ("System"). Consistent with past practice, the Company also evaluated short term (2022-2024) Target Reserve Margins and continues to use the System targets of 15.75% for summer and 25.5% for winter periods. Detailed reviews of the Company's seasonal planning requirements are set forth in CHAPTER 5 and Technical Appendix Volume 1.

1.2. LOAD AND ENERGY FORECASTS

The Company developed twenty-year forecasts of energy sales and peak demand to support its planning needs in this IRP. The load and energy forecasts include the retail classes of residential, commercial, industrial, MARTA, and governmental lighting. As further described in CHAPTER 6 and the Budget 2022 Load and Energy Forecast presented in Technical Appendix Volume 1, the robust period of economic growth from 2013 to 2019 was interrupted by a short but deep recession in the first half of 2020 due to the COVID-19 pandemic, followed by a sharp rebound in the second half of the year. In April 2020, Georgia Power's total weather adjusted retail sales fell by more than 9%, with commercial sales down more than 13% and industrial sales down nearly 18% compared to April 2019. During this same period, residential sales increased more than 8% as a large number of office workers transitioned to working from home. Total retail sales increased as the year progressed and the economy continued to recover, with total retail sales ending 2020 down just 2.2% from 2019. The Company's retail sales continued to rebound in 2021. Sales in the residential and industrial classes are now above pre-pandemic levels, although the commercial class has not yet fully recovered.

Georgia is expected to return to a period of healthy economic growth over the twenty-year forecast horizon. During this time, business growth and population increases are expected to drive an increase in energy sales. For example, from 2022-2041, total energy sales are projected to grow at an average annual rate of 0.8% and summer and winter peak demands are expected to increase at an average rate of 0.7% per year. The load and energy forecasts presented in this IRP support the Company's plan to reliably serve customers during this period of incremental growth.

1.3. DEMAND-SIDE STRATEGY

Georgia Power's demand-side management ("DSM") portfolio remains an important component of its resource mix. This IRP presents a combination of demand response programs, energy efficiency programs and pilots, pricing tariffs, and other energy efficiency initiatives. Consistent with the Commission policy, the Company continues to treat energy efficiency as a priority resource and works closely with the Commission Public Interest Advocacy ("PIA") Staff and the Demand-Side Management Working Group ("DSMWG") using the approved Demand-Side Management Program Planning Approach for program development. In preparation for this 2022 IRP, the Company prepared a Technical Reference Manual, completed and filed an energy efficiency potential study, and conducted a comprehensive analysis of potential DSM programs with the assistance and input of the DSMWG.

Forecasted low natural gas prices, modest load growth, and substantial increases in renewable generation continue to reduce the marginal cost of electricity generation, thus lowering the Company's avoided energy cost. Consequently, the relative value of each kilowatt hour ("kWh") saved as a result of DSM participation has significantly declined, negatively impacting the economics of DSM programs. Since the 2019 IRP, Total Resource Cost ("TRC") test results have continued to decline, as have Rate Impact Measure ("RIM") test results. This trend continues to raise concerns for the Company as it strives to balance the economic benefits that DSM programs provide to participating customers with the rate impacts to all customers, whether they participate in the programs or not. Nevertheless, in light of DSM program benefits, the Company supports the continuation of the majority of its DSM programs in this IRP. Therefore, the Company seeks to decertify one residential and one commercial program and proposes to continue six of its residential and four of its commercial DSM programs. The Company is also seeking certification of one new residential program. Additionally, the Company proposes to extend its Education and Energy Efficiency Awareness initiatives, pilot studies and annual pilot budget, and the Company's income-qualified Residential Investment for Saving Energy ("RISE") Pilot. As always, the Company will continue to monitor program costs and economics and will be prepared to modify programs if significant upward pressure on rates continues.

1.4. DISTRIBUTED ENERGY RESOURCES

As the electric system continues to evolve and the presence of DERs expands, the Company remains committed to providing its customers with clean, safe, reliable, and affordable energy solutions. In CHAPTER 9, the Company discusses its forward-looking strategy for addressing the growth of DERs in a way that benefits customers and supports System reliability. The Company provides an overview of its ongoing DER-focused activities, including its evaluation of distributed energy resource management systems ("DERMS") and DER-based transmission and distribution solutions, and discusses its strategy for implementing these versatile solutions moving forward. Additionally, the Company introduces a new customer-focused program (the "DER Customer Program") that provides demand response value to the benefit of all customers and also addresses the emerging resilience needs of commercial and industrial ("C&I") customers through dispatchable DER-based solutions. In addition to the Company's distributed solar programs described in CHAPTER 14, these initiatives will create a platform from which DER technologies can be further leveraged in the Company's planning processes and customer programs. As such, the Company's DER strategy creates significant value by offering options for customers that enhance System reliability and resilience.

1.5. SUPPLY-SIDE STRATEGY

The supply-side plan set forth in this 2022 IRP provides customers with substantial reliability and economic benefits while establishing a strategic plan for the incremental retirement of the Company's remaining coal units and three oil units and corresponding transition to cleaner and more economical resources. Continuing to invest in these units for the long-term increases the risk of new environmental compliance costs. In addition, low natural gas prices, modest load growth, and the growth of renewable resources will increase the economic pressure on these units. As further identified in CHAPTER 11, this strategic transition calls for the retirement and decertification of the following resources:

- Plant Wansley Units 1-2 and Unit 5A by August 31, 2022
- Plant Boulevard by August 31, 2022
- Plant Bowen Units 1-2 by December 31, 2027
- Plant Gaston Units 1-4 and Unit A by December 31, 2028
- Plant Scherer Unit 3 by December 31, 2028[2]

The Company will continue to invest in the reliable operation of Plant Bowen Units 3-4, which are critical to preserving reliability and resiliency in north Georgia and cannot be retired at this time without jeopardizing System reliability. However, as further discussed in CHAPTER 12, the infrastructure enhancements proposed in the Company's North Georgia Reliability & Resilience Action Plan will prepare the System for the long-term retirement of Plant Bowen Units 3-4, which is identified for planning purposes in this IRP as no later than December 31, 2035.

To accommodate the incremental retirement of coal and oil units, the Company proposes to certify an additional 2,356 megawatts ("MW") of capacity from natural gas power purchase agreements[3]

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[2] As further discussed in CHAPTER 11, although the Company has deferred a formal decision on retirement of Plant Scherer Units 1-2 at this time, the 2022 IRP reflects the retirement of these resources by December 31, 2028 for System planning purposes.
[3] Capacity listed in winter terms. Please see CHAPTER 11 for additional information on the natural gas PPAs.

("PPAs") procured through the Company's successful 2022-2028 Capacity RFP. The Company is also planning for an additional 6,000 MW of new renewable resources by 2035.

Consistent with its hydroelectric ("hydro") modernization plan approved in the 2019 IRP, the Company continues to make progress on modernizing Plant Tugalo, Plant Bartletts Ferry, Plant Nacoochee, and Plant Oliver. The modernization projects at Plant Terrora Units 1-2 have been substantially completed on time and under budget. As the Company progresses on these first five projects, it is imperative to continue the hydro modernization efforts on the remaining fleet, such as Plant Burton, Plant North Highlands, and Plant Sinclair. These three plants are in most pressing need of maintenance investment to prevent long-term unit outages. Therefore, the Company's 2022 IRP hydro modernization plan includes improvements necessary for the continued operation of Plant Burton, Plant North Highlands, and Plant Sinclair. This investment will allow these resources to operate for at least another forty years while improving the efficiency and integrity of the hydro fleet and preserving valuable and dispatchable carbon-free resources.

Finally, the Company is evaluating an extension of the operating license for Plant Hatch Units 1-2 through the Subsequent License Renewal ("SLR") process at the Nuclear Regulatory Commission ("NRC"). License renewal will enable the Company to preserve the option of continued operation of these units beyond their current 60-year licenses.

The supply-side resource plan proposed in this IRP will provide low-cost, reliable, resilient, and flexible resources that will substantially benefit customers for years to come.

1.6. ENVIRONMENTAL COMPLIANCE STRATEGY

Georgia Power presents a comprehensive ECS in this IRP that identifies the Company's plans to comply with all applicable state and federal environmental laws and regulations, including, without limitation, the Clean Air Act, Clean Water Act, the Resource Conservation and Recovery Act, and the Coal Combustion Residuals ("CCR") and Effluent Limitations Guidelines ("ELG") rules issued by the Environmental Protection Agency ("EPA") in 2015 and 2020, respectively. The 2020 ELG Reconsideration rule ("Reconsideration Rule") provided important new and updated compliance pathways for flue gas desulfurization ("FGD") wastewater. This rule included an adjustment of the latest generally applicable compliance date from December 31, 2023 to December 31, 2025. The rule also added alternative compliance options such as the Voluntary Incentive Program ("VIP") with more stringent wastewater effluent limitations by December 31, 2028 or compliance with the ELG rule by permanently ceasing coal combustion by December 31, 2028. Through its ECS, Georgia Power will manage a wide-ranging environmental compliance program and effectively address specific compliance requirements through the implementation of appropriate and cost-effective environmental control applications and compliance activities. The 2022 ECS includes, among others, the installation of scrubber wastewater controls on Plant Bowen Units 3-4 and Plant Scherer Units 1-2 to address the requirements of the EPA's most recent ELG rulemaking, and updates to the Company's strategy and progress on its CCR program to comply with state and federal CCR rules. The ECS and its associated costs are discussed in greater detail in Technical Appendix Volume 2 and the Environmental Compliance Cost Recovery ("ECCR") and CCR Asset Retirement Obligation ("ARO") tables in the Selected Supporting Information section of Technical Appendix Volume 1.

1.7. NORTH GEORGIA RELIABILITY & RESILIENCE ACTION PLAN

The North Georgia Reliability & Resilience Action Plan identifies a multi-faceted plan to address future reliability needs associated with the eventual retirement of Plant Bowen. The plan calls for an integrated solution comprised of new generation and transmission assets that will strategically address north Georgia's reliability and resilience needs. Accordingly, the Company has identified a comprehensive action plan that includes the installation of ELG controls at Plant Bowen Units 3-4, the issuance of an RFP with a focus on siting new renewable resources within north Georgia, the development of a strategic portfolio of projects to address the long-term transmission planning and operational needs of north Georgia, and the development of an integrated generation and transmission expansion plan aimed at meeting the long-term needs of the north Georgia area. The North Georgia Reliability & Resilience Action Plan is discussed in greater detail in CHAPTER 12.

1.8. RENEWABLE RESOURCES

Georgia is recognized as a national leader in the development of cost-effective renewable resources without a renewable portfolio standard ("RPS") or mandate. Through the leadership of the Commission and in collaboration with PIA Staff and stakeholders, Georgia Power will have deployed approximately 5,500 MW of renewable resources by the end of 2024. This portfolio of renewable resources includes approximately 480 MW of biomass and landfill gas, 250 MW of wind, and more than 4,700 MW of solar resources, and represents one of the largest voluntary solar portfolios in the nation for an investor-owned utility. These resources have been procured in a manner that delivers benefits to all Georgia Power customers, through a measured approach that maintains reliability and value for its customers.

The 2022 IRP builds upon this approach, but with an increased focus on transforming the electric system in response to changing market conditions and customer expectations. Georgia Power proposes to establish a longer-term plan – a roadmap for renewable development – that includes the addition of 6,000 MW of renewable resources by 2035 with certain economic scenarios indicating that a range of up to 9,000 MW could be economically beneficial for customers. To initiate this plan, Georgia Power, plans to procure 2,300 MW of new renewable resources through enhanced solicitations to be implemented before the next IRP in 2025. Many sizes and types of renewable generators will be solicited, including 2,100 MW from utility scale resources and 200 MW from distributed generation ("DG") resources designed to maximize benefits for customers. The Company is implementing changes to optimize its renewable resource procurements, including requirements for operational flexibility and locational guidance to guide developers to areas where System conditions are more favorable for interconnecting renewable resources. These new facets of Georgia Power's procurement strategy will enhance the efficiency of the reliable integration of new renewables on the System. Additionally, the Company proposes to evaluate and select resources based on the best cost provided to customers, evaluated using the Renewable Cost Benefit ("RCB") Framework, to ensure cost-effective resources. All renewable growth will continue to be guided by Georgia Power's renewable principles – no cost shifting to non-participating customers, an accurate valuation of costs and benefits, and competitive procurements to maximize value for customers. These procurements support a customer-focused strategy and provide the framework through which Georgia Power offers options that meet customer needs and improve the competitiveness of Georgia's business environment.

Since the 2019 IRP, customer interest in renewable resources and programs to support their sustainability goals has increased significantly and is becoming an important factor in economic development siting decisions. In this IRP, Georgia Power presents a portfolio of new and modified renewable programs designed to help meet individual customer needs while delivering long-term benefits to all customers, with innovative new options for income-qualified customers. The cornerstone of the proposed portfolio is the Clean And Renewable Energy Subscription ("CARES") program, modeled after the successful Customer Renewable Supply Procurement ("CRSP") program, and offers subscriptions to renewable energy through subscriptions to all 2,100 MW of utility scale resources proposed in this IRP. Within the CARES program, Georgia Power offers customized program opportunities designed based on direct feedback from customers. The Company also plans to offer opportunities for customers to subscribe to existing renewable resources through a reallocation of the RECs from existing resources through the Retail Renewable Energy Credit (“REC”) Retirement (“R3”) program. Additionally, the Company proposes to enhance renewable resource access to all customers through a robust portfolio of programs, including the Customer-Connected Solar Program (“CCSP”), a modified Simple Solar program, the new Flex Rec Program, and an augmented Community Solar program, which includes an Income-Qualified Community Solar pilot designed to improve access to renewable energy through lower prices for income-qualified customers. All of these programs are designed to prevent cost shifting by offering opportunities for interested customers to pay for subscriptions, while benefitting all customers through the addition of renewable resources to the Company’s diverse generation mix.

The Company remains committed to growing renewable energy for the benefit of all Georgia Power customers, while offering options to those customers with a heightened interest in supporting renewable energy. The Company continues to offer education, analysis, and the delivery of customer-focused renewable programs. As customer interest in renewables continues to grow, Georgia Power is dedicated to excellence and continuous improvement in the implementation of a vast renewable portfolio that delivers a myriad of benefits. Through this IRP, Georgia Power is leading the energy transformation on behalf of its customers in a way that ensures long term access to a low cost and reliable supply of clean electricity.

1.9. ENERGY STORAGE SYSTEMS

As the energy resource mix continues to evolve and the presence of intermittent renewable resources grows, Energy Storage Systems (“ESS”) such as battery storage technology will play an increasingly important role in ensuring the reliability of the electric system for customers. As discussed further in CHAPTER 13, the Company must own and operate sufficient ESS resources to support System operational and reliability requirements as renewable penetration increases. The Company has determined that 1,000 MW of ESS resources by 2030 are required to cost-effectively maintain reliability. The required ESS need is supported by the Company’s Renewable Integration Study, presented in CHAPTER 5 and Technical Appendix Volume 1, which demonstrates how the proposed ESS additions will significantly improve the Company’s ability to reliably integrate additional renewable resources. CHAPTER 13 provides specific details on the Company’s ESS deployment strategy, including an action plan for the establishment of technical engineering specifications, commencement of siting activities, and competitive solicitations for engineering, procurement, and construction ("EPC") services, and approval to develop a 265 MW battery energy storage system ("BESS") at McGrau Ford as part of the plan.

1.10. TRANSMISSION

The Company's updated ten-year transmission plan is summarized in CHAPTER 15 and identifies the transmission improvements needed to maintain a reliable System. The development of this plan was conducted in accordance with Southern Company and Georgia Integrated Transmission System ("ITS") transmission planning guidelines, and North American Electric Reliability Council ("NERC") reliability standards. Georgia Power, Georgia Transmission Corporation ("GTC"), Municipal Electric Authority of Georgia ("MEAG Power"), and Dalton Utilities (collectively, the "ITS Participants") developed this ten-year plan in support of the Georgia ITS. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia ITS. Additional transmission information is also provided in Technical Appendix Volume 3 and as required by Docket No. 31081.

1.11. WHOLESALE BLOCK CAPACITY

Approximately 88 MW of wholesale block capacity from Plant Yates Units 6&7 and various oil-fired generating units will be available to serve retail customers following the expiration of existing wholesale PPAs. Consistent with the Commission's July 30, 2008 Order in Docket No. 26550, Georgia Power is offering these 88 MW of capacity to the retail jurisdiction as each contract expires and the capacity becomes available to serve retail customers. Additional information on the wholesale-to-retail offer is provided in CHAPTER 16.

1.12. CARBON & CLIMATE

As a direct result of working with the Commission through the IRP process, the Company has already made significant cost-effective and reliable resource planning decisions, resulting in a lower-carbon mix of energy resources to the benefit of all customers. In this IRP, the Company continues to address the importance of planning strategically within the state regulatory framework to address the risks presented by carbon policy by ensuring a flexible generation fleet that can respond to the pressures of a low carbon future. Additionally, a growing number of new and existing customers are seeking clean energy solutions, with some focused on a zero-carbon energy supply. Thus, a lower-carbon mix of energy resources that benefits all customers is also becoming increasingly important for the community and economic development of the state of Georgia.

The Company's long-term planning approach considers these factors through a diverse resource portfolio leveraging low- and zero-carbon technologies, the development of new technologies to lower greenhouse gas ("GHG") emissions, and constructive engagement with stakeholders to address the evolving energy needs and preferences of customers. As evidenced by its well-balanced mix of resources put forth in this IRP, Georgia Power will continue to carefully evaluate relevant factors to inform its resource planning decisions to maintain the reliability and resiliency of its System. Above all, the Company remains committed to providing clean, safe, reliable, and affordable energy for its customers and the communities it serves as it responsibly transitions its generation fleet toward more cost-effective, low-carbon resources.

1.13. RESILIENCE PLANNING

This IRP reflects the Company's continued commitment to maintaining a robust and resilient electric system that is capable of reliably serving customers and effectively responding to disruptive events. The Company's focus on resilience planning remains critical as the generation mix evolves to include a larger share of intermittent resources or resources without on-site fuel storage. Key examples of the Company's focus on resilience planning in this IRP are the Company's DER initiatives (CHAPTER 9), the North Georgia Reliability and Resilience Plan (CHAPTER 12), ESS initiatives (CHAPTER 13), and Blackstart Resources (CHAPTER 18), all of which provide substantial benefits to customers and the System.

1.14. CONCLUSION

The 2022 IRP provides a strategic plan that demonstrates the Company's long-standing commitment to providing its customers and the communities it serves with clean, safe, reliable, and affordable electric service, even as customer preferences, society's energy needs, technology, and the energy landscape continue to evolve, by leveraging a diverse mix of energy resources, a comprehensive environmental compliance strategy, enhanced reliability and resilience, innovative customer programs, and state-of-the art technology. The forward-looking strategy and innovative solutions presented in this IRP position the Company to meet the energy needs of customers for years to come. Accordingly, the Company seeks approval of its 2022 IRP and associated Action Plan set forth in CHAPTER 19, including the following:

1. The Reserve Margin Study and its associated outputs, including the continued use of a 16.25% Summer Target Reserve Margin, a 26% Winter Target Reserve Margin, and the associated short-term Target Reserve Margins for each season.

2. A certificate of public convenience and necessity for one new DSM residential program, decertification of two DSM programs (one residential and one commercial), amended certificates for ten DSM programs, including continuation of the Thermostat Demand Response program, an extension of the Income-Qualified Tariff-Based pilot program, and approval of updated program economics for all ten previously certified DSM programs as further specified in the 2022 DSM Application, Docket No. 44161.

3. The revised calculation of the additional sum collected through DSM programs certified in the 2022 DSM Certification Application, Docket No. 44161.

4. Approval of the Company's proposed DER Customer Program as described in CHAPTER 9.

5. Approval of the DER Local Reliability and Constraints Pilot, including the capital and operation and maintenance ("O&M") costs the Company will incur for the seven DER local reliability and constraint pilots projects (but not yet the recovery of such costs).

6. Approval of transmission investments necessary to accommodate the retirements proposed by the Company in the 2022 IRP as well as the investments necessary to prepare the System for additional coal retirements. This includes the proposed retirements in this IRP of Plant Bowen Units 1-2, Plant Scherer 3, and Plant Wansley Units 1-2, as well as the steps necessary to allow for the anticipated future retirements of Scherer 1-2 and Bowen 3-4. The Company's transmission investments will also accommodate future renewable expansion. This approval includes the capital and O&M costs the Company will incur to prepare the transmission system for a reliable fleet transition as identified in the Selected Supporting Information section of Technical Appendix Volume 1. The Company will keep the Commission updated on the status of these projects or any newly identified projects in subsequent IRP proceedings.

7. The North Georgia Reliability and Resilience Action plan as described in CHAPTER 12.

8. The permanent cessation of coal combustion ELG compliance plan through retirement for Plant Bowen Units 1-2 and the associated decertification effective upon the

completion of the necessary transmission system improvements, which is projected to be no later than December 31, 2027.

9. The permanent cessation of coal combustion ELG compliance plan through retirement for Plant Scherer Unit 3 and the associated decertification effective by December 31, 2028.

10. The permanent cessation of coal combustion ELG compliance plan through retirement for Plant Gaston Units 1-4 and the associated decertification effective by December 31, 2028.

11. Decertification of Plant Gaston Unit A effective by December 31, 2028.

12. Decertification of Plant Wansley Units 1-2, Plant Wansley Unit 5A, and Plant Boulevard Unit 1, effective by August 31, 2022.

13. Reclassification of the remaining net book value of Plant Bowen Units 1-2, Plant Wansley Units 1-2, Plant Wansley Unit 5A, Plant Scherer Unit 3, and Plant Boulevard Unit 1 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period to be determined by the Commission in the Company's future base rate cases.

14. Reclassification of any unusable material and supplies inventory balance remaining at the unit retirement dates to a regulatory asset for recovery over a period to be determined by the Commission in the Company's future base rate cases, consistent with treatment of such balance in the 2019 IRP Order.

15. The capital, O&M, and CCR ARO costs (but not yet the recovery of such costs) and associated measures taken to comply with government-imposed environmental mandates, as set out in the ECS in Technical Appendix Volume 2 and the ECCR and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 1.

16. A certificate of public convenience and necessity for six PPAs with a capacity of 2,356 MW[4] from Plant Wansley Unit 7, Plant Dahlberg Units 2 & 6, Plant Harris Unit 2, Plant Dahlberg Units 1, 3, & 5, Plant Monroe Units 1-2, and Plant Dahlberg Units 8-10 procured in the 2022-2028 Capacity RFP.

17. The levelized additional sum amounts described in ATTACHMENT K based on the value of the PPAs procured in the 2022-2028 Capacity RFP as compared to the Company-owned proposal.

18. The capital and O&M costs the Company will incur for the SLR for Plant Hatch Units 1-2 (but not yet the recovery of such costs), as set out in ATTACHMENT D.

19. The capital and O&M costs the Company will incur for the modernization of Plant Burton, Plant North Highlands, and Plant Sinclair hydro facilities (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 1.

20. Approval of Company's use of the Renewable Integration Study for planning purposes and the Company's long-term plan to own and operate 1,000 MW of ESS by 2030 as described in CHAPTER 13. The Company will bring future ESS projects to the Commission for approval.

21. The authority to develop, own, and operate the McGrau Ford Battery Facility as an initial part of the Company's long-term ESS plan to reliably support renewable integration as described in CHAPTER 13.

22. The procurement of energy from an additional 2,100 MW of utility scale renewable resources through two separate utility scale RFPs, to be issued by 2025 and to be online by 2029, including resources located in North Georgia or other identified geographic areas of need, utilizing a market-based approach with best-cost procurements.

23. The procurement of energy from an additional 200 MW of DG renewable resources, utilizing a market-based approach with best-cost procurements.

[4] Capacity listed in winter terms. Please see CHAPTER 11 for additional information on the natural gas PPAs.

24. The levelized additional sum of $7.50 / kilowatt ("kW") alternating current ("AC") of the total capacity amount from which renewable energy is procured from utility scale and DG resources, annually for the term of each PPA.

25. Approval of the Company's renewable development customer program strategy set forth in Chapter 14:

    a. The CARES Program, including the Existing Load, New Load, municipalities, universities, schools, and hospitals ("MUSH"), Carbon Free Energy – Around the Clock ("CFE-ATC"), and Economic Development options.

    b. The R3 Program.

    c. Changes to the Community Solar Program, including the Income-Qualified Community Solar Pilot.

    d. Revisions to the Simple Solar Tariff Large Volume Purchase Option pricing.

    e. The Flex REC Program.

26. Certification of 88 MW of wholesale capacity from Blocks 2-4 and Blocks 5&6 to be placed in retail rate base effective January 1, 2024 and January 1, 2025, respectively.

27. The capital and O&M costs the Company will incur for the Tall Wind demonstration project (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 1.

28. The capital and O&M costs the Company will incur for the Integrated Hydrogen Microgrid pilot project (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 1.

CHAPTER 2. COMPANY OVERVIEW

Georgia Power, a wholly owned subsidiary of Southern Company, is an investor-owned electric utility that serves approximately 2.7 million retail customers in all but four of Georgia's 159 counties. Georgia Power electric service is available in 57,000 of the state's 59,000 square miles.

Southern Company is the parent of Georgia Power, Alabama Power Company ("Alabama Power"), Mississippi Power Company ("Mississippi Power"), Southern Power Company ("Southern Power"), and Southern Company Gas (formerly AGL Resources Inc.). Except where otherwise noted, Alabama Power, Georgia Power, and Mississippi Power (collectively, the "Retail OpCos") as well as Southern Power are considered the electric "Operating Companies" for this 2022 IRP. The Operating Companies operate their respective electric generating facilities and conduct their system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of an interchange contract among themselves. This is further described in ATTACHMENT G. The Retail OpCos are members of the Southeastern Electric Reliability Council ("SERC"), a group of electric utilities (and other electric-related utilities) coordinating operations and other measures to maintain a high level of reliability for the electrical system in the Southeastern United States ("US").

As of December 31, 2021, Georgia Power has ownership in 137 retail-serving generating units, including 5 combined cycle ("CC"), 15 fossil steam, 4 nuclear, 15 renewable, 66 hydro, and 32 combustion turbine ("CT") or diesel engine units, of which at least three have seasonal usage restrictions. Georgia Power meets retail customers' energy requirements and peak demands through a diverse portfolio of Company-owned resources, PPAs, and dispatchable demand-side options ("DSOs"). Of the energy generated to meet retail customers' needs in 2021, 47% was from natural gas, 16% from coal, 24% from nuclear, 6% from renewables, 2% from hydro, 5% from null energy,[5] and less than 1% from oil-fired resources. Georgia Power's forecasted energy and capacity mix is further described in CHAPTER 4, CHAPTER 10, and CHAPTER 11.

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[5] Null energy is the underlying unspecified and undifferentiated power remaining when renewable or other energy attributes like RECs have been separated and removed.

CHAPTER 3. EXECUTION OF THE 2019 IRP ORDER

The Company's 2019 IRP was approved with modifications as specified in the Commission's July 29, 2019 final order in Docket No. 42310 (the "2019 IRP Order"). Consistent with the 2019 IRP Order, the Company has taken or will take the following significant actions:

1. Retired Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2.

2. Completed the 2022/2023 Utility Scale Renewable RFP seeking a portfolio of 800-1,200 MW of utility scale renewable resources. The RFP process resulted in a 970 MW portfolio of standalone solar and solar plus storage resources with energy procured through five PPAs. The Commission certified the utility scale renewable PPAs on July 7, 2021.

3. Issued the 2023/2024 Utility Scale Renewable RFP in January 2022 to procure renewable energy from the remaining 1,030 MW of utility scale renewable resources approved in the 2019 IRP.

4. Designed and implemented the CRSP Program, which makes available for subscription energy from 1,000 MW of utility scale renewables resources, procured through the 2022/2023 Utility Scale Renewable RFP and the 2023/2024 Utility Scale Renewable RFP. The first Commission-approved CRSP Notice of Intent ("NOI") Period resulted in subscriptions for 300 MW of renewable energy by existing C&I customers and 200 MW of renewable energy by C&I customers with qualifying new load additions.

5. Issued the 2020 DG RFP seeking 160 MW of renewable resources sized up to 3 MW. Through December 31, 2021, Georgia Power has executed 20 PPAs for 52.95 MW of solar resources.

6. Launched the Renewable Energy Development Initiative ("REDI") Customer-Sited ("CS") DG II program, which resulted in 11.825 MW of projects from seven applications. The resulting projects are currently undergoing a detailed analysis in which the Company is evaluating project interconnection requirements before offering PPAs.

7. Launched the CCSP for customers interested in supporting on-site solar Facilities and contracting to sell energy to the Company. The Commission extended the CCSP until the

25 MW of available program capacity is filled. The Commission has already certified one CCSP PPA and Georgia Power is actively working with customers across the state considering program participation.

8. Engaged with the Commission's PIA Staff to evaluate certain RCB Framework issues identified in the 2019 IRP. This effort was summarized in a compliance filing on January 21, 2020.

9. Applied the RCB Framework in the evaluation of Company-owned renewable projects and renewable utility scale and DG RFPs.

10. Implemented seasonal planning providing visibility into both the summer and winter capacity or reliability needs.

11. Collaborated with PIA Staff to address reserve margin study modeling approaches.

12. Completed the 2022-2028 Capacity RFP, in consultation with PIA Staff and the Independent Evaluator ("IE"), which sought replacement generation with a required level of firmness and dispatchability for potential steam unit retirements, including bids from stand- alone storage as well as renewables paired with storage. The 2022-2028 Capacity RFP resulted in six PPAs from generation facilities offering a total of 2,356 MW[6] of capacity from natural gas resources.

13. Completed additional transmission assessments of the retirement of Plant Bowen Units 1-2 to review both traditional transmission solutions and alternatives to traditional transmission solutions (e.g., non-wire solutions) and compared the cost of each approach. This information was provided in the 2019 base rate case as ordered in the 2019 IRP.

14. Instituted capital expenditure limits of $19 million per year, or $57 million for the three-year period ending July 31, 2022, for Plant Bowen Units 1-2. The Company and PIA Staff developed Plant Bowen capital expenditure reporting requirements and the Company filed quarterly reports with the Commission.

[6] Capacity listed in winter terms. Please see CHAPTER 11 for additional information on the natural gas PPAs.

15. Substantially completed the modernization of Plant Terrora, the first hydro modernization project, on time and under budget.

16. Commenced the hydro modernization program for Plant Tugalo, Plant Bartlett's Ferry, Plant Nacoochee, and Plant Oliver. The Company and PIA Staff developed an information sharing process to monitor the modernization efforts. The Company provided the Commission with biannual Hydro Modernization reports.

17. Commenced development of a BESS portfolio totaling approximately 80 MW. The Company is developing three different configurations, including a large standalone transmission interconnected storage, solar plus storage, and small standalone distribution interconnected storage. On October 12, 2021, the Commission approved the Company's proposed Mossy Branch Battery Facility for a 65 MW / 260 megawatt-hour ("MWh") BESS. The Mossy Branch Battery Facility is a large standalone configuration that will be constructed on behalf of the Company by an engineering, procurement, and construction firm selected through a competitive EPC RFP process. For the remaining 15 MW of battery energy storage, the Company plans to co-locate a 13 MW, 4-hour BESS with an existing Company-owned solar facility. Additionally, the Company intends to utilize the remaining 2 MW to develop a small standalone distribution interconnected storage facility. Progress on these BESS is further described in CHAPTER 13.

18. Commenced execution of the approved ECS to comply with government imposed environmental mandates, including plans to address CCR at the Company's ash ponds and landfills as well as ELG at several plants. The Company completed the construction and installation of equipment necessary for dry ash conversions and wastewater treatment facilities to allow for all ash ponds to cease receipt of CCR and non-CCR waste streams as part of compliance with federal and state rules and permits including the Clean Water Act and Resource Conservation and Recovery Act. The Company submitted CCR project progress and cost updates semi-annually to the Commission through Docket No. 42310.

19. Investigated methodologies for allocating long-term annual energy sales for each class to monthly amounts to account for anticipated trends in seasonal energy sales.

20. Provided PIA Staff a Technical Reference Manual in December 2020 for use with the Company's DSM programs.

21. Implemented the Income-Qualified Tariff Based Energy Efficiency Pilot as approved by the Commission.

22. Filed the Achievable Energy Efficiency Potential Assessment February 1, 2021 in accordance with the Commission's approved DSM Program Planning Approach in Docket No. 43040.

23. Provided complete Process and Impact Evaluation result reports to Commission Staff in October 2021 for the energy efficiency programs certified in the 2019 DSM certification proceeding.

24. Developed the Company's 2022 IRP DSM plan consistent with the DSM Program Planning Approach.

25. Collaborated with PIA Staff to investigate methodologies to model DSM in supply-side System planning tools alongside traditional supply-side options. On April 30, 2021, the Company filed a DSM White Paper reviewing these methodologies.

26. Implemented the biomass portion of the 2022-2028 Capacity RFP seeking an additional 60 MW of new biomass capacity[7].

27. Commenced work in connection with a pilot project for lithium-ion batteries for a grid-connected charging system for electric vehicles ("EVs").

28. Continued offering the Automated Benchmarking Tool from the 2016 DSM IRP in accordance with the 2019 IRP Order.

29. Initiated Commission review of the Company's Public Utility Regulatory Policies Act ("PURPA") avoided cost methodology and computation in Docket Nos. 4822, 16573, and 19279 to ensure the appropriate valuation of renewable and demand-side resources. The Commission issued an order resolving certain issues associated with these dockets on March 11, 2021 ("PURPA Final Order").

[7] Through the RFP process, overseen by the Commission Staff and the IE, Georgia Power was unable to identify suitable biomass capacity with acceptable terms amongst the bids submitted into the 60 MW biomass solicitation at the time of the Company's filing of this 2022 IRP.

30. Conducted an analysis of the capacity value of different renewable and storage technologies using the Effective Load Carrying Capability ("ELCC") methodology in compliance with the Final Order in Docket Nos. 4822, 16573, and 19279. This analysis is described in CHAPTER 5 and in the ELCC Study located in Technical Appendix Volume 1.

31. Developed a proposal to study locational value in compliance with the PURPA Final Order in Docket Nos. 4822, 16573, and 19279, which is included in ATTACHMENT H.

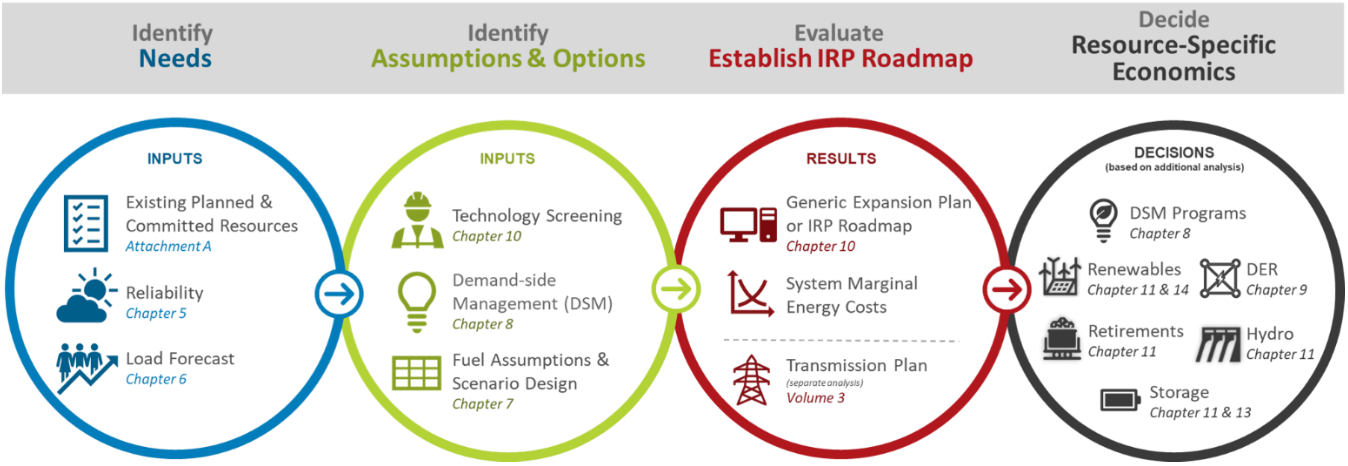
CHAPTER 4. INTEGRATED RESOURCE PLANNING OVERVIEW

The development of Georgia Power's triennial IRP is part of a continuous planning process involving many diverse disciplines and areas of expertise from Georgia Power and Southern Company Services ("SCS"). This 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.

The IRP process includes several sequential steps, ultimately leading to the development of a resource needs determination, the production of generic expansion plans, and System marginal energy costs forecasts that inform a variety of planning decisions. When developing the IRP, the Company begins by establishing reliability criteria while assessing the System's overall reliability needs. During this step, the Company establishes seasonal target reserve margins that define the appropriate level of reliability for the System. This step also considers the potential reliability contribution of new resource additions while routinely seeking to proactively identify potential evolutions in System reliability needs. The Company then applies these reliability criteria to the demand and energy forecasts to determine the amount and type of capacity that is required to reliably meet forecasted conditions. The amount of capacity required is compared to existing, planned, and committed resources. This comparison results in a needs determination, which establishes the amount and timing of capacity needs. After these steps, the Company then completes an expansion planning analysis that determines the optimal least-cost resource mix, or generic expansion plan. This analysis provides a roadmap of potential options to meet future needs. Using the generic expansion plan, more detailed production cost modeling is conducted to produce hourly forecasted marginal energy costs. For the first time in a Georgia Power IRP, the Company's 2022 IRP includes solar, battery storage, and wind resources as generic resource options selectable by the expansion planning model.

Using this information, the Company then performs resource-specific economic evaluations for both demand-side and supply-side options. If a need is identified in the timeframe required to plan and build the longest lead time resource, then a separate generation selection is performed. Once resource decisions are made, those decisions then become inputs that inform subsequent IRP processes. An overview of the process by which the IRP is developed is shown in Figure 1.

Figure 1: IRP Process



Given the inherent uncertainties of the future, numerous scenarios are developed to inform the Company's resource planning decisions. The steps of the IRP process are then conducted for each of the scenarios to produce a range of well-rounded results that facilitate the determination of the most appropriate solutions. This process is described in more detail throughout the 2022 IRP Main Document and associated Technical Appendices and results in a plan that incorporates demand-side and supply-side options to serve customers in an economical manner that appropriately accounts for reliability, flexibility, and risk. The Company's base case is established using the moderate gas, zero-dollar carbon ("MG0") planning scenario.

Figure 2 reflects the Company's projected 2022 and 2030 summer capacity mixes, which account for the most recent unit capacity ratings and reflect approval of certain certification and decertification requests made in this filing. Unit-specific capacity information can be found in ATTACHMENT A as well as the Resource Mix Study in Technical Appendix Volume 1.

Figure 2: Georgia Power's Projected Summer 2022 and Summer 2030[8] Capacity Mixes

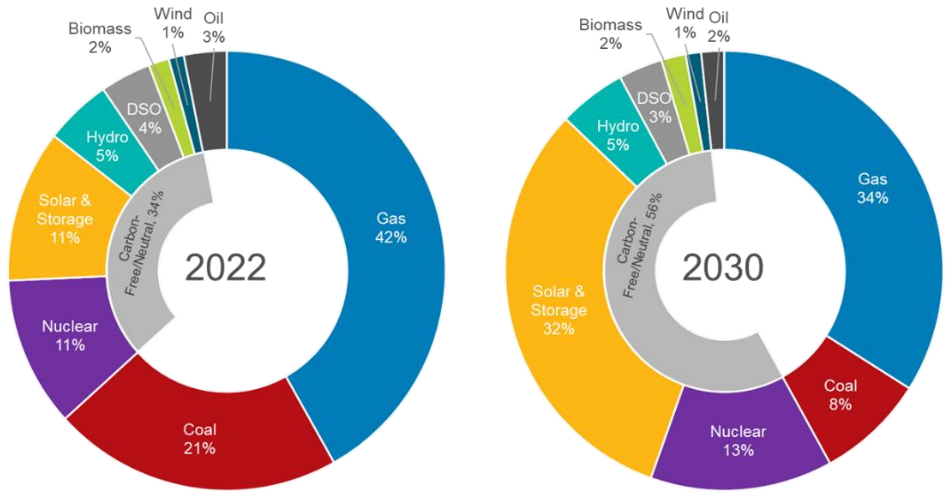
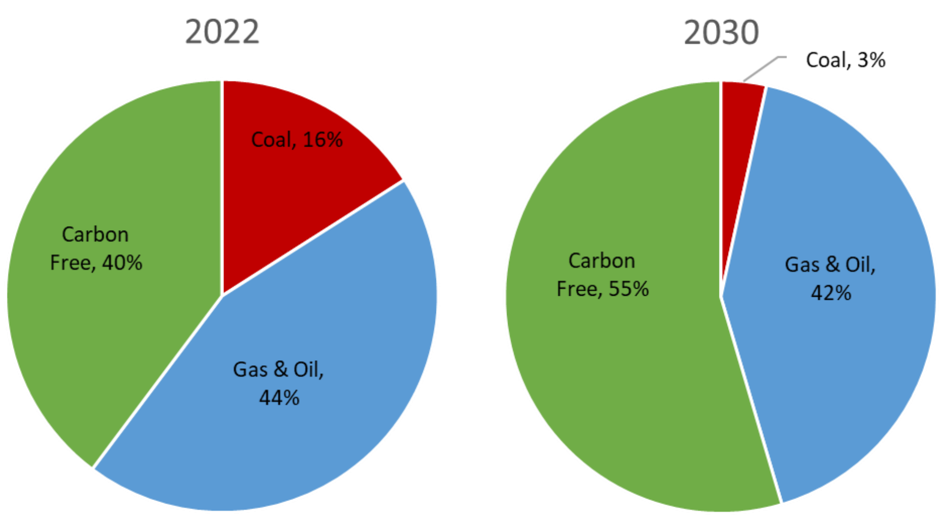


Figure 2 reflects changes in the Company's capacity mix over time. The capacity mix reflects the mix of physical output capability of the Company's combined capacity resources. The actual operation of these resources varies based on production costs, weather, and reliability needs. The projected energy mix helps demonstrate the expected electricity production from these resources over the timeframe as depicted in Figure 3.

Figure 3: Georgia Power's Projected 2022 and 2030 MG0 Energy Mixes



Note: These capacity and energy mixes reflect demonstrated retail capacity for traditional resources, nameplate capacity for retail-serving renewable resources, and program capacity for dispatchable DSOs. A portion of the projected renewable generation capacity includes capacity where the renewable generator or subscribing customer retains the related RECs.

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[8] This figure includes Georgia Power's existing, planned and committed resources. It does not reflect generic expansion plan resources.

Prudent utility practice requires that electric utilities maintain sufficient supply-side and demand-side resources to reliably serve the needs of their customers. The ability of supply-side and demand-side resources to meet electrical demand and maintain an appropriate level of system reliability is commonly referred to in the electric utility industry as “Resource Adequacy.” The Company establishes the appropriate level of system reliability through its reserve margin study. The Company also completes capacity equivalence studies, which ensure that resources that contribute to the Company’s Target Reserve Margin are assigned the appropriate capacity value or reliability benefit.

The combination of capacity equivalence valuations and target reserve margins ensure the Company has planned for sufficient capacity to meet peak demands. The Company’s resource mix is forecasted to become increasingly dependent on energy-limited and intermittent resources. While these changes in the Company’s resource mix are expected to provide economic benefits for customers, certain reliability impacts are not fully discernable through traditional reserve margin studies. Therefore, the Company has expanded its reliability analysis to examine the changes anticipated in the Company’s resource mix. The results of this study indicate a need for increased levels of operating reserves and/or flexible capacity, as further discussed in this chapter.

5.1. RESERVE MARGIN STUDY

Resource Adequacy requires consideration of not only the uncertainties associated with the demand for electricity, but also the uncertainty associated with the reliability of the resources available to meet that demand. The Company’s Target Reserve Margin represents the amount of resources needed above forecasted peak demand to account for these uncertainties. To ensure reliability, the Company must evaluate the required reserve margin using a combination of economic and reliability metrics. As such, a reserve margin study is produced in the year prior to each triennial IRP filing to establish a Target Reserve Margin for the System for both the short-term and the long-term planning horizons. The Company performed such a study in 2021, and a report describing the Company’s Reserve Margin Study is included in Technical Appendix Volume 1. The Reserve Margin Study report describes the methodology, metrics, assumptions, and results used to determine the Company’s Target Reserve Margin recommendations.

Seasonal Target Reserve Margins

The use of seasonal planning to provide greater visibility into both summer and winter capacity needs was approved in the 2019 IRP Order. In order to effectuate seasonal planning, the Company must also establish seasonal Target Reserve Margins. The Reserve Margin Study evaluated the need for these seasonal Target Reserve Margins. Notably, the results of the most recent Reserve Margin Study continue to reflect the significant increase in winter reliability risks. These risks are associated with the following drivers: (1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) cold-weather-related unit outages; (4) the penetration of solar resources; (5) increased reliance on natural gas; and (6) market purchase availability. Given the difference in customer load response as well as differences in both the availability and dependability of resources in the summer and winter peak periods, it remains necessary to independently evaluate Resource Adequacy in both the summer and winter peak periods to ensure that System reliability has been appropriately evaluated.

Defining Target Reserve Margins

The Target Reserve Margin is stated in terms of seasonal weather-normal peak demands and seasonal capacity ratings according to the following formula:

$$TRM_S = \frac{TC_S - PL_S}{PL_S} x\ 100\%$$

Where:

TRM_S = Seasonal Target Reserve Margin;

TC_S = Total Seasonal Capacity; and

PL_S = Seasonal Peak Load.

Target Reserve Margins

To appropriately address seasonal planning needs and winter reliability concerns, the Company will continue to implement seasonal planning as approved in the 2019 IRP Order. After analyzing the load forecast and weather uncertainties, expected unserved energy, as well as projected generation reliability of the System, the Company plans to maintain the current 16.25% long-term Target Reserve Margin for the System as the Summer Target Reserve Margin to be applied to the summer peak planning season. The Company also plans to maintain the current 26% long-term Target Reserve Margin for the System as the Winter Target Reserve Margin to be applied to the winter peak planning season. These Target Reserve Margins remain consistent with the Company's findings in the 2019 IRP.

For the short-term, the System plans to maintain a Summer Target Reserve Margin of 15.75%, and a short-term Winter Target Reserve Margin of 25.5%. A significant benefit of coordinated System planning and operations, which allow companies to share resources, is that each Operating Company can carry fewer reserves than the System target. Thus, the Summer Target Reserve Margin that will apply to Georgia Power will be 15.28% over the long-term and 14.78% over the short-term. Likewise, Georgia Power's proposed Winter Target Reserve Margin will be 25.18% over the long-term and 24.69% over the short-term. These targets can change as System load diversity changes.

5.2. THE RELIABILITY PLANNING MODEL

The 2021 Reserve Margin Study included in Technical Appendix Volume 1 was performed using the Strategic Energy and Risk Valuation Model ("SERVM"). SERVM is an industry-accepted generation reliability model used for Resource Adequacy analyses and is further described in ATTACHMENT C.

5.3. CAPACITY EQUIVALENCE

The capacity value of renewable resources and other energy-limited or non-dispatchable resources is often represented in the utility industry by the ELCC of the resource. The Company has traditionally valued renewable resources and other energy-limited supply- and demand-side resources using the Incremental Capacity Equivalent ("ICE") Factor, which is a form of ELCC. During the 2021 PURPA proceedings,[9] the Company and PIA Staff agreed it would be a beneficial exercise to study the capacity value of renewable resources with a more widely used form of ELCC, which determines the reliability value of a resource by its ability to serve an increase in load while keeping reliability, as measured by Loss of Load Expectation ("LOLE"), the same. In compliance with the PURPA Final Order in Docket Nos. 4822, 16573, and 19279, the Company

[9] Docket Nos. 4822, 16753 and 19279.

conducted this study for wind, solar, and battery storage. The results of this study are included in the ELCC Study located in Technical Appendix Volume 1.

5.4. RENEWABLE INTEGRATION STUDY

The integrated resource planning approach allows the Company and the Commission to assess the Company's ability to meet the reliability needs of customers while making strategic, long-term resource planning decisions. This focus on reliability is a cornerstone of the Company's IRP. In the 2019 IRP, the Commission approved the Company's recommendation to adopt seasonal planning to appropriately address the growing winter-based reliability risks. The Commission's careful oversight in assessing and approving the seasonal planning approach and the proactive implementation of corresponding enhanced reliability planning demonstrate the benefit of the IRP framework and associated vertically integrated utility model in ensuring System reliability. Moreover, the importance of System reliability is underscored by reliability events seen around the country since the completion of the 2019 IRP. The emphasis on System reliability will remain at the forefront of the Company's planning decisions as the System continues to evolve and transition from a heavy reliance on conventional thermal generating resources toward an increasing number of weather-dependent renewable generation resources.

Ensuring a reliable fleet transition necessitates continued forward-thinking and innovative reliability solutions. The Company has completed a reliability study with these objectives in mind. Specifically, the Company evaluated the reliability impacts of large solar penetration levels from an operational perspective. This assessment provides unique insights into certain challenges, opportunities and, most importantly, solutions that enable significant renewable penetration while maintaining a reliable System.

Operating Reserves

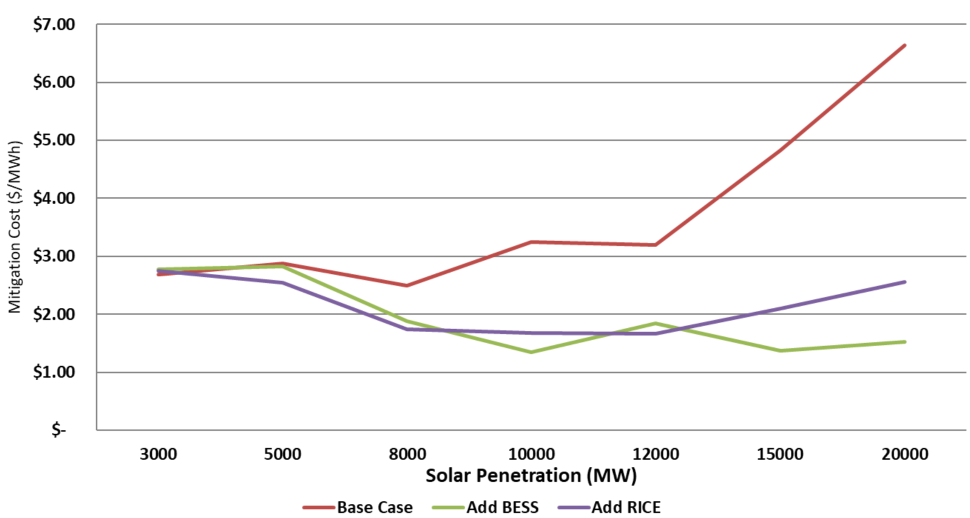
System operators commit and dispatch the System with a focus on maintaining reliability. In order to ensure reliable operation, operators must balance load and generation in real-time while managing inherent load and generator uncertainties. Operating reserves serve as a vital tool for System operators in managing these uncertainties. Operating reserves represent the capacity above real-time load requirements that is available to respond to unexpected unit outages, variability in loads or resource output, or similar unpredictable changes in system conditions. Operating reserves can be provided by resources that are either on-line or on-standby. As the System becomes increasingly reliant on intermittent, weather-dependent renewable resources, operating reserves will become an increasingly important consideration for reliability planning and the successful integration of renewable resources.

Renewable Integration Study

To identify the potential changes in the required operating reserves, the Company completed an intra-hour reliability assessment of renewable penetration levels that present reliability issues. The Company completed this study using the reliability planning model, SERVM, with industry expertise support provided by Astrape. This study is further described in Technical Appendix Volume 1.

This study indicates that significant increases in solar penetration can be achieved while maintaining appropriate levels of reliability for the System. However, the cost of integrating renewable resources while maintaining System reliability can be significantly reduced with the addition of flexible resources, such as BESS. The reliability assessment determined that maintaining sufficient amounts of stand-alone battery capacity, generally corresponding to 15% of the installed solar capacity on the System, significantly improves the cost-effectiveness of solar integration, while reducing curtailment of renewable resources and improving System reliability by providing critical grid reliability services. As the energy landscape continues to evolve and additional information becomes available, the Company will continue to update these types of reliability assessments to ensure it appropriately plans for System reliability. The results of the study are summarized in Figure 4.

Figure 4: Solar Integration Costs[10]



[10] Reciprocating internal combustion engine ("RICE").

CHAPTER 6. LOAD & ENERGY FORECAST

Twenty-year forecasts of energy sales and peak demand were developed to meet the planning needs of Georgia Power. The Budget 2022 Load and Energy Forecast include the retail classes of residential, commercial, industrial, MARTA, and governmental lighting. The baseline forecasts were started in the spring of 2021 and completed in the fall of 2021. A detailed discussion of the territorial energy and load forecasts is set forth in Budget 2022 Load and Energy Forecast, found in Technical Appendix Volume 1.

6.1. GENERAL FORECASTING AND ECONOMICS OVERVIEW

Georgia, like the United States generally, experienced robust economic growth from 2013-2019. Over this period, U.S. Gross Domestic Product ("GDP") growth averaged 2.5% per year, and employment growth averaged 1.7% per year. In Georgia, output and employment grew by 3.3% and 2.3% per year, respectively. In 2019, the U.S. unemployment rate dropped as low as 3.5%, while Georgia's rate fell to 3.3%.

The beginning of the COVID-19 pandemic in March of 2020 brought an abrupt end to this period of economic growth, with a short but deep recession and then a sharp rebound. Georgia lost more than 600,000 jobs from February to April 2020, and the unemployment rate jumped to 12.5%. Georgia Power's total retail sales fell by more than 9% in April of 2020, with commercial sales down more than 13% and industrial sales down over 18% compared to April 2019. Residential sales jumped more than 8% in April as people worked from home and students attended school virtually. Total retail sales increased as the year went on, as businesses reopened, and people began to resume some of their pre-pandemic activities. Total retail sales ended 2020 down 2.2% versus the prior year. Residential sales ended the year up 3.4%, while commercial and industrial electricity sales were down 5.3% and 4.5%, respectively. Sales continued to recover in 2021. Total retail sales for the year finished above pre-pandemic levels, led by growth in the residential and industrial classes. Sales to the commercial class in 2021 remain below their 2019 level.

Post pandemic, Georgia is expected to return to robust economic growth over the twenty-year forecast horizon. One factor that will help drive growth is that Georgia remains an attractive place to do business. Businesses are attracted by factors such as Georgia's low cost of doing business and low cost of living, a deep pool of knowledge and technical workers due to its university system, Georgia's globally connected airport and transportation infrastructure (e.g., ports and highways), and its business-friendly environment. Positive demographic trends will also drive economic growth in the state. As businesses continue to relocate and expand in Georgia, the state will experience solid employment growth, which will attract new residents. As a result, population growth in Georgia is projected to remain above the U.S. average.

Additional businesses and a growing population are expected to provide a boost to energy sales. From 2022-2041, total energy sales are projected to grow at an average annual rate of 0.8%. Residential sales are expected to grow by an average of 1.1% per year over this period as the increase in the number of customers outpaces the reduction in use per customer resulting from energy efficiency. Industrial sales are expected to increase at an average annual rate of 0.9%. Sales to the commercial class are expected to experience modest growth of 0.4% per year due in part to increased energy efficiency. Summer and Winter peak demands are also expected to increase at an average rate of 0.7% per year during this time. Georgia Power is expected to remain a summer-peaking utility over the forecast horizon.

6.2. FORECAST ASSUMPTIONS AND METHODS

Budget 2022 forecast assumptions were developed through a joint effort of Georgia Power and SCS. The load and energy forecasts were developed through careful consideration and methodical examination of key demographic and economic variables that have historically been significant indicators of energy consumption. Major assumptions include the economic outlook for the United States and Georgia, energy prices, and market profiles for class end-uses.

The economic forecast provides a description of the economy for the next 20 years and includes many elements of the economy such as gross product, population, employment, commercial building square footage, and industrial production. The economic and demographic forecasts for Budget 2022 were obtained from IHS Markit, a national provider of economic data and forecasts.

The models used to produce both the short-term and long-term energy forecasts include a variety of economic and demographic variables as drivers of energy use. Weather, income, employment, historical load data, and industry efficiency standards for electrical equipment are among the variables used in the forecasting models. “Normal” weather is defined as the average of cooling degree hours (“CDH”) and heating degree hours (“HDH”) from 1980-2020.

Short-term energy projections for the residential, commercial, and industrial classes are based on linear regression models. The short-term and long-term MARTA and governmental lighting forecasts are based on econometric models and information provided by Georgia Power field personnel. The details of these forecast models can be found in Section 4 of the Budget 2022 Load and Energy Forecast found in Technical Appendix Volume 1.

The long-term forecast models are end-use models. Budget 2022 uses the Load Management Analysis and Planning ("LoadMAP") model to produce the long-term residential, commercial, and industrial forecasts. The LoadMAP tool is discussed in greater detail in Section 5 of the Budget 2022 Load and Energy Forecast, found in Technical Appendix Volume 1.

The results of the short-term and long-term models are integrated into a unified forecast. In Budget 2022, the short-term forecast results were used for the years 2022 through 2025 and the long-term results from 2026 through 2041. Additional information on forecasting methodology can be found in Section 3 of the Budget 2022 Load and Energy Forecast, found in Technical Appendix Volume 1.

Budget 2022 uses hourly peak demand forecasting models to predict Georgia Power's weather-normal peak demands. The methodology and assumptions used in the peak demand models are discussed in greater detail in Section 6 of the Budget 2022 Load and Energy Forecast, found in Technical Appendix Volume 1.

CHAPTER 7. SCENARIO DESIGN & FUEL FORECAST

Many factors affecting resource planning are inherently uncertain because they involve the future. As part of its planning process, the Company develops scenarios to aid in understanding some forms of future uncertainty, thus allowing the Company to make appropriate planning decisions. Key uncertainties affecting planning include (i) the evolution of natural gas prices; (ii) future environmental pressures—especially regarding carbon-dioxide; (iii) cost and performance of future generating technologies; and (iv) future load growth. Therefore, in developing its scenarios, the Company identifies different plausible viewpoints in each of these four areas. These viewpoints are combined to create several scenarios. The viewpoints and scenarios are refreshed annually. For Budget 2022[11] ("B2022") the Company created 11 scenarios.[12]

7.1. B2022 SCENARIOS

The Company considers multiple views of the future price of natural gas, the future pressure on the Company's carbon dioxide ("CO_2") emissions, the future cost and performance of generating technologies, and future electricity consumption. For B2022, the Company assembled multiple views in each of the four areas into the 11 scenarios summarized in Table 1. By way of example, Scenario 1, which is abbreviated as MG0, is defined by moderate future natural gas prices, no additional pressure on CO_2 emissions (relative to today), standard value for future cost and performance of technologies, and the standard load forecast.

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[11] The analyses are conducted during calendar year 2021 for use during calendar year 2022.
[12] In several prior years, similar information and reports were developed by the Company's modeling consultant, Charles River Associates ("CRA").

Table 1: B2022 Scenario Design

Scenario	Natural Gas View	Greenhouse Gas Pressure View	Technology Cost & Performance View	Load View	Short Name
1	Moderate price path	$0 fee	SCS Gen-Tech App Stds[1]	SCS Forecasting[2]	MG0
2	Moderate price path	$20+ fee	SCS Gen-Tech App Stds	SCS Forecasting + MG20 delta	MG20
3	$50 CO_2 price path	$50+ fee	SCS Gen-Tech App Stds	SCS Forecasting + $50 delta	$50
4	Low price path	$0 fee	SCS Gen-Tech App Stds	SCS Forecasting + LG0 delta	LG0
5	Low price path	$20+ fee	SCS Gen-Tech App Stds	SCS Forecasting + LG20 delta	LG20
6	High price path	$0 fee	SCS Gen-Tech App Stds	SCS Forecasting + HG0 delta	HG0
7	High price path	$20+ fee	SCS Gen-Tech App Stds	SCS Forecasting + HG20 delta	HG20
8	Moderate price path	$0 fee	SCS Gen-Tech App Stds	Electrification-influenced load growth[3]	HL[3]
9	Moderate price path	$0 fee	SCS Gen-Tech App Stds	DER/EE-influenced load growth[4]	LL[4]
10	Moderate price path	$0 fee	Lower costs of zero-CO_2 technologies[5]	SCS Forecasting	Tech
11	Moderate price path	2050 CO_2 Intensity[6]	SCS Gen-Tech App Stds	SCS Forecasting	2050 CI

Notes:

1. Southern Company Services' Technology Application Standards, which contains company assumptions on technology cost and performance benchmarks
2. Standard forecasts produced by Operating Company Load Forecasting and SCS Load Forecasting
3. Higher load growth based on Electric Power Research Institute (“EPRI”) electrification study provided by SCS Forecasting
4. Lower load growth based on aggressive adoption of distributed resources and efficiency improvements provided by SCS Forecasting
5. Costs and performance of solar, wind, storage, and 4th gen nuclear provided by SCS Generation Planning & Development and SCS Research & Development
6. The CO_2 Intensity view is based on current legislative ideas

Additional details regarding the scenarios depicted in Table 1 are discussed below.

7.2. FUEL PRICE FORECAST

Natural Gas Prices

The future price of natural gas is unknown. For the B2022 planning process, the Company considered the following four different views of how natural gas prices could evolve over time: a lower path; a moderate path; a higher path; and a path consistent with significant pressure on CO_2 emissions. As part of its planning process, the Company bases its analysis on a reputable source for the paths. For B2022, the Company adopted and adapted paths produced by the U.S. Energy Information Administration ("EIA") for its 2021 Annual Energy Outlook[13] ("AEO"). Because the AEO is highly regarded and readily available, it is often used as a reference in conversations about the future of energy in the United States. EIA constructs several scenarios each year. For each scenario, the National Energy Modeling System ("NEMS") is used to identify price paths for fuel sources such as natural gas, coal, oil, and gasoline that are consistent with market conditions across the U.S. energy economy in that scenario. All key assumptions and results from the NEMS analysis for the AEO are publicly available without charge on EIA's website.

The Company also regularly reviews other sources of future fuel price estimates and the key assumptions behind those estimates. These other sources of information are used to help the Company understand other views and how they compare to the views adopted by EIA in producing the AEO.

For B2022, the Company adopted the following four different views of future natural gas prices:

- Lower price view: AEO's High Oil and Gas Supply case
- Moderate price view: AEO's Reference case
- Higher price view: AEO's Low Oil and Gas Supply case
- \$50 CO_2 price view: The Company adapted the natural gas price path from AEO's Alternative Policies case, which assumed a \$35 per ton fee on CO_2 emissions

[13] The AEO is a major annual product of the EIA. It is available on the EIA's website (https://www.eia.gov). The analysis supporting the AEO uses the National Energy Modeling System, EIA's main modeling system of the US energy economy. NEMS is detailed and comprehensive; full documentation is available at https://www.eia.gov/outlooks/aeo/nems/documentation. In addition to producing the AEO, EIA uses NEMS to analyze the energy content of policy proposals that Congress or the Administration asks about.

Estimates of technically recoverable tight/shale oil and natural gas resources are uncertain and change over time as new information is gained through drilling, production, and technology development. The "High Oil and Gas Supply" and "Low Oil and Gas Supply" views reflect this uncertainty.

In the AEO's Low Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% lower than in the Reference case for tight oil, tight gas, shale gas in the United States, undiscovered resources in Alaska, and offshore in the lower 48 states. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the United States.

In the AEO's High Oil and Gas Supply case, the estimated ultimate recovery per well is assumed to be 50% higher than in the Reference case for tight oil, tight gas, shale gas in the United States, undiscovered resources in Alaska, and offshore in the lower 48 states. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% higher than in the Reference case. These assumptions decrease the per-unit cost of crude oil and natural gas development in the United States. In addition, tight oil and shale gas resources are added to reflect new prospects or the expansion of known prospects. Crude oil pipeline and export capacity in the Liquid Fuels Markets Module is assumed to increase in the projection period to accommodate higher levels of domestic oil production.

The Company relied on AEO 2020 for its B2021 analyses and has relied on AEO 2021 for its B2022 analyses. Table 2 gives some of the key assumptions for AEO 2021 (B2022).

Table 2: Key Values for B2022 for Moderate Gas View

	Key Values for B2022 Moderate Gas View
Resource Size	• 474.8 Tcf in proved shale reserves for B2022 (36 Tcf increase from B2021) • 2,867 Tcf in total technically recoverable (TTR) U.S. dry natural gas resources (1.4% growth from AEO 2020 to AEO 2021)
Production Rates	• IP rate assumptions increase to 40% above current levels by 2059 • These assumptions were the same in B2021
Well Costs	• Fixed well cost down from current levels 40% by 2059 • B2021 assumed this same fixed well cost pattern • Variable sell costs decrease to 80% of current levels by 2059 • B2021 assumed this same variable well cost pattern

Future Coal and Oil Prices

The prices of coal and oil in the future are also uncertain. For B2022, the Company has adopted three different views of future coal prices and three different views of oil prices. These views are the coal and oil price paths from the AEO 2021 Reference, High Oil and Gas Supply, and Low Oil and Gas Supply cases.

Summary of Fuel Prices

The following illustrations give the fuel price paths that the Company has used in the B2022 scenario analyses.

Figure 5: Views of future price of Natural Gas at Henry Hub

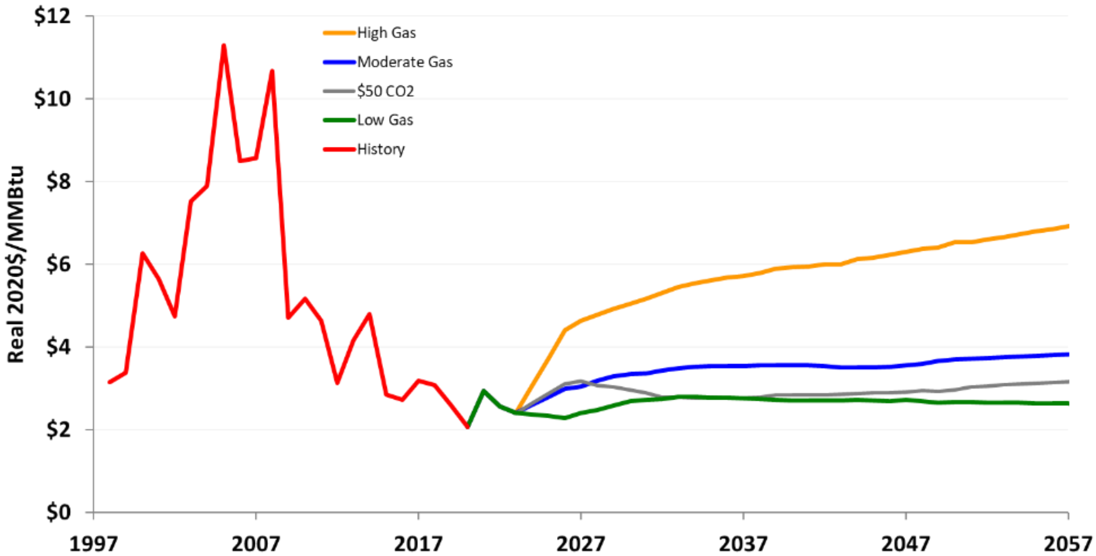


Figure 6: Views of future price of coal at mine, by scenario, Central Appalachia

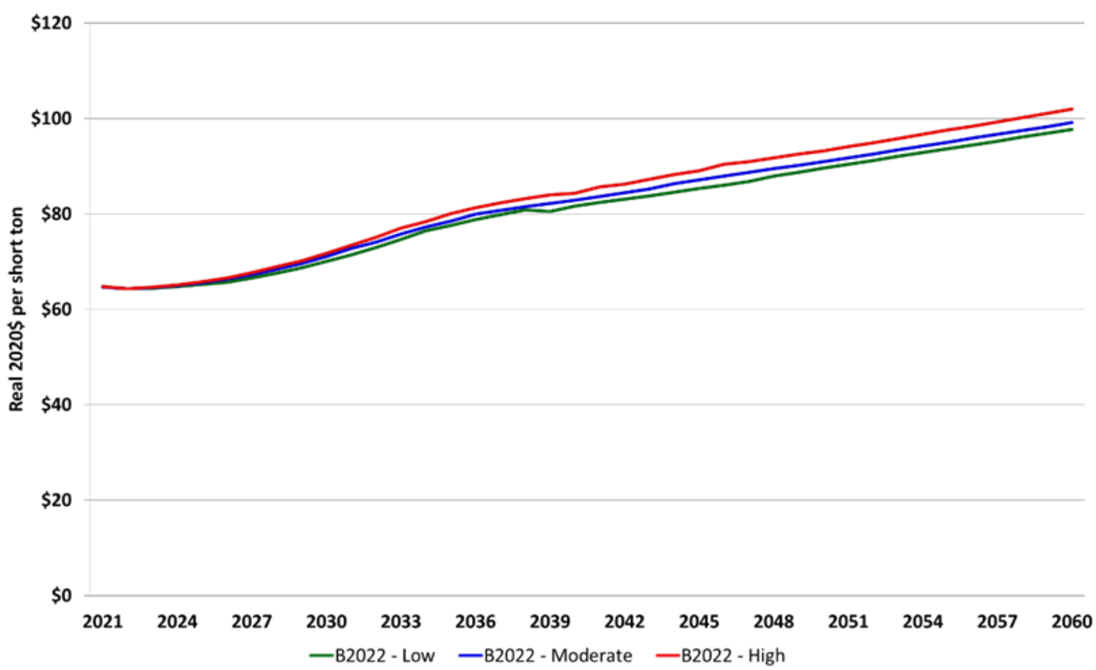


Figure 7: Views of future price of coal at mine, by scenario, Illinois Basin

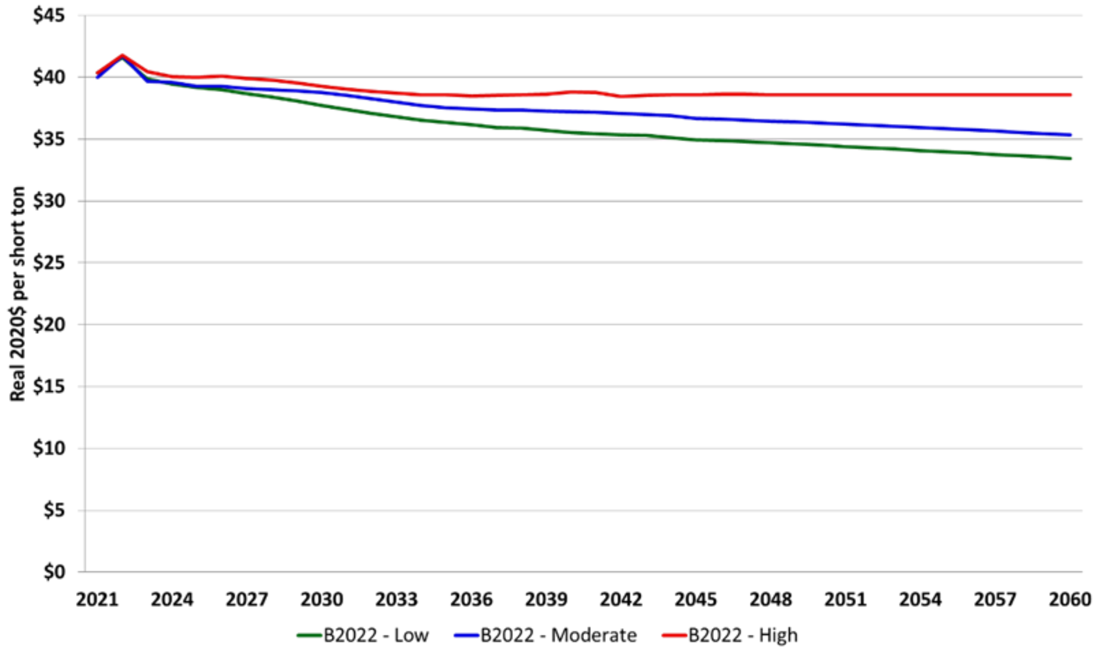


Figure 8: Views of future price of coal at mine, by scenario, Powder River Basin

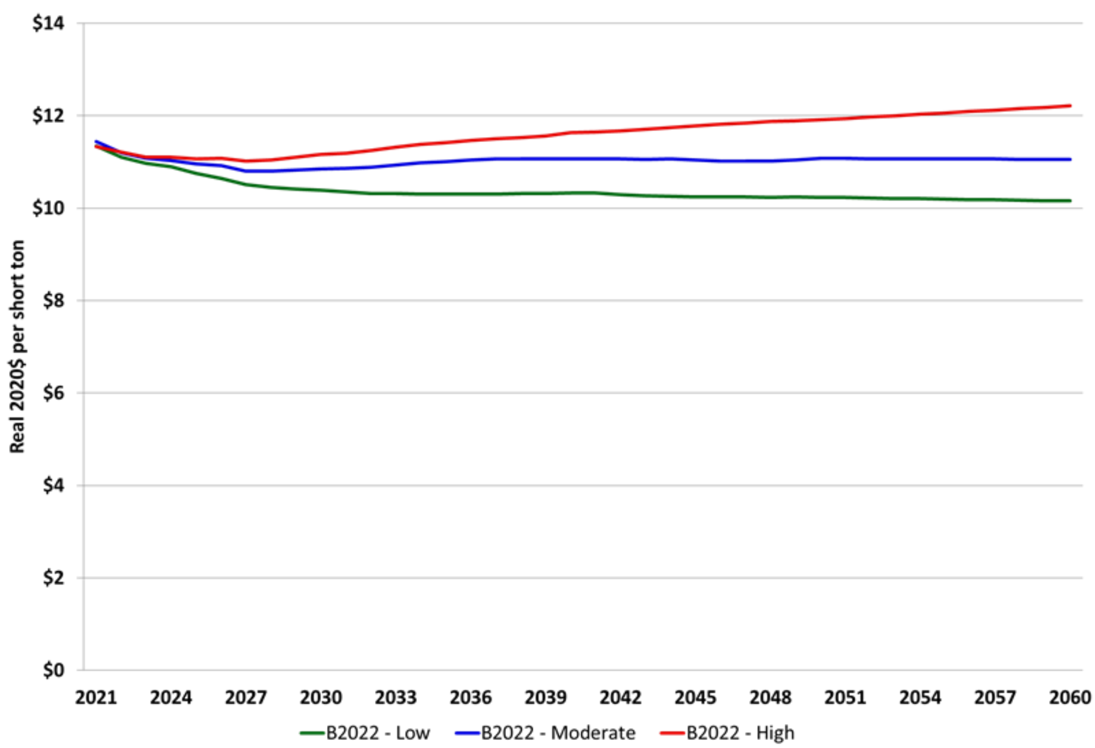
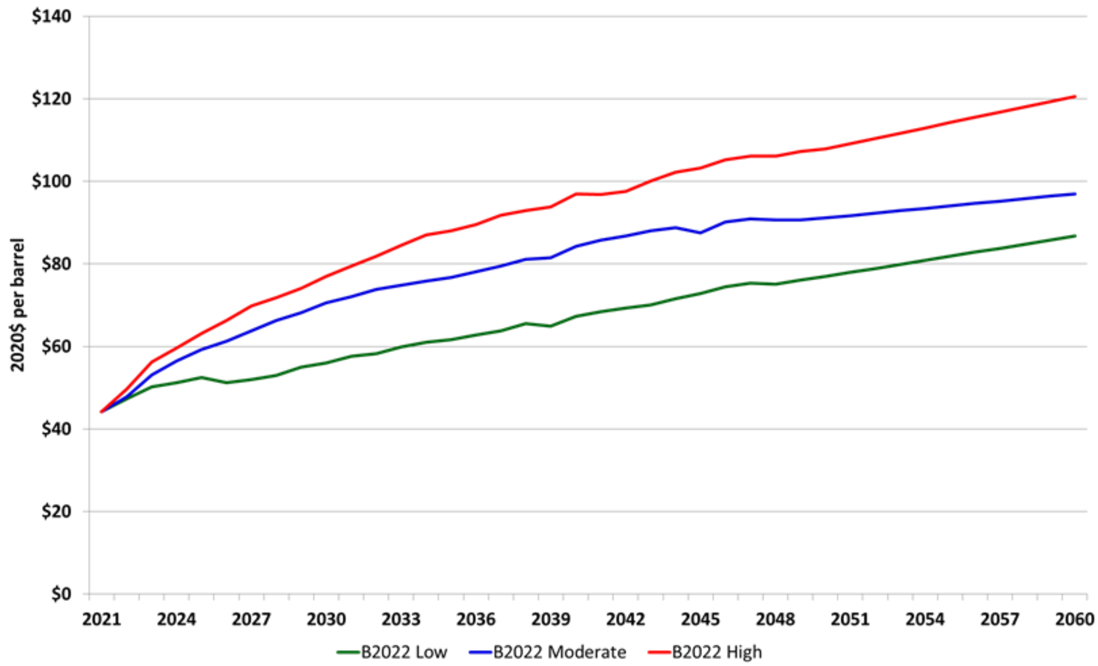


Figure 9: Views of future price of oil, West Texas Intermediate



7.3. GREENHOUSE GAS PRESSURE

The degree of pressure on greenhouse gas emissions in the future is uncertain. The Company has considered four different views of how that pressure could evolve. One of those views is the degree of pressure remains largely unchanged from where it is today ("$0" view). Two of those views involve a fee imposed on each ton of carbon dioxide that the Company emits ("$20" and "$50" views). A fourth view involves annual limits on the amount of carbon dioxide that the Company could emit ("CO_2 Intensity"). These views were chosen to span a range of current plausible outcomes.

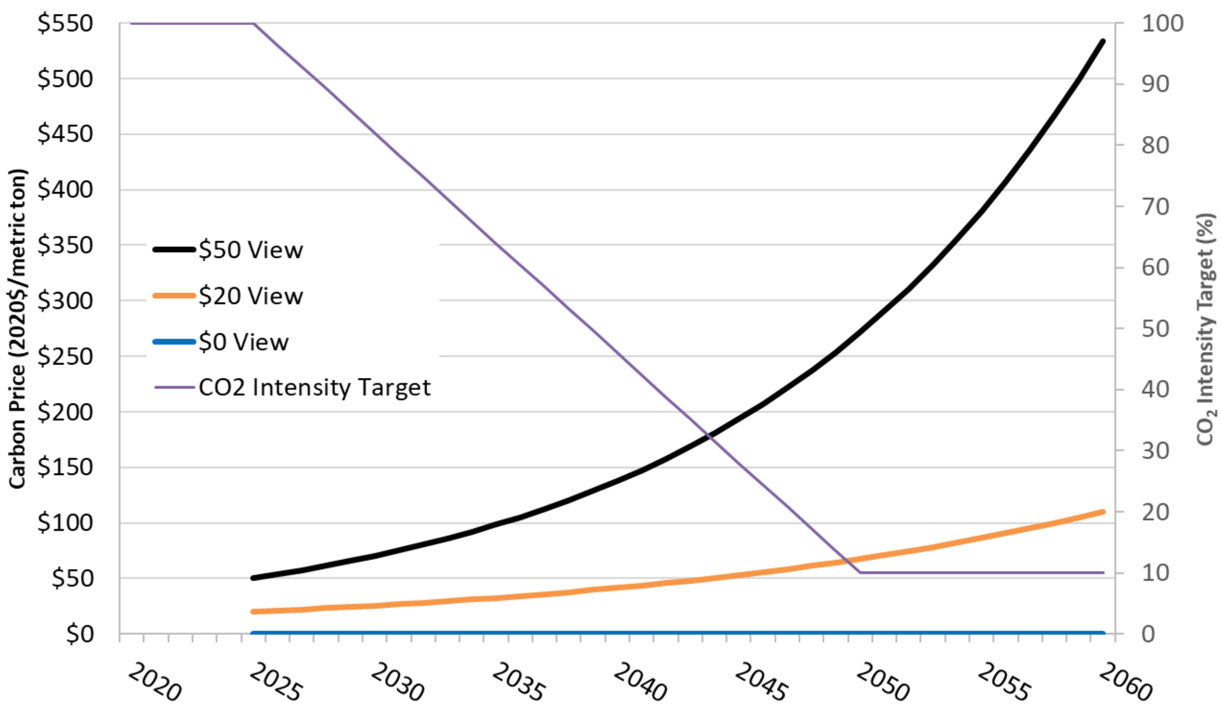
- The $0 view is the lightest plausible pressure the Company considered under the existing Clean Air Act. It involves no price on CO_2 emissions but does require carbon capture (90%) at all new gas combined cycle units beginning in 2040. This date is uncertain but is consistent with a more delayed sequence of reviews required under the Clean Air Act.
- The $20 view adds a price on CO_2 emissions that begins in 2025 at $20 (2020$) per metric ton of CO_2 and grows at 5% above inflation through the modeling horizon. The 2025 start year is consistent with current policy proposals. Carbon capture (90%) is required at all

new gas combined cycle units beginning in 2035. This date is uncertain but is consistent with a less delayed sequence of reviews required under the Clean Air Act.

- The \$50 view adds a price on CO_2 emissions that begins in 2025 at \$50 (2020\$) per metric ton of CO_2 and grows at 7% above inflation through the modeling horizon. Carbon capture (90%) is required at all new gas combined cycle units beginning in 2035. This view represents market-based pressure on CO_2 emissions consistent with targeting net zero emissions by 2050.
- The CO_2 Intensity view adds a requirement that the Company's annual CO_2 emissions fall to 10% of current levels by 2050. This view represents mass-based pressure on CO_2 emissions consistent with targeting net zero emissions by 2050.

These four views are illustrated in Figure 10. (Note that the CO_2 Intensity view refers to the right vertical axis; the other views refer to the left vertical axis.)

Figure 10: Views regarding future pressure on CO_2 emissions



7.4. TECHNOLOGY COST AND PERFORMANCE

Electricity generating technology is always evolving. While there are dozens of ways to satisfy the demand for electricity, the pace and direction of the evolution of each option is uncertain. The Company screens these approaches and identifies technologies that have the possibility of playing a cost-effective role in the System during the modeling horizon. Among the technologies that might play a cost-effective role, there remains uncertainty about the cost of each technology relative to its expected productivity and relative to other technology options.

For B2022 analyses, the technologies that screened as potentially cost-effective included natural gas combined cycle ("NGCC") (with and without carbon capture), natural gas combustion turbine ("NGCT") (with and without selective catalytic reduction ("SCR")), reciprocating internal combustion engine ("RICE"), solar photovoltaic ("PV"), wind, and battery energy storage. For Scenario 10 ("Tech" case), the Company also considered nuclear and natural gas direct-fired supercritical CO_2 cycle[14] with carbon capture and sequestration ("CCS"). Please see CHAPTER 10 for more information on technology screening and candidate expansion planning units.

7.5. LOAD GROWTH

Future electricity consumption is uncertain. The Company has three different views on future load growth. In addition, the Company recognizes that the future price of natural gas and future pressure on CO_2 emissions can impact the demand for electricity.

- **Base load forecast**. The Company annually updates its forecast of electricity consumption throughout the planning horizon. The forecast is done separately for each of the three major customer classes—residential, commercial, and industrial. This forecast is one view of future load growth. This forecast is described in CHAPTER 6.
- **Electrification-influenced load growth**. A second view of future load growth considers significant electrification of energy uses that currently use other fuels including transportation and space and water heating. This view has larger load growth than in the base load forecast.
- **End-use efficiency and customer generation**. A third view of future load growth considers significant ongoing increases in end-use efficiency and an increasing role for

[14] Also referred to as a supercritical CO_2 cycle.

customer-sited generation resources, which decrease the net load served by the utility. This view has smaller load growth than in the base forecast.

The consumption of electricity, the price of natural gas and the level of any fee on CO_2 emissions are interrelated. This interrelationship is not straightforward because natural gas is both an input to electricity production and a substitute for electricity in some end uses. Moreover, pricing of CO_2 emissions affects natural gas and electricity differently. Thus, the Company has developed a set of load growth adjustments used in scenarios with CO_2 pricing and with higher or lower future prices of natural gas. These load growth adjustments are derived from analyses using an integrated model of the U.S. energy economy. Such analyses yielded different electricity consumption paths associated with different views of future natural gas prices and different views of future CO_2 pressure reflecting the important feedbacks in those relationships.

For the B2022 planning process, the Company utilized the work that Charles River Associates ("CRA") did prior to B2020 to derive these series of load adjustments. Before B2020, the CRA modeling process produced a series of load adjustments used in scenarios with CO_2 pricing and with higher or lower future prices of natural gas. The Company analyzed the historical load adjustment data from three years of these analyses and averaged the observed adjustments to smooth out the year-to-year differences in the degree of adjustment. These adjustments were then applied to the base load forecast. Please see Technical Appendix Volume 1 Resource Mix Study for more information on the annual System peak loads for each scenario.

7.6. CONCLUSION

The scenario planning process provides a framework for understanding and considering the impact of some key uncertainties in resource planning. Such analyses provide information that is useful for making appropriate resource planning decisions when faced with future uncertainties.

CHAPTER 8. DEMAND-SIDE STRATEGY

This chapter summarizes the process used to assess demand-side resources for the 2022 IRP and addresses the following topics:

- A review of significant events since the Company's 2019 IRP filing that are relevant to the screening and assessment of demand-side resources
- A summary of newly proposed DSM programs, changes to existing programs, and recommended decertification of programs
- A discussion of the regulatory treatment of DSM program costs and the additional sum
- A presentation of the economic results of DSM programs for the 2022 IRP using the $0 carbon price (MG0) and $20 carbon price (MG20) scenarios

The identification and evaluation of demand-side resources for inclusion in this IRP involves market considerations, such as customer acceptance and applicability, customer economics, and electric supply economics using marginal cost calculations. As outlined in the 2019 IRP Order, the Company followed the process defined in the Commission's IRP rules and the DSM Program Planning Approach, which are discussed in more detail below.

8.1. REVIEW OF SIGNIFICANT EVENTS SINCE THE 2019 IRP

Following the 2019 IRP Order, the following events have influenced Georgia Power's screening of demand-side resources:

2019 IRP Filing Approval

In the 2019 IRP Order, the Commission decertified two programs, amended the certificates of three programs, and certified three new programs in the Company's DSM portfolio. In addition, the Commission ordered that the energy savings targets, for both the residential and commercial programs, be increased by 15 percent and the relative program budgets increased by 10 percent from what the Company originally proposed. The 2019 IRP Order approved program plans for the following programs:

Residential Programs:

- Behavioral
- Home Energy Improvement

- Specialty Lighting
- Refrigerator/Freezer Recycling
- Home Energy Efficiency Assistance
- Thermostat Demand Response
- Power Credit

Commercial Programs:

- Custom
- Midstream
- Prescriptive
- Small Commercial Direct Install
- Behavioral

Program Evaluation Results

As specified in the 2019 IRP Order, the Company was required to conduct process and impact evaluations on each of the eleven certified DSM programs prior to the 2022 IRP.

The Company selected BrightLine and Illume, for commercial and residential program evaluations, respectively. The evaluators developed evaluation plans, which were reviewed by Commission Staff. The Company filed the program evaluation plans with the Commission in 2020. Program evaluation results were provided to PSC Staff on October 29, 2021. These results were considered in the development of the 2022 IRP, as well as the program plans in the Company's 2022 DSM Certification Application.

In response to the ongoing COVID-19 pandemic, the Company paused the implementation of several of its program offerings, which had a direct result on program evaluations and results.

DSM Program Planning Approach

In accordance with the 2019 IRP Order, the Commission-approved nine step DSM Planning Process (renamed the "DSM Program Planning Approach") guided the development of the Company's 2022 IRP and DSM Certification plans. The Company met with the DSMWG eight times between 2020 and 2021 and engaged with the DSMWG in an effort to collaboratively develop program concepts for the 2022 IRP. The Company also met with DSMWG subcommittees in 2021 to discuss DSM program concepts and modeling a DSM sensitivity case proposed by certain members of the DSMWG. Finally, the Company hosted several conference calls and shared data with the DSMWG in preparation for, and leading up to, the 2022 IRP filing.

Continued IRP Avoided Cost/Fuel Price Decreases

The overall decline in forecasted fuel costs has reduced the marginal cost of generating energy. As a result, Georgia Power's diverse System has allowed the Company to generate more energy from the System's natural gas units relative to coal units. The lower cost of fuel not only saves customers money, but also lowers the Company's avoided cost. With these lower avoided costs, the value of each kWh saved as a result of DSM participation has declined significantly since the 2019 IRP.

These changes in avoided cost savings negatively impact the economics of the Company's current and proposed DSM programs. The Company's Proposed Case highlights that TRC Test results declined while RIM results remained negative, increasing concerns for the Company in its efforts to balance the economic benefits these programs provide for participating customers with the rate impacts to all customers, whether they participate in the programs or not.

8.2. DISCUSSION OF CURRENT AND PROPOSED DSM PROGRAMS

Residential DSM Programs

In its 2022 DSM Certification Application, the Company requests the following actions or adjustments for the following residential DSM programs:

Residential Program	Status	Action Requested
Behavioral	Existing	Certificate Amendment
Home Energy Improvement	Existing	Certificate Amendment
Refrigerator/Freezer Recycling	Existing	Certificate Amendment
Specialty Lighting	Existing	Certificate Amendment
Home Energy Efficiency Assistance	Existing	Certificate Amendment
Residential Thermostat Demand Response	Existing	Certificate Amendment and Waiver Requested
HopeWorks	Existing Non-certified Program	Grant a New Certificate
Power Credit	Existing	Decertify

Residential Thermostat Demand Response – The Company is seeking to continue this program in light of its significant demand-response value. Although the program does not reflect positive TRC results for the 2022 IRP cycle, it is expected to do so in 2031. Therefore, as discussed further in the 2022 DSM Certification Application, Docket No. 44161, Georgia Power is seeking a waiver of the TRC requirement within Commission Rule 515-3-4-.04(4)(a)3 for the continuation of this program in this IRP cycle.

The details regarding current and proposed programs are included in the program plans filed within the 2022 DSM Certification Application, Docket No. 44161. Additional details regarding the decertification request are listed below.

Power Credit – The Company requests decertification of the Power Credit program because the Residential Thermostat Demand Response program focuses on the transition to winter and summer peak seasons where Power Credit serves only summer peak events.

Increased Income-Qualified Initiatives

The Company's Proposed Case expands DSM offerings to income-qualified customers as part of the 2022 IRP. The Company seeks certification for an additional dedicated income-qualified program as well as including specific targets for income-qualified customers for many of the residential programs, thus helping increase program participation for customers who can benefit the most from program energy savings.

Commercial DSM Programs

In its 2022 DSM Certification Application, the Company requests the following actions or adjustments for the following commercial DSM programs:

Commercial Program	Status	Action Requested
Custom	Existing	Certificate Amendment
Prescriptive	Existing	Certificate Amendment
Small Commercial Direct Install	Existing	Certificate Amendment
Behavioral	Existing	Certificate Amendment
Midstream	Existing	Decertify

The details regarding current and proposed programs are included in the program plans filed within the 2022 DSM Certification Application, Docket No. 44161.

Midstream – The Company requests decertification of the Midstream program as market transformation has occurred with Midstream distributors over the current IRP cycle. This was confirmed during the third-party evaluation of the Midstream program in 2021. The measures previously included in the Midstream program have been moved to the Commercial Prescriptive program as the evaluation deemed them still viable measures.

Learning Power Education Initiative

Since 2011, the Company has been delivering the Learning Power Education Initiative curriculum throughout the state of Georgia. The curriculum promotes an understanding of energy and energy efficiency from a grassroots perspective. Lessons have been developed for grades pre-K-12. The method of delivery is highly interactive and hands-on, with lessons delivered by skilled Georgia Power employees, known as Education Coordinators. Education Coordinators are dedicated to a geographic region of the state, with an equitable distribution of students and schools among Education Coordinators.

Since the launch of the program, the Company has delivered 33,557 programs to 915,332 students through December 2021.

In the Fall of 2020, virtual-live, student self-paced, and pre-recorded lessons were added to the Learning Power portfolio of delivery options to meet schools' and educators' needs. Virtual platforms were used to deliver 3,180 lessons reaching 109,490 students.

In 2018 and 2019, approximately 1,791 teachers were surveyed. Results of the survey are as follows:

- It was beneficial to their students (99.1%)
- It increased their students' knowledge about energy efficiency (97.7%)
- It improved their students' commitment to energy efficiency (91.4%)

In addition, the presentations by Education Coordinators during the Learning Power Education Initiative results in teachers being well informed about energy and energy efficiency:

- Before the presentation, 41.8% felt very well informed about energy and energy efficiency
- After the presentation, 95.6% felt very well informed about energy and energy efficiency

Energy Efficiency Awareness Initiative

The Company's Energy Efficiency Awareness Initiative promotes the benefits of energy efficiency and educates customers about specific ways to save money and energy. In the 2016 and 2019 IRPs, the Commission approved a dedicated budget for residential and commercial general awareness. The Company seeks continued funding to support these efforts that increase general energy efficiency awareness in the residential and commercial markets.

The Company uses multiple marketing channels to efficiently reach its customer base. Television, radio, print, web, digital, and direct mail are the primary channels used. The Company has developed a number of online tools to enhance customers' education and awareness about energy efficiency. Customers are invited to visit www.georgiapower.com/energyefficiency or www.georgiapower.com/commercialsavings to learn ways to save energy through general energy efficiency information, helpful tips, and specific information about energy efficiency programs offered by the Company. Social media channels such as Facebook, Twitter, LinkedIn, and YouTube are also used to communicate with customers.

Demand Response Tariffs

The Company continues to offer its customers the following menu of demand response and dynamic pricing tariffs:

- Real Time Pricing, which offers customers marginal pricing for incremental load; as prices increase, customers can respond by reducing their demand
- Demand Plus Energy Credit ("DPEC"), which is an interruptible service tariff that provides commercial and industrial customers with a demand credit for the potential of demand reduction, plus an energy credit when DPEC is called
- Demand tariffs, which align with the Company's cost of service and encourage demand reduction
- Time of Use tariffs, which provide customers with pricing signals during different periods of the day that reflect the marginal cost of the energy in the specific time period (peak and off-peak) and encourage customers to modify their usage accordingly

Pilot Studies & Budgets

Georgia Power engages in pilot studies to better understand emerging energy efficiency and demand response options for the benefit of customers. In the 2019 IRP Order, the Commission approved a $3 million annual budget for DSM and energy efficiency pilot programs. Since 2020, Georgia Power launched four residential pilot initiatives: RISE, Water Heater Controller Demand Response, Energy Efficiency Voice Skills, and dual-market Multicultural Barriers Research, as well as a commercial Virtual Retro-Commissioning pilot. The learnings from these pilots directly influence the development of innovative DSM pilot and program delivery mechanisms, which also help enable historically under-represented customer segments to participate and bridge cultural preferences with residential and small and medium businesses.

As part of this 2022 IRP, the Company seeks Commission approval of its proposed $1.5 million budget for residential and $1.5 million budget for commercial pilots, as outlined in the supporting documents included in Company's 2022 DSM Certification Application in Docket No. 44161.

Residential Investment for Saving Energy (RISE) Pilot

Georgia Power's RISE Pilot[15] promotes energy efficiency improvements in existing, income-qualified single-family homes, as well as a limited number of multifamily properties. Georgia Power proposes to extend the 2020-2022 pilot into the 2022 IRP cycle and will continue to offer the program to income-qualified households that are historically under-represented in the Company's energy efficiency programs. The Pilot is intended to reach five hundred (500) income-qualified residential customers in select energy burdened areas of the state, with the goal of saving up to 25% of the baseline household electric energy usage with the Company's investment in energy efficiency upgrades not to exceed an average cost of $7,500 per household. The eligibility criteria for this Pilot will continue as previously approved in the 2019 IRP.

[15] The RISE Pilot refers to the Income Qualified Tariff Based Energy Efficiency Pilot that was approved in the 2019 IRP.

8.3. DSM RESOURCE ASSESSMENT AND INITIAL COST-EFFECTIVENESS SCREENING

Assessment and Screening Methodology

The assessment and screening methodology for DSM measures used in this IRP included identifying DSM measures and programs with input from the DSMWG. Economic evaluations were performed for each measure and program to determine the program cost-effectiveness based on the industry-standard benefit/cost tests and as required by the Commission IRP rules. The tests conducted are the RIM Test, TRC Test, Participants Test (“PT”), Program Administrator Cost Test (“PACT”), and Societal Cost Test (“SCT”). The RIM Test assesses fairness and equity by measuring what happens to customers’ rates due to changes in utility revenues and operating costs caused by the program. The TRC Test assesses economic efficiency and societal impact by measuring the net costs of a DSM program as a resource option based on the total costs of the program, including both the participants’ and the utility’s costs. The PT assesses the impact on a program participant by measuring the quantifiable benefits and costs to the customer due to participation in a program. The PACT assesses the net costs of a DSM program as a resource option based on the costs incurred by the program administrator (including incentive costs) excluding any net costs incurred by the participant. The SCT is a variant of the TRC Test and includes an adder to avoided fuel costs to simulate environmental externalities.

The Company met with the DSMWG eight times in 2020 and 2021 to discuss and share presentations related to DSM program design details. A smaller sub-group of the DSMWG met and identified the program concepts and measures considered for economic screening in support of the 2022 IRP development. Input from the sub-group participants was used in developing the list of programs and measures within these programs to analyze. This list was shared with the larger DSMWG for solicitation of additional feedback on this process. An agreement among certain parties of the DSMWG was reached regarding some programs to include in the analysis of the DSMWG Advocacy Case. The preliminary results of the program economic screening were also shared with the DSMWG in November 2021, ahead of the Company’s filing.

DSM Program Economic Screening Policy

The Company continues to follow the Commission’s economic screening policy outlined in the 2004 IRP Order in Docket No. 17687. This policy requires the Company to offer a DSM plan that minimizes upward pressure on rates and maximizes economic efficiency. Additionally, the

Company's DSM plan treats DSM as a priority resource. In fact, the first step in the Company's IRP process is to reduce the Company's load and energy forecasts by the Proposed Case's energy and demand impacts, prior to developing the supply-side alternatives. For the 2022 IRP, economic screening for DSM programs was completed using two scenarios. One scenario was based on a $0 carbon price, or MG0 scenario, with the additional scenario based on a $20 carbon price, or the MG20 scenario. Please see CHAPTER 7 for more information on these scenarios. The Proposed Case's cost-effectiveness results presented herein reflect the continuation of, or modifications to, certain current DSM programs, the addition of new DSM programs, and the decertification of certain existing DSM programs. Due to overall declines in projected avoided costs since the 2019 IRP, the rate impacts for the proposed programs will be larger than those in the DSM programs approved in the 2019 IRP Order. While the DSM portfolio continues to provide TRC benefits, such benefits are not as large as in the 2019 IRP due to declining projected avoided costs.

The energy efficiency programs in the Company's Proposed Case for the 2022 IRP achieve an average of approximately $78 - $103 million in TRC benefits while putting upward pressure on rates of approximately $264 - $283 million annually over years 2023 – 2025.

The Aggressive Case sensitivity's cost-effectiveness results are also presented here, as required by the DSM Program Planning Approach. The Aggressive Case sensitivity includes programs from the Proposed Case, but with customer participation at higher penetration levels with higher budgets, as well as additional programs, measures, and associated budgets resulting in significantly higher levels of cumulative energy savings.

At the request of some members of the DSMWG, the Company agreed to analyze the DSMWG Advocacy Case, which also assumes significantly higher levels of cumulative energy savings. The DSMWG's Advocacy Case is a ramp up of the energy savings targets included in the Company's Proposed Case, as well as additional programs proposed by certain members of the DSMWG.

The higher levels of market penetration in both the Aggressive and DSMWG's Advocacy sensitivity cases ultimately result in substantial upward rate pressure of approximately $572 - $610 million and $508 - $542 million per year, respectively, for years 2023 – 2025. Due to the increased impact on customer rates, the Company did not use the DSMWG Advocacy Case or the Aggressive Case and recommends that the Commission not adopt them either.

Data Development

In developing its list of DSM measures for initial screening, the Company conducted a comprehensive review of technical information sources for demand-side and energy efficiency technologies. This review evaluated the Company's previous IRP filings, as well as reviews of new sources of information, which include industry conferences and trade associations, among others. Additional input was provided by the DSMWG members, some of whom have many years of experience in DSM program development and implementation. Customer feedback was reviewed as a source of information for program additions and improvements. Additionally, Company representatives who work closely with Georgia Power's customers were also surveyed for their input. Information gathered was shared with the DSMWG in program development discussions. The results of the qualitative screening can be found in DSM Program Documentation in Technical Appendix Volume 2.

Residential Technology

More than 100 residential DSM measures were identified for economic screening and possible inclusion in residential programs. These measures provide potential energy savings through:

- Increased energy efficiency for electric equipment
- Electric space cooling and heating equipment
- Electric lighting
- Electric water heating
- Customer behavior improvements
- Heating and cooling savings resulting from improvements to the homes thermal shell

In addition to specific measures, building type (single family – new and existing; multifamily – new and existing; or manufactured housing – new and existing) was considered in the economic analysis.

Commercial Technology

More than 135 commercial DSM measures were identified for economic screening and possible inclusion in commercial programs. These measures provide energy savings through:

- Increased energy efficiency for electric equipment
- Electric space cooling and heating equipment

- Electric lighting
- Electric water heating
- Customer behavior improvements
- Heating and cooling savings resulting from improvements to the building's thermal shell

In addition to specific measures, building type (the type of customer operation, such as schools or offices) was considered along with the construction type (new and existing) when conducting the economic analysis.

Industrial Technology

No industrial programs are included in the Company's Proposed Case because the Company's experience has shown that industrial customers generally adopt DSM and energy efficiency measures on their own, thus providing benefits to the System and all customers without the need for customer funded incentive programs. Nevertheless, an industrial pilot program was included in the DSMWG Advocacy sensitivity case, while the Aggressive sensitivity case included an industrial custom program.

Economic Screening

Energy consumption and savings were calculated for all measures that were passed to economic screening. First, the energy usage characteristics for weather-sensitive HVAC and thermal shell measures were calculated using both algorithms and an engineering simulation model ("OpenStudio/EnergyPlus™"), which is described in ATTACHMENT C. Second, each potential measure that was passed to economic screening was then evaluated using the Profitability Reliability Incremental Cost Evaluation Model ("PRICEM"), which is described in ATTACHMENT C.

The following industry-standard, DSM cost-effectiveness tests were calculated for each measure and subsequent programs: the RIM Test, the TRC Test, the PT, the PACT, and the SCT. Additionally, the Cost of Saved Energy ("CSE"), also referred to as Levelized Cost per annual kWh saved, is provided for each program screened. The CSE is the total cost per kWh of realizing the efficiency improvement. CSE is determined by dividing levelized program costs by the annual energy savings, as shown in the following equation. Levelized program costs are calculated using a Capital Recovery Factor, which incorporates the number of years that the energy savings persist, and an annual discount rate.

CSE Equation:

$$CSE = \frac{Program\ Costs\ (\$)\ \times CRF}{Annual\ Energy\ Savings\ (kWh)}$$

Long-Term Percentage Rate Impacts

The Company analyzed the long-term percentage rate impact of its DSM Proposed Case and the Advocate and Aggressive sensitivity cases. See the DSM Program Documentation section of Technical Appendix Volume 2 for results of the long-term percentage rate impacts.

8.4. DEMAND-SIDE PROGRAM DEVELOPMENT

Demand-Side Resource Policy

In the 2004 IRP Order, the Commission directed that the Company's proposed DSM plans should minimize upward pressure on rates (negative RIM results) and maximize economic efficiency (positive TRC results). The Commission further directed that the cost/benefit analysis results of each initiative should use the five tests mentioned above and should balance economic efficiency (TRC benefits) with fairness and equity (RIM benefits/cost). This Commission policy has been applied in each IRP since 2004. The Company applied this same philosophy in analyzing the programs for the 2022 IRP. The Company adhered to the DSM Program Planning Approach in developing the 2022 IRP.

Twelve-Year DSM Program Plans

The Company has developed twelve-year program plans outlining the implementation details behind each individual program included in the Proposed Case. The program plans are provided in the 2022 DSM Certification Application, Docket No. 44161.

The following details are included in each program plan:

- Program Summary – outlines the goals of the program
- Program Structure – outlines the intended participant eligibility, home or facility eligibility, and specific measures and incentives where appropriate
- Program Implementation – outlines the intended target market, key market players, as well as marketing and outreach plans

- Program Operation – outlines the intended customer participation process and program administrative procedures
- Program Evaluation – outlines the intended performance metrics, expected program budget, cost-effectiveness expectations, as well as plans to develop an independent third-party evaluation plan after programs are approved

Each of the twelve-year DSM program plans allow for ongoing review and modification of program design features through regular program monitoring. In addition, a formal program evaluation plan at the end of the program cycle is conducted. Any significant changes to program design in support of market conditions or program economics will be included with ongoing reports filed with the Commission, program evaluation filings, and/or IRP updates. Additionally, as new measures and technologies evolve during the twelve-year filed program life, the Company may add such measures to these programs. Any new measures being added will follow the same economic screening process as those approved by the Commission, and the Commission would be made aware of any additions prior to the Company offering the new measures to customers as required.

8.5. REGULATORY TREATMENT OF DSM PROGRAM COSTS AND THE ADDITIONAL SUM

The Company requests the continued collection of costs for all approved and certified DSM programs and activities through the existing Residential and Commercial DSM tariffs. These tariffs will be filed as part of the Company's 2022 base rate case and would be implemented with any approved change in rates on January 1, 2023. The Company also requests the continued collection of an additional sum amount for certified energy efficiency programs with energy savings through these tariffs pursuant to a revised additional sum calculation methodology presented in the Company's DSM Certification Application in Docket No. 44161.

8.6. SUMMARY OF DSM CASES

Proposed Case

The energy efficiency and demand response programs in the Company's Proposed Case for the 2022 IRP achieve an average of approximately \$78 - \$103 million in TRC benefits while putting upward pressure on rates of approximately \$264 - \$283 million annually over years 2023 – 2025. The Company is concerned that these results do not strike the balance needed when considering energy efficiency programs but plans to continue the established energy efficiency programs approved in the 2019 DSM Certification filing, modified as proposed above, to achieve approximately the same levels of energy savings that are currently being achieved. The Company plans to continue these programs to minimize market disruption, to continue meeting customers' expectations, and to maintain positive relationships with vendors performing qualified program improvements. The Company's DSM portfolio included in the 2022 IRP consists of currently certified programs as well as new programs, modified based on data gathered in the implementation phase, as well as input from the DSMWG and an independent third-party evaluation. The Proposed Case will continue to enhance these programs as more information becomes available relative to market penetration and customer feedback through an ongoing evaluation process. The Company will keep the Commission fully informed of potential changes to programs through notification to, or approval by, Commission Staff, as required.

The Company's Proposed Case summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

DSMWG Advocacy Case

The DSMWG Advocacy Case was developed as a sensitivity case to the Company's Proposed Case and is based on requests made by certain members of the DSMWG. The Company presents the results of this case for informational purposes. If the DSMWG Advocacy Case were to be implemented, the portfolio would put additional upward pressure on rates of approximately $508 - $542 million on average annually for years 2023 – 2025. The DSMWG Advocacy Case includes a ramp up of the Company's Proposed Case, as well as additional programs proposed by certain members of the DSMWG, which included program assumptions with which the Company does not agree. Therefore, the Company does not recommend approval of the DSMWG Advocacy Case.

The DSMWG Advocacy Case summary tables are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

Aggressive Case

The Aggressive Case was developed to represent an aggressive DSM sensitivity to the Company's Proposed Case and was developed as outlined in the DSM Program Planning Approach. It serves as a reference point to estimate the maximum achievable potential for increased energy efficiency and the impacts of such aggressive adoption of DSM. This increased energy efficiency comes at a high cost to customers. The impacts from the Aggressive Case ultimately result in average annual upward pressure on rates of approximately $572 - $610 million for years 2023 – 2025. The Company does not recommend approval of the Aggressive Case.

The Aggressive Case summary tables are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

8.7. RECOMMENDED DSM ACTION PLAN

In summary, the Company's recommended DSM action plan includes the following items detailed in Section 8.2:

- Implementation of the seven residential and four commercial DSM programs
- Decertification of the residential Power Credit program and commercial Midstream program
- Continuation of the Learning Power Education and Energy Efficiency Awareness initiatives
- Continuation of pilot studies and approval of annual pilot budget
- Continuation of the RISE Pilot
- Continuation of the Thermostat Demand Response Program in the 2022 IRP cycle pursuant to a waiver of the TRC requirement in Commission Rule 515-3-4-.04(4)(a)3.

CHAPTER 9. DISTRIBUTED ENERGY RESOURCES

As the electric system continues to evolve and the presence of DER rapidly expands in Georgia and across the country, the Company remains committed to providing its customers with clean, safe, reliable, and affordable energy solutions. This chapter of the IRP sets forth the Company's forward-looking strategy for addressing the growth of DER technologies[16] in a way that ensures the continued reliability and resilience of the System and also benefits customers. In the 2019 IRP, Georgia Power indicated that it was preparing for greater integration of DER technologies and researching DERMS[17] and associated technologies that are needed to operate the System in harmony with DER. Thereafter, the Company continued evaluating DER and DERMS technologies to gain better understanding of these technologies and how they can be effectively deployed. For example, Georgia Power actively participates on Southern Company's Variable and Distributed Energy Resource ("VaDER") team to address the growth of DER and corresponding System impacts, monitor industry trends and DERMS technologies, and develop an enterprise DERMS strategy. The Company has also engaged with peer utilities, technology providers, and other entities such as the Electric Power Research Institute ("EPRI") to advance its understanding of DERMS.

To support critical System operations and reliability needs moving forward, Georgia Power will continue pursuing the implementation of DER and DERMS technologies that will provide enhanced System monitoring, assessment, and operational capabilities for the benefit of the Company's customers and the communities it serves. For example, Georgia Power plans to evaluate the impact of "behind the meter" customer-sited DER and gain real-time visibility into the operational dynamics between DER and the System. Georgia Power will also work closely with the VaDER team to identify and evaluate sophisticated DERMS solutions which will be critical to the Company's operations as the System continues to evolve with DER. A scalable and adaptable DERMS solution will give Georgia Power the ability to assess the impact of DER on the electric system in real-time, providing information that is vital to System operations, fleet operations, and reliability. Moreover, DERMS will provide Georgia Power the ability to coordinate System and fleet operations with DER, thus optimizing its operational capabilities and ensuring that the Company

[16] Examples of DER technologies include, without limitation, solar facilities, battery storage systems, internal combustion generators, microturbines, flywheels, electric vehicles, Volt/Volt-Amps Reactive ("VAR") applications, interruptible loads, critical pricing programs, and demand response.
[17] DERMS is an integrated software resource that provides insight into the impact of DER on the electric system and allows a utility to operate the System in harmony with DER through enhanced monitoring and operational capabilities.

can continue to deliver clean, safe, reliable, and affordable energy to customers as DER growth continues and technology advances.

9.1. DER LOCAL RELIABILITY & CONSTRAINTS PILOT

In the 2019 IRP, Georgia Power discussed the possibility of strategically deploying localized DER technology to address System operations and reliability needs, such as changing load requirements and voltage, thermal, power quality and other electrical system constraints, that would otherwise require expansion or upgrades to transmission and distribution lines. Based upon its research, the Company has identified three use cases for the deployment of DER technologies: (i) transition of wire capacity – the ability of equipment to remain within design limits; (ii) system reliability – the ability to ensure dependable service; and (iii) system resilience – the ability to withstand and/or recover from outage events.

To further evaluate these use cases, Georgia Power is proposing a pilot through which it will install one or more DER systems at seven strategic locations on the System. This pilot will allow the Company to assess the benefits, operational considerations, and costs related to the siting, installation, and ongoing operation and maintenance of DER technologies as potential transmission and distribution system solutions. Additional information about the seven pilot applications is provided in Table 3.

Table 3: 2022 IRP Local Constraints & Reliability DER Pilot Locations

Pilot	Region	Substation	Customers
A	Alpharetta	Spalding Drive	4,351
B	Atlanta	Moreland Way	2,131
C	Rome	First Mountain	2,328
D	Macon	Lake Sinclair	1,446
E	Atlanta	Morningside	2,492
F	Athens	Mansfield	1,087
G	Savannah	River Street	2,743
	Estimated Pilot Cost:	$33 Million	

9.2. DER CUSTOMER PROGRAM

The Company is introducing a new DER Customer Program that provides demand response value and corresponding System reliability benefits for all customers and also supports commercial and industrial customers with enhanced resiliency needs. Georgia Power will implement the DER Customer Program through two tariffs, a DER Demand Response Credit Tariff (“DRC-1”) and a Resilience Asset Service Tariff (“RAST-1”), which will be subsequently developed and submitted for Commission review upon approval of the DER Customer Program. DER Customer Program participation and service under these proposed tariffs will be completely optional.

DRC-1 will be an optional tariff available to qualifying commercial and industrial customers. Through DRC-1, Georgia Power will leverage dispatchable DER for demand response purposes, thus providing System resilience and reliability benefits to all customers. DRC-1 will be available to customers participating under RAST-1. Under this tariff option, Georgia Power will provide participating customers with a credit on their electric bill in exchange for Company use of qualifying DER located behind the participating customer’s meter for demand response purposes during System reliability events. Demand response value will result from the DER reducing the reliability pressures on the System during a reliability event, while at the same time allowing participating customers the ability to maintain operations during an electric service outage. The net result will be a benefit to all customers by making available the diverse resiliency resources that provide value to the grid during a reliability event. The DRC-1 credit will be based on the capacity equivalence value of the participating customer’s DER-enabled demand reduction. As proposed, DRC-1 currently applies to only Company-owned DER assets; however, the Company may consider customer-owned DER in the future.

RAST-1 will also be an optional tariff that will be available to qualifying commercial and industrial customers. Pursuant to RAST-1, Georgia Power will provide resiliency service to participating customers through a Company-owned DER that is installed, operated, and maintained behind the customer meter.[18] During times of electric service outage, the DER will continue providing participating customers with a source of electric energy to support their critical operations. Georgia Power will include the corresponding DER assets in rate base, and participating

[18] DER technology that may be made available under RAST-1 includes, but is not limited to, natural gas generators, diesel generators, and other technologies such as solar and battery storage facilities.

customers will pay a monthly resiliency service charge that covers the cost of service under RAST-1. Customers must also enter an agreement with Georgia Power that further establishes the terms and conditions of service.

The DER Customer Program coupled with the implementation of DERMS is expected to create additional value streams over time. Together, DER and DERMS may enable these customer offerings to serve as a platform for additional use cases that offer further benefits to a wider segment of customers. The DER Customer Program will also provide the Company with valuable knowledge and experience in the operations of behind-the-meter DER. As new DER technologies emerge, Georgia Power will leverage advanced technology to maximize benefits to customers and the System.

CHAPTER 10. GENERIC EXPANSION PLAN (MIX STUDY)

The Company's expansion planning analysis determines the optimal mix of resources that satisfy future capacity and energy demands in an economic and reliable manner. In this step of the planning process, demand-side resources are integrated with supply-side resources to provide a roadmap that informs long-term resource planning decisions. Significantly, generic expansion plans do not represent a resource planning decision by the Company but are indicative of what may be an optimal mix of resources within various scenarios.

As such, the purpose of the expansion planning process is to evaluate capacity and energy resource options to meet the capacity need across a wide range of potential future scenarios. This process utilizes programming techniques to minimize the net present value ("NPV") of the revenue requirements when deriving the least-cost expansion plan. To develop the expansion plan, the generation technologies that pass detailed screening are further evaluated using the AURORA production cost model, which is widely used throughout the electric industry. AURORA employs a generation mix optimization module that includes the following major inputs: (1) load forecast; (2) existing, planned, and committed resources; (3) fuel prices; (4) emission costs; (5) future generating unit characteristics and capital cost; (6) the capital recovery rates necessary to recover investment cost; (7) capital cost escalation rates; and (8) a discount rate. The AURORA model considers all possible combinations of capacity additions, on a yearly basis, that satisfy the Company's target reserve margin constraints. The resulting combination of candidate resources with the smallest production and capital cost over the planning horizon represents the least-cost plan.

The output of the AURORA model serves as the primary guide in developing the reference case System expansion plan for the Retail OpCos. This System expansion plan identifies the optimal capacity and energy additions that inform the type of capacity and energy resources that are most economical within a particular timeframe for the given assumptions. The Resource Mix Study in Technical Appendix Volume 1 provides a detailed technical review of the expansion planning analysis and its results.

10.1. SUMMARY OF INPUTS & ASSUMPTIONS

The expansion planning process incorporates a wide range of inputs and assumptions, including, but not limited to, reliability criteria, load and energy forecasts, and numerous key financial and economic scenarios.

Reserve Margin — The 2022 IRP reflects a 16.25% Summer Target Reserve Margin and a 26% Winter Target Reserve Margin for long-term resource planning decisions. CHAPTER 5 and Technical Appendix Volume 1 (Reserve Margin Study) provide additional information on the Company's Target Reserve Margin assumptions.

Economic Forecast — IHS Markit's macroeconomic forecast serves as the basis for inflation and cost of capital estimates. IHS Markit developed a forecast of economic variables and demographic statistics for the state of Georgia. Key descriptive variables from the economic and demographic forecast for Georgia were used to produce the Budget 2022 Load and Energy Forecast.

Load and Energy Forecasts — The Budget 2022 Load and Energy Forecast discussed in CHAPTER 6 were utilized for the Company's 2022 IRP generic expansion plan or Resource Mix Study. The load and energy forecasting process uses a combination of end-use and econometric analyses and is explained in detail in CHAPTER 6 and in Technical Appendix Volume 1. Certain load forecast scenarios are also discussed in CHAPTER 7.

Fuel and Carbon Forecast – The 2022 IRP generic expansion plan or Resource Mix study incorporates the fuel and carbon forecast information described in CHAPTER 7.

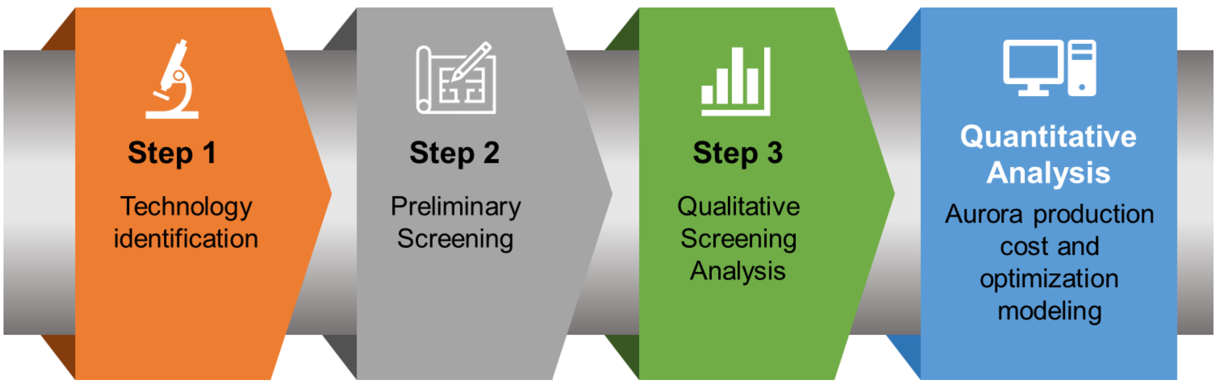
Financial Cost and Escalation — The Company assumes that long-term debt and common stock are issued to finance the construction of generating units. The returns demanded by the investment community are affected by perceptions of business risks and the inflation rate. Those returns along with the income tax rates, affect the carrying cost of the investment, which can in turn affect the resource capacity mix.

The IHS Markit forecast is the basis of the financing and inflation cost estimates used in the planning process. Discount analysis using the weighted average cost of capital is applied to place more emphasis on the near term. More information on the discount analysis and the financial parameters used in the mix process is shown in the Resource Mix Study in Technical Appendix Volume 1.

10.2. TECHNOLOGY SCREENING

The Company performs detailed expansion planning and production cost analysis during each IRP. This detailed analysis requires extensive and complex computational analysis. Therefore, the Company completes a technology screening assessment of new generation technologies to reduce the potential list of new supply-side options to a manageable list of technologies that are likely to be economically competitive. This technology screening assessment evaluates both established and emerging generating technologies. The objective is to assess the cost, maturity, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other relevant factors of new supply-side generation options.

The technology screening process includes three main steps: (i) the Technology Identification; (ii) Preliminary Screening; and (iii) Detailed Qualitative Screening Analysis. Supply-side options retained after these steps are then considered in the more detailed expansion plan modeling. The Technology Screening process is further reviewed in Technical Appendix Volume 1.



10.3. EXPANSION PLAN CANDIDATES

Electricity generating technology is always evolving. Therefore, as discussed previously, the Company's screening process identifies those technologies that have the greatest possibility of playing a cost-effective role in the System during the modeling horizon. Even among the technologies that might play such a cost-effective role, there remains uncertainty about the cost of each technology relative to its expected productivity and other technology options.

For Budget 2022 analyses, the technologies that screened as potentially cost-effective included natural gas combined cycle (with and without carbon capture), natural gas combustion turbine (with and without SCR), RICE, solar PV, wind, and battery storage. For Scenario 10 ("Tech" case), the Company also considered nuclear and natural gas direct-fired supercritical CO_2 cycle[19] with CCS.

Natural Gas Combined Cycle (NGCC): The Company's current assumption for planning purposes is that NGCC plants without carbon capture facilities are available for fleet expansion only through 2039 (\$0 CO_2 view) or 2034 (all other CO_2 views). Another planning assumption is that beginning in 2035 or 2040, depending on the CO_2 view, new NGCC plants must capture 90% of their carbon dioxide emissions. The timing of this requirement is based on the Company's understanding of the existing Clean Air Act and its statutory schedule for review of abatement technologies and requirements (New Source Performance Standards and Best Available Control Technology). With a carbon capture facility, NGCC plants are referred to as natural gas combined cycle with carbon capture and utilization or storage ("NGCC-CCUS").

Natural Gas Combustion Turbines (NGCT): The Company's current assumption for planning purposes is that CTs are available for fleet expansion through 2034. Beginning in 2035, new CTs must significantly reduce their NOx emissions by being installed with a SCR device. The timing of this requirement comes from the Company's understanding of the existing Clean Air Act and its statutory schedule for review of abatement technologies and requirements.

Reciprocating Internal Combustion Engine (RICE): RICE resources are available as an expansion resource beginning in the year of capacity need for each scenario. The Company's current assumption for planning purposes is that RICE resources use liquid or gaseous fuel to produce power through internal combustion.

Solar PV: Solar PV with single-axis tracking will be available as an expansion resource beginning in 2025. The Company's view is that solar PV procurement costs will continue to decline in real terms, meaning it will become increasingly cost-effective throughout the study timeframe. The Company has two views of the future cost of solar PV. The cost assumed in the Company's low-cost CO_2 abatement technology view is \$20/MWh[20] and the cost assumed in all other scenarios is \$25/MWh.[21]

[19] Also referred to as a supercritical CO_2 cycle.
[20] \$20/MWh in the first year of PPA and escalated at 3% thereafter.
[21] \$25/MWh in the first year of PPA and escalated at 3% thereafter.

Wind: Wind turbine is available as an expansion resource beginning in the year of capacity need for each scenario. The Company has two views of the future cost of wind turbines. The cost is assumed to decline until 2030 in the Company's low-cost CO_2 abatement technology view and escalate using construction cost escalation in all other scenarios.

Battery storage: Battery storage is available as an expansion resource beginning in the year of capacity need for each scenario. The Company's view is that battery storage costs will continue to decline, meaning that it will become increasingly cost-effective throughout the study timeframe. The Company has two views of the future cost of battery storage. Both views adopt costs that decrease for some portion of the planning horizon with the rate of that decline being higher in the Company's low-cost CO_2 abatement technology view and lower in all other scenarios.

Nuclear: Generation III+ Small Modular Reactors and Generation IV Nuclear technology are available as an expansion resource in the Company's low-cost CO_2 abatement technology view.

Direct-fired Supercritical CO_2 cycle: Natural gas direct-fired zero or near-zero carbon emission technology. This resource is available as an expansion resource in the Company's low-cost CO_2 abatement technology view.

The cost estimates for each of the natural gas, battery storage, wind, and nuclear technology options were developed based on proprietary sources of information. Current estimates for costs, spending curves, emissions, and operating characteristics for these resources are contained in the Technology Screening and Applications Standards, which is attached in Technical Appendix Volume 1.

10.4. CAPACITY NEEDS

Capacity needs are determined by comparing Georgia Power's forecasted demand and existing, planned, and committed supply and demand resources. Specifically, the capacity need is the difference in megawatts between existing, planned, and committed supply and demand resources and the forecasted annual peak and long-term planning reserve requirements. Please refer to the Resource Mix Study in Technical Appendix Volume 1 for detailed information on the Company's capacity needs.

Table 4: Forecasted Capacity Needs

Forecasted Georgia Power Capacity Needs (MW)[22]		
Year	Winter	Summer
2022	(806)	(1,760)
2023	(298)	(1,338)
2024	(974)	(673)
2025	(1,608)	(2,380)
2026	(1,651)	(2,422)
2027	(1,740)	(2,482)
2028	(570)	(966)
2029	1,034	290
2030	1,467	2,580
2031	3,723	2,775
2032	3,847	2,907
2033	4,140	3,216
2034	4,332	3,419
2035	6,941	6,383
2036	9,462	8,462
2037	9,801	8,891
2038	10,409	9,805
2039	11,097	10,089
2040	12,037	10,920
2041	12,513	11,398

[22] Based on 2022 IRP peak season capacity values and includes the 2022 IRP Certification and Decertification requests. Capacity reflects the ICE factor and Support Capacity Adjustment. A portion of the renewable nameplate generation capacity included in this chart includes capacity where the renewable generator retains the related RECs. Also, includes the effective capacity associated with Dispatchable Demand-Side Management programs that result in reduced customer demand at times of System peaks.

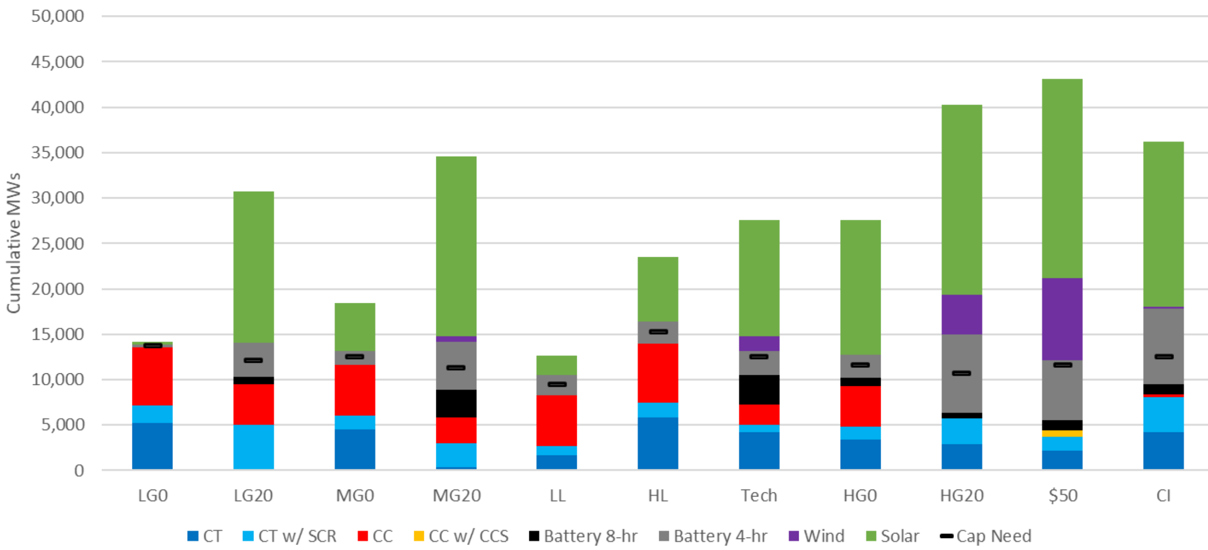
10.5. MODELING RESULTS

The expansion planning analysis maintains the Company's Target Reserve Margins while considering a wide range of possible future scenarios. The results of the expansion planning analysis ensure the Company is evaluating a range of economic conditions that may differ materially from current economic conditions. This process ensures the Company is making decisions with the best available information, while appropriately considering the risk associated with long-term resource planning decisions in the best interest of customers. The outcome of this method is a cost-effective mix of demand-side and supply-side resources that inform the Company's long-term avoided costs. When Georgia Power acquires resources to meet capacity needs identified in the IRP, the actual generation resource procured will be selected in accordance with the Commission's RFP rules.

For the first time in a Georgia Power IRP, the 2022 IRP includes solar, battery storage, and wind resources as generic resource options selectable by the expansion planning model. The long-term plan for each of the scenario cases, which is further described in CHAPTER 7, varies depending on the assumptions for that case. A mix of gas technologies (CTs and CCs), renewable technologies (solar and wind), and battery storage was selected for the scenario cases through the planning period when capacity was needed to maintain reliability, meet growing customer needs, or provide fuel-cost savings. Generic expansion plans for the eleven scenarios are summarized in Figure 11. The generic expansion plans identify the resource mix that is most economical for customers in each scenario.

Figure 11 shows the cumulative expansion plans over the 20-year planning period. The results indicate that in addition to CT and CC resource additions, there are a significant number of cases where battery storage is added to fulfill the capacity need. For battery storage, there are two factors considered. First, the generic battery capacity is expressed in terms of the ICE factor, which is a measure of the contribution to reducing expected unserved energy as compared to that of a dispatchable CT. Second, as more of the same duration batteries are installed, the relative value of such batteries in contributing to reliability (and therefore capacity need) is diminished. Given these two factors, multiple battery tranches were modeled with a declining capacity value as the penetration of batteries increases. To account for solar PV being modeled as energy only and the declining capacity values for battery, the capacity added above the solid line represents the portion installed that does not contribute to the capacity need but is still economical to add.

Figure 11: B2022 Generic Expansion Plan Results (2022-2041)



The results of the expansion plan or mix study are summarized in Figure 11. These results of generic expansion plan modeling are combined with the existing fleet of resources as inputs into more detailed production cost modeling to produce hourly avoided energy costs for each scenario. Please refer to the Resource Mix Study in Technical Appendix Volume 1 for more information on the generic expansion plan.

10.6. SENSITIVITIES

The planning scenarios and sensitivity analyses combine to provide a robust view of potential future outcomes that inform the Company's decision-making. Table 5 summarizes sensitivities to the base case, or the MG0 scenario, that were performed in accordance with the Commission's IRP rules and analyzed in detail in the Resource Mix Study and Financial Review, each found in Technical Appendix Volume 1.

Table 5: IRP Sensitivity Summary

	Sensitivity	Study
1	Forecast of load	The Company considers a range of load forecasts in Sensitivities 1-7. Sensitivities 8-9 specifically assume higher and lower load forecasts.
2	In-service dates of supply and demand resources	Sensitivities 1-11 evaluate the impacts of varying in-service dates and amounts of supply and demand resources through the scenario planning cases. These sensitivities produce separate evaluations of the impacts on the load and energy forecasts, which include effects from demand-side programs and new supply-side resources. Sensitivities 12 and 13 evaluate differing levels of demand-side programs.
3	Unit availability	Sensitivities 1-11 evaluate the impacts of varying in-service dates and amounts of supply and demand resources through the scenario planning cases. Additionally, the Reserve Margin Study evaluates unit outages.
4	Fuel prices	Sensitivities 1-7 evaluate the impacts of fuel prices through the scenario planning cases which have three separate fuel price environments and resulting forecasts combined with varying estimates of carbon prices.
5	Inflation in plant construction costs and costs of capital	Sensitivity 10 evaluates lower cost of carbon free technologies as compared to the other scenarios. These alternative costs could be driven by numerous factors, including inflation in plant construction costs and cost of capital.
6	Availability and costs of purchased power	Sensitivity 14 evaluates the impacts of differing availability and cost of purchased power.
7	Pending federal or state legislation or regulation	Sensitivities 1-7 and Sensitivity 11 evaluate the impact of pending legislation or regulation through the scenario planning cases. The impacts of pending legislation or regulation can be analyzed by varying estimates of carbon and fuel prices.
8	Rate Impact Analysis	All of the sensitivities analyze the impacts on rates of the varying changes in assumptions. The rate impacts are included in the Financial Review in Technical Appendix Volume 1

CHAPTER 11. SUPPLY-SIDE STRATEGY

The supply-side plan set forth in the 2022 IRP provides customers with substantial reliability and economic benefits while establishing a strategic plan for the incremental retirement of the Company's remaining coal resources and corresponding transition to resources that will deliver clean, safe, reliable, and affordable energy for decades to come. It also identifies cost-effective replacement generation procured through the 2022-2028 Capacity RFP consisting of 2,356 MW[23] of capacity from natural gas PPAs, which include resources historically under contract with Georgia Power. This plan includes the addition of 1,000 MW of ESS by 2030, which includes the McGrau Ford Battery Facility, a plan for 6,000 MW of new renewables by 2035, and continued investment in hydro-powered resources. These resource additions and investments provide customers access to low-cost, reliable, resilient, flexible, and lower-carbon resources.

As discussed further below, the transition away from coal resources has become beneficial for customers. Coal resources lack the necessary economic and flexibility attributes to remain a competitive resource within an electric system with large renewable penetration or in a future with continued environmental pressures. However, in the near term, coal resources remain an important reliability resource, which is incorporated into the Company's coal fleet transition strategy described in this chapter. As Georgia Power seeks to transition its generating fleet away from coal toward cleaner and more economical resources, it will carefully consider any impacts – both opportunities and challenges – that these changes will have on our employees, communities and customers.

A list of Georgia Power's planned and committed resources is contained in ATTACHMENT A.

11.1. PREVIOUS RESOURCE COMMITMENTS

The supply-side plan reflects previous resource decisions and actions resulting from the 2019 IRP, including the retirements of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2. The supply-side plan also includes the 970 MW of solar already procured from the Company's 2022/2023 Utility Scale renewable solicitation, up to 160 MW of DG solar, 25 MW of REDI Customer-Sited II solar and 25 MW of solar from the CCSP, as well as a potential 1,030 MW that will be procured from the

[23] Capacity listed in winter terms.

2023/2024 Utility Scale RFP. The plan also includes the Mossy Branch 65 MW, 4-hour battery facility. Finally, the supply-side plan assumes the addition of 60 MW of woody biomass[24] generation and additional resources that were ordered by the Commission in prior IRPs and in other dockets.

As communicated by the Company in the 25th Vogtle Construction Monitoring ("VCM"), the Company's target in-service dates for Plant Vogtle Units 3-4 are third quarter of 2022 and second quarter of 2023,[25] respectively. Since the 2019 IRP, progress continues to be made at Plant Vogtle Units 3-4, as described in the semi-annual VCM report filings in Docket No. 29849.

11.2. DECERTIFICATION OF RESOURCES

The economic analysis for the Company's coal resources does not support long-term continued operation. The combination of forecasted low natural gas prices, modest load growth, continued environmental risk and costs, as well as the combination of limited flexibility of the coal units and substantial renewable penetration, creates economic challenges for these plants.

The economic challenges facing the Company's coal resources necessitate the development of strategic transition plans for these resources. As outlined in this section, the Company's transition plan takes into account the ELG Reconsideration Rule cessation of coal combustion option. This compliance option requires the Company permanently cease coal combustion at a unit no later than December 31, 2028. Therefore, this option provides the Company with additional time to prepare the System for retirements while reducing or avoiding additional environmental related investments for certain resources. Alternate ELG compliance pathways require additional ELG controls. Please see the ECS in Technical Appendix Volume 2 for more information on the ELG rule. The Company's fleet transition strategy and proposed unit retirements appropriately balance cost and reliability, thus ensuring the Company will continue to deliver reliable, resilient, and low-cost service to its customers.

Transition plans for specific generation units are further set forth below:

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[24] Through the RFP process, overseen by the Commission Staff and the IE, Georgia Power was unable to identify suitable biomass capacity with acceptable terms amongst the bids submitted into the 60 MW biomass solicitation at the time of filing this 2022 IRP.

[25] The Company's expansion planning analysis assumed Plant Vogtle Units 3-4 in-service dates of July 1, 2022 and April 1, 2023, respectively. As communicated by the Company in the 25th VCM, the Company's target in-service dates for Plant Vogtle Units 3-4 were extended to September 2022 and June 2023, respectively.

- **Plant Bowen Units 1-2**: In accordance with the decision in the 2019 IRP, the Company has continued to significantly reduce spending on Plant Bowen Units 1-2. Based upon the Company's updated reliability assessments, the earliest projected retirement date for Plant Bowen Units 1-2 is in 2027. Retirement in 2027 provides the Company with sufficient time to complete the necessary transmission system improvements to accommodate retirement. Cost-effective replacement capacity was identified in the 2022-2028 Capacity RFP. This capacity is available prior to 2027 and ensures the Company can satisfy its target reserve margin requirements. Therefore, the 2022 IRP includes the planned retirement of Bowen Units 1-2 upon the completion of transmission system improvements, which is projected to be no later than December 31, 2027.

- **Plant Gaston Units 1-4**: Plant Gaston Units 1-4 are steam resources located in Alabama. 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. The ability to maintain coal backup is impacted by the requirements of the ELG rule. This impact would likely require the Company to eliminate coal backup and make long-term investments in expensive annual firm gas transportation to ensure reliable operation and avoid installation of ELG controls. Given the age and declining economics of these resources, it is not cost-effective to invest in their long-term operation and the associated annual firm gas transportation. Cost-effective replacement capacity was identified in the 2022-2028 Capacity RFP. This capacity is available prior to 2028 and ensures the Company can satisfy its target reserve margin requirements while also supporting the reliable transition of the fleet. Therefore, the 2022 IRP identifies the planned retirement of Gaston Units 1-4 by December 31, 2028.

- **Plant Scherer Units 1-3**: Economic conditions continue to deteriorate for Plant Scherer. In the 2019 IRP, the Commission did not approve the Company's offer to return 25 MW of Scherer Unit 3 capacity to the retail rate base. In December 2021, Florida Power and Light ("FPL") and Jacksonville Electric Authority ("JEA") retired Plant Scherer Unit 4. The Company's 2022 IRP retirement studies reflect long-term economic risk associated with operation of Plant Scherer Units 1-3. However, retirement of all three units requires substantial transmission system upgrades that will be difficult to complete by December 31, 2028. Given the large reliability barriers to retirement, the Company's IRP reflects ELG compliance paths for these units that balance cost with reliability while preserving decision-making flexibility.

- **Plant Scherer Unit 3**: The IRP reflects the retirement of Plant Scherer Unit 3 on December 31, 2028. Establishing a known retirement date provides the Company with an opportunity to reduce operating costs while preparing the System for retirement and supporting the reliable transition of the fleet.

- **Plant Scherer Units 1-2**: The Company currently plans to install ELG controls on Plant Scherer Units 1-2. As described in the ECS and in Section 11.7, the ECS reflects the plan to install physical-chemical-biological treatment while alternative membrane-based technology remains under consideration. The Company's ELG notice of planned participation ("NOPP") filing with the Georgia Environmental Protection Division ("EPD") reflected the VIP for ELG compliance. The VIP option provides the Company with additional time to evaluate the membrane-based technology (possibly a cost-competitive solution that may provide additional operational flexibility), and defer the final installation of controls prior to December 31, 2028. This later compliance date provides additional time for continued evaluation of the previously mentioned membrane technology, economics, reliability needs, and potential changes in environmental regulation or legislation. The economics of Plant Scherer Units 1-2 are challenged. Therefore, to reduce reliance on these resources for long-term reliability and preserve decision-making flexibility, the Company will make certain retirement preparations, such as transmission system improvements. Given these factors, the Company's 2022 IRP reflects the potential retirement of these resources on December 31, 2028 for System planning purposes. This strategy ensures the retirement option remains achievable in the event economics worsen in the future while preserving the ability to continue operating should economics improve. The Company will continue to work with its co-owners as it continues to evaluate the future operation of these units.[26]

[26] Georgia Power's share in Plant Scherer Units 1-2 is 8.4%.

- **Plant Wansley Units 1-2**: Similar to the Company's other coal resources, economic conditions continue to deteriorate for Plant Wansley. The Company's reliability assessments indicate that Plant Wansley Units 1-2 can retire immediately without significant transmission barriers. The Company can also satisfy its target reserve margin requirements upon immediate retirement, and replacement capacity is a more cost-effective way of meeting forecasted capacity needs. This IRP reflects the retirement of Plant Wansley Units 1-2 on August 31, 2022.

- **Oil CTs (Boulevard, Wansley 5A, & Gaston A):** This IRP also reflects the retirement of three oil-fired resources. Each of these resources are aging and nearing the end of their useful life. As such, the Company plans to retire Plant Boulevard Unit 1 on August 31, 2022. It also plans to retire Plant Wansley Unit 5A upon the retirement of the Wansley coal-fired resources, which is August 31, 2022. Lastly, the Company is planning to retire Plant Gaston Unit A upon the retirement of Plant Gaston Units 1-4, which is planned to occur by December 31, 2028.

This IRP reflects the continued operation of Plant Bowen Units 3-4 with ELG controls in place. Although these coal units are not immune from the economic challenges facing coal resources, they remain critical to preserving System reliability and resiliency in north Georgia. As such, they cannot be reliably retired at this time without significant reliability risk. Therefore, the Company will continue to make prudent investments in the near-term reliable operation of Plant Bowen Units 3-4 while simultaneously reducing long-term reliance on these units to provide for their eventual retirement. For planning purposes, this IRP assumes an unavailability date for Plant Bowen Units 3-4 on December 31, 2035. This long-term retirement strategy is further described in CHAPTER 12, which describes the Company's North Georgia Reliability & Resilience Action Plan.

Additional details regarding the assumptions, compliance strategies, and economic analyses for the generation units addressed in this section are provided in the ECS and Unit Retirement Study within Technical Appendix Volume 2.

11.3. CERTIFICATION OF CAPACITY RESOURCES

The 2019 IRP acknowledged the economic challenges associated with the continued operation of steam resources while highlighting the reliability risk associated with their retirement. To ensure reliability in the event Plant Bowen Units 1-2 and any additional steam units were retired, the 2019

IRP Order authorized the Company to issue capacity-based RFPs that require a level of capacity firmness and dispatchability, developed in conjunction with Commission Staff and the IE through the RFP development process required by the Commission's IRP rule. To provide flexibility around future resource retirement and replacement capacity decisions, the Company completed the 2022-2028 Capacity RFP in accordance with the 2019 IRP Order and Commission RFP rule. This Capacity RFP proved extremely successful, providing valuable market options with low-capacity prices and attractive firm gas transportation rates. The Company's supply-side strategy for the 2022 IRP reflects the 2022-2028 Capacity RFP results, which include six PPAs with a total capacity of 2,356 MW,[27] as summarized in Table 6.

Table 6: 2022-2028 Capacity RFP Results

Unit	Type	Nominal/Summer Capability	Winter Capability	PPA Start	Length
Plant Harris Unit 2	NGCC	660 MW	689 MW	12/1/2024	10 years
Plant Wansley Unit 7	NGCC	598 MW	622 MW	12/1/2024	10 years
Plant Dahlberg Units 1,3, and 5	NGCT	228 MW	256 MW	1/1/2028	10 years
Plant Dahlberg Units 2&6	NGCT	152 MW	171 MW	6/1/2025	10 years
Plant Dahlberg Units 8-10	NGCT	228 MW	258 MW	6/1/2025	10 years
Plant Monroe Units 1&2	NGCT	309 MW	360 MW	12/1/2024	15 years

ATTACHMENT K sets forth the Company's 2022-2028 Capacity RFP certification application and Technical Appendix Volume 4 includes the six executed PPAs.

11.4. PLANT HATCH SUBSEQUENT LICENSE RENEWAL

Georgia Power's Hatch Nuclear Plant is jointly owned by Georgia Power (50.1%), Oglethorpe Power Corporation (30%), Municipal Electrical Authority of Georgia (17.7%), and Dalton Utilities (2.2%). With the current 60-year license for Plant Hatch Unit 1 expiring August 2034 and the current 60-year license for Plant Hatch Unit 2 expiring June 2038, the Company is proposing to

[27] Capacity listed in winter terms.

request SLR from the NRC, thus providing the option to continue operating these units for an additional twenty years.

The nuclear industry within the U.S. has begun the process of extending nuclear plant operating licenses to 80 years. Several plants have already received 80-year licenses from the NRC and others have applications currently under NRC review. Anticipating a potential SLR Application ("SLRA") filing with the NRC for Plant Hatch Units 1-2, Georgia Power conducted a feasibility study and developed preliminary economics associated with continued operation of the units. The feasibility study concluded that Plant Hatch could operate reliably beyond 60 years, with no unexpected or unusually large capital expenditures identified. Additionally, the preliminary economics associated with continued operation appear beneficial for customers.

The continued operation of Plant Hatch pursuant to an extended license would contribute to the Company's fuel diversity and provide a source of zero carbon energy. In light of the benefits associated with the continued operation of Plant Hatch, as supported by positive preliminary economics and a favorable feasibility study, the Company is requesting approval to spend approximately $28 million required to pursue SLR for both Hatch Units 1 and 2. ATTACHMENT D provides additional information on the proposed SLRA.

11.5. RENEWABLE EXPANSION PLAN

The supply-side strategy for the 2022 IRP incorporates a long-term renewable expansion plan that provides for the addition of cost-effective generation resources and supports System reliability requirements. This plan includes 6,000 MW of new renewable resources by 2035, more than doubling the previously approved portfolio of renewable resources procured by Georgia Power. This long-term procurement strategy is informed by the Company's expansion planning model, which determines the economically optimal amount of renewable resource additions.

The Company's renewable expansion study, described in ATTACHMENT F, indicates that a range of renewable procurements up to 9,000 MW could be economically beneficial for customers depending on future economic and market conditions. For example, the economically optimal renewable expansion plan reflects lower renewable procurements in scenarios where carbon emissions are not assigned a price, as compared to scenarios with a cost of carbon. A similar observation is noted across a range of gas or fuel prices. As such, higher fuel or gas price scenarios support more economically viable renewable procurements than scenarios with lower gas or fuel prices. Ultimately, in scenarios with higher fuel and emissions costs, the Company's expansion planning model selects more solar or renewable energy as economical. Similar impacts are identified as the Company varies the cost of solar or renewable procurements, such that lower cost renewable procurements result in more renewable expansion than do cases with higher renewable procurement costs. These dynamics demonstrate the need for the Company's long-term resource procurement strategy to be adaptable to support the economic procurement of resources. Notably, the Company's renewable expansion analysis includes scenarios with over 9,000 MW of new renewables by 2035, with more selected after 2035. The Company will continue to monitor market conditions,[28] System reliability needs, and other key factors to ensure its long-term strategy remains economical and serves the best interests of customers.

As an initial step towards its long-term strategy outlined above, in this 2022 IRP the Company is seeking to procure energy from 2,300 MW of new renewable resources as described in CHAPTER 14. This amount represents an appropriate level of near-term procurements of new resources as the Company navigates the challenges of renewable integration, such as transmission system limitations.

While navigating these challenges and preserving the balance between cost and reliability, the Company is providing pathways that improve and optimize its procurement activities and meet the needs of customers. Additional information on the Company's renewable procurement plans is provided in CHAPTER 14.

Lastly, the Company's 2022 IRP reflects a capacity need in 2029. This capacity need grows sizably into 2030-2031, primarily due to natural gas PPA expirations and expected retirements. The Company will continue to monitor this need and consider issuing an all-source RFP to address these capacity needs in the future. Such an RFP would provide additional renewable expansion opportunities beyond the 6,000 MW identified in the expansion plan.

11.6. ENERGY STORAGE

The 2022 IRP demonstrates that significant renewable expansion remains a key element of the Company's long-term resource plan. The expansion of ESS will provide essential grid services that enable reliable expansion of renewable resources. As discussed in CHAPTER 5, ESS will specifically support the real-time operating needs of the System by providing operating reserves,

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[28] Supply chain issues, cost of capital, inflation, labor costs, land availability, policy changes, gas or fuel prices, and similar factors could impact market conditions and the associated renewable procurement costs and benefits.

which are impacted by renewable growth. ESS will also provide energy arbitrage value, capacity benefit, and similar System benefits that meet the needs of customers. The Company's supply-side strategy carefully considers the relationship between renewable growth and ESS and the benefits they can provide to the System when appropriately deployed, and specifically identifies the Company's need to own and operate 1,000 MW of storage resources by 2030 to support the projected levels of installed intermittent renewable capacity on the System at that time. This storage deployment strategy is further described in CHAPTER 13, which includes the addition of the McGrau Ford Battery Facility.

11.7. ENVIRONMENTAL COMPLIANCE STRATEGY

Georgia Power has a long history of demonstrating environmental stewardship while meeting the energy needs of customers. Complying with federal and state environmental requirements is a fundamental element of the Company's longstanding commitment to meet these energy needs. Consistent with the Company's efforts to supply clean, safe, reliable, and affordable energy, the ECS describes the comprehensive strategy to comply with environmental laws and regulations through the implementation of cost-effective environmental controls and actions.

The 2022 ECS reflects the Company's strategy to comply with numerous federal and state requirements, including the revised ELG rule and both the federal and state CCR rules for the Company's coal-fired plants. The ELG rule requires the installation of additional environmental controls for wastewater treatment, whereas the CCR rule requires closure of ash ponds and adds additional requirements for Georgia Power's 12 existing CCR landfills. In light of the CCR requirements, Georgia Power is permanently closing 29 ash ponds at 11 facilities. In doing so, Georgia Power is incorporating site-specific closure strategies to comply with the rules, which were approved in the 2019 IRP, that appropriately address multiple factors such as pond size, location, and geology, as well as the amount of material at each site. Closure of the ash ponds is regulated under both state and federal CCR rules, and further regulated by EPD through site-specific permits that mandate defined compliance actions for each ash pond and landfill. Costs associated with the closure of ash ponds and landfills under the CCR rule are reflected in the CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 1.

The evolution of the ELG rule since 2015 has introduced significant regulatory uncertainty impacting the Company's ability to make decisions and finalize and implement the prior environmental compliance strategy regarding ELG. Due to the ELG Reconsideration Rule, the

Company's current FGD wastewater strategy costs are based upon the installation of physical-chemical-biological treatment systems at Plants Bowen and Scherer.

Based upon its evaluation of the compliance paths in, and as required by, the ELG Reconsideration Rule, the Company filed an update on its coal generation ELG compliance plans with the EPD on October 13, 2021. In its filing, the Company indicated that it plans to stop coal combustion at Plant Scherer Unit 3, Plant Bowen Units 1-2, and Plant Wansley Units 1-2 by no later than December 31, 2028. In addition, the Company has informed EPD that Plant Bowen Units 3-4 will comply with the generally applicable effluent limits by December 31, 2025. The Company has also informed EPD of its plans to pursue the VIP at Plant Scherer Units 1-2, which will require ELG controls to be installed by December 31, 2028.

The pursuit of the VIP option at Plant Scherer Units 1-2 is based upon the use of membrane-based treatment that is potentially uniquely available to the Plant Scherer units. This option would be pursued as an alternative to the physical-chemical-biological treatment that has been maintained as a conservative cost basis of the ECS. Ongoing research and testing of the full membrane-based treatment solution is needed and is being performed to determine if appropriate technical performance, reliability, operational flexibility, and cost-competitiveness can be achieved. The NOPP filing with EPD was required to reserve the option of membrane-based treatment and provides an additional three years for compliance with the ELG Reconsideration Rule to complete necessary study and planning activities. Notably, the ELG Reconsideration Rule allows for transition to a different compliance approach if technical or economic challenges arise with respect to the current approach at the Plant Scherer units.

In a similar filing on behalf of Georgia Power, on October 13, 2021, Alabama Power filed an update with the Alabama Department of Environmental Management that Plant Gaston Units 1-4 would stop coal combustion no later than December 31, 2028.

The ECS also discusses various key environmental rules that continue to evolve, including both the ELG and CCR rules and power plant carbon emission regulations and policy. However, even with significant shifts in policy from the federal government amidst administration changes, overall trends are clear. Coal-fired power plants will continue to face increasingly stringent requirements from existing and new environmental regulations. Over the past decade, there has been significant activity in Congress on climate-related legislation to reduce GHG emissions and mandate renewable or carbon-free energy. Of note, several bills have been introduced that focus on an economy-wide carbon tax. These proposals typically impose an initial economy-wide price on carbon (e.g., dollars per ton CO_2), with varying degrees of escalation each year until the proposal's specific national emission reduction targets are achieved. The proposals contemplate initial pricing in a range from $15/ton to $52/ton and increase annually at varying rates. Another approach to pricing carbon, a clean electricity standard, has also been proposed. Several congressional actions have been contemplated, such as the Clean Energy Standard and Clean Electricity Payment Program, and additional legislative activity is expected in the future.

In this IRP, Georgia Power presents the potential risks the Company faces from the uncertainty around future federal regulatory and policy changes addressing carbon emissions not only of the utility industry but also of customer operations. CHAPTER 17 further describes how Georgia Power plans to continue reducing the risk of potential carbon regulation or legislation.

ECCR

The Company anticipates the ECCR tariff will need to be updated in the 2022 base rate case to appropriately reflect the incremental costs of environmental compliance. The incremental capital and O&M environmental compliance costs for which the Company seeks approval in this IRP are more specifically described in the Selected Supporting Information section of Technical Appendix Volume 1.

11.8. HYDROELECTRIC GENERATION

Georgia Power operates 17 hydro generation facilities and has an ownership interest in an 18th – Plant Rocky Mountain – with a total of 66 hydroelectric generating units in Georgia. These facilities are all licensed by the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act. In all, Georgia Power has ownership rights to over 1,100 MW of hydroelectric capacity. The following information provides details about the hydro fleet, relicensing schedules, and the estimated risk of environmental challenges to continued operation associated with hydro facilities.

Continued Investment in the Hydro Fleet

As discussed in the 2019 IRP, Georgia Power has conducted an extensive review of its hydro fleet and determined that numerous, essential components at several facilities are at or near the end of their useful lives and require additional investment to continue operation. The investments the Company is making will allow these resources to operate for at least another forty years while improving the efficiency and integrity of the hydro fleet and preserving valuable, dispatchable carbon-free resources for the long-term benefit of customers.

The hydro modernization effort seeks to strategically plan projects while optimizing resources, design, planning, and execution of work in a more efficient manner than a longer-term piecemeal approach. The Company's modernization plan recognizes that the hydro fleet as a whole has served customers for several decades, and therefore, a coordinated modernization effort is necessary to cost effectively and efficiently address the challenges at each facility. The Company's modernization approach gives continuity and efficiency of engineering design, minimizes construction mobilization costs at the sites, allows volume procurement, and optimizes the design and selection of equipment. This approach also minimizes unit outages and maximizes the generation potential at each site.

Finally, the investments being made will address required maintenance and upgrades related to issues such as cavitation damage to turbines, aging head gate operators, aging relays and gauges, and cracking in wicket gates. The investments would also provide for much needed generator rewinds and the replacement of turbines, cranes, piping, oil-filled circuit breakers, spillway gates and flashboards, and other equipment critical to the operation of these facilities. Moreover, replacing leaking spillway gates, replacing flashboards with modern gates, and replacing wicket gates will reduce current energy losses from these plants and improve their performance.

Progress since the 2019 IRP

In the 2019 IRP, the Commission approved five projects in the hydro modernization plan: Plant Terrora, Plant Tugalo, Plant Bartletts Ferry, Plant Nacoochee, and Plant Oliver. Since then, the Company has focused its hydro modernization efforts on these five projects, making significant progress while managing the unique challenges required for design and engineering as well as procuring highly specialized parts amid the COVID-19 pandemic. Notably, the modernization projects at Plant Terrora Units 1 and 2 have been substantially completed on time and under budget. The scoping and engineering work has been completed for Plant Tugalo, and Tugalo Unit 1 site work is currently in progress. Scoping and detailed engineering are in progress for the remaining plants. The Company has kept the Commission abreast of its progress on these units through its bi-annual reporting in Docket No. 42310. For more information on the project schedules in this filing, please refer to the Selected Supporting Information in Technical Appendix Volume 1.

Next Steps: Plant Burton, Plant North Highlands, and Plant Sinclair

As the Company progresses on the first five projects, it is imperative to continue the hydro modernization efforts on the remaining fleet. Plant Burton, Plant North Highlands, and Plant Sinclair require near-term attention. These plants have the most pressing need of maintenance and are most likely to have extended unit outages in the near future. The inclusion of these plants in the overall modernization effort also provides an opportunity to effectively utilize a trained and experienced workforce, improving the Company's ability to successfully modernize its remaining units. Currently, there are two experienced engineering teams working on the hydro modernization portfolio. Continuing their momentum, these teams will be available to start engineering on the next set of plants in the hydro fleet in 2022. These plants were selected as the next set in the program based on priority as well as optimizing the program schedule. The total hydro capital budget, including the estimated costs of the investments for these three plants, is included in the Selected Supporting Information section of Technical Appendix Volume 1. It is important to note, for units that have not been completed or approved for modernization, outages and equipment failures remain a heightened risk. The Company will take the steps necessary to maintain these units, which may require individual equipment replacement in lieu of the holistic approach utilized in the Hydro Modernization Program. Until these units are approved by the Commission for inclusion in the program, managing inefficiencies and maintaining reliability of these units will remain challenged.

11.9. TECHNOLOGY ADVANCEMENTS & PILOTS

Technology cost and performance improvements are at the forefront of planning considerations. As the energy landscape continues to evolve, new and emerging technologies have the potential to fundamentally alter the way energy is created, transported, and ultimately consumed. As a core component of the planning process, the Company monitors technology advancements to ensure it is prepared and ready to adopt new technologies that benefit customers. For the 2022 IRP, the Company has identified long-duration storage, hydrogen, and tall wind technologies as areas of emphasis.

As the Company's resource mix continues to evolve, it is foreseeable that System needs could eventually shift towards long-duration or multi-day storage applications. In this scenario, the

Company would consider the potential need for weekly, monthly, or even seasonal storage resources. New technologies are emerging that may provide such services, but commercial viability of these long-duration storage solutions requires additional testing, monitoring, and demonstration. Ultimately, these types of technologies could provide an economic and reliable avenue to reduce reliance on fossil fuel-based generating resources while supporting renewable growth. When these technologies mature, they have the potential to fundamentally alter the energy landscape. Southern Company, through its membership in Energy Impact Partners, is an investor in one such technology, the Form Energy[29] iron-air battery storage technology. This technology can utilize relatively abundant materials, such as iron, for energy storage applications that can be optimized to store energy for 100-hour durations. This multi-day storage technology can also reduce the risk of thermal runaway and is considered easier to recycle than other battery storage chemistries. Southern Company and Georgia Power have a long-standing commitment to innovation to better serve customers. As such, the Company will continue to evaluate opportunities to support, invest, and learn more about this type of long-duration storage. The Company plans to evaluate opportunities in the 5-15 MW range to deploy this transformational technology. Once the Company has identified an optimal application to demonstrate the multi-day storage technology, it will return to the Commission for project approval.

Hydrogen is also an area that may provide customers with benefits as renewable penetration increases and technology improvements occur. Using a process known as electrolysis, energy providers can create hydrogen using electrical energy and water. As discussed in CHAPTER 10, the Company's expansion planning analysis demonstrates that significant renewable expansion is cost-effective. One side-effect of this expansion is the potential for reoccurring periods of solar curtailment on the System. The electrolysis process can efficiently utilize otherwise curtailed solar energy to produce green hydrogen. As low, or even zero-dollar, marginal energy cost hours increase in the future, the cost to produce hydrogen energy could decrease rapidly. This new economic possibility, when combined with the potential for technology advancements and carbon constrained futures, supports further exploration of hydrogen as a potential new energy source for numerous applications.

[29] Southern Company is the founding member of Energy Impact Partners ("EIP"), a global venture capital platform leading the transition to a sustainable future. EIP is an investor in Form Energy, Inc.

The potential impact of hydrogen extends beyond its usefulness in managing renewable power generation (bulk energy storage). Although it can be used for electricity production, hydrogen fuels can be utilized in many different applications. For electricity production, hydrogen fuel can offset or eliminate natural gas while reducing carbon emissions. For Georgia, this could provide an avenue to create in-state hydrogen using in-state renewable generation as an alternative for natural gas purchased and transported from out-of-state. This hydrogen opportunity could provide significant benefits to CT and CC resources by simultaneously reducing their carbon footprint, expanding fuel diversity options, and potentially providing certain levels of fuel storage. Hydrogen can also be utilized in DER applications, as a transportation fuel, or even in certain industrial processes. Through stored hydrogen, these energy end uses could be decarbonized, providing additional low-carbon energy to energy users throughout Georgia.

The Company believes the 2022 IRP is the appropriate time to initiate a hydrogen pilot project to ensure the Company is better prepared for potential technology cost declines, large increases in solar penetration, and potential carbon-related constraints and costs. To prepare for this possibility, the Company is partnering with key stakeholders to develop an integrated hydrogen microgrid. This project seeks to create hydrogen from an electrolysis system utilizing grid energy. The hydrogen produced will then be utilized in a fuel cell microgrid application as well as for a transportation fuel. The fuel cell component will create electricity that can be utilized to charge EVs, provide backup power, or provide peaking services. The transportation component will include six zero-emission utility trucks. Three trucks will be battery electric utility vehicles charged by the fuel cell. The remaining three trucks will directly consume hydrogen as their primary fuel source. This pilot project will provide new insights into the various capabilities of hydrogen to meet the needs of customers in the evolving energy landscape, while minimizing costs through key partnerships. Please see the Selected Supporting Information section of Technical Appendix Volume 1 for more information on the Integrated Hydrogen Microgrid project.

The Company's 2022 IRP generic expansion plan also reflects the possibility that wind generation may be cost-effective, including wind located in the state of Georgia. As described in CHAPTER 14, the Company has identified this opportunity based on its latest research. To ensure the Company is prepared to take advantage of in-state wind resources, the Company is seeking to deploy two tall wind turbines using the latest emerging technology. Please see CHAPTER 14 for more information on this pilot project.

CHAPTER 12. NORTH GA RELIABILITY & RESILIENCE ACTION PLAN

As a vertically integrated utility, the Company must develop and implement comprehensive plans for the operation of a reliable electric system comprised of a vast network of generation and transmission facilities that work in concert with one another. The addition or retirement of generation resources, transmission capacity, and expansion plans for load growth are closely related, and the Company must consider these elements together in its comprehensive planning process. The North Georgia Reliability & Resilience Action Plan presented in this IRP provides a multi-faceted plan to address future reliability needs associated with the retirement of Plant Bowen, which is best mitigated with an integrated planning approach. Specifically, the Company identified the north Georgia region of the state as a geographic area of focus. This region relies on the transmission system to bring in needed power from south Georgia. As retirements in north Georgia occur, the Company must enhance its generation and transmission systems and operational capabilities to avoid the potential for a major loss of load (i.e., outages). Preventing these occurrences will require proactive planning and close coordination with other ITS Participants. As discussed further herein, the generation and transmission expansion plans provided for in the North Georgia Reliability & Resilience Action Plan will be essential to ensuring the long-term reliability and resilience of the power grid moving forward.

12.1. PLAN FOR SERVING LOAD IN NORTH GEORGIA

The current projected transmission and generation infrastructure cannot sufficiently support reliable electric service to north Georgia following the retirement of Plant Bowen Units 1-4. However, the combination of renewable generation expansion, low load growth, forecasted low gas prices, and substantial environmental pressures will continue to place a significant burden on coal unit economics, including Plant Bowen. Therefore, the Company, along with the ITS Participants, must prepare the System for the eventual retirements of Plant Bowen Units 1-2 and Plant Bowen Units 3-4.

New local area generation is a critical component of the long-term solution to continue reliably serving load in north Georgia. Options to add new generation are generally limited by the location of suitable sites. Georgia Power’s ability to add new transmission assets is similarly limited based on land and right-of-way needs for optimum location of the lines and substations, as well as environmental permitting requirements. New generation and transmission solutions must also provide an economical means of supporting reliability and resilience of the bulk electric system in north Georgia. To date, strategic projects remain under development with ITS Participants. Due to the number of System constraints and time required to construct projects, the Company plans to install ELG controls and continue operating Plant Bowen Units 3-4, thus preserving north Georgia reliability and resilience in the most economical manner. The Company will continue to study both generation and transmission options for best serving north Georgia.

12.2. NORTH GEORGIA RENEWABLE RFP

There is a significant gap between generation and load forecasted in north Georgia which will be further increased by future coal retirements. This gap will require the transmission system to transport large amounts of energy from south to north Georgia and place additional strain on the existing transmission system. Moreover, overreliance on generation from distant geographic regions can create adverse conditions that aggravate power System reliability and resiliency issues.

To support north Georgia resilience needs, the first phase of utility scale renewable procurements proposed in the 2022 IRP will target renewable resources in north Georgia. These procurements are further described in CHAPTER 14. This renewable development strategy will support the Company's north Georgia resilience needs through the development of new renewable resources strategically sited in north Georgia, with a focus on counties located north of interstate 20.

12.3. ACTION PLAN

As part of its North Georgia Resilience and Reliability Action Plan, the Company will complete transmission system improvements necessary to support the retirement of Plant Bowen Units 1-2, which are identified in the 10-year transmission plan. Additionally, to reduce the long-term reliance on Plant Bowen Units 3-4, the Company plans to complete the following steps:

1) Install ELG controls on Plant Bowen Units 3-4 to allow for continued operation.
2) Issue the north Georgia Renewable RFP.
3) Work with the ITS Participants to develop a strategic portfolio of projects to address the long-term transmission planning and operational needs of north Georgia beyond the future retirement of Plant Bowen Units 3-4.
4) Develop a consolidated expansion plan addressing future generation needs for north Georgia.

CHAPTER 13. ENERGY STORAGE

The Company's diverse portfolio of resources – comprised of demand response, energy efficiency, nuclear, natural gas, oil, coal, hydro, solar, wind, landfill gas, and biomass generation – provides for a reliable and resilient System. In the 2022 IRP, the Company has identified a growing need for additional energy storage capabilities to support the continued reliable and cost-effective operation of the System as it evolves. As discussed further below, the Company will address this need through the procurement of Company-owned ESS, including the McGrau Ford site. In addition to Company-owned ESS, Georgia Power will continue to include storage resources in the Company's market-based competitive renewable and capacity-based RFPs.

Maintaining Reliability with Growing Intermittent Resources

As the energy mix continues to evolve, and intermittent renewable resources become more prevalent, the effective deployment of ESS will play an increasingly important role in the operation and reliability of the electric system. Given the significant energy and operational impacts of these changes, Georgia Power must continuously adapt its planning to ensure customers receive reliable service. Energy storage resources will be a particularly useful tool for ensuring long-term reliability both during and after the integration of increased levels of intermittent renewable resources. Storage affords the Company the ability to efficiently address the intermittency of renewable resources and provides its customers with the confidence that Georgia Power will be able to maintain reliability when solar and wind resources are not available.

In the 2019 IRP, the Commission approved a Stipulation that provided for significant amounts of additional intermittent renewable resources, and similarly approved the Company's development of energy storage resources to begin to address some of the previously mentioned intermittency challenges facing the Company. The Commission's decision recognized the difficulties faced by the Company from adding intermittent generation as well as the need for the Company to manage those challenges with energy storage resources it can rely on. The 2022 IRP further reduces the amount of firm capacity resources available to serve customers through the proposed coal unit retirements discussed in CHAPTER 11 and provides for significant expansion of new renewable resources, thus increasing the Company's need for reliable storage resources.

The Company's ability to address the reliability challenges associated with increasing levels of intermittent resources is significantly enhanced by its ownership and operation of dependable energy storage resources it can rely upon and control. As battery and other storage technologies mature, the Company's near-term investments and experience with operating this technology as an integral component of the System will be critical to ensuring long-term reliability and meeting customer needs.

As a vertically integrated utility with an obligation to serve its customers, the Company is subject to the jurisdiction and oversight of the Commission and is required to appropriately invest in and operate a reliable and economical electric system consistent with the IRP requirements. The Company has utilized competitive procurements through the Commission approved RFP process to add new renewable resources even in the absence of a capacity need. This process has worked well to produce benefits for Georgians and will continue to be used as the Company seeks to replace expiring power purchase contracts, serve new load growth, and/or solicit new renewable resources approved through the IRP. The Commission has also historically acknowledged the need for Georgia Power to maintain a minimum percentage of capacity under its control.[30] The Company must have the ability to develop, own, operate and maintain a sufficient portion of the resources needed to reliably serve its customers. Company ownership of ESS is a logical extension of this policy and supports market development of renewable resources by allowing that growth to continue without compromising reliability for customers. Notably, consistent with the 80 MW of Company-owned BESS approved by the Commission in the 2019 IRP, any addition of Company-owned battery storage facilities needed to support intermittent renewable growth would follow the Company's own competitive procurement process for engineering, procurement, and construction agreements. Following this competitive procurement process ensures that such resources are procured in an economical manner to provide value to customers.

Finally, ensuring that reliability can be maintained through Company ownership of ESS is particularly relevant today where resources being procured may provide benefits, but also create unique challenges, for utilities obligated to reliably serve the needs of their customers. The current transition to lower carbon resources has created an environment where the Company's generation mix is becoming more heavily weighted towards third-party PPAs, which the Company does not own or operate. The Company believes this trend will continue as solar, when added responsibly, is currently the most cost-effective energy resource addition available in Georgia. Given the current and anticipated growth in solar, it is critical to recognize the necessity of

[30] See Commission Rule 515-3-4-.04(3)(f)(7).

Company-ownership of ESS to support renewable growth while maintaining accountability for providing reliable service to customers.

Storage Solutions

As discussed previously, energy storage will play a vital role in cost-effectively managing the unique reliability challenges associated with the increasing penetration of intermittent renewable resources. The establishment of an appropriate level of Company-owned storage resources provides a mechanism to advance the growth of renewable resources in Georgia, while ensuring the Company can continue to serve its customers reliably. To appropriately utilize ESS and ensure optimal System operation and reliability consistent with Georgia's IRP framework, the Company should own and operate 1,000 MW of storage capacity by 2030 based on the projected levels of installed intermittent renewable capacity on the System at that time. Support for adding this amount of storage capacity is provided by the Company's Renewable Integration Study, which demonstrates that this level of storage significantly improves the reliable integration of large renewables resource additions. The Renewable Integration Study is further described in CHAPTER 5 as well as Technical Appendix Volume 1. The Company will utilize the renewable integration study for planning purposes and will bring ESS projects to the Commission for approval.

13.1. BATTERY ENERGY STORAGE SYSTEM DEMONSTRATION PROJECTS

As approved by the Commission in the 2019 IRP, the Company continues to make progress on the development of 80 MW of Company-owned and operated BESS. The Company has chosen to develop three different configurations to maximize learnings and overall value to customers. These configurations include a large standalone transmission-interconnected storage system, a solar plus storage system, and a small standalone distribution-interconnected storage system.

The large standalone transmission-interconnected storage project plan was approved by the Commission by Order dated October 12, 2021. This project will consist of a 65 MW, 4-hour lithium-ion BESS located at the Mossy Branch Battery Facility in Talbot County, Georgia. Engineering and procurement work for this project is underway, with commercial operation expected in 2023. The objectives of the Mossy Branch Battery Facility are to evaluate in a real-time environment the commercial operation performance of a standalone grid-charging storage asset and to refine the BESS operation and maintenance practices to maximize the asset's useful life.

Of the remaining Commission-approved 15 MW of battery energy storage, the Company is working with the Army to co-locate a 13 MW, 4-hour BESS with an existing Company-owned solar facility at Ft. Stewart. A competitive solicitation for EPC services was issued in December 2021, with an expected commercial operation date in the second half of 2024. The development of this proposed facility will support examination of the costs and benefits of energy storage technology integrated with renewable resources. Additionally, the Company intends to deploy the final 2 MW to develop a small standalone distribution-interconnected storage facility. Development of a distributed grid-charging BESS will enable the Company to analyze the necessary technical requirements for interconnecting BESS to local distribution feeders and validate the operational and performance capability of such assets in a real-time environment.

Development of these BESS projects has already resulted in a significant advancement of the Company's knowledge and understanding of energy storage systems. These learnings have been utilized to bolster Georgia Power's design standards and procurement practices of energy storage to ensure safe and reliable operation. An essential product developed as a result of these projects includes a standard EPC Agreement that includes key technical design requirements specific to energy storage. The Company has also carried out important development work related to the communication and control of BESS, including the addition of a forward-looking energy storage optimization module to the current automatic generation control ("AGC") functionality. This work supports Georgia Power's capability to dispatch current and future energy storage assets economically and efficiently.

13.2. COMPANY-OWNED BATTERY FACILITY

The Company has identified the next storage addition required to meet the forecasted storage need previously discussed. This resource is the McGrau Ford Battery Facility located in Cherokee County, Georgia. This battery storage resource will consist of a 265 MW 2-hour lithium-ion facility interconnected at the McGrau Ford substation. The Company has also completed a cost-benefit analysis, as provided in Technical Appendix Volume 2, demonstrating the substantial benefits a BESS facility will provide customers for at least 20 years.

Plans for the 265 MW Battery System were developed by the Company and improved using learnings and industry relationships cultivated via the 2019 IRP 80 MW battery demonstration projects. Preliminary site development surveys have been completed for this location, including soil and environmental analyses, and results show the Georgia Power-owned land near the

McGrau Ford substation is a suitable location for constructing a BESS facility. Additionally, the interconnection studies for this proposed Facility indicate that this location provides for cost-effective interconnection to the transmission system. This preliminary development work positions Georgia Power to expeditiously procure the BESS through a competitive EPC RFP process. The Company anticipates the McGrau Ford Battery Facility can achieve commercial operation by 2026. The Company will provide the Commission with the proposed EPC Agreement prior to undertaking construction and procurement for the project.

13.3. SECOND LIFE ELECTRIC VEHICLE BATTERIES

Given that used EV batteries may still have useful energy storage capability, the Company was ordered in the 2019 Integrated Resource Plan to develop a pilot project utilizing used lithium-ion batteries from EVs to create a battery system that can be installed near EV chargers. The purpose for this design is to help insulate the grid from spikes in electricity demand due to intermittent EV charging demands. The 2019 IRP Order set the project budget at $250,000.

Initially, Georgia Power managed the project and identified a potential site host with an industry-leading partner in the electric transportation market. The Company is in the process of finalizing a site agreement with the host and expects to sign the agreement by Q2 2022. Also, Georgia Power executed a contract with Southern Research ("SR") for the BESS specification, vendor identification, testing and final report. Finally, SCS is serving as the project lead on behalf of Georgia Power.

Following the 2019 Order, the Company spent considerable time identifying vendors able to build the BESS given the budget for the project. The first vendor identified was acquired by another company and withdrew from participation in this project. Georgia Power, SR, and SCS have since evaluated three other vendors and identified one that is interested in moving forward. SCS is developing a Master Service Agreement ("MSA") with the new vendor and anticipates completion of the MSA in early 2022. If the MSA and site host agreement are executed according to schedule, the Company expects the project to be installed by the end of 2022.

13.4. ENERGY STORAGE PROCUREMENT ACTION PLAN

Numerous procurement related activities will be required to develop the necessary storage systems in accordance with the Company's forecast. Major activities include the completion of siting and competitive solicitations for EPC services. The Company's siting activities, pursued in conjunction with the Company's ongoing activities to identify valuable locations for renewable and other generation resources, will seek to identify the most reliable and cost-effective locations for energy storage while considering Company-owned land, retired or retiring plant locations, military bases, and other favorable locations. The Company anticipates developing projects in conjunction with the Company's renewable resource forecast as it works toward fulfilling the 1,000 MW of ESS by 2030 supported by the Renewable Integration Study. The Company will file for approval of selected projects in accordance with the battery storage procurement action plan described below.

The Company's battery storage procurement action plan generally includes:

1. Identify desirable locations for new storage resources and obtain site control, as appropriate.
2. Complete preliminary site layout and engineering drawings.
3. Initiate transmission interconnection studies.
4. Issue competitive RFP for turnkey EPC storage resources.
5. Complete cost-benefit analysis.
6. File for Commission approval of project(s).

CHAPTER 14. RENEWABLE RESOURCES

As part of Georgia Power's strategy to deliver clean, safe, reliable, and affordable energy from a diverse fleet of generation resources, the Company continues to work with the Commission and renewable stakeholders to develop a nationally recognized portfolio of renewable projects and programs, including solar, wind, biomass, and biogas resources. Georgia Power's steady and measured approach to growing renewable resources includes the procurement of renewable energy from both small and large-scale generators, the development of Company-owned solar generation facilities, and implementation of customer-focused renewable programs, all designed to meet the renewable energy needs of participants while creating long-term value for all customers. As a result of these efforts, energy is now being delivered to Georgia Power customers from more than 3,070 MW of renewable resources, with more than 2,330 MW of additional renewable projects under contract or development and anticipated to be online by the end of 2024.[31]

Since the 2019 IRP, the state of Georgia and Georgia Power Company have been recognized by both the Smart Electric Power Alliance ("SEPA") and the Solar Energy Industries Association ("SEIA") as an innovative leader in solar energy. Most recently, SEIA ranked the state of Georgia 7th in solar photovoltaic installations for 2020, and SEPA recognized Southern Company as the 2020 "Utility Business Models Power Player of the Year," which highlighted Georgia Power's CRSP program. Through the leadership of the Commission and collaboration with the renewable energy community, Georgia Power has set a national standard for responsible renewable energy growth without a mandate or renewable portfolio standard. This approach has been developed by working closely with the Commission and Commission Staff to deliver cost-effective renewable energy strategies, while upholding the principles of customer fairness, applying accurate costs and benefits, and maximizing value for customers by using market driven procurement practices. Figure 12 illustrates the historical and expected cumulative renewable capacity for Georgia Power through 2025, by resource type.[32]

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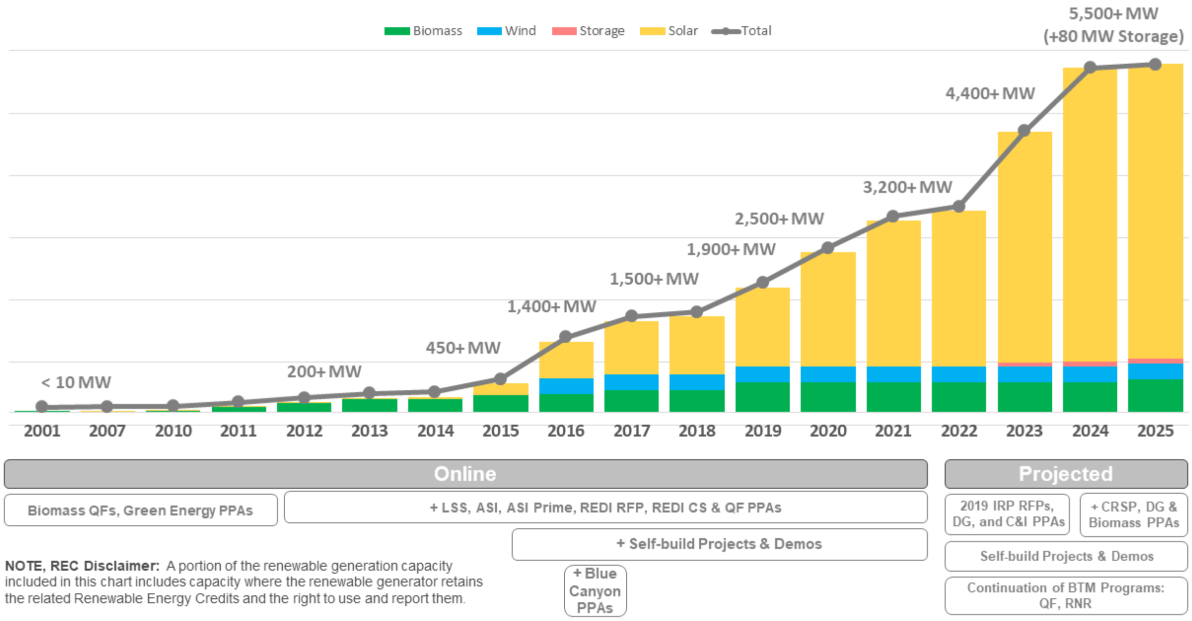
[31] Georgia Power purchases only the null energy output from some renewable generating facilities that have contracted to sell energy from their facilities to Georgia Power. The ownership of the associated RECs is specified in each respective PPA and the party that owns the RECs retains the right to use the RECs. Georgia Power does not report emission reductions from the null energy purchased through PPAs that do not bundle the RECs for sale to Georgia Power.

[32] All current and forward-looking online and contracted solar capacity numbers are shown in AC or direct current ("DC") values, based on program reporting.

Figure 12: Historical and expected cumulative renewable capacity for Georgia Power



While industry comparisons are an important measure of success, Georgia Power's greatest accomplishment with respect to renewable development is effectively responding to customer needs and creating long-term value for customers.

Georgia Power actively monitors market trends, policy changes, and technology advancements to continuously adapt its innovative and customer-focused renewable programs. As the cost of renewable energy continues to decline, and the importance of carbon-free generation sources expands, customer interest, investment, and support of renewables continues to grow. Customers with an interest in sustainability are leveraging Georgia Power's renewable programs to support their goals. Moreover, Georgia Power remains committed to helping meet individual customer needs through renewable programs that align with its long-term resource planning strategy and provide value from market-based procurements that maximize long-term benefits for the entire customer base.

Through direct feedback and market research released by JD Power & Associates in August 2021, customers have confirmed their support of the Company's approach to renewable procurement and programs. As such, the Company plans to continue working with the Commission, customers, and other stakeholders to enhance existing programs and design new programs that build upon the Company's experience and best practices to deliver industry-leading, customer-focused renewable solutions. This experience is applied to program design and procurements in accordance with Georgia Power's three core renewable energy principles:

(1) maintain customer fairness by minimizing or eliminating cross-subsidization of programs across customer groups; (2) appropriately value costs and benefits of renewable energy as defined by the RCB Framework; and (3) generate maximum value for customers by prioritizing market-based procurement strategies.

With these principles in mind, Georgia Power proposes to continue procuring cost-effective renewable resources from utility scale, distributed generation, and customer-sited projects that provide carbon-free generation to meet customer needs. C&I customers will have access to a growing portfolio of renewable options, including subscription based, REC-based, and customer-sited programs. Residential customers can participate in the REC-based Simple Solar program, buyback programs for on-site generation, and an enhanced Community Solar Program, including a new income-qualified option. The Company remains committed to supporting all customers by offering analysis and guidance to support their decisions as they consider renewable options.

14.1. NEW RENEWABLE RESOURCES

As discussed in CHAPTER 11, the Company's supply-side strategy now incorporates a strategic long-term renewable expansion plan that indicates customers could benefit from the procurement of energy from at least 6,000 MW of new renewable resources by 2035. In this IRP, the Company is specifically requesting Commission approval to procure energy from 2,300 MW of new renewable resources that will achieve commercial operation by year-end 2029. The Company will provide updated procurement targets and timelines in future IRPs. While completing these initial procurements, the Company will continue to implement best practices that address the challenges associated with reliably integrating significant amounts of intermittent resources, including improvements to the transmission system and fleet operational requirements.

While navigating these challenges to preserve an appropriate balance of cost and reliability, the Company is implementing changes to optimize its renewable resource procurements. These improvements include operational requirements (including operational flexibility delivered through AGC) and locational guidance to guide developers to areas where System conditions are more favorable for interconnecting renewable resources. These facets of Georgia Power's procurement strategy will enhance the efficiency of the reliable integration of new renewables on the System. Requiring renewable resource flexibility and encouraging efficient siting will help maximize the value these resources provide to customers. Additionally, the Company proposes to evaluate and select resources based on the best cost and value provided to customers, using the RCB

Framework, to ensure cost-effective resource additions. The 2022 IRP renewable expansion plan reflects an adaptable cadence of renewable procurements, and a long-term commitment to the renewable market in Georgia that provides certainty of regular renewable solicitations. By leveraging the RFP process, the Company can routinely engage in the marketplace, facilitate a constructive transfer of information, and update the timing and requirements of the procurements between solicitations. These changes are proposed with the goal of maintaining the Company's industry leading procurement practices to support cost-effective, efficient, and reliable resource additions.

Flexible Renewable Resources

As discussed in CHAPTER 5 and in the Renewable Integration Study in Technical Appendix Volume 1, the Company has identified certain operational reliability issues associated with large-scale renewable expansion. However, the Company also identified solutions that can assist in the management of these issues, which will now be incorporated into the long-term procurement strategy. These solutions include increases in the amount of flexible capacity on the System—resources with the ability to quickly adjust output up or down—such as BESS. To further help with the management of these issues, the Company is requiring additional flexibility[33] from new renewable resources. The Company will continue to monitor these operational issues and adapt renewable procurements to select resources that protect the reliability of the System and avoid creating adverse conditions that could jeopardize System operations.

Locational Guidance

The Company has identified locational reliability and resiliency challenges associated with future coal retirements and known renewable expansion in certain areas of Georgia. These challenges are described in CHAPTER 12. To assist in the management of these issues, the Company plans to improve the geographic diversity and siting efficiency of new renewable resources. As such, the Company's future renewable additions proposed in this IRP may be region-specific and/or locationally steered.

- **Utility Scale:** As informed by System operational conditions, the Company will issue one or more geographically targeted RFPs. These targeted RFPs will convey to potential

[33] For this purpose, Flexible Renewables is defined as solar resources on AGC. System operators would have the ability to increase or decrease solar output based on System needs and solar availability.

bidders preferred geographic areas for new resources, to maximize the value of these renewable resources as the Company strives to meet its locational resource needs. As proposed, the next utility scale RFP will solicit resources in north Georgia in support of the Company's North Georgia Reliability and Resiliency Action Plan.

- **Distributed Generation:** As an enhancement to the interconnection guidance services offered to current DG market participants, the Company will provide a web-based hosting capacity tool for DG resources based on area of interconnection. The intent of the tool is to indicate where available capacity may exist on the distribution system, with a goal to minimize costs and increase the efficiency of the siting and interconnection processes for Distributed Generators. The hosting capacity tool will be designed to aid bidders/developers in the selection of a location and the acquisition of land for DER development by indicating whether potential capacity exists for interconnection. The hosting capacity tool is not a replacement for the Company's existing interconnection processes, but instead is a process enhancement. Georgia Power will continue to study the interconnection of eligible DG facilities to measure the impact of power quality and ensure System reliability. The use of the hosting capacity tool, which will be updated annually, does not guarantee real-time accuracy, nor does it confirm the availability of distribution capacity, but rather it represents an improvement to the DG procurement process that will provide useful information to participants in the Company's DG programs, potentially increasing the value these resources provide to customers.

Best-Cost Procurements

The results of the expansion plan confirm that new renewable resource additions are in the best interest of customers when considering a range of future scenarios. One of the changes the Company proposes to optimize its renewable resource procurements is a transition to a best-cost analysis by removing the avoided cost ceiling limit as the primary determinant of customer benefit in its evaluation and selection of renewable projects. In the past, the Company only selected renewable resources that offered projected energy savings to customers and put downward pressure on rates in relation to avoided cost. That threshold remains the critical evaluation metric in determining the value to customers of renewable resource additions; however, adding new renewable resources above that threshold may be deemed appropriate to help the Company meet certain System needs.

As such, the Company proposes to evaluate and select resources by focusing on the best-cost resources. An enhanced portfolio selection process will ensure cost-effective resource additions through procurement enhancements focused on an efficient and reliable fleet transition. For utility scale and DG procurements, the Company will continue to rely on the RCB Framework to identify and rank cost effective bids, and then select a portfolio that balances all the appropriate costs and benefits. Consistent with past practice, selection of these portfolios is made in collaboration with Commission Staff and the IE and approved by the Commission.

Procurement Frequency

The Company continually adapts its RFPs to ensure that procurements provide the best value to customers, that they meet System energy and operational needs, and that real time best practices and lessons learned are incorporated. As such, the Company proposes to modify the timing, cadence, and adaptability of RFPs to provide for the consideration and incorporation of such improvements within each successive solicitation. The Company will incorporate modifications to the schedule and capacity targets of individual solicitations to be able to adapt to market and System conditions, while maintaining a procurement trajectory that supports the Company's long-term renewable resource plan. The Company is incorporating timing and sequencing improvements into its utility scale and DG renewable procurement strategy.

To facilitate this continual improvement, the Company plans to routinely issue utility scale and DG renewable RFPs until it reaches the long-term plan of at least 6,000 MW of new renewable resources by 2035. As proposed, this approach will promote ongoing renewable opportunities for both small and large projects and allow for the most efficient use of internal and external resources that support these procurements. The establishment of this long-term procurement strategy, with the ability to modify timing, total procurement target amounts, and other requirements in future RFPs, provides more certainty to stakeholders, flexibility for the Company, and will facilitate overall efficiency improvements. As proposed, the Company seeks permission to offer the first 3 RFPs as part of this long-term procurement strategy:

- A Utility Scale RFP targeting 1,050 MW, to be issued in 2023 with proposed CODs of 2026/2027.
- Distributed Generation RFPs targeting 200 MW, through two 100 MW solicitations in 2023 and 2024 with proposed COD's of 2024/2025.

- A second Utility Scale RFP targeting 1,050 MW, expected to be issued in 2025 with proposed CODs of 2028/2029.

Additional procurement schedules will be updated in future IRPs. The Company may also request Commission approval for additional procurements, for example to support the CARES Economic Development option, between IRP cycles.

In addition, the Company will continue to offer a year-round DG customer-sited program, CCSP, that allows customer-sited solar resources to provide energy to the grid through long-term, fixed price agreements with RECs retired on behalf of the host customers. The CCSP program was recently extended and will remain available for interested customers.

14.2. NEW PROCUREMENT PROGRAMS

The Company proposes to continue a measured and disciplined procurement strategy to maintain the steady growth of renewable generation in Georgia. Adding new renewable resources in this manner will deliver benefits to all Georgia Power customers. Securing these benefits for all customers, as well as providing access to renewable energy through innovative renewable programs that align with customer needs, validates the need for additional competitive procurement of cost-effective utility scale renewable resources. Additionally, the Company proposes to continue to procure renewable energy through enhanced DG programs with the goal of maximizing value for customers. These expanded programs and procurements will play a critical role in adding to a diverse generation mix as part of the overall IRP. The costs to administer and implement renewable energy programs will continue to be managed efficiently and recovered through the fuel clause.

Utility Scale Procurement Strategy

Georgia Power proposes to procure energy from up to 2,100 MW of utility scale renewable resources greater than 6 MW_{AC} in size. In accordance with the Company's long-term procurement plan, the Company will issue a north Georgia utility scale renewable RFP in 2023 and will select the resources that provide the best total value for customers. Based on the results of the RFP, the Company will establish the guidelines and schedule for the next utility scale procurement. Consistent with the Company's plan to procure resources at best-cost, the Company proposes an additional sum of a levelized \$7.50 / kW_{AC} of the procured amount, annually for the term of each PPA. This new methodology represents an appropriate incentive to the Company to competitively procure additional resources and fairly considers lost revenues, changed risks, and an equitable sharing of benefits consistent with the requirements of O.C.G.A. § 46-3A-8. The Company will purchase and take ownership of all RECs produced by these facilities to leverage them for the benefit of all customers. As proposed, the revenues collected as participation fees in the proposed CARES program will be applied to reduce costs in the Fuel Cost Recovery ("FCR") clause, which benefits all customers, and the RECs procured through these solicitations then retired on behalf of CARES program participants. Bid fees will be established to recover RFP-related administrative and evaluation costs incurred by the Company.

Distributed Generation RFP Procurement Strategy

In conjunction with the Company's forward-looking strategy related to DER technologies, procuring renewable energy from distributed generation continues to play an important part of the Company's objectives. Georgia Power proposes to procure energy from up to 200 MW of renewable resources through two RFP's leveraging an enhanced procurement process. In addition to the transition to a best-cost evaluation methodology, the Company also proposes several improvements to make the DG RFP more efficient. First, the size range for renewable DG resources will now target resources greater than 250 kW but not more than 6 MW potentially improving the economies of scale for the projects. Additionally, these resources will be procured through a competitive RFP process updated to follow the Utility Scale RFP process more closely, which will evaluate and select a portfolio of projects based on the best overall value in relation to each other and the RCB avoided costs. And as previously discussed, the enhanced interconnection guidance program, featuring the hosting capacity tool, will facilitate a more efficient interconnection process. These improvements, based on learnings from prior DG programs, will enable a more efficient procurement of energy from DG resources. Consistent with the methodology proposed for utility scale procurements, the Company seeks approval of an additional sum methodology that provides for a levelized amount of $7.50 / kW AC of the procured amount, annually for the term of each PPA. Bid fees and interconnection guidance fees will be updated to recover the administrative and implementation costs incurred by the Company.

Distributed Generation Customer-Sited Program Strategy

Like the DG RFP, the distributed generation customer-sited program remains an important part of the Company's customer-focused renewable strategy. The Company continues to evaluate program participation results from the CCSP as approved in 2020 and extended in December

2021. Based on feedback from interested customers, Georgia Power will continue to enhance aspects of the CCSP to broaden participation and help meet customers' growing renewable energy needs. The goal of the program remains unchanged, targeting procurement of energy from eligible solar resources that are located on property belonging to or adjacent to a Georgia Power customer. The RECs will be retired on behalf of the host customers, thus allowing the participants to claim the renewable attributes associated with the program resources. The Company proposes to offer a year-round rolling application period that allows customers sufficient time to fully explore program requirements and benefits and to obtain necessary internal approvals. The Company will evaluate and select projects on a first come, first-served basis. The Company will communicate any future CCSP modifications with Commission Staff, customers, and stakeholders.

14.3. TALL WIND DEMONSTRATION

Georgia Power evaluates wind resources where they may prove economical for its customers. Wind energy is a renewable resource that is complementary to solar due to its availability overnight and during winter mornings. The current wind potential for standard 80-meter hub height wind turbines in Georgia is uneconomical. However, as referenced in the 2016 IRP, the US Department of Energy ("DOE") and the National Renewable Energy Laboratory ("NREL") developed several studies supporting the utilization of taller wind turbines with larger rotors to achieve a capacity factor greater than 30% in the Southeast. To further study the potential for higher hub height wind resources in Georgia and validate the site-specific locations identified by NREL as "High Wind Potential," the Commission authorized Georgia Power to commence a High Wind Study in the 2016 IRP. The results of this study validated the model-based wind maps presented by NREL and concluded that this data could be leveraged to potentially develop economical wind resources in Georgia at hub heights of 120 meters or greater.

Recent advancements in turbine and tower technology have allowed for increases in both turbine rotor diameter and hub height. These increases lead to an overall larger capacity factor and energy capacity per turbine, which increases the cost effectiveness of these generators. The primary constraint related to constructing wind turbines at heights of 120 meters or greater is the transportation of the tower from the manufacturing facility to the site. Georgia Power has continued to research and evaluate potential technologies for tall wind tower construction and has identified a potential solution to help overcome these transportation limits.

The Company proposes a demonstration project to develop two wind turbines, up to four MW each, with a hub height between 140 – 165 meters. The proposed towers will utilize innovative spiral weld technology that employs on-site fabrication techniques. This project is designed to demonstrate the economic and technical feasibility of tall wind in Georgia as well as validating the in-field construction techniques required for the spiral weld technology at higher hub heights. The Company plans to team with the spiral weld technology company to leverage DOE funding awarded to the technology vendor for the further development and demonstration of this innovative spiral weld tower technology.

Additional information and the projected costs for this project are provided in the Selected Supporting Information section of Technical Appendix Volume 1.

14.4. RENEWABLE PROGRAMS FOR CUSTOMER PARTICIPATION

Georgia Power is committed to providing industry-leading customer service related to renewable energy. Since the creation of the Renewable Development organization in 2013, customer interest in solar and renewable options has continued to grow, and the Company has enhanced its ability to provide education and analysis to residential, commercial, and industrial customers of all sizes so that they can make more informed decisions when considering participation in one of the Company's renewable programs. Renewable Development employees field thousands of calls and emails from customers interested in Georgia Power's renewable programs and have completed more than 1,700 customized analyses with guidance on buy-back program options since 2016. Georgia Power's Renewable Development team remains committed to providing accurate and useful information to help customers make informed solar decisions, including information about Georgia Power's latest portfolio of program options.

Georgia Power offers a vast portfolio of renewable programs for customers who want to expand their use of renewable energy. In this IRP, Georgia Power proposes to expand its robust menu of renewable program options to meet the growing needs of customers across all customer types. C&I customers will have additional opportunities through the CARES program options, which have been designed based upon direct feedback from interested customers and the successful REDI C&I and CRSP programs. Residential customers will also enjoy additional program enhancements, with a focus on improving access to the benefits of renewable energy for income-qualified customers. Table 7 summarizes the proposed renewable customer program portfolio, with detailed descriptions to follow.

Table 7: Proposed Renewable Customer Program Portfolio

Program	Subset	Requirement	Procurement	Participation
Clean And Renewable Energy Subscriptions (CARES) Program	Existing Load	≥ 3 MW	900 MW	Pro-Rata
	New Load	≥ 15 MW	500 MW	First-Come, First-Served
	MUSH[34]	1MW ≥ 3 MW	50 MW	Pro-Rata
	CFE-ATC[35]	≥ 25 MW	650 MW	Pro-Rata
	Economic Development	≥ 50 MW	As Needed	As Needed
Total			2,100 MW	

Program	Subset	Requirement	Allocation	Participation
Existing Resource Retail REC Retirement (R3) Program	Existing Load	≥ 15 MW	1,000 MW	Pro-Rata
	Economic Development	≥ 50 MW	1,000 MW	First Come, First Served
Total			2,000 MW	

Program	Subset	Customer	REC Source	Note
Simple Solar	Simple Solar	Any Customer <100,000 kwh/month	Solar	Updated Pricing

Program	Subset	Customer	REC Source	Note
Flex REC	Flex REC – Large Volume	Over 100,000 kwh/month	Solar, Wind & other potential resources	Offer a variety of REC resources and modify pricing tiers
	Economic Development	New Customers	As Needed	New option to offer fixed price RECs

[34] Municipalities, universities, schools, and hospitals (MUSH).
[35] Carbon Free Energy (CFE) and Around The Clock (ATC).

Program	Rate	Customer	Price	Note
Community Solar	R	Residential	$27.99 per month	Updated Pricing
	GS	Commercial	$29.99 per month	New Rate Availability

Program	Sponsor	Participant	Price	Note
Income-Qualified Community Solar	Corporate Partner	Residential Customer	$6.99 per month (75% discount)	Up to 5,000 Blocks from existing CS Farms to be used for program

This enhanced portfolio of customer-focused renewable options will provide interested customers the opportunity to support the growth of renewable energy, while adhering to longstanding Commission principles aimed at minimizing cost shifting and upward rate pressure.

Clean And Renewable Energy Subscription (CARES) Program

Building on the success of Georgia Power's CRSP program, the Company plans to grow the amount of renewable energy available for customer subscription by making the energy from all the utility scale renewable procurement solicitations approved in this IRP available for subscription. This design will allow participating customers the opportunity to support renewable energy, while non-participating customers benefit through projected downward pressure on fuel costs from subscription revenues collected from participating customers. Similar to CRSP, the CARES program offers C&I customers the ability to subscribe to a portion of the energy output and RECs from a portfolio of new renewable resources. Georgia Power will procure energy from up to 2,100 MW of utility scale renewable resources through the two RFPs described previously, with all 2,100 MW available for subscription through several options targeting specific C&I segments. Within the CARES program, Georgia Power will offer a carve-out for MUSH customers, a program specifically designed for customers seeking around the clock carbon free energy from carbon free resources (CFE-ATC), and an option targeting new economic development load, in addition to expanded existing load and new load options previously offered through the CRSP program approved in the 2019 IRP.

CARES Existing Load

- Georgia Power will offer subscriptions to the output from a 900 MW portfolio of renewable generation to existing customers with a minimum annual peak demand of 3 MW at one account or an aggregate of accounts under common ownership and control. An existing C&I customer may participate in the CARES program in an amount up to 100% of its preceding year's total annual energy consumption associated with the customer's premises qualifying for the program. If the level of existing customer capacity interest exceeds the available MW for each solicitation, Georgia Power will allocate available MW for subscription on a pro-rata basis among participating customers who complete the NOI process.

CARES New Load

- The CRSP program generated interest from many customers, including many large customers adding new load to the Georgia Power system for whom the availability of renewable energy options is important to their business goals and a significant factor in determining where to locate their businesses. To support this customer need, Georgia Power will offer 500 MW of renewable generation for subscription by customers adding incremental, new load of 15 MW or greater. The subscription capacity will be offered on a first-come, first-served basis.

CARES Municipalities, Universities, Schools, and Hospitals (MUSH)

- The CRSP program also generated interest from many smaller customers with load under 3 MW. To provide a more robust renewable option for these customers, Georgia Power is proposing to offer 50 MW of renewable generation for subscription by MUSH customers with an aggregate annual peak demand of 1 to 3 MW. If the level of MUSH customer capacity interest exceeds the available MW for each solicitation, Georgia Power will allocate MW on a pro-rata basis among participating customers who complete the NOI process.

CARES Carbon Free Energy - Around The Clock (CFE-ATC)

- The CARES CFE-ATC is a new program option designed to provide eligible customers an option to subscribe to renewable energy around the clock. The resources associated with this offering will be similar to Georgia Power's other subscription programs but will leverage renewable resources and BESS resources to optimize delivery of renewable energy to the grid during all hours of the day. The energy generated from the renewable and BESS resources will serve the needs of all retail customers but will be dispatched in a manner to deliver energy beyond normal renewable resource production hours. This program will offer up to a 100 MW block for subscription, supplied by energy from up to 650 MW of renewable resources along with the appropriate sizing of BESS. Participating customers will receive energy and capacity credits based on their subscription level. Existing customers with a minimum annual peak demand of 25 MW at one account (or an aggregate of Georgia Power accounts under common ownership and control) may participate and can subscribe in an amount up to 100% of their preceding year's total annual energy consumption for each of the customer's qualifying premises aggregated to meet the eligibility criteria. If the level of CFE-ATC customer capacity interest exceeds the available MW, Georgia Power will allocate MW on a pro-rata basis among participating customers who complete the NOI process.

CARES Economic Development

- The CARES Economic Development offering will provide an opportunity for additional renewable solicitations to encourage economic development in the state of Georgia. As such, this offering provides the adaptability to procure additional renewable resources to meet customer needs beyond the capacity available through the CARES New Load program. In cases where the New Load program is already fully subscribed or does not meet the needs of a qualifying customer, Georgia Power will request Commission approval to procure energy from new renewable resources in addition to the 2,100 MW of utility scale resources proposed in this IRP. This offering will be available for subscription by customers adding incremental, new load of 50 MW or greater.

Like the CRSP program, all customers participating in the CARES program will participate pursuant to a tariff and will be required to enter a customer agreement specifying the pricing and terms and conditions of their participation. Additionally, as part of the CARES program, the Company is proposing two subscription options:

A. Similar to the current methodology used in CRSP, customers participate through a monthly subscription, which includes a customer participation charge and hourly energy credits on their electric bill based on the actual production of the renewable resources supplying the program portfolio.

B. Customers can participate through a monthly subscription based on a fixed cost per MWh, determined at the time of contracting. Customers participating under this option would not receive hourly energy credits.

The CARES program is designed to collect program-related costs from participating customers. The monthly fee to participate in the CARES program will be in addition to the customer's regular monthly electric service payments. The associated franchise fees and applicable taxes will continue to be applied to the entire bill. Interested customers will be given the opportunity to submit an NOI identifying their proposed subscription level in MW, contract term length, and other requirements related to their interest in the program. To offset the cost of pre-program implementation, there will be a $5,000 NOI participation fee. Any portion of the renewable procurements that are not subscribed to by participating customers (whether existing, new, or MUSH) will be procured to serve all Georgia Power customers.

As an additional option, customers participating in the CARES program will have the opportunity to support renewable energy for specific communities through a community adder fee in addition to the program charge. Once the renewable resources supplying the CARES program are online, the funds generated from participating customers though the community adder would be used to fund a dedicated community-based program to be developed and approved by the Commission in a future proceeding.

Existing Resource Retail REC Retirement (R3) Program (Up to 2,000 MW)

The proposed R3 program will provide participating customers the ability to claim renewable benefits from existing renewable resources through a reallocation of the RECs from resources that are already online or are in the process of coming online. The RECs and environmental attributes that would otherwise be retired on behalf of all customers will be made available for subscription by interested customers. Participating customers will be able to subscribe to up to 1,000 MW of the current REDI I and REDI II portfolios approved in the 2016 IRP and up to 1,000 MW of the 2022/2023 and 2023/2024 portfolios from the 2019 IRP once these resources come online. As part of the subscription, customers will pay a fixed cost per MWh for the RECs that are generated from these portfolios. As proposed, participating customers will enter into a customer agreement with a term of up to five years that specifies the pricing, terms, and conditions of their participation in the R3 program. The monthly fee to participate in R3 will be in addition to the customer's regular monthly electric service payments and will be based on the value of the RECs at the time the customer agreement is executed. The associated franchise fee and applicable taxes will continue to be applied to the entire bill. Consistent with the Commission's Orders in Docket Nos. 41596, 42625, and 43814, the revenue collected from the program will be applied to the FCR account and will reduce costs for the benefit of all customers. The costs to administer and implement programs will continue to be recovered through the fuel clause. The subscription capacity will be allocated on a pro-rata share basis for existing customers and offered on a first-come, first-served basis to new load customers.

Existing customers with a minimum annual peak demand of 15 MW at one account (or an aggregate of Georgia Power accounts under common ownership and control) are eligible and can subscribe in an amount up to 100% of their preceding year's total annual energy consumption. Up to 1,000 MW from the R3 program will be available for subscription by existing customers. Georgia Power will offer up to 1,000 MW of renewable generation from the R3 program for subscription by customers adding new load of 50 MW or greater.

RECs from any portion of the total 2,000 MW of renewable capacity that are not subscribed by participating customers will continue to be retired on behalf of all Georgia Power customers.

Simple Solar

Georgia Power's Simple Solar program was introduced in the 2016 IRP and has been well received by customers. The program provides an option for any customer to support the growth of renewable resources without an on-site installation or a long-term commitment. Customers can participate by matching either 50 or 100 percent of their monthly energy usage with solar RECs retired on their behalf.

Based on the rising cost of procuring RECs for the Simple Solar Program, the Company proposes to raise the price for Simple Solar from 1¢ per kWh to 1.25¢ per kWh. This increase reflects current market conditions where REC costs have increased and includes costs for program marketing and administration expenses such as customer education, program promotion, and REC tracking. Additionally, existing Simple Solar Large Volume contract customers will transition to the proposed Flex REC program at the conclusion of their current contract. New contracts for Simple Solar Large Volume option will not be available beyond 2022.

Flex REC Program

As customer interest in the Simple Solar program continues to grow, Georgia Power has identified the need for greater flexibility for its large customers. The proposed Flex REC program replaces the Simple Solar Large Volume program that provides flexible REC procurement to help larger customers meet their growing renewable and sustainability goals.

Current market conditions indicate that Simple Solar may not meet all the needs of large customers based on solar REC availability in the voluntary REC market. Therefore, the new Flex REC program will be supplied with RECs from a variety of sources, including solar, wind, and potentially other renewable sources.

The Company proposes to mimic the Simple Solar Large Volume pricing approach by offering tiered pricing based on customer usage while reflecting current REC market conditions. The proposed program pricing is designed to prevent cost shifts by collecting for REC costs, program marketing, and administration expenses, including customer education, program promotion, and REC tracking. At any point that the current market price for RECs equals the price of the fourth tier under the Flex REC program, the Company will adjust program pricing for new subscriptions to appropriately account for REC price increases as they occur.

Table 8: FLEX REC Program Pricing Tiers

	Current Pricing and Tiers (Simple Solar LV)	Proposed Pricing and Tiers (Flex REC)
Tier 1	First 50,000 @ 1.00 ¢/kWh	First 100,000 @ 1.25 ¢/kWh
Tier 2	Next 100,000 @ 0.800 ¢/kWh	Next 150,000 @ 1.00 ¢/kWh
Tier 3	Next 200,000 @ 0.600¢/kWh	Next 350,000 @ 0.750¢/kWh
Tier 4	Next 1,650,000 @ 0.500 ¢/kWh	Next 400,000 @ 0.625 ¢/kWh
Tier 5	All remaining kWh @ market rate	All kWh >1,000,000 kWh/month @ contracted/market price + 5%

The Company also proposes a new Economic Development Flex REC option. This option will be available to customers that qualify for the large load exception of the Georgia Territorial Electric

Service Act[36] and who purchase a minimum of 2,000,000 kWh monthly through Flex REC, or 24,000,000 kWh annually for a fixed rate, quantity, and term. The pricing is customer-specific and will be negotiated by Georgia Power and the customer on a case-by-case basis for a defined contract period (up to three years), during which Georgia Power will procure and retire RECs on behalf of the customer. To continue to provide additional flexibility to customers, Georgia Power will also transition the Simple Solar one-time purchase and Special Event purchase options to the Flex REC program.

Community Solar

Georgia Power's Community Solar program currently gives residential customers the opportunity to support the development of solar power in Georgia by subscribing to a portion of the output of local solar resources. To increase participation, the Company proposes to expand the customer tariffs eligible for program participation. In addition to residential customers, the Company proposes to offer Community Solar to commercial customers on the General Service tariff. The pricing for Community Solar will differ for each tariff and is designed to collect program costs from participating customers. Consistent with this principal, the following table provides updated pricing for each rate.

Table 9: Community Solar Program Pricing

Rate	Customer	Current Pricing	Proposed Pricing	Note
R-24	Residential	$24.99	$27.99 / month	Modify Current Pricing
GS-11	Commercial	NA	$29.99 / month	Add New Rate to Program

Income-Qualified Community Solar Pilot

Aligning with Georgia Power's commitment to the communities it serves and recognizing barriers that may prevent income-qualified customers from accessing renewable energy, the Company is proposing a new Income-Qualified Community Solar Pilot that will provide income-qualified customers access to 5,000 Community Solar subscription blocks at discounted prices. The

[36] O.C.G.A. § 46-3-8(a).

Income-Qualified Community Solar Pilot will include subscription blocks for income-qualified customers to be supplied by existing capacity from Georgia Power's Community Solar facilities. The eligibility criteria for this pilot will be based on income qualification set at 200% of the then current federal annual poverty level.

Under Georgia Power's Income-Qualified Community Solar Pilot, the Company will seek corporate sponsorships to reduce the price for qualified customers through a buydown of the monthly subscription fee. Georgia Power has communicated with potential corporate sponsors and expects subscription blocks in the pilot to be sponsored and available for subscription by income-qualified customers. As proposed, a customer on the R rate would participate at a price of $6.99 per month for each block, a 75% discount to the full $27.99 price, as proposed. The Company will market the program through established relationships with community partners, including housing authorities and customer education and awareness organizations. To maintain availability of subscription blocks for new customers, the Company requests Commission approval to develop additional Community Solar facilities once the available capacity is 75% subscribed. Once the subscribed capacity target is achieved, Georgia Power will file with the Commission its plan to develop additional Community Solar facilities.

The Income-Qualified Community Solar Pilot will operate exactly like the existing Community Solar program, with customers receiving energy credits on their monthly electricity bill based on the production of program solar facilities. The credits will offset the $6.99 paid in monthly subscription fees by participating income-qualified customers. One hundred percent of the RECs produced by the community solar facilities will be retired on behalf of the donating corporate sponsors in an amount corresponding to the number of blocks sponsored. Costs for program administration, customer education, and awareness campaigns will be recovered from participating corporate sponsors in the form of an administration fee.

Behind the Meter (BTM) Customer-Sited Renewable Options

Customers interested in installing renewable generation on site have multiple program options to consider and Georgia Power will continue to engage with customers to ensure they have accurate program information. Currently, customers can participate in one of three Behind-the-Meter ("BTM") programs. Customers of any size and class that want to reduce their energy usage and plan to match their energy consumption with their BTM energy generation can participate in Georgia Power's Energy Offset Only ("EOO") program. Customers seeking to sell the excess energy, meaning the energy that is not consumed onsite and therefore put back onto the grid, can participate in one of the Company's buy-back programs. Customers with BTM generators larger than 250 kW will continue to have the option to sell renewable energy to Georgia Power as Qualifying Facilities ("QF"). Additionally, the Renewable Non-Renewable Resources ("RNR") tariff is a buy-back option for customers with solar photovoltaic, fuel cell, or wind turbine distributed generation facilities that are smaller than 250 kW for commercial and industrial customers or 10 kW for residential customers. Georgia Power will continue to encourage and support customers to understand their program options and the potential costs and savings associated with participating in one of the programs.

Georgia Power has seen a significant increase in interest and participation in its BTM programs since the 2019 IRP. Much of this growth is attributed to program and policy changes, most notably, a monthly netting calculation of the RNR tariff ("RNR-Monthly Netting"). This policy change, which introduced a monthly energy credit or "netting" for excess energy, was approved in the 2019 Rate Case as a pilot program with a participation cap of 5,000 customers. The RNR Monthly Netting pilot is still in the process of being implemented, as customer project applications for interconnection and participation are reviewed and approved. As of July 26, 2021, Georgia Power received enough applications to fully subscribe the pilot and all initial project applications that qualified for this program have currently been reviewed. As of December 31, 2021, 3,300 customer projects were online and receiving the compensation benefits of RNR Monthly Netting. Of the remaining program applicants, 700 applications are pending project installation and 1,000 projects are under development or pending completion.

As the Company continues to implement the RNR Monthly Netting program and manages the overall growth in all BTM programs, enhancements and improvements have been made to Georgia Power's processes. For example, since 2019 the Company has introduced the use of its PowerClerk platform for BTM Interconnection Applications. This tool provides an efficient method for customers and their contractors to apply for interconnection of a BTM generator and participation in available programs and helps ensure the safe and reliable integration of these new Distributed Energy Resources. This platform provides better project documentation, ensures program compliance, provides greater consistency in reviews, and improved information sharing internally and externally as customers' projects are reviewed, approved, and interconnected. The Company plans to introduce in the 2022 Rate Case an update to the Georgia Power Rules, Regulations and Rate Schedules for Electric Service a new requirement for all customers installing solar behind the meter pay a set application fee (amount to be determined) based on the size of the system being installed. This application fee requirement is consistent with many other utilities and will help offset costs and facilitate more expeditious project reviews for Customers.

While the Company is still in the process of evaluating the full rate impacts to both participating and non-participating customers from the RNR Monthly Netting pilot, Georgia Power has identified several immediate concerns that must be closely evaluated to ensure accuracy, fairness, safety, and reliability for customers as more distributed generation resources are put on the grid. The issues of greatest concern to Georgia Power include:

- the impact of cost shifting to non-participants
- the rapid infiltration of aggressive and uninformed solar marketers providing customers misinformation about programs and processes
- impacts on effectively operating the System with an increase of variable energy resources and unplanned generation
- installer and customer compliance with rules, regulations, and program requirements for interconnection of BTM generation

Based on the cost shifts and increases already identified in the monthly netting pilot, the Company does not support any expansion of monthly net metering. Georgia Power will continue to work with the Commission and its Staff to evaluate and report the impacts of the rapid growth in BTM renewable generation and the RNR Monthly Netting pilot. In the interim, the Company will continue to engage with customers to provide accurate information and safe interconnection of customer-sited generation, as well as encourage customers to participate in Georgia Power's remaining programs such as CCSP, EOO, RNR-Instantaneous Netting, or as a QF.

14.5. RENEWABLE COST BENEFIT (RCB) FRAMEWORK

An important principle underlying the growth of renewable energy at Georgia Power is to accurately calculate and apply appropriate costs and benefits created by the energy delivered by a renewable generator. The deployment of new renewable resources is expected to continue well into the future. To support and inform the Company's procurement decisions, as has been done for prior procurements and Company-owned project evaluations, the Company will continue to apply the RCB Framework for determining the costs and benefits of renewable resource additions.

Many of the core components of the RCB Framework remain consistent with prior iterations. These components include avoided energy costs, deferred generation capacity costs, avoided transmission losses, deferred transmission investment, and avoided distribution losses. For the 2022 IRP, the Company has improved this iteration of the RCB Framework to include industry-leading renewable integration assessments, as discussed in CHAPTER 5, examining the impacts of substantial renewable growth on the System. This assessment provides new insights into the challenges, opportunities, and solutions that enable significant renewable expansion. Notably, these assessments capture the interactions of renewables at high penetration levels with other System resources necessary to support reliable renewable integration. The Company is always seeking to improve its modeling and analytical capabilities to ensure it continues making decisions in the best interest of customers. This new renewable integration assessment is one of those improvements and represents a significant increase in the analytical sophistication that supports renewable expansion. Please see Technical Appendix Volume 2 for more information on the RCB Framework.

14.6. UPDATE ON 2019 AND PRIOR IRP INITIATIVES

The Company continues to implement successful, industry leading renewable initiatives as approved in previous IRPs, due in large part to the leadership of the Commission and the constructive collaboration with industry stakeholders. Georgia Power leverages experience gained from these programs to improve the design and effectiveness of new programs with each phase of development to deliver maximum benefit to all customers and stakeholders. Since 2019, Georgia Power has responded to more than 15,000 customer or market inquiries about the Company's renewable programs and procurements and facilitated the new participation of 5,377 customers in renewable programs. The sections below provide an update on the Company's completed and ongoing renewable solicitations and customer programs.

Utility Scale Procurement

As approved by the Commission in the 2019 IRP Order, the procurement of energy from 2,000 MW of utility scale renewable resources through two RFP solicitations remains in progress. Each solicitation sought proposals from all types of renewable resources sized greater than 3 MW and included options for renewable-coupled storage proposals. The first RFP issued in 2020 sought facilities with an in-service date in 2022 or 2023, and resulted in the procurement of energy from a 970 MW portfolio of five solar facilities located in Georgia via 30-year PPAs. The average energy price procured in this solicitation was 3.0¢/kWh. The second RFP is ongoing, with proposals due in Q1 2022, and seeks to procure energy from 1,030 MW of renewable resources with an in-service date in 2023 or 2024.

2020 DG RFP

As part of the 2019 IRP Order, the Commission approved the procurement of renewable energy from distributed generation facilities through the 2020 DG RFP, which sought to competitively procure energy from 160 MW of solar resources. The 2020 DG RFP sought to procure energy from solar facilities sized 1 kW up to and including 3 MW AC. Bid pricing for the 2020 DG RFP, which included the price for the solar output plus the project's interconnection cost, could not exceed the Company's long-term projected avoided cost. The 2020 DG RFP was challenged to completely fill the 160 MW target due to the high number of projects released because of high interconnection costs that caused the project to exceed the avoided cost threshold. Through the process, the Company self-identified several areas for improvement in its evaluation methodology and worked with stakeholders to improve the pro forma contracts and contracting process. As detailed in section 14.2, other learnings gained through the process have been leveraged to make proposed improvements to future DG procurements. Through December 31, 2021, Georgia Power has executed 20 PPA's for 52.95 MW of solar resources in the 2020 DG RFP. The majority of the facilities are expected to achieve mechanical completion in 2022.

DG REDI Customer-Sited II (REDI CS DG II) / Customer-Connected Solar Program (CCSP)

As approved in the 2019 IRP Order and subsequent Commission Orders, REDI CS DG II and CCSP each sought to fulfill a 25 MW portfolio of distributed generation solar resources (50 MW total). Eligible DG customer-sited resources can be sized between 1 kW and 3 MW AC and are required to be located either on, or adjacent to, an existing customer's premises. The application period for REDI CS DG II was open from December 1, 2020 until January 29, 2021, and resulted in 11.825 MW from 7 applicants. The projects are all currently undergoing more detailed analysis that includes evaluating the interconnection requirements before offering contracts. As previously described, the CCSP application period opened in July 2021 and will remain open until the Company fulfills the 25 MW portfolio. Georgia Power continues to work with customers across the state to evaluate the feasibility of program participation. To date, the Commission has certified a single, 1 MW AC project through the CCSP program.

Simple Solar Program

As discussed in greater detail in section 14.3 above, Georgia Power's Simple Solar program has been in place since the 2016 IRP. This program is designed to allow customers to support and foster the growth of solar energy by enabling Georgia Power to purchase and retire RECs generated from solar energy resources. The Simple Solar program has seen a significant increase in interest, and growth of 176% in kWh sold in 2021, driven by 10 new Large Volume participants. As of December 31, 2021, there are 1,871 customers enrolled in the program. In 2021, customers purchased 85,345,336 kWh of RECs. Georgia Power will continue employing a broad range of marketing efforts to create additional awareness and increased participation in 2022.

Community Solar Program

The Commission initially approved the development of the 3 MW Community Solar program in the 2016 IRP. Following the 17th VCM proceeding, this program was expanded to include an additional 5 MW, creating a total of 8 MW of program capacity. As of 2021, the Community Solar program is supplied by three solar facilities in operation near Athens, Augusta, and Savannah, Georgia. The Community Solar program is designed to provide residential customers an opportunity to purchase a monthly subscription of solar blocks, in exchange for a bill credit based on the actual output of the solar facility. Subscriptions are purchased in 1 kW block increments. Currently, 2,013 blocks out of the 8,000 blocks available are subscribed, representing 1,170 unique customers. In addition to the proposed Income-Qualified Community Solar Pilot, Georgia Power will continue employing a broad range of marketing efforts to create awareness and grow participation in the program.

Customer Renewable Supply Procurement (CRSP)

As part of the Company's 2019 IRP, Georgia Power was approved to provide 1,000 MW of additional renewable energy procured through the utility scale competitive procurements mentioned above for subscription by C&I customers. Georgia Power hosted its first NOI for the CRSP program in 2020, during which eligible customers indicated interest in the program. The first iteration of the CRSP program was well received, with eight Georgia Power customers subscribing to a total of 500 MW through the CRSP Program for terms of at least ten years in length. The 300 MW available to existing customers was fully subscribed, and 200 MW of the available 400 MW was subscribed for the New Load portion of the program. The CRSP program's second and final NOI period is now open to eligible customers and will close on July 30, 2022.

Behind the Meter Update

The Georgia market for customer-sited solar projects is robust and growing. As previously mentioned, much of this growth can be attributed to the RNR-Monthly Netting Pilot; however, Georgia Power has seen increased interest in other BTM solar programs as well. In 2019, Georgia Power received a maximum of 50 interconnection applications per month with most months averaging 36 project applications. BTM application volume continued to grow in 2020 to upwards of 240 project applications each month, with a peak of 786 new BTM project applications in one month in 2021. Currently, Georgia Power receives an average of approximately 15 new project applications per day. Accordingly, Georgia Power has added resources and streamlined processes to work with customers and installers to facilitate the interconnection of more than 3,219 new solar projects since 2019, including customers who choose to participate in EOO, either RNR program option, or as a QF. As approved in the 2019 IRP, and to maintain the safety and reliability of the System, the Company has also implemented a new requirement to execute interconnection agreements for all customers with Distributed Generation. These agreements, either standalone or as part of PPAs, allow Georgia Power to accurately account for all generation connected to its infrastructure and ensure safety and reliability of service to all customers. The Company has worked with an additional 1,100 customers that were participating in one of Georgia Power's BTM programs prior to 2019, to update their service agreement or facilitate an accurate interconnection agreement for their existing BTM installation.

Company-Owned Renewable Projects

The Company continues to develop Company-owned solar assets to benefit customers in accordance with Commission certification of projects that support the goals of military and other special public interest customers. Since the 2019 IRP, Georgia Power has achieved commercial operation of its 128 MW solar facility at Robins Air Force Base ("AFB"), 49.5 MW solar facility at Moody AFB, and 10.8 MW solar facility at Fort Valley State University. As mentioned previously, the Company also completed the 8 MW portfolio for the Community Solar program, which was distributed between three locations near Athens, Augusta, and Savannah.

Georgia Power successfully managed the development of these projects and maintained project costs below deemed certified amounts, all the while navigating numerous challenges, including supply chain and construction concerns related to the pandemic. Development and construction of these facilities required careful coordination with many stakeholders including the military and university customers, who each had unique requirements. The completion of these projects brings Georgia Power's Company-owned solar utility scale projects to 350.8 MW across twelve different projects, with the Robins AFB Solar project being the largest to date. Additionally, Company-owned solar assets are under development at Georgia College and State University. There remains 19 MW of approved but uncommitted Company-owned capacity, and the Company continues to evaluate the development of this capacity at viable locations in Georgia.

In the 2019 IRP, the Company received approval to develop 80 MW of Company-owned energy storage capacity. Updates on this initiative are discussed in the energy storage strategy found in CHAPTER 13.

14.7. UPDATE ON DEMONSTRATION PROJECTS UNDER DEVELOPMENT

The Company remains committed to research and development ("R&D") while assessing the overall market opportunities for deployment of new renewable resources. As such, the Company conducts meaningful demonstration projects that increase its understanding of changing renewable technologies and applications.

High Wind Study

The High Wind Study approved in the 2016 IRP allowed the Company to further study the potential for higher hub height wind resources in Georgia through the purchase, siting, and installation of wind measurement instrumentation that will monitor high elevation wind data at multiple locations. The High Wind Study was completed in 2019. Details on this demonstration project were provided to the Commission through regular, quarterly reports through project completion. The Company proposes to leverage these learnings to support its Tall Wind Demonstration project and future wind development.

Closed Ash Pond Solar

In the 2016 IRP, the Commission approved the development of up to 10 MW of solar generation at Company-owned coal-fired generating facilities. The scope includes evaluation of different technologies, including traditional and non-traditional racking systems. The output of the project(s) will be interconnected to the site's existing infrastructure and will serve Georgia Power customers. The project(s), pending Georgia EPD approval, will provide the Company with a hands-on, detailed understanding of the requirements to permit and build solar generation facilities on closed solid waste sites, remediated sites, and/or underdeveloped plant properties.

The Company plans for these projects to be located at closed ash ponds at Plant McDonough, Plant Hammond, and Plant McIntosh, with preliminary plans included as part of the ash pond closure permits, currently under review by the Georgia EPD. At the time of this filing, project expenditure was minimal as permitting is not yet complete. The Company will continue its efforts to obtain permits for these facilities and, with EPD regulatory approval, proceed with siting, infrastructure, and design plans for the project. Details on this demonstration project are provided to the Commission through regular, quarterly reports.

In addition, the Company deployed a 38 kW installation at Plant McDonough that began operation in early 2019. This pilot project is specifically testing ash pond closure cover systems that could substantially increase the closed ash pond acreage available for solar PV installations. The Company has actively monitored the performance of the ash pond closure cover system and is reviewing results for consideration in future solar generation development on ash ponds.

Right of Way Solar

Georgia Power, working closely with MZC Foundation (d/b/a "The Ray") and the Georgia Department of Transportation ("GDOT"), has developed an 800 kW AC fixed-tilt, solar generation facility located in the right-of-way at the intersection of Highway 27 and Interstate 85. This project is demonstrating the feasibility of a solar energy facility in the highway right-of-way. The project also includes an EPRI-sponsored Georgia Power Pollinator Habitat Area ("PHA") research effort to advance the understanding, use and management of certain groundcover solutions around and beneath installed solar arrays. These solutions have the potential to foster soil quality improvements, improving benefits to wildlife and pollinators, and lowering integrated plant maintenance costs. The levelized cost of energy for the right of way project is 2.5 times more than that of the Company's larger Company-owned facilities. The primary contributing factors were the smaller scaled facility, more costly site control, and reduced efficiency of construction in the right-of-way of an interstate highway. The facility achieved commercial operation on February 28, 2020, and the Company will monitor performance over a five-year period.

CHAPTER 15. TRANSMISSION

This IRP includes the Company's ten-year transmission plan, which identifies the transmission improvements needed to maintain a strong and reliable transmission system, based upon current planning assumptions. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia ITS summarizing studies, project lists, processes, data files, and other information as required by the amended Rules adopted by the Commission in Docket No. 25981.

15.1. TRANSMISSION PLANNING PRINCIPLES

The purpose of the transmission planning principles is to provide an overview of the standards and criteria that are used for transmission expansion and upgrade proposals. These principles are designed to help ensure the coordinated development of a reliable, efficient, and economical electric power system for the transmission of electricity for the long-term benefit of the transmission users. These principles also recognize that planning should be proactive to ensure timely system adjustments, upgrades, and expansions. The principles that apply to Georgia Power's transmission planning are as follows:

1. Identify and recommend projects that are consistent with the Guidelines for Planning the ITS and the Guidelines for Planning the Southern Company Electric Transmission System.
2. Identify and recommend projects that are consistent with the NERC Reliability Standards.
3. Minimize costs associated with the transmission system expansion, considering the impact on system reliability and system operations.
4. Identify projects with sufficient lead-time to provide for the timely construction of new transmission facilities.
5. Coordinate transmission system plans with the plans developed by Georgia Power's Power Delivery Planning groups.
6. Coordinate transmission system plans with all ITS Participants and other transmission owners to enhance reliability and minimize associated costs.
7. Coordinate future transmission plans with other Georgia Power departments, other ITS Participants, other SCS departments and the regions surrounding the Southeast in the project development and planning processes.
8. Maintain adequate interconnections with neighboring utilities.

9. Communicate with Georgia Power management to ensure proper awareness of the importance of adequate transmission improvements and system expansion.
10. Utilize existing resources (for example, reusing rights of way, increasing the capacity of existing facilities, implementing voltage conversions, and constructing double-circuit lines) and favoring substation projects and non-wire alternatives over new line construction where feasible.
11. Minimize transmission losses when cost effective.
12. Avoid the loss of life to transmission equipment from forced operation at higher loading levels.

These principles provide guidance to transmission planners and/or planning authorities that are called upon to explore existing issues and any future problems encountered in the transmission planning process.

15.2. TEN-YEAR TRANSMISSION PLAN

Georgia Power is a participant in the ITS, which consists of the physical equipment necessary to transmit power from the generating plants and interconnection points to the local area distribution load centers. The ITS consists of electric transmission facilities that are individually owned and maintained by the ITS Participants. Transmission Planning identifies investments required to maintain sufficient capacity in the ITS to reliably meet the power needs of the public. Justifications for these decisions are based on technical and economic evaluations of options that may be implemented to meet these needs. Under the ITS Agreements, the ITS Participants are responsible for meeting their full load requirements, including generation, and are responsible for making necessary transmission improvements to their facilities along with building new facilities to accommodate load growth, changes in network flows, system reliability, or system operations.

Transmission Planning-East ("TP-E") of SCS and Power Delivery Planning, Operations and Policy of Georgia Power are responsible for planning the transmission system for Georgia Power. TP-E develops a planning model of the transmission system for each year for ten years into the future. This planning model is used to identify transmission constraints and to evaluate alternative solutions to address those constraints.

All Transmission Planning information required by the Commission in Docket Nos. 25981 and 31081 is provided in Technical Appendix Volume 3.

15.3. FLEET TRANSITION PLAN

A key feature of the IRP is the ability to consider the impacts to the transmission system when making generating resource decisions. The Company routinely takes these considerations into account by completing evaluations separate from the standard ten-year transmission planning work. For the 2022 IRP, these transmission system evaluations considered various scenarios of unit retirements beyond those assumed in the ten-year transmission plan.[37] These assessments identified certain transmission system limitations that must be addressed to reliably accommodate future retirements. As discussed in CHAPTER 11, the Company's economic analysis indicates that now is the appropriate time either to retire, or prepare for the future retirement, of the majority of the Company's remaining coal units. To support retirements, the Company, along with the other ITS Participants, must initiate the transmission projects necessary to accommodate the combined retirement of Plant Wansley Units 1-2, Plant Bowen Units 1-2, and Plant Scherer Units 1-3. The list of projects necessary to accommodate this portfolio of retirements is included in the Selected Supporting Information section of Technical Appendix Volume 1. The Company will work with the ITS Participants to complete these projects, or other equivalent solutions, that ensure the transmission system is prepared for this retirement scenario.

The Company's transmission system assessments demonstrate that it is not feasible to retire Plant Bowen Units 3-4 by year-end 2028 to avoid ELG controls. In order to reduce long-term reliance on Plant Bowen Units 3-4, the Company, in coordination with the other ITS Participants, will implement the North Georgia Reliability and Resilience Action Plan described in CHAPTER 12. This plan will include additional study of the future retirement of Plant Bowen Units 3-4 as well as the addition of new generation and reactive sources in north Georgia. Additionally, the Company will continue to coordinate with other in-state utilities and ITS Participants to prepare for the possible addition of renewable resources in south Georgia.

[37] The retirements of Plant Wansley Units 1-2 and Plant Bowen Units 1-2 were the only assumed coal retirements in the 2021 ten-year transmission plan.

CHAPTER 16. WHOLESALE BLOCK CAPACITY

The Commission's July 30, 2008 Order in Docket No. 26550 requires Georgia Power to offer certain wholesale capacity blocks to the retail jurisdiction on then-current wholesale market terms (the "Wholesale Action Plan"). Previous wholesale capacity blocks have been offered under this arrangement and accepted or rejected by the Commission. As additional wholesale contracts expire, the Company evaluates when to offer wholesale capacity blocks to the retail jurisdiction.

Approximately 199 MW of wholesale block capacity from Plant Gaston Units 1-4, Plant Yates Units 6-7, Plant Scherer Unit 3, and various oil-fired generating units serve EnergyUnited Electric Membership Corporation ("EnergyUnited") and Flint Electric Membership Corporation ("Flint EMC") through contracts that expire within the procurement period of the 2022-2028 Capacity RFP, as shown in Table 10 below.

Table 10: Wholesale Block Capacity Expiring in 2022-2028

Wholesale Blocks	Units	Capacity (MW)	Date Available to Retail
Blocks 2-4 Converted Units Resource	Plant Gaston Units 1-4 Plant Yates Units 6&7	115.552	1/1/2024
Blocks 5&6	Plant Gaston, McManus, and Wilson oil-fired CTs	22.987	1/1/2025
Blocks 2-4 Coal Block Resource	Plant Scherer Unit 3	60.779	1/1/2026

Given Georgia Power's request to retire Plant Gaston Units 1-4 and Unit A, and Plant Scherer Unit 3 by December 31, 2028, the Company has excluded the wholesale block capacity associated with these units from its offer to the retail jurisdiction. For purposes of the Wholesale Action Plan, the Company requests that the Commission deem the Company's obligations as it pertains to Plant Gaston Units 1-4 and A and Plant Scherer Unit 3 satisfied, thereby releasing the Company from any further requirement to offer wholesale capacity from these units to the retail jurisdiction prior to any remarketing of that capacity. If the Commission approves a retirement date later than December 31, 2028, for either Plant Gaston Units 1-4 and Unit A, or Plant Scherer Unit 3, the Company reserves the right to offer the wholesale block capacity associated with such units to the retail jurisdiction at a later date. In this IRP, Georgia Power is offering approximately 88 MW of wholesale block capacity to the retail jurisdiction, as shown in Table 11. The capacity would become available to serve retail customers as each contract expires.

Table 11: Wholesale Block Capacity Offered to Retail

Wholesale Blocks	Units	Capacity (MW)	Date Available to Retail
Blocks 2-4 Converted Units Resource	Plant Yates Units 6&7	65.359	1/1/2024
Blocks 5&6	Plant McManus, and Wilson oil-fired CTs	22.715	1/1/2025

In prior wholesale capacity offers, the Commission has approved the application of a Market Differential Adjustment ("MDA") to meet the requirement that the transaction be offered at then-current wholesale market terms. The MDA represents the difference between the levelized market value and the levelized revenue requirement of the net asset over its assumed remaining life, expressed on a dollar per kilowatt-month basis. The Company's offer of the 88 MW of wholesale block capacity utilizes the same MDA construct as previous offers but also leverages data from the Company's recently completed 2022-2028 Capacity RFP to help determine the market value of the wholesale block capacity.

If the Commission accepts the Company's offer of approximately 88 MW of wholesale block capacity to the retail jurisdiction, the Company requests that the capacity also be certified in this 2022 IRP. Additional information on the offer is found in the Selected Supporting Information section of Technical Appendix Volume 1, and the formal certification application is included in ATTACHMENT J of the Main Document.

Beyond the procurement period for the 2022-2028 Capacity RFP, all remaining wholesale block capacity obligations are associated with Plant Scherer Unit 3. First, approximately 55 MW of wholesale block capacity serves Flint EMC through the end of 2029. A future offer of this capacity depends on the Commission's decision regarding Plant Scherer Unit 3 in this IRP. Second, approximately 79 MW of formerly wholesale block capacity serves retail customers until 2031. Such capacity from Plant Scherer Unit 3 was accepted into the retail jurisdiction for a term of fifteen years by Commission order on September 15, 2009. The order obligates the Commission to notify the Company on or before January 1, 2023 ("Additional Offer Request Date") if the Commission seeks an additional offer of this capacity beyond the original fifteen-year term. Furthermore, Georgia Power is required to make a good faith effort to notify the Commission of the expiration of the Additional Offer Request Date in a reasonable time prior to the Additional Offer Request Date being reached. With this paragraph, Georgia Power satisfies its notification obligation from the September 15, 2009 Order and understands that any additional offer will depend on the outcome of Plant Scherer Unit 3 in this IRP.

CHAPTER 17. CARBON & CLIMATE

Georgia Power's planning process has historically considered a wide range of factors that inform long-term decision making. This type of long-term strategic planning improves the development of a reliable, resilient, and cost-effective System that can respond to near-term economic conditions while focusing on the long-term needs of customers. This focus is paramount to the development of Georgia's critical infrastructure, which requires investment decisions that commonly span decades. Therefore, these decisions must anticipate and contemplate changes in market conditions and policies beyond today's current conditions. This consideration is especially true for climate issues, which are increasingly driving the decision-making of governmental entities. Considering the improving cost effectiveness of low and zero carbon resources, and evolving legislative and regulatory requirements, Georgia Power must plan strategically within its state regulatory framework to transition the generation fleet to reduce carbon emissions risk for the benefit of customers.

The IRP framework provides Georgia Power and the Commission with a constructive platform to address these issues, enabling them to consider the long-term implications of a carbon constrained future while addressing this risk at the local level. The Company's 2022 IRP remains consistent with past practice while also acknowledging the evolving energy landscape and the growing emphasis on climate, through thoughtful scenario planning, fleet transition strategies, and visibility into emerging technologies.

Georgia Power's approach to a low-carbon future seeks to maximize optionality and operational flexibility to best serve customers. Under the state-regulated, vertically integrated utility model, Georgia Power relies on the IRP framework to specifically evaluate these potential future conditions and associated options with the Commission. This provides a holistic view into the reliability and resiliency needs of customers, with direct visibility into numerous elements of, and planning for, the electricity supply chain such as generation, transmission, and distribution. To build on this approach and plan for the future, further consideration of a low-carbon future can utilize a net-zero approach, whereby any direct GHG emissions produced are counterbalanced by an equal amount of GHG removed through "negative carbon solutions," which may include various forms of carbon capture or carbon offset.

To benefit customers through competitive costs and reduced carbon emissions risk, Georgia Power's climate approach is consistent with the three pillars set forth in Southern Company's

2050 net-zero goal[38] of pursuing a diverse energy resource portfolio, developing new technologies to lower GHG emissions, and constructively engaging with stakeholders. Georgia Power recognizes that the feasibility of continued progress toward a low-carbon future, including a net-zero future, is highly dependent on the continued use of natural gas and continued technology advancements that will facilitate a reliable and economic low carbon electricity supply.

This chapter explains Georgia Power's climate approach, the progress and path forward using resource-planning drivers, and potential future areas of evaluation or technology development needed to continue to make cost-effective decisions for customers.

Georgia Power's Climate Approach & Drivers

As a direct result of working with the Commission, Georgia Power has demonstrated how progress towards decarbonization of electricity generation can be achieved through a state regulatory framework, resulting in more than 60% reduction in Scope 1[39] GHG emissions from direct Company operations since 2007[40]. The Company is responsibly transitioning its coal generation fleet to more cost-effective natural gas and zero-carbon resources to continue to serve customers with clean, safe, reliable, and affordable energy. Continued prioritization of a flexible transition that aligns with the timing and availability of technology advancements will be critical.

Georgia Power recognizes the importance of this climate approach being driven by optimizing costs and mitigating risks to customers. Focusing on keeping rates competitive remains critically important to serving Georgia Power's customers. As such, Georgia Power's climate approach must allow for economic decisions that benefit all customers through the IRP process. As technology advances, the Company's proactive planning will help ensure customers realize the

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[38] In April 2018, Southern Company issued the *Planning for a low-carbon future* report. This report established goals to reduce carbon emissions. In September 2020, Southern Company provided an addendum to that report with additional information on progress and plans to decarbonize the Southern Company System. This addendum, entitled Implementation and action toward net zero, included an update of the long-term goal to net zero emissions by 2050.

[39] The World Resources Institute defines Scope 1 as "direct GHG emissions from sources that are owned or controlled by the company." Retrieved from https://www.wri.org/sustainability-wri/dashboard/methodology.

[40] The 2020 decrease in emissions is due to a variety of factors, including changes in fuel mix of decreased coal and increased renewable and nuclear generation. In 2020, the combination of the COVID-19 pandemic and relatively mild weather significantly reduced demand. As these factors fluctuate, coal generation and GHG emissions may vary in future years.

benefits of zero-carbon resources, negative carbon solutions, and enhanced energy efficiency initiatives as they become increasingly cost effective.

Finally, Georgia Power is proactively planning to mitigate future risks and challenges that could impact customer costs. Carbon risks include the uncertainty around federal regulatory and policy changes addressing the carbon footprint, not only of the utility industry, but also of customers, as detailed in Georgia Power's 2022 ECS document located in Technical Appendix Volume 2. In addition, potential challenges to future decarbonization for Georgia Power include the uncertainties around complex operational impacts of new technologies, unknown geologic feasibility of CCS in the state of Georgia, and potential infrastructure timeline restrictions associated with pipelines and grid transmission systems that could impact the transition of the generation mix to low-carbon resources. Taking proactive steps to incorporate evaluation of, and planning for, these risks and challenges is critical to help mitigate and shield customers from future costs.

Georgia Power's Path and Progress

Georgia Power's outstanding track record for maintaining high reliability and low cost as the Company's generation fleet evolves is heavily rooted in the state-regulated framework, which has successfully brought about numerous cost-effective, reliable, and low-carbon resource decisions. Georgia Power customers have benefitted from these decisions by having a diverse resource mix to mitigate risks and optimize costs. Through this process, the Commission has approved, and the Company has achieved or plans to achieve:

- Over 3,500 GWh of energy efficiency (2011-2021)
- economic retirements of over 4,500 MW of coal, oil, and gas capacity
- the conversion of over 1,200 MW of coal resources to natural gas
- the addition of approximately 5,000 MW of solar and wind resources
- the addition of over 390 MW of biomass and landfill gas resources
- the addition of over 3,000 MW of nuclear resources, including the future Plant Vogtle Units 3-4
- the reliable operation of approximately 1,100 MW of hydroelectric generation resources
- the addition of 80 MW of battery storage

For over a decade, the Company's scenario planning process has included evaluations of higher and lower natural gas prices, along with variations in loads and carbon pricing, among other key factors. For the 2022 IRP, Georgia Power has expanded its economic evaluations associated with carbon risk. The scenarios and sensitivities address the potential for technology advancements, numerous carbon pricing levels, electrification, and clean portfolio standards. The evaluation of these multiple scenarios is discussed in CHAPTER 7.

In the 2022 IRP, the Company has identified economic hurdles associated with the long-term operation of its remaining coal units. These challenges, as detailed in CHAPTER 11, require the Company to begin formalizing a planned retirement schedule for these units while simultaneously identifying reliable and cost-effective replacement resources. Additionally, the 2022 IRP provides a pathway to add 6,000 MW of new renewable resources by 2035, supported by energy storage resource additions. This portfolio will provide optionality and risk mitigation through a cost-competitive, low-carbon, and reliable resource mix that will benefit all customers, while also providing clean energy options to meet the needs of customers. The proposed portfolio positions the Company to address risks and challenges of potential future national climate policy.

Potential Net-Zero Technology Evaluations

In addition to the resource portfolio proposed in the 2022 IRP, the Company is engaged in a proactive strategy to remain well-positioned to address the evolving climate landscape. The continued transition of the Company's generation mix from coal to natural gas and other low- or zero-carbon resources is estimated to reduce Scope 1 GHG emissions from Georgia Power operations by over 75% compared to 2007 levels by 2030, considering full implementation of the proposed long-term 2022 IRP resource portfolio. This reduction of GHG emissions provides protection against potential future emission compliance costs.

To continue mitigating impacts to customers, sustained progress toward a lower carbon future will require intentional planning to identify technically and economically feasible technologies for Georgia Power to both reduce direct emissions and potentially offset emissions through negative carbon solutions. Zero-carbon resources under evaluation by the Company include hydrogen, wind energy, and long-duration battery storage, and adding these resources as costs decline and technology improves will be critical to maximizing the benefits for Georgia Power customers.

Negative carbon solutions are an important component of a net-zero carbon approach and counterbalance direct GHG emissions from Company operations through either the actual capture and storage of GHG or the application of carbon offset credits created by qualifying GHG reduction projects. While many of these negative carbon solutions are still evolving or in development across the industry and the country, Georgia Power faces some unique challenges for carbon capture and storage in the state of Georgia. Unlike some neighboring states with extensive oil and gas exploration and development, Georgia lacks the detailed geological information needed to prepare for CCS deployment. To minimize risks to customers in a net-zero future, carbon capture technology and viable locations for storage will likely be necessary for continued fossil fuel operations. CCS could potentially be applied as an add-on environmental control to a generating unit to remove GHG emissions at their source or could be used to remove GHG from ambient air, known as direct air capture ("DAC"). Due to the lack of geologic feasibility studies in the state of Georgia, Georgia Power began partnering in 2021 with Southern Company to evaluate the technical and economic viability of CCS in potential locations in Georgia.

DAC technologies, which could provide flexibility in the location of carbon capture, are being researched at the National Carbon Capture Center, which is managed and operated by Southern Company. Southern Company is actively scouting technological advancements in DAC and exploring pilot projects in collaboration with the DOE, universities, and DAC technology developers.

Customer Decarbonization Solutions

In addition to achieving significant emissions reductions from Company operations, Georgia Power has a proven track record for developing programs, including renewable energy, energy efficiency, and electrification, that support customer decarbonization goals. A growing number of new and existing customers are seeking clean energy solutions, with some focused on a zero-carbon energy supply. Many potential new commercial and industrial customers are considering locations for siting new facilities with consideration for an electricity provider that can offer options to help them meet their sustainability goals. Thus, a lower-carbon mix of energy resources that benefits all customers is also becoming increasingly important for the community and economic development of the state of Georgia.

When addressing carbon risk, Georgia Power will continue to consider elements that allow it to best serve customers by preparing for future challenges, leveraging existing resources, and growing flexibility in serving its customers. The 2022 IRP will position the Company well to continue to provide clean, safe, reliable, and affordable electricity for customers.

CHAPTER 18. RESILIENCE NEEDS

As society develops and becomes increasingly reliant on electric energy, the Company remains committed to maintaining a robust and resilient electric system that is capable of reliably delivering electric energy, even in the face of unexpected events such as natural and man-initiated disruptions. The Company generally agrees with the definition of resilience proposed by FERC which is “the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.”[41] The Company has an excellent track record managing and planning for reliability risk through its reserve margin process, transmission planning analysis, and similar reliability studies, while also demonstrating substantial commitment to infrastructure protection initiatives. As the Company continues to evolve its generation fleet toward a larger share of resources that either have no on-site fuel storage or are intermittent, there is increased fuel transportation risk associated with providing reliable electric service to customers. Additionally, the threat of high-impact events that have low probability, such as physical- and cyber-attacks, continues to grow. Therefore, as customers and the economy become increasingly dependent on electricity, it is even more important that the Company remain vigilant in its commitment to maintaining a robust and resilient electric system that can deliver clean, safe, reliable, and affordable energy to its customers. Many items in this IRP reflect the Company’s focus on reliability and resiliency.

The Company regularly evaluates generation risks such as outage risk, weather risk, and even fuel transportation risk as demonstrated in its Reserve Margin Study. This study does not focus on other potential long duration, high impact events. Rather, the objective of the Company’s overall planning process is to maintain reliable and affordable service across a range of possible futures that represent anticipated recurrence of past variations in weather, loads, etc. As future coal retirements occur, the Company will need to balance the economic benefits of retirement and the ability to take advantage of low-cost gas resources against the potential risk associated with gas fuel supply. Striking the right balance requires consideration of numerous options such as energy storage, inactive reserve, and fuel storage, which may preserve on-site fuel. The Company is addressing these resilience considerations through its North Georgia Reliability and Resilience Action plan. This plan preserves on-site fuel supply at Plant Bowen Units 3-4, while also building out the appropriate transmission infrastructure to support targeted renewable

[41] 162 FERC ¶61,012 at P23 (2018).

procurements. This combination of on-site fuel storage, renewable growth, and transmission system investments will preserve reliability and resilience in north Georgia.

18.1. BLACKSTART RESOURCES

For System emergency restoration purposes, certain generating units, designated as "Blackstart Resources," provide the ability to start without power from the grid so that they can begin restoring the transmission system from a blackout condition. A Blackstart Resource is defined by the NERC Reliability Standards[42] as "a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan."[43] A review and assessment of Blackstart Resources and the Company's Transmission Operator System restoration plan is conducted in conjunction with unit retirement studies. System restoration plans undergo an annual review, and updates to the plans may also take place outside of the annual review as needed.

The location and type of generation resources in the Company's fleet has changed significantly in recent IRPs as well as this current IRP, including the retirement of generating units previously incorporated in System restoration plans. In addition, the mix of generation in the daily fleet dispatch continues to evolve as increasing amounts of solar displace baseload generation. A comprehensive review of the Company's blackstart plan is warranted to assess the effectiveness of existing Blackstart Resources to efficiently restore the System. To be clear, recent assessments indicate that the Company's current plan fully meets the NERC Reliability Standards and can restore the grid in a blackstart situation. However, timely restoration would be a primary concern during a blackout event, and a comprehensive review would help quantify the time required to completely restore the grid under various scenarios, the efficiency of the current plan, and the locations where additional Blackstart Resources could reduce restoration times. As such, the Company proposes to engage EPRI to study the Company's current blackstart plan to determine potential improvements to the restoration time if additional Blackstart Resources were strategically added to the fleet. In addition, EPRI proposes to study the effectiveness of using

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[42] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx.
[43] Glossary of Terms Used in NERC Reliability Standards - https://www.nerc.com/files/glossary_of_terms.pdf.

battery technology as a Blackstart Resource. The cost for the EPRI study is estimated at $130,000, and the Company plans to undertake this work with EPRI as part of the approval of this IRP.

CHAPTER 19. CONCLUSION & ACTION PLAN

The 2022 IRP reflects the Company's plan to continue to provide clean, safe, reliable, and affordable energy to customers and the communities it serves by leveraging a diverse mix of energy resources, a comprehensive environmental compliance strategy, enhanced reliability and resilience, and state-of-the art technology. This IRP details the Company's plan to support future reliability and resiliency through continued seasonal planning, establishment of a comprehensive fleet transition strategy, and innovative renewable integration assessments with associated energy storage deployment strategies, while making appropriate reliability-based investments in the transmission system. The Company also proposes innovative customer programs, the modification and continuation of demand-side programs, investment in hydro-powered resources, and a plan to retire certain coal units to mitigate the risk of future environmental costs on customers. In addition to the items specifically contained in the conclusion of CHAPTER 1, pending Commission approval where necessary, the Company plans to take the following actions:

- Build, operate, and maintain the necessary generation and power delivery infrastructure to ensure adequate reliability and serve the needs of Georgia.
- Work with the ITS Participants to develop a strategic portfolio of projects to address the long-term transmission planning and operational needs of north Georgia beyond the future retirement of Plant Bowen Units 3-4.
- Initiate execution of the ECS, as approved by the Commission, to comply with government-imposed environmental requirements.
- Continue to provide and assess opportunities to integrate cost-effective resources.
- Continue to pursue the implementation and integration of a DERMS system and related technologies that will provide enhanced System monitoring, assessment, and operational capabilities.
- Identify opportunities to pilot and demonstrate the iron-air long-duration storage technology.
- Complete the locational value study described in ATTACHMENT H.
- Engage EPRI to study the Company's blackstart plan.
- Utilize the methodologies outlined in the RCB Framework for resource evaluations.
- Implement a hosting capacity tool.
- Pursue enhanced visibility for existing DERs located on the distribution system (ahead of or behind the meter).

ATTACHMENT A. PLANNED AND COMMITTED RESOURCES

Attachment A lists the Company's planned and committed resources included in the 2022 IRP. The Company's capacity needs are listed in CHAPTER 10. When determining capacity needs, the Company considers the summer and winter capacity contribution, including the appropriate capacity equivalence adjustments. For detailed seasonal values and capacity equivalence information, please see Technical Appendix Volume 1.

A.1. COMPANY-OWNED CONVENTIONAL RESOURCES

Fuel Type	Resource Name	2022 Summer Retail Capacity (MW)[A]	2022 Winter Retail Capacity (MW)[A]	Georgia Power Ownership	In-Service Date	Assumed Unavailability[B]
Nuclear	HATCH 1	438.9	438.9	50.10%	12/1975	08/2034
Nuclear	HATCH 2	442.4	442.4	50.10%	09/1979	06/2038
Nuclear	VOGTLE 1	538.6	538.6	50.70%	05/1987	01/2047
Nuclear	VOGTLE 2	539.5	539.5	50.70%	05/1989	02/2049
Nuclear	VOGTLE 3[44]	509.1	509.1	45.70%	09/2022	08/2082
Nuclear	VOGTLE 4[45]	509.1	509.1	45.70%	06/2023	05/2083
Coal	BOWEN 1	714	714	100.00%	10/1971	12/2027
Coal	BOWEN 2	718	718	100.00%	09/1972	12/2027
Coal	BOWEN 3	883	883	100.00%	12/1974	12/2035
Coal	BOWEN 4	885	885	100.00%	11/1975	12/2035
Coal	SCHERER 1	72.2	72.2	8.40%	03/1982	12/2028
Coal	SCHERER 2	72.2	72.2	8.40%	02/1984	12/2028
Coal	SCHERER 3	503.7	503.7	75.00%	01/1987	12/2028
Coal	WANSLEY 1	466.5	466.5	53.50%	12/1976	08/2022
Coal	WANSLEY 2	466.5	466.5	53.50%	04/1978	08/2022
Gas	MCDONOUGH 4	835	913	100.00%	01/2012	12/2057
Gas	MCDONOUGH 5	825	902	100.00%	04/2012	12/2057
Gas	MCDONOUGH 6	811	894	100.00%	10/2012	12/2057
Gas	MCINTOSH 10	658.6	680.1	100.00%	06/2005	12/2050
Gas	MCINTOSH 11	657.1	679.6	100.00%	06/2005	12/2050
Gas	GASTON 1 GAS	127	127	50.00%	05/1960	12/2028
Gas	GASTON 2 GAS	128	128	50.00%	07/1960	12/2028

[44] The Company's expansion planning analysis assumed Plant Vogtle Units 3-4 in-service dates of July 1, 2022 and April 1, 2023, respectively. As communicated by the Company in the 25th VCM, the Company's target in-service dates for Plant Vogtle Units 3-4 were extended to September 2022 and June 2023, respectively.

[45] Please see footnote 5244.

Gas	GASTON 3 GAS	102	102	50.00%	06/1961	12/2028
Gas	GASTON 4 GAS	102.6	102.6	50.00%	06/1962	12/2028
Gas	YATES 6 GAS	322.7	322.7	100.00%	07/1974	12/2034
Gas	YATES 7 GAS	325.7	325.7	100.00%	04/1974	12/2034
Oil	BOULEVARD 1	14	18.6	100.00%	09/1970	08/2022
Oil	GASTON A	7.7	9.7	50.00%	06/1970	12/2028
Gas	MCDONOUGH 3A	-	31.4	100.00%	05/1971	None
Gas	MCDONOUGH 3B	-	31.4	100.00%	05/1971	None
Gas	MCINTOSH 1	82.2	94.5	100.00%	05/1995	12/2040
Gas	MCINTOSH 2	82.2	94.5	100.00%	04/1995	12/2040
Gas	MCINTOSH 3	82.2	94.5	100.00%	06/1994	None
Gas	MCINTOSH 4	82.2	94.5	100.00%	05/1994	12/2039
Gas	MCINTOSH 5	82.2	94.5	100.00%	05/1994	12/2039
Gas	MCINTOSH 6	82.2	94.5	100.00%	05/1994	12/2039
Gas	MCINTOSH 7	82.2	94.5	100.00%	04/1994	None
Gas	MCINTOSH 8	82.2	94.5	100.00%	02/1994	12/2039
Oil	MCMANUS 3A	44.4	55.4	100.00%	01/1972	01/2030
Oil	MCMANUS 3B	44.4	55.4	100.00%	01/1972	None
Oil	MCMANUS 3C	44.4	55.4	100.00%	01/1972	None
Oil	MCMANUS 4A	44.4	55.4	100.00%	12/1972	01/2030
Oil	MCMANUS 4B	44.4	55.4	100.00%	12/1972	01/2030
Oil	MCMANUS 4C	44.4	55.4	100.00%	12/1972	01/2030
Oil	MCMANUS 4D	44.4	55.4	100.00%	12/1972	01/2030
Oil	MCMANUS 4E	44.4	55.4	100.00%	12/1972	01/2030
Oil	MCMANUS 4F	44.4	55.4	100.00%	12/1972	01/2030
Oil	MCMANUS DIESEL	-	-	100.00%	01/1964	01/2030
Oil	WANSLEY 5A	-	32.1	53.50%	11/1980	08/2022
Gas	WARNER ROBINS 1	80	93	100.00%	05/1995	None
Gas	WARNER ROBINS 2	80	93	100.00%	05/1995	None
Oil	WILSON 1A	39.5	52.5	None	12/1972	None
Oil	WILSON 1B	54	65.0	None	12/1972	None
Oil	WILSON 1C	47.2	59.2	None	12/1972	None
Oil	WILSON 1D	39.5	54.5	None	02/1973	None
Oil	WILSON 1E	52.1	59.1	None	04/1973	None
Oil	WILSON 1F	52.1	63.1	None	04/1973	None
Oil	WILSON DIESEL	-	-	None	01/1972	None
4-hr BESS	MOSSY BRANCH	65.0	65.0	100.00%	09/2023	12/2043

A.2. COMPANY-OWNED HYDROELECTRIC RESOURCES

Fuel Type	Resource Name	2022 Summer Retail Capacity (MW)[A]	2022 Winter Retail Capacity (MW)[A]	Georgia Power Ownership	In-Service Date	Assumed Unavailability[B]
Hydro	ROCKY MTN 1-3 PS	190.1	190.1	25.4%	1995	None
Hydro	WALLACE DAM 1-2, 5-6 PS	213.1	213.2	100%	1980	None
Hydro	BARTLETTS FERRY 1-4	71	72.2	100%	1926-1951	None
Hydro	BARTLETTS FERRY 5-6	117.9	120	100%	1985	None
Hydro	BURTON 1-2	9.5	8.7	100%	1927	None
Hydro	FLINT RIVER 1-3	6.4	5.7	100%	1921-1925	None
Hydro	GOAT ROCK 3-8	33.7	34.4	100%	1912-1956	None
Hydro	LLOYD SHOALS 1-6	22.5	22.5	100%	1911-1917	None
Hydro	MORGAN FALLS 1-7	10.7	11.4	100%	1904	None
Hydro	NACOOCHEE 1-2	6.0	6.0	100%	1926	None
Hydro	NORTH HIGHLANDS 1-4	34.4	34.7	100%	1963	None
Hydro	OLIVER 1-4	59.1	58.2	100%	1959	None
Hydro	SINCLAIR 1-2	43.8	43.9	100%	1953	None
Hydro	TALLULAH 1-6	72.9	72.9	100%	1913-1920	None
Hydro	TERRORA 1-2	16.6	16.6	100%	1925	None
Hydro	TUGALO 1-4	52.3	52.4	100%	1923	None
Hydro	WALLACE DAM 3-4	114.8	114.9	100%	1980	None
Hydro	YONAH	28.5	28.6	100%	1925	None

A.3. COMPANY-OWNED RENEWABLE RESOURCES

Fuel Type	Resource Name	2022 Nameplate Capacity (MW)[C]	Georgia Power Ownership	In-Service Date	Assumed Unavailability [B]
Solar	COMER COMMUNITY SOLAR	2.2	100%	1/5/2018	12/31/2053
Solar	GUYTON COMMUNITY SOLAR	3.6	100%	7/25/2019	12/31/2054
Solar	WAYNESBORO COMMUNITY SOLAR	2.4	100%	6/28/2019	12/31/2054
Solar	FORT BENNING	30.0	100%	12/31/2015	12/31/2050
Solar	FORT GORDON	30.0	100%	10/4/2016	12/31/2051
Solar	FORT STEWART	30.0	100%	10/4/2016	12/31/2051
Solar	KINGS BAY	30.2	100%	12/1/2016	12/31/2051
Solar	MCLB	31.2	100%	2/16/2018	12/31/2053
Solar	FALCONS	1.0	100%	10/16/2017	12/31/2052
Solar	UGA SOLAR	1.0	100%	2/1/2016	12/31/2051
Solar	FORT VALLEY STATE UNIVERSITY	10.8	100%	11/30/2021	12/31/2056
Solar	GEORGIA COLLEGE & STATE UNIVERSITY	3.5	100%	12/31/2022	12/31/2057
Solar	MOODY AFB	49.5	100%	6/23/2020	12/31/2055
Solar	ROBINS AFB	128.0	100%	4/15/2021	12/31/2056
Solar	RIGHT OF WAY SOLAR	0.8	100%	2/28/2020	12/31/2055

A.4. PURCHASED CONVENTIONAL RESOURCES

Fuel Type	Resource Name	2022 Summer Retail Capacity (MW)[A]	2022 Winter Retail Capacity (MW)[A]	PPA Start Date	PPA Term Length	PPA End Date
Gas	ADDISON 1 (WEST GA)	148.5	177	1/1/2015	15	5/31/2030
Gas	ADDISON 3 (WEST GA)	148.5	175	1/1/2015	15	5/31/2030
Gas	DAHLBERG 1, 3, 5	228	255.9	1/1/2028	10	12/31/2037
Gas	DAHLBERG 2	74.0	89	6/1/2010	15	5/31/2025
Gas	DAHLBERG 2 & 6	152	171.3	6/1/2025	10	5/31/2035
Gas	DAHLBERG 4	73.5	89	1/1/2015	15	5/31/2030
Gas	DAHLBERG 6	74.9	89	6/1/2010	15	5/31/2025
Gas	DAHLBERG 8	74.0	89	6/1/2010	15	5/31/2025
Gas	DAHLBERG 8-10	228	258	6/1/2025	10	5/31/2035
Gas	DAHLBERG 10	75.2	89	6/1/2010	15	5/31/2025
Gas	EXELON HEARD 1	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 2	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 3	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 4	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 5	157.5	157.5	6/1/2010	20	5/31/2030
Gas	EXELON HEARD 6	157.5	157.5	6/1/2010	20	5/31/2030
Gas	HARRIS 1	640.6	667.7	6/1/2016	14	5/31/2030
Gas	HARRIS 2	660.4	689.5	12/1/2024	10	11/30/2034
Gas	MID-GEORGIA COGEN	300.0	300	6/1/1998	30	5/31/2028
Gas	MONROE POWER	309.4	309.4	6/1/2009	15	5/31/2024
Gas	MONROE 1 & 2	309	360	12/1/2024	15	11/30/2039
Gas	WALTON COUNTY	465.2	465.2	6/1/2009	15	5/31/2024
Gas	WANSLEY 7	597.9	621.7	12/1/2024	10	11/30/2034
Gas	WASHINGTON COUNTY	312.8	312.8	6/1/2009	15	5/31/2024

A.5. PURCHASED RENEWABLE RESOURCES

Fuel Type	Resource Name	Nominal Capability (MW)[C]	PPA Start Date	PPA Term Length	PPA End Date	# of Projects
Biomass	2019 IRP BIOMASS[46]	60	6/1/2024	20	6/1/2044	1
Biomass	ALBANY RENEWABLE ENERGY	49.5	6/1/2017	20	5/31/2037	1
Biomass	GEORGIA RENEWABLE POWER FRANKLIN LLC	58	12/14/2019	27	5/31/2047	1
Biomass	GEORGIA RENEWABLE POWER MADISON	58	12/14/2019	27	5/31/2047	1
Biomass	GREEN POWER SOLUTIONS	29	6/1/2015	20	5/31/2035	1
Biomass	INTERNATIONAL PAPER - FLINT RIVER	24.8	6/1/2015	22	5/31/2037	1
Biomass	INTERNATIONAL PAPER - PORT WENTWORTH	27.7	4/13/2017	20	5/31/2037	1
Biomass	PIEDMONT GREEN POWER	55	10/1/2012	20	9/30/2032	1
LFG	COCA-COLA	6.3	12/1/2015	20	11/30/2035	1
LFG	CONYERS RENEWABLE ENERGY	3.1	4/25/2018	19	5/31/2037	1
LFG	MAS GEORGIA LFG - OAK GROVE	6.2	12/1/2016	20	11/30/2036	1
LFG	MAS GEORGIA LFG - PINE RIDGE	6.3	6/1/2016	20	5/31/2036	1
LFG	MAS GEORGIA LFG - RICHLAND CREEK	10.4	12/1/2016	20	11/30/2036	1
LFG	SUPERIOR - WASTE MANAGEMENT	6	2/8/2012	20	5/31/2037	1
Wind	BLUE CANYON	250	1/1/2016	20	12/31/2035	2
Solar	ASI CLASSIC 210 MW - DG S1320	0.8	5/1/2013	20	4/30/2033	10
Solar	ASI CLASSIC 210 MW - DG S1420	9.3	5/1/2014	20	4/30/2034	25
Solar	ASI CLASSIC 210 MW - DG S1520	28.5	5/1/2015	20	4/30/2035	108
Solar	ASI CLASSIC 210 MW - DG S1620	2.4	5/1/2016	20	4/30/2036	5
Solar	ASI CLASSIC 210 MW - DG W1420	17.1	1/1/2014	20	12/31/2033	50
Solar	ASI CLASSIC 210 MW - DG W1520	18.6	1/1/2015	20	12/31/2034	70
Solar	ASI CLASSIC 210 MW - DG W1620	1.4	1/1/2016	20	12/31/2035	7

[46] Through the RFP process, overseen by the Commission Staff and the IE, Georgia Power was unable to identify suitable biomass capacity with acceptable terms amongst the bids submitted into the 60 MW biomass solicitation at the time of filing this 2022 IRP. The Company's modeling analysis assumed the addition of this biomass capacity. This assumption will be updated as additional information is acquired during future budget cycles.

Solar	ASI CLASSIC 210 MW - US 1: DUBLIN SOLAR CENTER	4.1	4/23/2015	20	4/22/2035	1
Solar	ASI CLASSIC 210 MW - US 1: RICHLAND SOLAR CENTER	20.0	12/14/2015	20	12/13/2035	1
Solar	ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	16.0	12/16/2016	20	12/15/2036	1
Solar	ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM	20.0	2/12/2016	20	2/11/2036	1
Solar	ASI CLASSIC 210 MW - US 2: DECATUR COUNTY SOLAR	18.9	1/1/2016	20	12/31/2035	1
Solar	ASI CLASSIC 210 MW - US 2: HECATE ENERGY	20.0	11/14/2016	20	11/13/2036	1
Solar	ASI CLASSIC 210 MW - US 2: SOLAR GLYNN	17.7	12/1/2016	20	11/30/2036	1
Solar	ASI PRIME 525 MW - DG S1625	0.2	5/1/2016	25	4/30/2041	3
Solar	ASI PRIME 525 MW - DG S1635	0.3	5/1/2016	35	4/30/2051	6
Solar	ASI PRIME 525 MW - DG S1725	4.0	5/1/2017	25	4/30/2042	5
Solar	ASI PRIME 525 MW - DG S1730	6.1	5/1/2017	30	4/30/2047	6
Solar	ASI PRIME 525 MW - DG S1735	7.0	5/1/2017	35	4/30/2052	16
Solar	ASI PRIME 525 MW - DG S1815	0.2	5/1/2018	15	4/30/2033	3
Solar	ASI PRIME 525 MW - DG S1820	0.0	5/1/2018	20	4/30/2038	2
Solar	ASI PRIME 525 MW - DG S1835	0.1	5/1/2018	35	4/30/2053	3
Solar	ASI PRIME 525 MW - DG W1725	13.2	1/1/2017	25	12/31/2041	32
Solar	ASI PRIME 525 MW - DG W1730	6.1	1/1/2017	30	12/31/2046	16
Solar	ASI PRIME 525 MW - DG W1735	1.9	1/1/2017	35	12/31/2051	10
Solar	ASI PRIME 525 MW - DG W1815	0.6	1/1/2018	15	12/31/2032	15
Solar	ASI PRIME 525 MW - DG W1820	0.4	1/1/2018	20	12/31/2037	10
Solar	ASI PRIME 525 MW - DG W1825	9.2	1/1/2018	25	12/31/2042	13
Solar	ASI PRIME 525 MW - DG W1830	22.7	1/1/2018	30	12/31/2047	21
Solar	ASI PRIME 525 MW - DG W1835	6.3	1/1/2018	35	12/31/2052	27
Solar	ASI PRIME 525 MW - US 1: BUTLER SOLAR	100.0	12/13/2016	30	12/12/2046	1
Solar	ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR	79.9	1/1/2016	25	12/31/2040	1
Solar	ASI PRIME 525 MW - US 1: PAWPAW SOLAR	30.0	3/11/2016	30	3/10/2046	1
Solar	ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	51.0	1/1/2017	30	12/31/2046	1
Solar	ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	76.5	1/1/2017	30	12/31/2046	1
Solar	ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	101.3	1/1/2017	30	12/31/2046	1

Solar	AXIUM US SOLAR HOLDINGS (SD&D)	1.0	6/1/2012	15	5/31/2027	1
Solar	LSS 50 MW - HSH PEMBROOKE	1.0	6/3/2015	20	6/2/2035	1
Solar	LSS 50 MW - SIMON SOLAR FARM	30.0	6/1/2015	20	5/31/2035	1
Solar	LSS 50 MW - SOLAR D&D CAMILLA	16.0	6/1/2015	20	5/31/2035	1
Solar	LSS 50 MW - SOLAR D&D CAMP (MERIWETHER COUNTY)	3.0	6/1/2015	20	5/31/2035	1
Solar	REDI 1400 MW - C&I: DOUGHERTY COUNTY SOLAR	120.0	12/11/2019	30	12/10/2049	1
Solar	REDI 1400 MW - C&I: TANGLEWOOD SOLAR	57.5	3/12/2020	30	3/11/2050	1
Solar	REDI 1400 MW - DG CS S1920	2.3	5/1/2019	20	4/30/2039	2
Solar	REDI 1400 MW - DG CS S1925	2.7	5/1/2019	25	4/30/2044	3
Solar	REDI 1400 MW - DG CS S1930	4.1	5/1/2019	30	4/30/2049	4
Solar	REDI 1400 MW - DG CS S1935	14.0	5/1/2019	35	4/30/2054	10
Solar	REDI 1400 MW - DG CS W1925	1.6	1/1/2019	25	12/31/2043	2
Solar	REDI 1400 MW - DG CS W1930	0.6	1/1/2019	30	12/31/2048	1
Solar	REDI 1400 MW - DG CS W1935	10.6	1/1/2019	35	12/31/2053	11
Solar	REDI 1400 MW - DG S2030	2.0	5/1/2020	30	4/30/2050	1
Solar	REDI 1400 MW - DG S2035	75.3	5/1/2020	35	4/30/2055	33
Solar	REDI 1400 MW - DG W2030	2.5	1/1/2020	30	12/31/2049	1
Solar	REDI 1400 MW - DG W2035	6.9	1/1/2020	35	12/31/2054	3
Solar	REDI 1400 MW - US 1: QUITMAN SOLAR	150.0	12/16/2019	30	12/15/2049	1
Solar	REDI 1400 MW - US 1: SOUTHERN OAK SOLAR ENERGY	160.0	2/4/2020	30	2/3/2050	1
Solar	REDI 1400 MW - US 1: TWIGGS COUNTY SOLAR	200.0	9/5/2020	30	9/4/2050	1
Solar	REDI 1400 MW - US 2: QUITMAN II	150.0	11/30/2021	30	11/29/2051	1
Solar	2022/2023 US - TIMBERLAND SOLAR	140.0	11/30/2023	30	11/29/2053	1
Solar + Storage	2022/2023 US - FLINT RIVER SOLAR	200.0	11/30/2023	30	11/29/2053	1
Solar + Storage	2022/2023 US - DOUBLE RUN SOLAR	220.0	11/30/2023	30	11/29/2053	1
Solar + Storage	2022/2023 US - WADLEY SOLAR	260.0	11/30/2023	30	11/29/2053	1
Solar + Storage	2022/2023 US - WASHINGTON COUNTY SOLAR	150.0	11/30/2023	30	11/29/2053	1
Solar + Storage	REDI 1400 MW - US 2: BROKEN SPOKE	195.5	11/30/2021	30	11/29/2051	1
Solar + Storage	REDI 1400 MW - US 2: COOL SPRINGS	213.0	11/30/2021	30	11/29/2051	1

Solar	2019 IRP CCSP DG	25.0	1/1/2023	30	12/31/2052	1
Solar	2019 IRP REDI CS2	25.0	7/1/2022	30	6/30/2052	1
Solar	2019 IRP RENEWABLES - DG	160.0	11/30/2023	30	11/29/2053	1
Solar	2019 IRP RENEWABLES - US 2	1000.0	11/30/2024	30	11/29/2054	1
Solar	2022 IRP_SOLAR_A	750.0	1/1/2028	30	12/31/2057	1
Solar	2022 IRP_SOLAR_B	750.0	1/1/2029	30	12/31/2058	1
Solar	2022 IRP_SOLAR_C	750.0	1/1/2030	30	12/31/2059	1
Solar	2022 IRP_SOLAR_D	750.0	1/1/2031	30	12/31/2060	1
Solar	2022 IRP_SOLAR_E	750.0	1/1/2032	30	12/31/2061	1
Solar	2022 IRP_SOLAR_F	750.0	1/1/2033	30	12/31/2062	1
Solar	2022 IRP_SOLAR_G	750.0	1/1/2034	30	12/31/2063	1
Solar	2022 IRP_SOLAR_H	750.0	1/1/2035	30	12/31/2064	1

Notes:

[A] The retail capacity values listed reflect the capacity value attributable to retail adjusted for Georgia Power ownership and capacity equivalence. The capacity listed reflects the capacity in 2022 unless otherwise noted. For resources not online in 2022, the capacity listed is consistent with the expected capacity at the resource's in-service date. Please refer to Technical Appendix Volume 1 Resource Mix Study supporting documentation for annual capacity values.

[B] IRP modeled unavailability dates are based on the resource's assumed useful life, but no earlier than January 1, 2030 unless otherwise noted. Useful life assumptions are 60-year life for steam units, 45-year life for CT/CC units, and the length of the current operating license for nuclear units. Blackstart, restoration, and hydro resources do not assume an unavailability date. Units the Company is seeking to retire reflect the retirement date listed in the decertification application. CTO denotes that the resource is assumed to continue to operate throughout the planning period if it is available.

[C] The nominal capability listed reflects the capacity in 2022 unless otherwise noted. For resources not online in 2022, the nominal capacity listed is consistent with the capacity at the resource's in-service date. These values do not reflect capacity equivalence. Please refer to Technical Appendix Volume 1 Resource Mix Study supporting documentation for seasonal capacity values.

A.6. DEMAND-SIDE OPTIONS

Resource Name	Type	2022 Summer Retail Capacity (MW)[D]	2022 Winter Retail Capacity (MW)[D]
Real Time Pricing Extreme Day Ahead	Price Responsive Demand	29.4	44.6
Real Time Pricing Extreme Hour Ahead	Price Responsive Demand	182.6	72.1
Conservative Voltage Reduction Level 1	Power Delivery	313.1	310.2
Conservative Voltage Reduction Level 2	Power Delivery	156.5	155.1
Demand Plus Energy Credit	Interruptible Load	144.2	159.6
Thermostat Energy Management Program	Interruptible Load	9.1	14.4

Notes:

[D] For Demand-Side Options, the ratings are based on the program capacity adjusted for the Incremental Capacity Equivalent (ICE), availability and losses. The ICE Factor is a measure of the effect of a demand-side option on generating System reliability. The availability factor is a measure of the probability of an active demand-side option being available at the time it is needed.

ATTACHMENT B. RETIREMENTS SINCE 2007

Unit	MW	Primary Fuel	IRP or Authority	Retirement Date
McDonough 1	254	Coal	Docket 24506-U	2/29/2012
McDonough 2	254	Coal	Docket 24506-U	9/30/2011
Branch 1	250	Coal	2011 IRP Update[47]	4/16/2015
Branch 2	319	Coal	2011 IRP Update	10/1/2013
Mitchell 4C	33	Oil	2011 IRP Update	3/26/2012
Branch 3	509	Coal	2013 IRP	4/16/2015
Branch 4	507	Coal	2013 IRP	4/16/2015
Kraft 1-3	201	Coal	2013 IRP	10/13/2015
Kraft 4	115	Gas/Oil	2013 IRP	10/13/2015
McManus 1	43	Oil	2013 IRP	4/16/2015
McManus 2	79	Oil	2013 IRP	4/16/2015
Yates 1-5	579	Coal	2013 IRP	4/16/2015
Boulevard 2	14	Oil	2013 IRP	7/17/2013
Boulevard 3	14	Oil	2013 IRP	7/17/2013
Bowen 6	32	Oil	2013 IRP	4/25/2013
Mitchell 3	155	Coal	2016 IRP	8/2/2016
Mitchell 4A	31	Oil	2016 IRP	8/2/2016
Mitchell 4B	31	Oil	2016 IRP	8/2/2016
Kraft 1 CT	17	Gas/Oil	2016 IRP	8/2/2016
Intercession City	143	Oil	2016 IRP[48]	8/2/2016
Hammond 1	110	Coal	2019 IRP	7/29/2019
Hammond 2	110	Coal	2019 IRP	7/29/2019
Hammond 3	110	Coal	2019 IRP	7/29/2019
Hammond 4	510	Coal	2019 IRP	7/29/2019
McIntosh 1	142.5	Coal	2019 IRP	7/29/2019
Estatoah 1	0.1	Hydro	2019 IRP	7/29/2019
Langdale 5-6	0.2	Hydro	2019 IRP	7/29/2019
Riverview 1-2	0.1	Hydro	2019 IRP	7/29/2019
Total	**4,562**			

[47] The 2013 IRP final order revised the retirement date of Plant Branch Unit 1 to be consistent with the retirement date of Plant Branch Units 3-4.
[48] In the case of the Intercession City CT unit, located in Florida and previously co-owned with Duke Energy Florida, the Company exercised its contractual option in May 2015 to terminate the transmission service and sell the Company's previous ownership interest in the unit to Duke Energy Florida.

ATTACHMENT C. MAJOR MODELS USED IN THE IRP

SERVM

SERVM is a generation reliability model that is widely accepted across the industry and used for Resource Adequacy analyses. SERVM is an hourly, chronological model that utilizes Monte Carlo techniques. Random draws from unit historical failure and repair times are used to simulate unplanned outages. The model executes beginning with 1 A.M. on January 1, committing units, tracking available hydro energy, operating pumped storage units, considering weather-appropriate renewable output, making economic and reliability purchases from other entities in the region, calling interruptible load as needed, and, if necessary, curtailing firm load.

Evaluations are typically performed for multiple weather-years, multiple peak load forecast error assumptions, and multiple different start days for the year, resulting in hundreds of cases evaluated per simulation. Each case itself is processed multiple times using random unit outage draws with each iteration and the results of these iterations averaged together to develop a case-specific result. Each case has its own probabilistic weighting and is then averaged together with all cases to obtain a weighted average, expected result for the whole simulation. The Reserve Margin Study in Technical Appendix Volume 1 contains details regarding the number of simulations run to generate the Target Reserve Margin recommendations.

Useful information provided by SERVM includes (but is not limited to):

- Expected unserved energy, which is the amount of energy that cannot be served due to generating capacity shortages
- Loss of load expectation, which is the number of days per year in which firm load is not served
- Interruptible load, which is the number of times that interruptible load is called upon
- Production costs, which are the generation and purchase costs associated with serving load requirements throughout the year

Econometric Forecasting Models

Georgia Power’s short-term forecasts are produced using econometric forecasting models, which estimate the relationships between economic and demographic variables and energy use. These models use ordinary least squares regression techniques.

Load Management and Planning: Residential

The Residential LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the residential sector. This model was updated in 2020 by Applied Energy Group.

Load Management and Planning: Commercial

The Commercial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the commercial sector. This model was updated in 2020 by Applied Energy Group.

Load Management and Planning: Industrial

The Industrial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the industrial sector. This model was updated in 2020 by Applied Energy Group.

Hourly Peak Demand Model

The hourly peak forecasting models produce projections of peak demand using forecasted class energy, historical class load shapes and corresponding weather, and a description of typical (normal) weather. These models use ordinary least squares regression techniques.

EnergyPlus/OpenStudio

EnergyPlus ™ models were used to predict hourly energy consumption in buildings based on construction characteristics, occupancy, orientation, local weather, and other attributes. EnergyPlus™ is DOE's open-source whole-building energy modeling (BEM) engine. OpenStudio is an open-source software development kit which aids model modification by presenting EnergyPlus inputs and outputs as a dynamic, object-oriented data format.

PRICEM

PRICEM is a spreadsheet-based marginal cost model designed by SCS to predict the change in revenue requirements and other effects attributable to changes in loads and/or revenues. PRICEM takes data from other major models and combines them in a single spreadsheet to provide a quick, yet relatively detailed, evaluations of options. Data inputs are consistent with inputs to AURORA and as such are taken from: (1) revenue requirements stream from Standard Analysis Model ("SAM"); (2) marginal energy cost from AURORA; (3) ICE factors from SERVM; and (4) technology cost assumptions.

PRICEM models the year with 864 load points and uses the peaker method, which is a technique allowing the total of generating capacity cost and energy cost to be estimated with peaking capacity and marginal energy cost. The peaker method provides a quick screening of many alternatives. Useful information that can be gathered from PRICEM includes:

- RIM – A NPV calculation of the total benefits and total costs over the life of the program; and
- Predictions of the amount of generating capacity needed to maintain System reliability after a change in interruptible or firm loads.

AURORA

AURORA is used to identify the optimal expansion plans and estimate marginal energy costs for use in various models and analyses.

Expansion Plans

AURORA employs a generation mix optimization module that includes the following major inputs: (1) future generating unit characteristics and capital cost; (2) the capital recovery rates necessary to recover investment cost; (3) capital cost escalation rates; and (4) a discount rate. AURORA utilizes programming techniques to minimize the NPV of the revenue requirements when deriving the least-cost expansion plan that considers all possible combinations of capacity additions on a yearly basis that would satisfy the reserve margin constraints. The combination of alternatives with the smallest production and capital cost over the planning horizon is the least-cost plan.

The output of the model is used as the primary guide in developing the base case System expansion plan for the Retail OpCos. This System expansion plan identifies the capacity additions that serve as a guide for the type of capacity and energy resources that are most economical in a particular timeframe with the given assumptions. The output is also an input into the hourly production cost modeling, which is described below.

Marginal Energy Costs

AURORA is an hourly model that utilizes Monte-Carlo techniques to randomly simulate unit forced outages.

The useful information that can be gathered from AURORA includes:

- Projections of marginal energy cost by hour for 30 years into the future
- Projections of the SO_2 and NO_X marginal costs of serving an additional block of load
- The cost effects of changing the characteristics of individual units, such as changing heat rates, station service requirements, or similar factors

AURORA supplies important data to many studies. It is used or has been used in: (1) developing the Company's annual energy budget; (2) determining the value of improving existing units; (3) developing the marginal energy cost for use in PRICEM, RCB Framework applications, and elsewhere; and (4) developing the SO_2 and NO_X marginal costs for use in PRICEM.

SAM (Standard Analysis Model)

SAM is a financial program used to convert capital expenditures into annual revenue requirements. It incorporates projections of the costs of capital, tax rates, and depreciation rates.

The useful information that can be gathered from SAM includes:

- Annual revenue requirements necessary to earn a return on and return of the investment
- NPV of revenue requirements
- Levelized fixed charge rates
- Economic carrying costs

SAM provides key calculations for numerous studies. It is used or has been used in: (1) calculating revenue requirements streams and economic carrying cost rates for PRICEM; and (2) calculating the economic carrying cost rates and NPV of revenue requirements for many studies, including for use in AURORA.

ATTACHMENT D. PLANT HATCH SUBSEQUENT LICENSE RENEWAL

Georgia Power's Edwin I. Hatch Nuclear Plant, located near Baxley in southeastern Georgia, is jointly owned by Georgia Power (50.1%), Oglethorpe Power Corporation (30%), Municipal Electrical Authority of Georgia (17.7%), and Dalton Utilities (2.2%). Plant Hatch Unit 1 began commercial operation in December 1975 while Plant Hatch Unit 2 began commercial operation in September 1979. The FERC nameplate rating for each unit, which represents a gross output amount, is 924 MW. Plant Hatch was an industry leader in the initial license renewal effort, receiving the first renewed licenses for a boiling water reactor. With both units having received the initial license renewal, the current 60-year license for Plant Hatch Unit 1 expires August 6, 2034, and the current 60-year license for Plant Hatch Unit 2 expires June 13, 2038.

D.1. CURRENT SLR ACTIVITY IN THE U.S.

A predictable regulatory process now exists for SLR from the NRC, allowing plant operation for an additional twenty years. As such, the industry has now started the process of extending plant licenses to 80 years using the SLR process. To date, three plants, including Florida Power & Light's Turkey Point Units 3 & 4, Exelon's Peach Bottom Units 2 & 3, and Dominion's Surry Units 1 & 2 have received their 80-year licenses, and the NRC successfully met budget and schedule targets with these applicants. Another four U.S. nuclear plants currently have SLRA under review at the NRC, while additional utilities have publicly announced plans to apply for SLR.

D.2. QUALITATIVE BENEFITS OF SLR FOR HATCH

Nuclear energy continues to bring important fuel diversity and fuel savings benefits for Georgia Power customers. In addition, nuclear energy could serve to mitigate the risk of potential environmental uncertainty, especially as it relates to carbon regulation or legislation. Also important is preserving the Company's option for baseload power generation to support future capacity and energy needs. Lastly, Plant Hatch brings a significant positive impact to the local community by providing numerous jobs and generating state and local tax revenues, while producing zero carbon energy to support the communities Georgia Power serves.

D.3. ECONOMICS OF SLR

Unlike the process of deciding whether to make a significant investment in a coal plant to meet a future environmental regulation or instead retire the coal plant, there is not necessarily a significant upfront investment that would need to be made at Plant Hatch to continue operations beyond the current license expiration date. Rather, a determination of the necessary capital and O&M budgets required to keep the plant reliably operating during the period of extended operation is made. As part of that process, the Company conducted a feasibility study, which concluded that Plant Hatch can operate reliably beyond 60 years. No unexpected or unusually large capital expenditures were identified, and it was determined that projects that were identified could be managed within the plant's normal capital and O&M budgets.

Using the budgets developed for the period of extended operation, an economic analysis was performed to provide a preliminary look at the viability of continued operations, including SLR, for Plant Hatch. The analysis was performed in a manner similar to the unit retirement studies developed for evaluating the economics of the steam units in this IRP. However, given the timing of the start of the period of extended operation for Plant Hatch Unit 2, there is one notable difference in that the replacement CC unit in the SLR analysis assumes CCS is required.

As conveyed in the analysis found in the Selected Supporting Information section of Technical Appendix Volume 1, preliminary economics appear beneficial for customers and support pursuit of SLR for Plant Hatch. Please see the Unit Retirement Study in Technical Appendix Volume 2 for additional information regarding how the economic analysis is developed and presented.

D.4. PROPOSED TIMELINE AND COST FOR SLR

Pending Commission approval of Georgia Power's request to pursue SLR for Plant Hatch, development of the SLRA would begin in the first quarter of 2023 with a fourth quarter 2025 target to file the SLRA at the NRC. Based on recent SLRA reviews undertaken by the NRC, NRC review of Georgia Power's Plant Hatch SLRA is estimated to take approximately two years, which would place the expected approval of the Plant Hatch SLRA in fourth quarter 2027. If, at that time, it is deemed beneficial for customers, the Company envisions bringing to the Commission in the 2028 IRP a request to utilize SLR approval to extend operations at Plant Hatch Units 1 & 2 for up to an additional twenty years beyond the current licenses.

The estimated cost for the time needed to develop the SLRA and then work with the NRC as they undertake their review of the SLRA is approximately $51 million. Accounting for Georgia Power's 50.1% ownership in Plant Hatch as well as Allowance for Funds Used During Construction ("AFUDC"), Georgia Power's share comes to approximately $28 million. This cost, budgeted for a period of approximately six years, shows spend beginning in 2023 and covers the Company's development of the SLRA as well as key steps of the NRC's SLRA approval process at both the federal and state levels.

The NRC staff will follow essentially the same process for reviewing SLRAs as it did for initial license renewals.[49] The process starts with an initial NRC acceptance review followed by safety and environmental reviews. The NRC will conduct pre-application meetings with potential applicants to discuss technical or plant-specific issues in the application and to engage federal and state entities earlier in the environmental review process. Key federal approvals include obtaining both a Safety Evaluation Report ("SER") and an Environmental Impact Statement ("EIS"), both of which originate with different departments within the NRC. At the state level, continued renewal of the existing permits issued by the Georgia EPD and confirmation of the existing or issuance of a new Section 401 Water Quality Certification will be required. At this time, the Company does not see any significant hurdles to receiving the necessary permits.

D.5. SPECIFIC REQUEST IN THE 2022 IRP

Supported by strong preliminary economics and a positive feasibility study, the Company requests approval to spend approximately $28 million to pursue SLR for both units at Plant Hatch. This would enable the Company to preserve the option of continuing operation of the two units beyond their current 60-year licenses, bringing numerous potential benefits to Georgia Power customers.

[49] Background on Subsequent License Renewal | NRC.gov

ATTACHMENT E. HYDROELECTRIC RELICENSING SCHEDULE

In 1920, Congress passed the Federal Water Power Act, which gave the Federal Power Commission (“FPC”), FERC’s predecessor, its original authority to license and regulate non-federal hydropower projects. FERC requires qualifying hydroelectric projects to have operating licenses. Licenses are issued as 30-, 40-, or 50-year licenses. During the relicense process, hydroelectric resources undergo an environmental review in accordance with the National Environmental Policy Act. During the relicense process, numerous entities provide input on the project and the FERC environmental review considers other statutes that affect hydropower regulation. Georgia Power is required to relicense existing operating licenses at the end of the license term and also ask for license amendments for modernization projects.

During relicensing, FERC may impose additional license conditions on Georgia Power based on input from federal and state environmental and other resources agencies, non-governmental organizations, and other stakeholders. Outside of the FERC relicensing proceeding, FERC may require additional license conditions during a license term, including in some instances, requirements imposed by federal and state agencies. These requirements may result in loss of capacity and/or generation due to increased minimum flows, seasonal limits on generation, increased water withdrawals, limits on reservoir fluctuations, or dam removal. Additionally, reductions in peaking capability, ancillary services (e.g., voltage control), and operational flexibility could arise due to imposed ramping rates or modifications to current operational regimes. Finally, additional license requirements could come in the form of increased capital investment such as installation of facilities and equipment for environmental purposes (e.g., dissolved oxygen or fish passage facilities), installation and enhancement of recreational facilities, shoreline changes, habitat enhancements, monitoring and surveillance of environmental parameters, or replacement of capacity.

The following section highlights recent and upcoming relicensing proceedings for various Georgia Power hydro plants.

Hydro License Schedule		
Project	**License Expiration Date**	**Georgia Power Starts Relicensing Per NOI/ILP**
Lloyd Shoals	December 31, 2023	Filed December 31, 2021
Rocky Mountain	December 31, 2026	Filed December 10, 2021
Middle Chattahoochee (Goat Rock, Oliver, and North Highlands)	December 31, 2034	File between July 1, 2029 & December 31, 2029
Sinclair	April 30, 2036	File between October 30, 2030 & April 30, 2031
North Georgia (Burton, Nacoochee, Terrora, Tallulah Falls, Tugalo, and Yonah)	September 30, 2036	File between March 30, 2031 & September 30, 2031
Morgan Falls	February 28, 2039	File between August 28, 2033 & February 28, 2034
Flint River	October 31, 2039	File between April 30, 2034 & October 31, 2034
Bartletts Ferry	November 30, 2044	File between May 30, 2039 & November 30, 2039
Wallace Dam	May 31, 2060	File between November 30, 2054 & May 31, 2055

Wallace Dam

New License Issued June 1, 2020

Beginning in 2020, post-license enhancements required by the new FERC license began construction. These enhancements include an in-reservoir pure oxygen aeration injection system to improve dissolved oxygen in the plant discharge, an overhaul of existing recreation facilities, the addition of new bank fishing access areas for the public, and the implementation of mandatory conditions from the U. S. Forest Service, primarily consisting of recreation facility improvements on their lands within the FERC project boundary. Work on these projects continues through 2024 (and will continue periodically for the life of the FERC license for the mandatory conditions).

Lloyd Shoals Projects

License Expires December 31, 2023

The Lloyd Shoals relicense process started internally in 2017. A Notice of Intent to relicense the project was filed with FERC on July 3, 2018 and the Final License Application was filed December 31, 2021.

Langdale and Riverview Projects

Licenses Expire December 31, 2023

Georgia Power filed a Notice to Surrender these projects on December 18, 2018. Field studies are ongoing. The Final Surrender Decommissioning Plan and Environmental Assessment will be submitted to FERC in Q1 2022.

Rocky Mountain Pumped Storage Project (co-owned and jointly licensed with Oglethorpe Power)

License Expires December 31, 2026

A Notice of Intent to relicense the project was filed with FERC on December 10, 2021. Oglethorpe Power is leading the relicensing effort.

ATTACHMENT F. RENEWABLE EXPANSION PLAN ANALYSIS

For the 2022 IRP, the Company completed an economic optimization analysis to determine the appropriate renewable expansion strategy. This analysis represents a significant increase in analytical sophistication enabled by the Company's transition to the AURORA model for expansion planning. This model is specifically designed to evaluate the interactions between the Company's resource mix and various candidate expansion resource options. The model can compare the cost of adding conventional generation, such as natural gas, renewables, battery storage, and other resource options. By simulating the dispatch of the System, AURORA seeks to minimize total System costs, including both production and capital costs, while maintaining the Company's target reserve margins. This information serves as the foundation for the Company's long-term renewable resource plan of adding 6,000 MW by 2035 and demonstrates the cost-effectiveness of renewable additions.

The Company's expansion planning analysis includes a range of possible future loads, fuel prices, and carbon impacts. The analysis also considers both high and low-price renewable resource additions. The key assumptions that inform the Company's renewable expansion plan are further described in this attachment.

F.1. SCENARIOS

These scenarios are further described in the 2022 IRP Main Document CHAPTER 7. The scenarios listed below were selected for the renewable expansion plan study:[50]

1. Moderate gas prices and zero carbon ("MG0")
2. \$50 CO_2 price path and fifty-dollar carbon ("\$50")
3. Low gas prices and zero carbon ("LG0")
4. Low gas prices and twenty-dollar carbon ("LG20")
5. High gas prices and zero carbon ("HG0")
6. High gas prices and twenty-dollar carbon ("HG20")

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[50] The Company believes this list of scenarios provides sufficient information to make an informed renewable expansion decision. Notably, this group of scenarios provides insight into how gas prices and carbon prices will impact the desired amount of renewable resource additions. The solar selected as a component of this process is considered a planned and committed resource addition. AURORA will have the opportunity to select solar or renewable resources above the amount selected by this process for all scenarios in the final 2022 IRP or Budget 2022 expansion planning analysis.

F.2. PRICING ASSUMPTIONS

In addition to the scenarios listed above, the Company also varied the potential price of solar PPA additions. The pricing sensitivities ensure the Company is considering the possibility of two PPA prices associated with solar procurements. The Company considered the following pricing:[51]

1. $25/MWh (equivalent to $34/MWh levelized)
2. $20/MWh (equivalent to $27/MWh levelized)

The model does not apply any inflation and does not increase the first-year price in any year during the planning horizon. Therefore, in real terms, the Company is assuming a declining PPA price for solar. Once selected, the model does assume that the price of the PPA will escalate by 3% per year during the asset's life. The Company's 2022-2023 Utility Scale RFP resulted in an average cost of 3 cents per kilowatt hour ("c/kWh") or $30/MWh over their thirty-year terms, which closely aligns with these assumptions.

F.3. BUDGET VINTAGE ASSUMPTIONS

The Company understands and appreciates that large additions of new renewable or solar resources can have impacts on other resource decisions considered in the IRP. To holistically capture these impacts, the Company is including the results of this study in the final resource assumptions[52] for the 2022 IRP. Therefore, the solar resources selected by this study are assumed in-service across all planning scenarios for the final 2022 IRP and captured in other IRP studies. To facilitate this effort, the Company must identify the final renewable expansion plan recommendation well in advance of the final IRP studies. Therefore, the Company completed this analysis using Budget 2021 ("B21") information.

[51] The solar prices modeled are consistent with industry sources including Lazard's Levelized Cost of Energy Analysis—Version 14.0.
[52] Georgia Power's 2022 IRP resource assumptions are included in the 2022 IRP Main Document ATTACHMENT A.

F.4. EXPANSION PLANNING RESULTS

The Company's expansion planning results indicate that a range of renewable procurements is economically optimal for customers but remains dependent on market conditions and procurement costs.

Optimal expansion plan with **$25 / MWh** assumption:

Table 12: Cumulative build under $25 / MWh assumptions

Cumulative MW Build ($25/MWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
HG0	0	0	0	339	509	1192	1882	2750	3625	4508
MG0	0	0	0	0	0	0	0	0	0	173
LG0	0	0	0	0	0	0	0	0	0	0
HG20	1683	2531	3042	3895	4074	4940	5816	6704	7594	8496
LG20	168	506	845	1185	1188	1192	1882	2578	3452	4335
$50	1683	2531	3380	4234	5093	5962	6158	7048	7940	7976
Average (MW)	589	928	1211	1609	1811	2214	2623	3180	3768	**4,248**
Average $0 CO_2	0	0	0	113	170	397	627	917	1208	1561

Optimal expansion plan with **$20 / MWh** assumption:

Table 13: Cumulative build under $20 / MWh assumptions

Cumulative MW Build ($20/MWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
HG0	505	1350	1352	2201	2207	3066	3934	4813	5696	6416
MG0	0	0	169	1016	1358	2214	2566	2578	2762	2774
LG0	0	0	0	508	509	681	1197	1547	2071	2254
HG20	1683	2531	3380	4234	5093	5962	6842	7735	8630	9537
LG20	1683	2193	2197	2201	2207	2214	2737	3266	4142	5028
$50	1683	2531	3380	4234	5093	5962	6842	7735	8458	9363
Average (MW)	925	1434	1746	2399	2744	3350	4020	4613	5293	**5,895**
Average $0 CO_2	168	450	507	1242	1358	1987	2566	2980	3510	3815

ATTACHMENT G. SUMMARY OF THE SYSTEM POOLING ARRANGEMENT

Introduction

Georgia Power is a member of the Pool, which consists of the Operating Companies.[53] The Operating Companies function as a single, integrated public-utility system through adherence to the Southern Company System Intercompany Interchange Contract ("IIC"), an agreement on file with FERC. SCS acts as agent for the Operating Companies in the administration of the IIC. The IIC provides a framework whereby the generating resources of the Operating Companies are operated in a coordinated and integrated fashion to economically serve their aggregate firm obligations, as well as to engage in shorter term transactions in the wholesale markets. Using traditional concepts of economic dispatch, the Pool deploys available generation to satisfy the aggregate obligations of the System at any given time in a reliable and economic fashion. The IIC also provides for coordinated planning between the Operating Companies and for the sharing of temporary surpluses and deficits of capacity. The IIC ensures that the after-the-fact accounting associated with joint System dispatch (energy) and reserve sharing (capacity) is handled in accordance with the principles set forth in that agreement. It should be noted that the coordinated planning process for the Retail OpCos is functionally separate from the planning process for Southern Power.[54]

Relationship of the Operating Companies under the IIC

The Southern Company Pool is a coordinated Pool, not a centralized Pool. Although the generating facilities of each Operating Company are committed to a centralized economic dispatch, each individual Operating Company retains the right and the responsibility for providing the generation and transmission facilities necessary to meet the requirements of its customers.

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[53] For purposes of the IIC, Operating Companies currently consist of the Southern Operating Companies (Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Southern Power Company) as well as Florida Power & Light Company (FP&L), as successor to Gulf Power Company. On January 1, 2019, Southern Company completed the sale of Gulf Power Company to NextEra Energy. Per the terms of sale, Gulf Power Company (now FP&L) would remain part of the Pool for five years or until it elects to withdraw from the Pool upon 180 days' notice. As of January 2022, FP&L has provided its 180 days' withdrawal notice and is expected to exit the pool by the end of Q2 2022. The details outlining FP&L's participation in the Pool as a non-affiliate are included in Appendix A to the IIC that was filed at FERC on July 3, 2018.

[54] Gulf Power Company will develop its own resource plans to be verified by SCS and aggregated with the plans of the other Pool members. Gulf Power Company is expected to have adequate resources to reliably serve its own obligations and is required to provide sufficient information to demonstrate compliance with such expectation during the Transition Period. No Operating Company specific information for the Southern Company Operating Companies will be shared with NextEra Energy or Gulf Power Company.

Each Operating Company has its own management that reports to its own board of directors, with the management and the board of directors of each Operating Company being directly responsible for making the decisions that affect that Operating Company and its customers. They are also responsible for working with local regulators and adhering to the requirements of state law.

Accordingly, each Operating Company has its own distinct characteristics regarding types of generation and load. For example, Alabama Power, Georgia Power, and Southern Power bring hydro and nuclear generating capacity to the Pool, while the other Operating Companies do not. Similarly, the load characteristics of the Operating Companies vary due to the types of customers each brings to the Pool. The differing economies within each Operating Company territory and customer base lead to different load growth rates and load shapes for each Operating Company.

The IIC provides for an Operating Committee that consists of a designated representative from each Southern Operating Company and SCS, with the SCS representative acting as a non-voting Chairman.[55] The functional separation of certain activities of Southern Power restricts the participation of its Operating Committee member in some matters (such as discussions and recommendations involving the coordinated planning of the Retail OpCos). A unanimous vote of the Operating Committee voting members is required in order to change the IIC.

Interconnections

The Operating Companies are interconnected with 12 non-associated utilities through 61 different transmission facilities. These transmission lines are operated at voltages of 46 kV, 69 kV, 115 kV, 161 kV, 230 kV, and 500 kV, and include facilities that are operated normally open. The non-associated utilities with which the System is interconnected are shown in Table G-1.

[55] As of January 1, 2019, Gulf Power no longer has a representative on the Operating Committee but instead has a designated contact to be notified of changes to the IIC or policies, practices, or procedures used in its implementation.

Table G-1: Non-Associated Utilities

Florida Power & Light Company	Duke Energy Florida
JEA	City of Tallahassee
Duke Energy Corporation (Carolinas)	South Carolina Electric & Gas Company
Tennessee Valley Authority	South Carolina Public Service Authority
Entergy Corporation	Crisp County Power Commission
PowerSouth Energy Cooperative	South Mississippi Electric Power Association

Basic Principles of the IIC

The basic principles of the IIC can be summarized as follows.

1. Each Operating Company submits its load and generation to the Pool for joint commitment and economic dispatch.
2. Energy Principles:
    a. Each Operating Company retains its lowest cost resources to serve its customers.
    b. An Operating Company's excess energy is next made available to the other Operating Companies to serve their customers if the cost of the Pool energy is less than the cost of energy from their own resources.
    c. Energy in excess of that necessary to serve the Operating Companies' customers is marketed by the Pool to the wholesale markets.
3. The IIC provides for coordinated planning among the Retail OpCos and for the sharing among all Operating Companies of temporary surpluses and deficits of capacity.[56]
4. Under the IIC, each Operating Company shares in the benefits and pays its share of the costs resulting from their coordinated operations.

Participation in the Southern Company Pool provides benefits to the Operating Companies and to their customers. Pool participation not only enhances Georgia Power's ability to provide reliable, low-cost electric service to its customers but also to achieve economies of scale in any required investments. Benefits of Pool participation include:

[56] Gulf Power Company will develop its own resource plans to be verified by the Agent and aggregated with the plans of the other Pool members.

- Staggering construction of new generating facilities so that each retail Operating Company can construct and install the optimum sized generating facilities while utilizing economies of scale;
- Sharing temporary surpluses and deficits of generating capacity that can arise as a result of coordinated planning or other circumstances (e.g., staggered construction schedules, variations in load patterns, load forecast uncertainties, etc.);
- Coordinating scheduled maintenance to provide greater flexibility, including major maintenance requiring relatively long unit outages, as well as mitigating the cost impact (to customers) of these required outages;
- Carrying a lower generation planning reserve margin (due primarily to System load diversity), which enables each Operating Company to have a lower investment in generating resources;
- Providing reliable service with shared operating reserve requirements (which puts downward pressure on fuel costs);
- Access to lower cost energy from other Operating Companies;
- Enhanced reliability of electric service through the use of transmission interconnections to provide backup service in case of emergencies as well as providing the ability to import lower cost energy when available; and
- Acting as a Pool (instead of individual Operating Companies) to identify shorter term purchase and sale opportunities in the wholesale markets that may be available from time to time.

Basic Operation of the IIC

The concept of economic dispatch, which seeks to minimize the total System production cost, is one of the major benefits of the Pool. The generating assets of all the Operating Companies in the Pool are committed and dispatched as a common System without regard to the ownership of each generating facility. Subject to operational constraints and reliability considerations, the lowest cost generation assets are dispatched during each hour to meet the total needs of the customers of all the Operating Companies. The goal of this process is to ensure that the lowest cost energy is produced every hour. It also should be reiterated that each Operating Company retains its lowest cost generation to serve that Operating Company's customers.

The Pool also interfaces with the wholesale markets on behalf of the Operating Companies for both sales and purchases. When the Pool has excess power available, it will pursue wholesale sales opportunities for which there is a reasonable expectation that the transaction will result in positive net margin for the Operating Companies. There are two primary reasons for the Pool to seek purchase opportunities: (1) economics; and (2) reliability. The Pool will pursue purchase opportunities from the wholesale markets if such purchases are expected to be more economical than System resources (again, subject to operational constraints and System reliability). In the event the Pool experiences reliability challenges, then the Pool may seek purchases in response to such operating conditions.

Reserve Sharing

As noted in the introduction, the IIC contains capacity provisions, commonly referred to as "reserve sharing," that provide for a sharing of temporary generating capacity surpluses and deficits that are a result of coordinated planning or other circumstances. As participants in the coordinated operation of the integrated electric system, each Operating Company enjoys the same level of service reliability. In any given month, however, one or more Operating Companies will have a temporary surplus or deficit of capacity relative to the overall level of actual System reserves. Consistent with the goal of sharing in the benefits and burdens of the coordinated and integrated electric system, the reserve sharing provisions of the IIC provide for the equitable allocation of such temporary surplus or deficit capacity. The resulting purchase and sale of capacity is transacted on a monthly basis.

Reserve sharing is determined by comparing each Operating Company's load responsibility with its respective capacity resources recognized through the coordinated planning process. The Operating Companies must own or purchase sufficient capacity (including capacity available for load service and that which is unavailable due to forced outage, partial outage, and maintenance outage) needed to reliably serve their respective load responsibilities. Capacity above that amount is considered reserve capacity, and each Operating Company is responsible for a portion of such reserve capacity based upon historical peak load ratios. If an Operating Company's reserve capacity is less than its reserve responsibility, that Operating Company will make reserve sharing payments under the IIC for the month.

Each Operating Company develops an annual charge (payments are based on monthly capacity worth) based upon the cost of its most recently installed or purchased peaking resource(s). The Operating Companies that are "selling" capacity to the Pool will receive a payment from the Pool based upon their respective capacity rates. The Operating Companies that are "buying" capacity from the Pool will make payments to the Pool based upon the weighted average of the capacity rates of the “selling” Operating Companies. In this way, all the buying Operating Companies pay the same composite cost in a given month for reserve sharing purposes. By definition, the amount by which one or more Operating Companies are “short” (make payments) will be equal to the amount by which one or more Operating Companies are “long” (receive payments).

Energy Transactions

Energy transactions within the Pool are accounted for on an hour-to-hour basis, with the accounting occurring after-the-fact utilizing the actual flows among the Operating Companies.

The actual real-time operation of the System is based upon the concept of economic energy dispatch, which through on-line computer control assures that available generation is dispatched so as to choose the most economical generation available to serve the total System obligation at any given time. An adequate set of lowest-cost generating resources is committed in advance to meet the total System obligation, with due regard for generation requirements associated with service area protection, voltage control, unit protection, and other operating limitations considerations.

For billing purposes under the IIC, each Operating Company is deemed to have retained its lowest-cost energy resources (most notably hydro and nuclear) to serve its own territorial customers, plus whichever of its resources that may have been operating outside of economic dispatch for purposes of service area protection or voltage control. To the extent an Operating Company’s generation exceeds its own load obligations, such energy is sold to the Pool under the IIC. If an Operating Company’s generation is not equal to or greater than its own load obligations, the difference is purchased from the Pool. The energy rate for energy sold to or purchased from the Pool by each Operating Company is referred to as the Associated Interchange Energy Rate and represents the incremental System cost of serving the Operating Companies’ aggregate firm obligations. Under the IIC, the determination of which Operating Companies are buying from and which are selling to the Pool is made on an hourly basis, and an invoice that accounts for these energy transactions is rendered monthly.

Peak-Period Load Ratios

Peak-Period Load Ratios are utilized in the allocation of certain energy and capacity transactions by the Pool with non-associated systems, hydro regulation energy losses, increases in cost due to hydro regulation, and other allocations provided for in the IIC and the Manual to the IIC.

The Peak-Period Load Ratios for each contract year are based upon the prior year's actual peak-period energy in the months of June, July, and August for each Operating Company. The peak period is defined to be the 14 hours between 7:00 a.m. and 9:00 p.m. of each weekday, excluding holidays. The System peak-period energy is equal to the sum of all the Operating Companies' peak-period energy.

The Peak-Period Load Ratios are determined by dividing each Operating Company's summation of the June, July, and August actual weekday peak-period energy loads by the total System June, July, and August actual weekday peak-period energy loads.

NOTE: Southeast Energy Exchange Market ("SEEM") Proposal

In 2021, a group of southeastern utilities filed a petition at FERC to create a new automated market platform in the region called the Southeast Energy Exchange Market. SEEM is designed to be an intra-hour market which automatically matches participating buyers and sellers of energy to one another using otherwise unutilized available transmission. An independent third-party consultant estimates substantial savings will be realized across the region as a result of implementing this new platform. With the SEEM proposal becoming effective in October 2021, Georgia Power anticipates participating in SEEM as a member of the Southern Company Pool, with the goal of realizing further savings for customers. As required by the PURPA Final Order in Docket Nos. 4822, 16573, and 19279, issued March 11, 2021,[57] within six months of approval of SEEM by FERC, Georgia Power will provide additional details about the impact of SEEM, if any, on the calculation of avoided costs.

[57] PURPA Final Order.

ATTACHMENT H. LOCATIONAL VALUE STUDY PROPOSAL

In compliance with the Georgia Public Service Commission's PURPA Final Order, Georgia Power has brought forward in the 2022 IRP a proposal to study locational value following the conclusion of the 2022 IRP. In October 2021, the Company met with the Commission Staff to discuss ideas related to how locational value of renewable resources might be accounted for in the Company's payments to QFs as contemplated in the PURPA dockets. Incorporating feedback from Staff, the Company presents the following proposal in this IRP in compliance with the PURPA Final Order.

Given that (1) Georgia Power exists in a regulated market where the elimination of constraints is a primary focus of transmission planning and (2) the net demand (location and magnitude of generation sources and forecasted load) is a key input to the determination of such constraints, the Company's proposal for valuing the location of renewable resources is focused on how that location aids, or impedes, in the mitigation of transmission constraints. To determine this locational value, the Company proposes to follow a methodology similar to that used to calculate the Deferred Transmission Investment component in the RCB Framework, with a focus on Georgia. That is, tranches of distributed energy resources will be injected into the modeled transmission system in different Georgia load pockets, or zones, and then transmission line contingency analyses (i.e., N-1 and N-G-1 analyses) will be performed to determine what transmission projects, if any, are added, advanced, displaced, or deferred due to the injection of the DER tranche.

The basis for the locational value zones selected for the locational value analysis are the traditional transmission planning zones utilized in developing the 10-year plan presented in Technical Appendix Volume 3, with geographic aggregations made as needed for the model to calculate meaningful results given the varying load penetration within the locational value zones. Using the results of the N-1 and N-G-1 analyses, changes in the resulting transmission cost, as compared to the base case prior to injection of the DER, would be calculated for each locational value zone. If projects are displaced or deferred in the DER scenario case compared to the base case, the value of the changes in the resulting transmission cost will represent a benefit, while the value will represent a cost if projects are added or advanced. These values, which could represent a benefit or a cost depending on the location of the renewable project, could then be converted into a $/kW-year value for each locational value zone and potentially applied in payments to QFs. Note that this adjustment to the QF payment would be in addition to the benefits already provided for in the current payment calculation approved in the PURPA dockets, such as compensation for avoided energy costs (comprised of fuel, emissions, variable operations & maintenance, and fuel handling), unit commitment costs, and reduced transmission and/or reduced distribution losses, as appropriate.

Once the study commences after the IRP's conclusion, it is estimated that the study would take four to six months to complete. At the study's conclusion, the Company proposes to present the study results to the Commission Staff and discuss its possible incorporation into payments to QFs.

ATTACHMENT I. RESEARCH ACTIVITIES

Georgia Power, as a subsidiary of Southern Company, is involved in a range of research activities and programs to facilitate the development of new technologies with the potential to benefit Georgia Power's customers. Southern Company is an industry leader in the R&D of emerging energy technologies and, on behalf of the Operating Companies, manages a diverse research portfolio. This ensures Southern Company and its subsidiaries have the capabilities and knowledge to successfully deploy technologies to meet customers' energy needs today and in the future. Current R&D activities are organized into a comprehensive strategy designed to meet four primary needs for Southern Company, its Operating Companies, and its customers. The R&D strategy is organized into four strategic aspirations, as outline below, that define the top-level focus areas within the R&D portfolio. Each research program develops a specific portfolio strategy in support of these aspirations, as well as near-term objectives to ensure consistency between long-term strategy and near-term tactics. The R&D organization operates in teams according to subject matter expertise including Generation Fleet; Advanced Energy Systems; Carbon Capture, Storage, and Utilization; Energy End-Use; Power Delivery; and Renewables, Storage and Distributed Generation. The R&D program teams work collaboratively on projects that are directly connected to each specific research objectives to deliver the R&D strategy in an efficient and aligned manner. SCS-lead R&D projects within each of programs may be specific to a particular Operating Company.

Strategic Aspiration 1: Develop a sustainable energy future through customer-focused, cost-effective solutions

- Modernize the domestic nuclear industry landscape to enable broad deployment of advanced nuclear technology in the 2030s. As a part of this effort, R&D will support the development and implementation of a new, risk-informed and performance-based NRC licensing pathway by mid-2020s for use regulating advanced reactors. R&D will support the establishment of critical infrastructure and supply chains, including advanced reactor fuel, for advanced reactor demonstrations. Additionally, R&D will explore sustainable technical options for nuclear fuel life cycles.
- Develop low carbon generating options that put downward pressure on rates. This area will focus on a broad range of generating technologies including wind, advanced nuclear, hydrogen, and oxy-combustion technologies. Wind R&D will work to develop competitive wind options in the Southeast, examining onshore, offshore, and tall wind options.

Included efforts will work to develop low-cost renewables that are predictable, dispatchable, and sustainable. Work on advanced power cycles will include efforts to assess, scale up, demonstrate, and validate novel power cycles, such as the Allam cycle. Advanced nuclear work will continue with demonstrations of various aspects of TerraPower's Molten Chloride Fast Reactor technology. Additional research will examine the potential role of hydrogen for power production.

- Advance carbon capture for power generating technologies through improved flexibility and integration. The R&D organization will continue to operate the DOE-sponsored National Carbon Capture Center in Wilsonville, AL to advance technologies to reduce greenhouse gas emissions from natural gas- and coal-based power plants.
- Continue to investigate relevant carbon capture technologies to develop cost models and front-end engineering and design ("FEED") studies to develop cost models for deployment within natural gas generating plants.
- Engage in additional efforts to reduce atmospheric carbon through negative emissions technology. The R&D team will perform cost/benefit analysis of DAC and natural systems technologies for carbon-negative approaches.
- Enable the dispatchability, predictability, and sustainability of renewables. The R&D team will work to develop technologies that will allow renewable to be deployed similar to fossil fuel plants. Through development of improved forecasting tools, the team will work to reduce impact of renewable variability.
- Demonstrate CO_2 storage and utilization concepts to offset cost to the customer. Research will continue to demonstrate the feasibility of carbon storage at a commercial scale. Included scope will support the development of potential storage business models and perform key site assessments within the service territory.

Strategic Aspiration 2: Provide delivery, storage, and distributed generating solutions that meet reliability, resiliency, and flexibility needs

- Develop a comprehensive strategy for evaluation and application of energy storage. This work focuses on developing a comprehensive framework for evaluating energy storage needs, key attributes, and costs. This work will inform future R&D strategy through the development of tools to assess the economic feasibility and value of energy storage projects.

- Continue to demonstrate potential energy storage technologies at relevant scales, including hydrogen storage, thermal energy storage, and flow battery concepts to enable low-carbon storage with a sustainable life cycle. Hydrogen work will include analysis to assess the value of integrated hydrogen production, storage, and utilization. Additionally, this work will examine the potential of developing utility-side supply solutions for zero-carbon energy carriers. As a part of this work, a hydrogen blending test is planned to be performed in 2022 at Plant McDonough. The test is a collaboration between EPRI, Mitsubishi Power, and Georgia Power and will result in four test runs of hydrogen blends up to 20% by volume on Unit 6 at McDonough.
- Focus R&D efforts related to lithium-ion batteries on the safe transfer of these technologies into the business. Work will develop design and safety standards related to lithium-ion storage concepts.
- Enhance System reliability and resilience while maintaining affordable energy to customers. This research includes a strategic focus on electromagnetic pulse ("EMP")/geomagnetic disturbance ("GMD") resiliency and driving efficiency and flexibility with digital applications. Work will focus on improving the ability for the grid to withstand and respond to major threats and extreme events from both man-made and natural domains. R&D will leverage real-time digital simulation of power grid and network communications to develop alternative approaches to detect, and withstand, and respond to cyber-attack utilizing grid information. Additionally, to drive efficiency in power grid management, restoration, and security, R&D will work to develop unmanned inspection technologies.
- Utilize grid data to enhance operational efficiencies by performing advanced analytics using machine learning combined with high powered simulation tools. Work will utilize data analytics and Artificial Intelligence ("AI") to predict, detect, and mitigate impending grid disturbances. R&D will develop robust modeling and simulation techniques to address increased complexities on the grid that facilitate efficient analyses of offline and real-time scenarios including hardware-in-the-loop applications. Enhanced digital worker applications will be leveraged to address a rapidly changing workforce and increased regulatory and compliance requirements, while taking advantage of new all-digital design processes and their potential integration with digital substation. Finally, holistic power quality monitoring and automated data analysis will maintain superior power quality in the face of increasing grid complexity, delivering new insights and operational efficiencies.

- Enable the necessary grid reliability and flexibility to accommodate changing generation sources and increasing electrification in a net-zero market. R&D will support the development of multiple enabling technologies for deployment of DERMS platforms including power flow control devices, expanded fiber optic infrastructure for DER integration, and scalable communications systems for edge of grid awareness, advanced circuit protection to match the speed of inverter-based resources, and maintaining superior customer power quality in the presence of widespread inverter-based resources. These technologies will culminate in a System-level DERMS Pilot Demonstration.

Strategic Aspiration 3: Develop end use technologies that support expanding customer needs

- Support the advancement of the transportation sector through decarbonization technologies, enabling infrastructure, and identification of new business opportunities. This work will focus on a broad range of vehicle platforms including light-duty passenger vehicles, medium- and heavy-duty vehicles, bus, forklift, and off-road applications. Work will examine and demonstrate enabling technologies for low-carbon transportation.
- Support the residential and commercial buildings sector to increase energy efficiency, increase affordability, decrease carbon footprint, improve comfort, and improve resiliency. Research focus will develop decarbonization strategies for residential and commercial buildings in support of customer needs. Electric end-use technologies will continue to be developed for easy-to-electrify needs. Research will continue on enabling technologies for low-carbon buildings applications, such as buildings-to-grid technologies to enable grid flexibility and resiliency. Buildings R&D will also evaluate affordable decarbonization technology options for low-income housing, businesses, and communities.
- Support customer needs for sustainability and resiliency through industrial process solutions. This research area will develop industrial sector decarbonization strategies and roadmaps for industrial customers. Technology focus areas will include zero-carbon energy carriers, process heat technologies, and technologies to retrofit heavy-emitting industry sectors.
- Develop a long-term strategy and examine the potential of micro-nuclear reactor technologies in support of customer decarbonization needs. Work includes evaluation of multiple potential reactor technologies, technoeconomic analysis, and technical support of future pilot demonstrations.

- Perform assessment and opportunity analysis of large data analytics technologies and applications. Work will leverage advanced data analytics, AI and Machine Intelligence, for insight into customer needs to advance customer targeting, energy efficiency, and other business objectives. A holistic value assessment will be developed, utilizing internal and external data repositories to identify compelling use cases.

Strategic Aspiration 4: Advance the existing generating fleet through minimizing cost and improving efficiency

- Develop solutions to address environmental risks and look for business development opportunities in the process. This research will focus on improving and developing economical and technically viable solutions to support groundwater corrective action requirements associated with ash pond closures, water treatment requirements associated with ash pond closures and ELG compliance, and advancements in water conservation technologies that can be employed at Company facilities.
- Research the development of technologies to increase the overall amount of CCRs harvested from ponds for beneficial use projects, as well as development of specific beneficial use projects, such as separation of rare earth elements from CCRs.
- Develop cross-cutting technologies that will lead to a reduction in O&M, an increase in flexibility, and/or an increase in resiliency in the transforming fleet. R&D will work to fully demonstrate a digital plant concept leading to development of Advanced Controls and AI, allowing Gas plants to reduce work force and transition to almost complete conditioned based maintenance.
- Provide technology solutions to minimize future stranded assets. Work will evaluate the potential of transitioning gas turbines to alternate fuels, such as hydrogen or ammonia within 15 years and continue to explore technically and economically viable re-powering options.

ATTACHMENT J. APPLICATION FOR CERTIFICATION OF CAPACITY FROM BLOCKS 2-4 AND BLOCKS 5&6

Executive Summary

Capacity Resources

Georgia Power seeks to certify approximately 65 MW of capacity from Plant Yates Units 6&7 ("Blocks 2-4 Converted Units Resource") and approximately 23 MW of capacity from Plant McManus Units 3A-3C and 4A-4F and Plant Wilson Units 1A-1F ("Blocks 5&6") pursuant to the terms and conditions offered in this filing. This capacity is made available to the retail jurisdiction pursuant to the Wholesale Action Plan. The Wholesale Action Plan provided that certain wholesale capacity blocks would be offered to the retail jurisdiction (1) on terms equivalent to that which the Company could obtain in the then-current markets, (2) in a manner that would not adversely affect the Company's ability to continue to sell such resources into the wholesale markets, and (3) in a manner such that the RFP process was not adversely affected.

Georgia Power's offer of approximately 88 MW of wholesale capacity from various generating units is consistent with the mandates of the Commission-approved Wholesale Action Plan. Additional information on the Company's offer can be found in the Selected Supporting Information section of Technical Appendix Volume 1. In accordance with the Wholesale Action Plan, the Company now files for certification pursuant to Commission Rule 515-3-4-.04(3)(f) and O.C.G.A. § 46-3A-3. The Company requests that Acceptance and Certification, or rejection, of this offer be determined in the final decision issued in this case.

History of the Capacity Resource Offer

On December 20, 2007, the Commission initiated a proceeding to consider whether it has the authority to require Georgia Power to first make capacity available to retail customers through a competitive solicitation before entering into any new contracts with wholesale customers. The Company and various intervenors submitted comments on the matter. Based upon the comments received, the Commission amended its Procedural and Scheduling Order in Docket No. 26550-U to provide the Parties an opportunity to make a good faith effort to resolve the matter and develop a resource specific plan of action. The Company conferred with other Parties and developed a plan that would provide for the Company to offer certain wholesale capacity blocks to the retail jurisdiction on a one-time basis. At its Administrative Session on July 15, 2008, the Commission approved this Plan, and, subsequently, the Commission Order approving the Plan was filed on July 30, 2008. The Commission has previously certified several offers to bring resources to the retail jurisdiction under the Plan, including resources at Plant Scherer Unit 3 and resources from Wholesale Blocks 1, 2-4, and 5&6.

The Company's offer in this 2022 IRP to bring additional capacity from Blocks 2-4 and Blocks 5&6 to the retail jurisdiction is the next step in the implementation of the Wholesale Action Plan. As required by the July 30, 2008 Order in Docket No. 26550-U, Georgia Power is offering approximately 65 MW of capacity from the Blocks 2-4 Converted Units Resource and approximately 23 MW of capacity from Blocks 5&6 to the retail jurisdiction to serve retail customers when the capacity becomes available from each existing wholesale contract. Please see the Selected Supporting Information section of Technical Appendix Volume 1 for the Company's offer of this capacity.

Certification Process

Terms of Purchase

In conjunction with adherence to the Wholesale Action Plan, the Company offers wholesale block capacity at current market prices based on results of the Company's 2022-2028 Capacity RFP. The specific terms of the offer of the wholesale block capacity to the retail jurisdiction are found in the Selected Supporting Information section of Technical Appendix Volume 1.

Cost of Purchase

The Company proposes to offer the wholesale block capacity under the same MDA construct utilized in previous offers. The MDAs for the Blocks 2-4 Converted Units Resource and Blocks 5&6 would serve to impact base rates by adjusting projected retail revenues. The offer included in the Selected Supporting Information section of Technical Appendix Volume 1 details the purchase cost for the wholesale block capacity.

Proposed Ratemaking Treatment

The assets shall be placed in retail rate base at their current book value, accompanied by the utilization of an MDA. To ensure the proper allocation of the MDA to the retail jurisdiction, the MDA will be treated as an adjustment to retail base revenues available for regulatory purposes, thereby resulting in an adjustment in retail base revenue requirements.

Similar to other assets in retail rate base, all prudently incurred actual fuel costs associated with the resources will be recovered through the FCR process. The assets shall be placed in retail rate base and treated in the same manner as all other generation assets in retail rate base. There are no additional warranties for performance, and the recovery of all costs will be consistent with the recovery for cost on all other retail rate base generation assets. For example, costs incurred due to a change in law will be included in retail rate base; the Company does not warrant any level of availability or heat rate; actual non-fuel O&M costs shall be recovered in retail base rates. For additional details on the offer, please see the Selected Supporting Information section of Technical Appendix Volume 1.

Depreciation Analysis

The estimated depreciation schedule for the Blocks 2-4 Converted Units Resource and Blocks 5&6 can be found in the Selected Supporting Information section of Technical Appendix Volume1.

Cost Benefit Analysis

To comply with the requirement to offer wholesale block capacity on terms equivalent to that which the Company could obtain in the then-current market, Georgia Power is utilizing the same MDA construct as previous offers but is also able to leverage market data from the Company's recently completed 2022-2028 Capacity RFP. The evaluated cost of the last winning bid approved in the 2022-2028 Capacity RFP is added to the projected energy benefits of each wholesale block resource to determine the total market value of each wholesale block resource. By utilizing an MDA for each wholesale block resource, the book value of each resource is accompanied by the MDA such that retail customers pay for only the market value of each wholesale block resource. In this 2022 IRP, the Commission can weigh the cost of adding existing, reliable resources to the retail jurisdiction at the same cost as the last winning bid in the 2022-2028 Capacity RFP against other significant planning decisions. Please refer to the Company's offer presented in the Selected Supporting Information section of Technical Appendix Volume 1 for the economics of the Blocks 2-4 Converted Units Resource and Blocks 5&6.

Analysis of Transmission Impacts

There are no transmission facilities added, modified, or avoided as a result of this certification request.

Impact on 2022 IRP

The return to retail jurisdiction of the wholesale block capacity is not reflected in the various analyses presented in the 2022 IRP. The addition of approximately 65 MW of capacity from the Blocks 2-4 Converted Units Resource in 2024-2034 and approximately 23 MW of capacity from Blocks 5&6 in 2025-2029 would defer future capacity needs by the amount of capacity in each block.

Commission Rule Exception to the RFP Requirement

Pursuant to the Commission's Order Approving Georgia Power Company's Proposal to Offer Certain Wholesale Capacity Blocks to the Retail Jurisdiction, the Company is required to offer certain wholesale capacity blocks to retail customers. As part of the Commission's Order, the Company agreed to offer the wholesale blocks as they become available to the retail jurisdiction (1) on terms equivalent to that which the Company could obtain in the then-current wholesale market, (2) in a manner that would not adversely affect the Company's ability to continue to sell such resources into the wholesale market, and (3) in a manner that the RFP process is not adversely affected. As noted earlier, the Company has made several offers to the Commission since the Commission Order approving the Company's Proposal was issued on July 30, 2008. The Order clearly recognizes the importance of timing of the offers to the ability to remarket capacity and the importance of the IRP in that process. Through prior Orders certifying wholesale-to-retail capacity, the Commission has exempted that capacity from the Commission's RFP rules as specified in Commission Rule 515-3-4-.04. Pursuant to Commission Rule 515-3-4-.04(3)(f)(3), which exempts from the RFP requirement "supply-side capacity resources of extraordinary advantage that require immediate action," the Company requests that the wholesale block capacity offer of approximately 88 MW of capacity be exempted as provided by Commission Rule.

<u>Conclusion</u>

As set forth in the preceding sections, the wholesale block capacity is offered to the retail jurisdiction in compliance with the Wholesale Action Plan and provides a reliable source of capacity and energy from existing resources for Georgia Power customers at a cost-effective market price. Therefore, the Company requests that the Commission Accept and Certify this offer.

ATTACHMENT K. APPLICATION FOR CERTIFICATION OF THE POWER PURCHASE AGREEMENTS WITH SOUTHERN POWER COMPANY FROM PLANTS DAHLBERG, HARRIS, AND WANSLEY AND WITH MPC GENERATING, LLC, FROM THE MPC GENERATING PLANT

Introduction

Pursuant to O.C.G.A. § 46-3A-4, Georgia Power seeks to certify six power purchase agreements ("PPAs") that will be utilized to support an economical and reliable supply of capacity and energy for the Company's retail customers. Specifically, the Company seeks to certify:

1. A ten-year PPA with Southern Power that will provide 660.4 MW of nominal capacity, equivalent to 689.5 MW of winter capacity, and associated energy beginning December 1, 2024, from Plant Harris Unit 2, located in Autauga County, Alabama ("Harris 2 PPA"). The Harris 2 PPA will expire on November 30, 2034.
2. A ten-year PPA with Southern Power that will provide 597.9 MW of nominal capacity, equivalent to 621.7 MW of winter capacity, and associated energy beginning December 1, 2024, from Plant Wansley Unit 7, located in Heard County, Georgia ("Wansley 7 PPA"). The Wansley 7 PPA will expire on November 30, 2034.
3. A ten-year PPA with Southern Power that will provide 228 MW of nominal capacity, equivalent to 255.9 MW of winter capacity, and associated energy beginning January 1, 2028, from three simple cycle CTs, specifically identified as CT01, CT03 and CT05, located at Plant Dahlberg in Jackson County, Georgia ("Dahlberg 1, 3, and 5 PPA"). The Dahlberg 1, 3, and 5 PPA will expire on December 31, 2037.
4. A ten-year PPA with Southern Power that will provide 152 MW of nominal capacity, equivalent to 171.3 MW of winter capacity, and associated energy beginning June 1, 2025, from two, simple cycle CTs, specifically identified as CT02 and CT06, located at Plant Dahlberg in Jackson County, Georgia ("Dahlberg 2&6 PPA"). The Dahlberg 2&6 PPA will expire on May 31, 2035.
5. A ten-year PPA with Southern Power that will provide 228 MW of nominal capacity, equivalent to 258 MW of winter capacity, and associated energy beginning June 1, 2025, from three simple cycle CTs, specifically identified as CT08, CT09 and CT10, located at

Plant Dahlberg in Jackson County, Georgia ("Dahlberg 8-10 PPA"). The Dahlberg 8-10 PPA will expire on May 31, 2035.

6. A fifteen-year PPA with MPC Generating, LLC ("MPC Generating") that will provide 309 MW of nominal capacity, equivalent to 360 MW of winter capacity, and associated energy beginning December 1, 2024, from two dual fuel CTs, specifically identified as W501FC and W501FD1, located at MPC Generating plant in Walton County, Georgia ("Monroe 1&2 PPA"). The Monroe 1&2 PPA will expire on November 30, 2039.

Issuance of the 2022-2028 Capacity Request for Proposals

The six PPAs that will provide a total of 2,175.3 MW of nominal capacity, equivalent to 2,356 MW of winter capacity, and energy to Georgia Power customers were procured through the Company's 2022-2028 Capacity RFP. The 2019 IRP Order approved two capacity-based RFPs as requested in Georgia Power's 2019 IRP filing. First, a 2022-2023 capacity-based RFP was approved to procure replacement capacity in light of economic challenges associated with Plant Bowen Units 1-2 and the potential retirement of such units by December 2023, which was the latest applicability date for compliance with the ELG rule at the time. Second, a 2026-2028 capacity-based RFP was approved to procure replacement capacity in the event the Company decided to retire additional steam units beyond Plant Bowen Units 1-2. Further developments affected both the amount and timing of the Company's future capacity needs, such as the increased renewable procurement resulting from the 2019 IRP Order and an updated load forecast following the 2019 IRP. To allow for the greatest flexibility for retirement and replacement capacity decisions, a single capacity RFP was developed to address all capacity needs between 2022 and 2028.

In accordance with the Commission's RFP rule, an IE was selected by the Commission and retained by Georgia Power on August 29, 2019. The Company drafted the Capacity RFP and the Capacity RFP pro forma PPAs (collectively, the "RFP Documents") with input from Commission Staff and the IE over a period of several months. On April 30, 2020, draft versions of the RFP Documents were posted on the IE Website. From April 30, 2020, through May 18, 2020 ("Comment Period"), potential bidders and interested parties could suggest edits and comment on the RFP Documents through the comment feature on the IE Website. On May 12, 2020, the Company hosted a Bidders Conference webinar where potential bidders and interested parties received more information about the Capacity RFP from Georgia Power, Commission Staff, and the IE. In addition to a Q&A board and the comment feature on the IE Website, the Bidders

Conference provided interested parties further opportunity to submit questions and comment on the RFP Documents. Georgia Power received approximately 42 comments and 38 questions from interested parties throughout the Comment Period. The Company then reviewed its responses to each Comment with the Commission Staff and the IE, and thereafter responded to each comment. On July 1, 2020, Georgia Power filed the draft RFP Documents, which reflected feedback received from all interested parties throughout the drafting process. The Commission approved the RFP Documents on August 6, 2020.

On August 31, 2020, Georgia Power issued the 2022-2028 Capacity RFP to the market, seeking to procure 1,000 to 3,000 MW of capacity and energy from facilities sized between 100 and 1,200 MW. Eligible facilities included resources already in commercial operation or new capacity resources to be constructed. Proposals could be structured as PPA bids, Asset Purchase and Sale Agreement ("APSA") bids, or Company-owned Proposals. PPA bids of existing or new resources were required to commence delivery between 2025 and 2028. APSA bids of existing resources could begin delivery as early as 2022 if the bid evaluation determined that was an economical option for customers. Company-owned Proposals of new resources were required to commence delivery between 2025 and 2028. All proposals could utilize any type of energy resource, provided the resource could meet the required firmness and dispatchability criteria as specified in the RFP Documents. By the bid due date on October 9, 2020, Georgia Power had received 70 proposals for more than 25,000 MW from eleven different bidding companies.

Bid Evaluation

In accordance with the RFP Documents, and the RFP Rules, an evaluation process was established to evaluate the proposals that included an initial screening, selection of the Competitive Tier, a pricing refresh, a detailed evaluation, selection of the Short List and Reserve List, and the execution of selected winning contracts.

The initial screening assessed bids and bidders for compliance with the basic requirements as defined in the RFP Documents. This occurred after the bid due date and was conducted by the IE with the assistance of the Company and under the oversight of Commission Staff.

Bid proposals that met the responsiveness screens were evaluated and ranked using a net evaluated cost analysis approach. The net evaluated cost determined for each proposal was the NPV of the generation and transmission aspects of each proposal in dollars per kilowatt ($/kW). Following the responsiveness screens, proposals were ranked on a generation-only basis. The net generation cost was comprised of the fixed costs of each proposal as well as the variable costs and energy benefits associated with the operational parameters of each proposal, which were used in production cost model simulations. The Strategist production cost model was used to quantify the energy benefits of a particular offer when dispatched with Southern Company generating resources. All PPA bids were evaluated on a ten-, fifteen-, or thirty-year basis, respective to the term submitted in each bidder's proposal. APSA bids were assumed to operate for the expected remaining useful life of the specific asset proposed. Company-owned Proposals were evaluated over the expected useful life associated with the technology included in the proposal. The Company evaluated all proposals over a common study period that concluded with the end of the longest expected useful life, which was forty years for a Company-owned Proposal. A generic combustion turbine filler unit was utilized in years prior to the RFP required commencement date for proposals with anticipated contract commencement dates that were beyond the RFP required commencement date. A generic combustion turbine filler unit was also utilized on the backend of proposals for which the expiration or end of useful life occurs prior to the end of the study period.

Georgia Power selected the Competitive Tier on March 30, 2021, based on the net generation cost of all proposals. This Capacity RFP utilized a "competitive tier and refresh process" as defined in the Commission's RFP Rule and the RFP document. Following selection for the Competitive Tier, all bidders were allowed a one-time opportunity to refresh the pricing of their proposal(s) as a final best offer. Following the bid refresh due date of July 2, 2021, Georgia Power conducted a detailed evaluation of the Competitive Tier proposals. The detailed evaluation calculated a net evaluated cost in dollars per kilowatt ($/kW) for each proposal and included evaluation of both generation and transmission. As part of this process, proposals were analyzed using a consistent methodology that was locked down prior to the receipt of bids.

The detailed Competitive Tier evaluation results were used to select a Short List comprised of nine proposals. Following this selection and notification of status to all parties per the RFP rule, the Company, Commission Staff, and the IE met with all Short-Listed bidders individually to discuss their bids and to clarify or acquire any additional information necessary that could affect the detailed evaluation. After the bidder meetings and consultation with Commission Staff and the IE, Georgia Power placed two proposals on the Reserve List and continued to evaluate the seven remaining Short List proposals.

Portfolio Analysis

To identify the best portfolio of supply-side resources for satisfying the Company's needs, a portfolio analysis is necessary if: (1) more than one proposal is necessary to satisfy the need; and (2) there is a moderate to significant level of transmission interaction between proposals. The Company performed a portfolio analysis for six proposals and then again for seven proposals. The six-bid portfolio provides projected transmission savings when compared to the seven-bid portfolio and the six-bid portfolio reliably meets Georgia Power's projected capacity needs through 2028. Following portfolio analysis, Georgia Power proposed that the six proposals be selected as the winning portfolio and proceed to contract execution. Both Commission Staff and the IE concurred with the Company's selection.

Winning Bidders' PPAs

As stated above, the winning bidders are Southern Power and MPC Generating, a subsidiary of Southeast PowerGen, LLC ("Winning Bidders"). Southern Power is a wholly owned subsidiary of Southern Company and is an affiliate of Georgia Power.

The Company negotiated with the Winning Bidders to adapt the pro forma PPAs to the Winning Bidders' facilities. The PPAs were executed by the Company and the Winning Bidders on December 2, 2021, and the PPAs are expressly conditioned on the Commission's approval. The Winning Bidders' PPAs will provide the Company with a total of 2,175.3 MW of nominal capacity and energy. Five of the six winning PPAs have ten-year terms that commence between December 1, 2024, and January 1, 2028. The Monroe 1&2 PPA has a fifteen-year term that commences on December 1, 2024. The Winning Bidders will supply capacity from existing natural gas facilities that are in commercial operation in Heard County, Jackson County, and Walton County, Georgia and Autauga County, Alabama. Trade Secret and Public Disclosure versions of the Winning Bidders' PPAs are provided in Technical Appendix Volume 4. No approval of any other state commission or federal entity was necessary for the parties to execute the PPAs. However, the Southern Power PPAs remain subject to FERC approval, which Southern Power will seek if the Commission certifies the Southern Power PPAs.

Cost Recovery

Georgia Power proposes to recover the costs associated with the Winning Bidders' operating and finance lease PPAs in its retail cost of service, consistent with other PPAs certified by the

Commission. For the PPAs that are treated as operating leases, the assets and obligations will be included in rate base. For the PPAs that are treated as finance leases, the assets will be included in rate base, and the finance lease obligations will be included in cost of capital as a component of long-term debt. Per current accounting guidance, the extension of some existing PPAs that were formerly treated as operating leases may require that they be recognized as finance leases as of the effective date of new PPAs for the same generating assets.

Additional Sum

The IRP statute, O.C.G.A. § 46-3A-8, specifies that the Company is entitled to an additional sum for purchased power resources. When calculating an additional sum, the statute requires that lost revenues, changed risks, and an equitable sharing of benefits between the utility and its retail customers be considered. The Company has calculated the benefit of contracting with the Winning Bidders compared to developing the Company-owned Proposal in this solicitation. Consistent with other sharing mechanisms approved by the Commission, the Company proposes that 20% of the benefits be retained by the Company and 80% of the benefits be retained by Georgia Power's retail customers.

The Company is requesting an additional sum of $8.63/kW-year, $9.03/kW-year, $8.67/kW-year, $8.12/kW-year, $6.70/kW-year, and $6.77/kW-year for the Wansley 7, Dahlberg 2&6, Harris 2, Dahlberg 1, 3, and 5, Monroe 1&2, and Dahlberg 8-10 PPAs, respectively.

Company-Owned Assets

Per Commission Rule 515-3-4-.04(3)(f)7, it is the Commission's policy that investor-owned electric utilities under its regulation shall maintain a minimum percentage of their capacity as "self-owned" rate-based assets. Such percentage shall be set by Commission order and may be changed from time to time. In situations in which the soliciting utility is nearing or finds that it would fall below this minimum percentage level, the soliciting utility shall inform the Commission of this eventuality in advance of the RFP Process at which time the Commission, in its discretion, may suspend these rules and provide guidance to the soliciting utility as to how it should proceed.

In the 2001 IRP Final Order, the Commission set the limit of supply-side capacity provided through purchased power contracts to 30 percent of total supply-side resources and stated that when the limit is reached, the utility will meet its next capacity need through a traditional self-build project to be placed in rate base. Certification of the Winning Bidders' PPAs will result in the Company surpassing the 30 percent limit in 2029 and 2030. The Company is providing this notice in advance of its next capacity procurement and in compliance with Commission Rule 515-3-4-.04(3)(f)7.

Conclusion

The 2,175.3 MW of nominal capacity, equivalent to 2,356 MW of winter capacity, from the Winning Bidders' PPAs provide the best-cost solution to reliably meet Georgia Power's capacity needs through 2028. The RFP process ensured fair and equal treatment of all bidders. Commission Staff and the IE were involved throughout the process from the development of the RFP Documents through the evaluation of proposals and negotiations between the Company and the Winning Bidders. The use of the IE Website for questions and comments regarding this RFP further ensured that the process was not only fair and equitable, but also transparent to all participants. The IE report regarding Georgia Power's 2022-2028 Capacity RFP will be filed in the 2022 IRP detailing the process and the IE's evaluation of the solicitation.

The evaluation process involved a thorough analysis of the market options available in the 2022-2028 period. The analysis was consistent and fair to all parties. The combination of the resources identified for certification represents the best-cost option available for reliably meeting Georgia Power's capacity needs in 2022-2028. Therefore, the Company requests that the Commission certify the six PPAs identified through the 2022-2028 Capacity RFP and grant the Company cost recovery, and an additional sum, as described above.

ATTACHMENT L. APPLICATION FOR DECERTIFICATION OF PLANT WANSLEY UNITS 1-2 AND 5A, PLANT BOULEVARD UNIT 1, PLANT BOWEN UNITS 1-2, PLANT GASTON UNITS 1-4 AND A, AND PLANT SCHERER UNIT 3

Introduction

Together with the 2022 IRP, the Company hereby files this Application for Decertification of Plant Wansley Units 1-2 and 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant Gaston Units 1-4 and A, and Plant Scherer Unit 3 (“2022 Decertification Application”) pursuant to O.C.G.A. § 46-3A-3 and Commission Rule 515-3-4-.08. The units presented for decertification represent 3,581 MW of winter generating capacity for Georgia Power. The Company hereby incorporates by reference all other portions of the Company’s 2022 IRP filing into this 2022 Decertification Application.

Decertification Requests

Need for Decertification

As described in CHAPTER 1 and CHAPTER 11 of the IRP Main Document, an orderly retirement and decertification plan for Plant Wansley Units 1-2 and 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant Gaston Units 1-4 and A, and Plant Scherer Unit 3 is in the best interest of customers. While these units have provided benefits to customers over the years, the analysis provided in the Unit Retirement Study in Technical Appendix Volume 2 demonstrates that retirement of these units is in the best interest of all customers.

Plant Wansley Units 1-2 are coal-fired units that were placed in service in 1976 and 1978, each with a generating capacity of 872 MW. Plant Wansley Unit 5A is an oil-fired combustion turbine that was placed in service in 1980, with a winter generating capacity of 60 MW. Plant Wansley Unit 5A has zero summer generating capacity due to non-attainment area run-time restrictions. Georgia Power owns 53.5% of Plant Wansley, resulting in Georgia Power capacity of 466.52 MW from each coal-fired unit and 32.1 MW from the oil-fired unit. Plant Boulevard Unit 1 is an oil-fired combustion turbine with a generating capacity of 18.6 MW that was placed in service in 1970. Plant Bowen Units 1-2 are coal-fired units that were placed in service in 1971 and 1972. Unit 1 has a capacity of 714 MW, and Unit 2 has a capacity of 718 MW. Plant Gaston Units 1-4 were placed in service as coal-fired units in 1960-1962 but were converted to natural gas-fired units in

2015 and 2016. Units 1 and 3 each have a capacity of 254 MW, and Units 2 and 4 each have a capacity of 256 MW. Plant Gaston Unit A is an oil-fired combustion turbine with a generating capacity of 20 MW that was placed in service in 1970. Plant Gaston Units 1-4 and A are owned by Southern Electric Generating Company ("SEGCO"), a joint venture of Alabama Power and Georgia Power. One half of each SEGCO unit is made available to Georgia Power through a 1959 Power Contract between SEGCO, Alabama Power, and Georgia Power, resulting in Georgia Power capacity of 127 MW from Units 1 and 3, 128 MW from Units 2 and 4, and 10 MW from Unit A. Plant Scherer Unit 3 is a coal-fired unit with a generating capacity of 860 MW that was placed in service in 1987. Georgia Power owns 75% of Plant Scherer Unit 3, resulting in Georgia Power capacity of 645 MW. The economic analyses for Georgia Power's ownership of Plant Wansley Units 1-2 and 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant Gaston Units 1-4 and A, and Plant Scherer Unit 3 are contained in the Unit Retirement Study in Technical Appendix Volume 2. The analysis for each unit shows that long-term continued operations is no longer in the best interest of customers.

Analysis of Transmission Impacts

In accordance with the Commission's order in Docket No. 31081, the Company performed an analysis of the results of the requested decertifications on transmission facilities. The Company's transmission analysis accounted for the simultaneous or overlapping retirement of this portfolio of resources. The results of this assessment include certain transmission system upgrades required to support retirement. The results of this analysis are included in Selected Supporting Information section of Technical Appendix Volume 1.

Plant	Project Name	Project Need Year	Impact
Plant Wansley Unit 5A	N/A	N/A	N/A
Plant Boulevard Unit 1	N/A	N/A	N/A
Plant Wansley Units 1-2	BULL CREEK - VICTORY DRIVE 115 KV	2024	Projects are needed if Plant Wansley Units 1-2 are retired.
Plant Wansley Units 1-2	KLONDIKE-NORCROSS 500KV (SWITCH REPLACEMENT)	2024	
Plant Wansley Units 1-2	ARKWRIGHT - LLOYD SHOALS 115 KV	2024	
Plant Wansley Units 1-2	TENASKA - HEARD CO 500 KV	2024	
Plant Wansley Units 1-2	BLAKELY PRIMARY - WEBB (APC) 115 KV	2026	
Plant Wansley Units 1-2	CORN CRIB - LAGRANGE 115 KV	2027	
Plant Wansley Units 1-2	ARLINGTON PRIMARY - DAWSON PRIMARY 115KV	2028	
Plant Bowen Units 1-2	LAGRANGE - NORTH OPELIKA 230 KV	2027	Projects are needed if Plant Bowen Units 1-2 are retired along with Plant Wansley Units 1-2.
Plant Scherer Units 1-3	MORROW - YATES COMMON 115 KV	2028	Projects are needed if Plant Scherer Units 1-3 are retired along with Plant Wansley Units 1-2 and Plant Bowen Units 1-2.
Plant Scherer Units 1-3	S COWETA BANK A	2028	
Plant Scherer Units 1-3	HOLLINGSWORTH FERRY - YELLOW DIRT 230 KV	2028	
Plant Scherer Units 1-3	DRESDEN - HOLLINGSWORTH FERRY 230 KV	2028	
Plant Scherer Units 1-3	GORDON - SANDERSVILLE #1 115 KV	2028	
Plant Scherer Units 1-3	BONAIRE PRIMARY - BUTLER 230 KV	2028	
Plant Scherer Units 1-3	HAMMOND - WEISS DAM (APC) 115 KV	2030	
Plant Gaston Units 1-4, A	N/A[1]	N/A	N/A

Cost Recovery

In connection with the proposed decertifications, the Company requests that the Commission approve the following:

1. Reclassification of the remaining net book value of Georgia Power's ownership of Plant Wansley Units 1-2, Plant Bowen Units 1-2, and Plant Scherer Unit 3 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period to be determined by the Commission in the Company's future base rate cases, consistent with treatment of such balance in the 2019 IRP Order

2. Reclassification of the remaining net book value of Plant Wansley Unit 5A and Plant Boulevard Unit 1 as of their respective retirement dates to regulatory asset accounts and

the amortization of such regulatory asset accounts ratably over a 3-year period in the next base rate case; and

3. Reclassification of any unusable material and supplies inventory balance remaining on the unit retirement dates to a regulatory asset for recovery over a period to be determined by the Commission in the Company's next base rate case, consistent with treatment of such balance in the 2016 and 2019 IRP Orders.

Conclusion

As set forth in the Company's 2022 IRP, Georgia Power's current supply-side plan, which incorporates the requested decertifications contained herein, is sufficient to provide cost-effective and reliable sources of capacity and energy for customers. The known and reasonably expected effects of these retirements on the Company's 2022 IRP are described more fully in the IRP Main Document and the Technical Appendices. The requests contained in this 2022 Decertification Application are in the public interest and substantially comply with the relevant Commission rules. Therefore, the Company requests that the Commission approve the following:

1. Decertification of Plant Wansley Units 1-2 and 5A and Plant Boulevard Unit 1 effective as of August 31, 2022.

2. Decertification of Plant Bowen Units 1-2 effective upon the completion of transmission system improvements, which is projected to be no later than December 31, 2027.

3. Decertification of Plant Gaston Units 1-4 and A and Plant Scherer Unit 3 effective by December 31, 2028.

4. The related cost recovery as detailed in the Cost Recovery section of this 2022 Decertification Application.

ATTACHMENT M. ACRONYMS, ABBREVIATIONS, AND TERMINOLOGY

2019 IRP Order	Commission Order on July 29, 2019, approving the 2019 IRP with modifications
2022 Decertification Application	Application for Decertification of Plant Wansley Units 1-2 and 5A, Plant Boulevard Unit 1, Plant Bowen Units 1-2, Plant Gaston Units 1-4 and A, and Plant Scherer Unit 3
$50	$50 CO_2 price path and fifty-dollar carbon
Additional Offer Request Date	On or before January 1, 2023
AEO	Annual Energy Outlook
AFB	Air Force Base
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
AI	Artificial Intelligence
APC	Alabama Power Company
APSA	Asset Purchase and Sale Agreement
ARO	Asset Retirement Obligation
AURORA	See model description in ATTACHMENT C
B21	Budget 2021
B22 or B2022	Budget 2022
BESS	Battery energy storage system
Blackstart Resources	Defined by the NERC Reliability Standards[1] as "a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan
Blocks 2-4 Converted Units Resource	Capacity from Plant Yates Units 6&7
Blocks 2-4 Coal Block Resource	Capacity from Plant Scherer Unit 3
Blocks 5&6	Capacity from Plant McManus Units 3A-3C and 4A-4F and Plant Wilson Units 1A-1F
C&I	Commercial & Industrial
CARES	Clean And Renewable Energy Subscription
CC	Combined cycle
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CCSP	Customer-Connected Solar Program

CDH	Cooling degree hours
CFE-ATC	Carbon Free Energy – Around the Clock
CO_2	Carbon dioxide
CO_2 Intensity	Greenhouse gas pressure view that involves annual limits on the amount of carbon dioxide that the Company could emit
Comment Period	The timeframe from April 30, 2020 through May 18, 2020 in which potential bidders and interested parties could suggest edits and comment on the RFP Documents
Commission	Georgia Public Service Commission
Company	Georgia Power Company
CRA	Charles River Associates
CRSP	Customer Renewable Supply Procurement
CS	Customer-Sited
CSE	Cost of Saved Energy
CT	Combustion turbine
DAC	Direct Air Capture
Dahlberg 1, 3, and 5 PPA	A ten-year PPA with Southern Power that will provide 228 MW of nominal capacity, equivalent to 255.9 MW of winter capacity, and associated energy beginning January 1, 2028, from three simple cycle CTs, specifically identified as CT01, CT03 and CT05, located at Plant Dahlberg in Jackson County, Georgia
Dahlberg 2&6 PPA	A ten-year PPA with Southern Power that will provide 152 MW of nominal capacity, equivalent to 171.3 MW of winter capacity, and associated energy beginning June 1, 2025, from two, simple cycle CTs, specifically identified as CT02 and CT06, located at Plant Dahlberg in Jackson County, Georgia
Dahlberg 8-10 PPA	A ten-year PPA with Southern Power that will provide 228 MW of nominal capacity, equivalent to 258 MW of winter capacity, and associated energy beginning June 1, 2025, from three simple cycle CTs, specifically identified as CT08, CT09 and CT10, located at Plant Dahlberg in Jackson County, Georgia
DC	Direct Current
DER	Distributed Energy Resource
DER Customer Program	Customer-focused program that addresses the emerging resilience needs of commercial and industrial customers through dispatchable DER-based solutions, while also providing demand response value to the benefit of all customers
DERMS	Distributed Energy Resource Management System
DG	Distributed generation
DOE	Department of Energy

DPEC	Demand Plus Energy Credit
DRC-1	Demand Response Credit Tariff
DSM	Demand-Side Management
DSMWG	Demand-Side Management Working Group
DSOs	Demand-side options
ECCR	Environmental Compliance Cost Recovery
ECS	Environmental Compliance Strategy
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitations Guidelines
EMP	Electromagnetic Pulse
EOO	Energy Offset Only
EPA	Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPD	Environmental Protection Division
EPRI	Electric Power Research Institute
ESS	Energy Storage Systems
EV	Electric Vehicle
FCR	Fuel Cost Recovery
FEED	Front-End Engineering and Design
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FPC	Federal Power Commission
FPL	Florida Power and Light
GDOT	Georgia Department of Transportation
GDP	Gross Domestic Product
Georgia Power	Georgia Power Company
GHG	Greenhouse gas
GMD	Geomagnetic Disturbance
GTC	Georgia Transmission Corporation
Harris 2 PPA	A ten-year PPA with Southern Power that will provide 660.4 MW of nominal capacity, equivalent to 689.5 MW of winter capacity, and associated energy beginning December 1, 2024, from Plant Harris Unit 2, located in Autauga County, Alabama
HDH	Heating Degree Hours
HG0	High gas prices and zero carbon
HG20	High gas prices and twenty-dollar carbon
Hydro	Hydroelectric
ICE	Incremental Capacity Equivalent
IE	Independent Evaluator

IHS Markit	Information Handling Services Markit
IIC	Intercompany Interchange Contract
IRP	Integrated Resource Plan
IRP Act	Integrated Resource Planning Act of 1991
ITS	Integrated Transmission System
ITS Participants	Georgia Power, Georgia Transmission Corporation, MEAG Power, and Dalton Utilities
JEA	Jacksonville Electric Authority
KW	Kilowatt
kWh	Kilowatt Hour
LG0	Low gas prices and zero carbon
LG20	Low gas prices and twenty-dollar carbon
LoadMAP	Load Management Analysis and Planning
LOLE	Loss of Load Expectation
MARTA	Metropolitan Atlanta Rapid Transit Authority
MDA	Market Differential Adjustment
MEAG Power	Municipal Electric Authority of Georgia
MG0	Moderate gas, zero-dollar carbon
Monroe 1&2 PPA	A fifteen-year PPA with MPC Generating, LLC that will provide 309 MW of nominal capacity, equivalent to 360 MW of winter capacity, and associated energy beginning December 1, 2024, from two dual fuel CTs, specifically identified as W501FC and W501FD1, located at MPC Generating plant in Walton County, Georgia
MPC	Mississippi Power Company
MPC Generating	MPC Generating, LLC
MSA	Master Service Agreement
MUSH	Municipalities, universities, schools, and hospitals
MW	Megawatt
MWh	Megawatt hour
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NGCC	Natural Gas Combined Cycle
NGCC-CCUS	Natural Gas Combined Cycle with Carbon Capture and Utilization or Storage
NGCT	Natural Gas Combustion Turbine
NOI	Notice of Intent
NOPP	Notice of Planned Participation
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance

Operating Companies	Georgia Power Company, Alabama Power Company, Mississippi Power Company, and Southern Power Company
PACT	Program Administrator Cost Test
PHA	Pollinator Habitat Area
PIA	Public Interest Advocacy
Pool	The Operating Companies operate their respective electric generating facilities and conduct their system operations
PPAs	Power Purchase Agreements
PRICEM	Profitability Reliability Incremental Cost Evaluation Model - See model description in ATTACHMENT C
PT	Participants Test
PURPA	Public Utility Regulatory Policies Act
PURPA Final Order	The Georgia Public Service Commission's Final Order in Docket Nos. 4822, 16573, and 19279, issued March 11, 2021
PV	Photovoltaic
QF	Qualifying Facilities
R&D	Research and Development
R3	Retail REC Retirement
RAST-1	Resilience Asset Service Tariff
RCB	Renewable Cost Benefit
REC	Renewable Energy Credit
Reconsideration Rule	2020 ELG Reconsideration Rule
REDI	Renewable Energy Development Initiative
Resource Adequacy	The ability of supply-side and demand-side resources to meet electrical demand and maintain an appropriate level of system reliability
Retail OpCos	Georgia Power Company, Alabama Power Company, and Mississippi Power Company
RFP	Request for Proposals
RFP Documents	the Capacity RFP and the Capacity RFP pro forma PPAs
RICE	Reciprocating internal combustion engine
RIM	Rate Impact Measure
RISE	Residential Investment for Saving Energy
RNR	Renewable Non-Renewable
RNR-Monthly Netting	A monthly netting calculation of the RNR tariff
RPS	Renewable Portfolio Standard
SAM	Standard Analysis Model - See model description in ATTACHMENT C
SCR	Selective Catalytic Reduction
SCS	Southern Company Services
SCT	Societal Cost Test

SEEM	Southeast Energy Exchange Market
SEGCO	Southern Electric Generating Company
SEIA	Solar Energy Industries Association
SEPA	Smart Electric Power Alliance
SER	Safety Evaluation Report
SERC	Southeastern Electric Reliability Council
SERVM	Strategic Energy Risk Evaluation Model - See model description in ATTACHMENT C
SLR	Subsequent License Renewal
SLRA	SLR Application
SPC	Southern Power Company
SR	Southern Research
System	Southern Company System
Target Reserve Margin	The generation capacity required above the forecasted peak demand
The Ray	MZC Foundation d/b/a The Ray
TP-E	Transmission Planning-East
TRC	Total Resource Cost
US	United States
VaDER	Variable and Distributed Energy Resource
VAR	Volt-Amps Reactive
VCM	Vogtle Construction Monitoring
VIP	Voluntary Incentives Program
Wansley 7 PPA	A ten-year PPA with Southern Power that will provide 597.9 MW of nominal capacity, equivalent to 621.7 MW of winter capacity, and associated energy beginning December 1, 2024, from Plant Wansley Unit 7, located in Heard County, Georgia
Wholesale Action Plan	Order approving Georgia Power Company's Proposal to Offer Certain Wholesale Capacity Blocks to Retail Jurisdiction, Docket No. 26550-U (July 30, 2008)
Winning Bidders	Southern Power and MPC Generating, a subsidiary of Southeast PowerGen, LLC