Santee Cooper

Integrated Resource Plan 2024 Update

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EXECUTIVE SUMMARY

Santee Cooper submits to the Public Service Commission of South Carolina ("Commission") this Integrated Resource Plan 2024 Update ("2024 IRP Update") as an update to its triennial 2023 Integrated Resource Plan ("2023 IRP") approved by the Commission in Order 2024-171.

The 2024 IRP Update includes changes to base planning assumptions[1] and evaluates impacts on Santee Cooper's Preferred Portfolio identified in the 2023 IRP. This 2024 IRP Update also provides the status of items identified in the 2023 IRP's Short-Term Action Plan, including resource actions, pursued collaboratively with Central Electric Power Cooperative, Inc. ("Central"), to meet near-term capacity needs. Santee Cooper values the input received from stakeholders during the preparation of this 2024 IRP Update, and the planning process has benefited from stakeholder input.

Santee Cooper respectfully submits this 2024 IRP Update to the Commission for consideration and acceptance.

KEY CONCLUSIONS

The analyses performed for the 2024 IRP Update confirm the primary conclusions reached in the 2023 IRP regarding preferred resource additions to the Combined System[2] portfolio:

- Development of a large natural gas combined cycle ("NGCC") facility of approximately 1,000 MW to coincide with the retirement of Winyah.
- Addition of substantial new solar resources totaling 1,500 MW by 2030 and 3,500 MW by 2040.
- Addition of natural gas combustion turbine ("NGCT") and battery energy storage system ("BESS") to meet system peaking needs beginning in the late 2020s.

Due to the increase in the Combined System load forecast, as discussed later in this Executive Summary and in the body of this report, the 2024 IRP Update identifies the following resource additions and changes beyond those recommended in the 2023 IRP:[3]

- Conversion of Rainey Generating Station ("Rainey") combustion turbines ("NGCT") 2A and 2B to combined cycle and upgrades to other NGCT and NGCC resources at Rainey. The conversion and upgrades add over 250 MW of capacity to the system by year-end 2027.
- Acceleration and addition of more peaking capacity and BESS capacity to meet projected increasing demand:
    - Addition of 250 MW of BESS capacity by year-end 2027

[1] The major changes to base planning assumptions include a significantly higher load forecast, higher long-term natural gas prices, higher capital costs for new NGCC and NGCTs, and higher projected PPA prices for solar and BESS resources.
[2] The term "Combined System" refers to the power supply resources and bulk transmission network of Santee Cooper and Central.
[3] Depicted resources are for the 2024 Portfolio with PPAs, described more fully below and in the report section entitled 2024 Portfolios Evaluated.

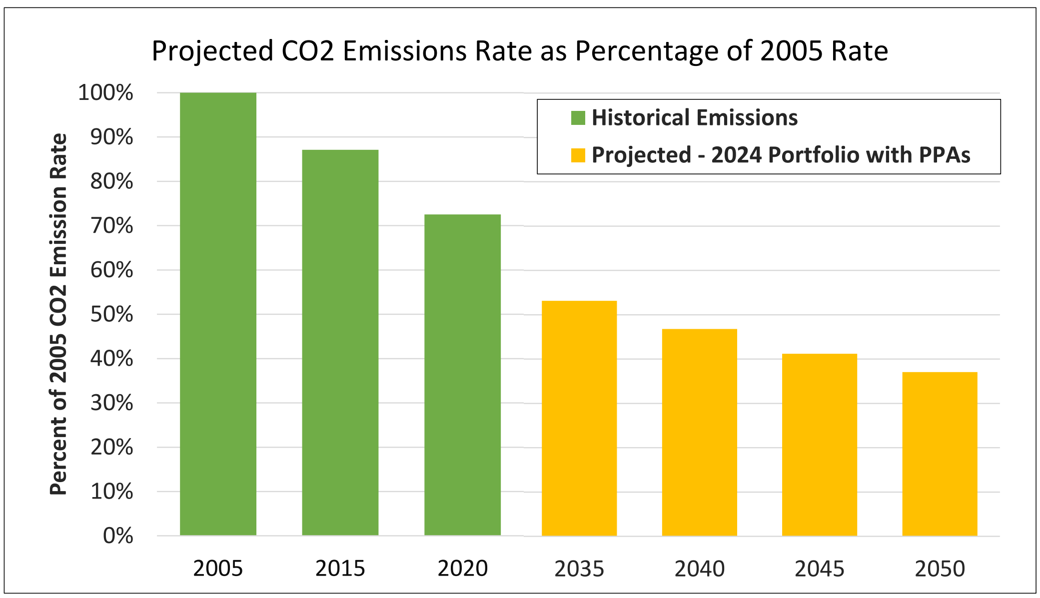
- Addition of a 447 MW NGCT by 2031
- Power Purchase Agreements ("PPAs") sized to meet demand in the 2030s

As is demonstrated by the results of evaluations presented herein, each of the evaluated portfolios selects one or more NGCC, NGCT, solar, and BESS resources, whether the longer-term goal for the Combined System is to minimize costs, phase out coal resources under Greenhouse Gas ("GHG") regulations, or consider PPA options during the 2030s. Moreover, the NGCC and solar resource options were found to be appropriate whether the future brings lower or higher load levels or lower or higher fuel prices.

The resource changes identified above would provide several benefits as described below. These benefits are very similar to the benefits from the 2023 Preferred Portfolio demonstrated in the 2023 IRP.

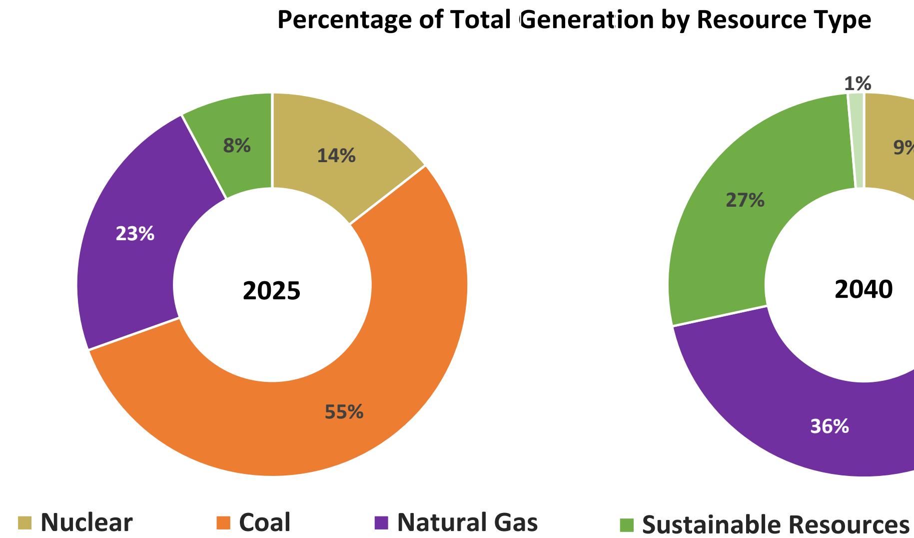
- Reduction of CO_2 emissions rates to approximately 47 percent of 2005 levels by 2040 as shown in Figure 1, based on the selected portfolio as discussed later herein.

Figure 1. Projected CO_2 Emissions



- Significantly improved portfolio diversity, reducing risks to customers. Figure 2 illustrates significant improvements in resource diversity that are achieved by 2040. Reliance on coal would be reduced to less than half and the proportion of energy provided from sustainable resources would more than triple, mostly due to additions of solar resources.

Figure 2. Projected Change in Energy by Fuel Type



- Instead of being largely reliant on coal, the portfolio would rely on a diverse mix of natural gas, sustainable, and coal resources, which reduces risk to customers.
- The resource options offer flexibility to further adjust as conditions change or if customer demand for electricity is higher or lower than currently projected.

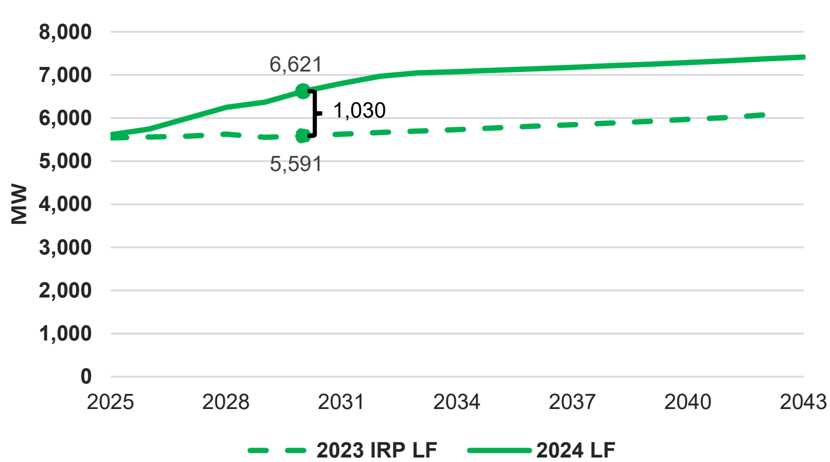
Finally, the resource changes are appropriate irrespective of the outcome of legal challenges to the EPA's recently published final rule regulating GHG emissions.

KEY DRIVERS AND CONSIDERATIONS

2024 LOAD FORECAST

The load forecast is a key assumption for resource evaluations, and Santee Cooper and Central work collaboratively to develop the Combined System load forecast. Since the development of the load forecast used for the 2023 IRP, Santee Cooper and Central's member cooperatives have received multiple inquiries for potential service from industrial and other customers, many with substantial new peak demand and energy requirements. This trend is consistent with observations from utilities in many parts of the country, including the Southeast. The Commission recognized this trend and ordered Santee Cooper to "engage stakeholders to discuss the additional economic development in the state and how best to

Figure 3. Forecast Winter Peak Demand



incorporate and anticipate new loads into its load forecast." Santee Cooper has incorporated these recommendations into its 2024 load forecasting process to plan for new loads. In addition, Santee Cooper sought and incorporated input from stakeholders regarding the approach used to forecast new large loads. Figure 3 highlights the difference in winter peak demand from the 2023 IRP load forecast to the 2024 IRP Update, which is projected to reflect an increase of over 1,000 MW by the early 2030s as a result of new customers that have joined the system and the adjustment for potential loads. This increase in demand is the key driver of the need for additional resources identified in the 2024 IRP Update relative to the 2023 IRP.

GREENHOUSE GAS REGULATIONS

The U.S. Environmental Protection Agency published a final rule ("EPA GHG Rule") in the Federal Register regulating the emission of GHGs from new gas-fired combustion turbines and existing coal, oil, and gas-fired steam generating units. As of the filing of the 2024 IRP Update, twenty-five states, including South Carolina, have filed for an appeal of the rule with the U.S. Court of Appeals for the D.C. Circuit Court ("D.C. Circuit Court"), which denied a request to stay the rule during proceedings. These states have additionally filed an emergency appeal with the U.S. Supreme Court to stay the rule pending proceedings and final decisions by the D.C. Circuit Court.

Under the EPA GHG Rule, coal units must either cease operations before January 1, 2032, or choose one of two potential compliance pathways: (i) convert to co-fire with natural gas before January 1, 2030 (at 40 percent or greater co-firing) and cease all operations before January 1, 2039; or (ii) implement 90 percent carbon capture and sequestration ("CCS") before January 1, 2032. Neither compliance pathway is expected to be viable for Santee Cooper and therefore our current analysis of the impacts of the EPA GHG Rule assumes ceasing operations of Cross Generating Station ("Cross") by 2032.

New natural gas-fired combustion turbine and combined cycle electric generating units have three potential compliance pathways as follows.

i. Base load units (i.e., units operating at greater than 40 percent annual capacity factor) must meet CO_2 emission standards for highly efficient combined cycle generation upon startup and then must comply with 90 percent CCS before January 1, 2032.

ii. Intermediate load units (i.e., units operating at annual capacity factors between 20 percent and 40 percent) must meet CO_2 emission standards for highly efficient simple cycle generation (CO_2 emissions rate of less than 1,170 lbs/MWh).

iii. Low load units (i.e., units operating at annual capacity factors less than 20 percent) must utilize low-emitting fuels (CO_2 emission rate of less than 160 lbs/MMBtu).

Existing combustion turbines (whether operated as simple cycle or combined cycle units) are not addressed in the final EPA GHG Rule.

For the 2024 IRP Update, Santee Cooper has evaluated a resource portfolio that meets the requirements of the EPA GHG Rule, and the results presented in this report show significant potential costs to customers and implementation challenges to comply with the rule as currently written. The EPA GHG Rule would increase the need for resources upon the retirement of Cross, including the need for additional NGCC, NGCT, renewable, and BESS resources. The resource changes identified in the 2024 IRP Update are similar in all resource portfolios evaluated, including portfolios that would be developed if the Rule survives in its present form. This confirms that the recommended resource changes are robust and would contribute to meeting the goals of the EPA GHG Rule.

Santee Cooper will continue to evaluate compliance pathways for the EPA GHG Rule and will monitor the status of the rule and legal challenges.

RESOURCE ADDITIONS THROUGH 2030

As noted above, the 2024 Load Forecast projects a significant increase in loads for the Combined System, resulting in the need for substantial resource additions over the next few years and into the future. Santee Cooper, working collaboratively with Central, has identified several resources, including both short-term PPAs and longer-term resources that can help meet this need. The acquisition and planning for these resources is consistent with the Short-Term Action Plan developed for the 2023 IRP.

NEAR-TERM RESOURCE ADDITIONS

Since filing the 2023 IRP, Santee Cooper has worked with Central to identify and secure several purchased power resources summarized in Table 1, below. To meet the system's near-term capacity needs through 2030, Santee Cooper is currently evaluating potential extensions to certain purchases identified below.

Table 1. Power Purchase Agreements

Resource	Term End Date/Year	Capacity (MW)
Purchase 1	2024-2028	200
Purchase 2	2024-2028	50
Purchase 3	2025-2028	150
Purchase 4	2024	47

Subsequent to the filing of the 2023 IRP, Santee Cooper also acquired the Cherokee facility, which is a 98 MW NGCC located in Gaffney, South Carolina. The power purchases and Cherokee facility add valuable capacity and energy to the system and help meet planning reserve margins to ensure system reliability.

RAINEY UPGRADES

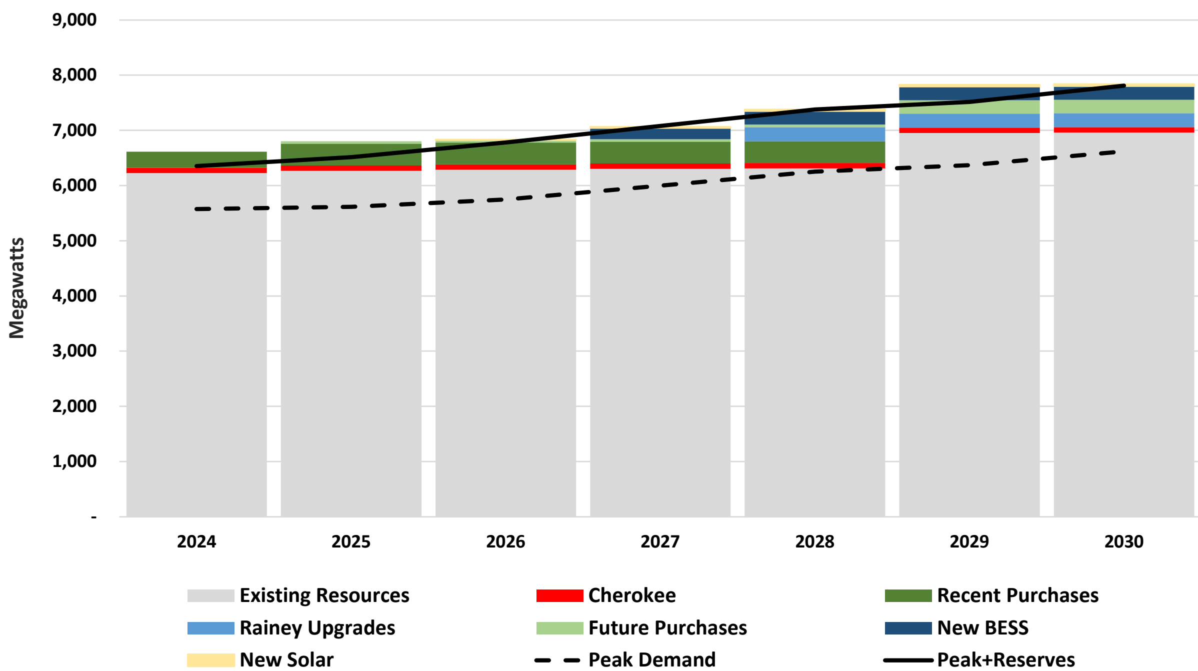
Santee Cooper is pursuing opportunities to upgrade the Rainey NGCT and NGCC generating resources and evaluated these upgrades as resource options within the portfolios prepared for the 2024 IRP Update. The Rainey upgrades, which include the following, are planned to be completed before 2028 and represent industry-standard operating decisions that provide long-term benefits of enhanced capability, efficiency, and reliability for the Combined System.

- Add heat recovery steam generation facilities and a steam turbine generator to the existing Rainey Unit CT2A and CT2B facilities to convert these facilities to combined cycle operation. Rainey Units CT2A and CT2B are existing F-class combustion turbines. The conversion provides an estimated total of 178 MW of incremental winter capacity.
- Upgrade Rainey NGCT Units 3, 4 and 5 with axial fuel staging modifications to each turbine during the next major overhaul of these units. Units 3, 4, and 5 are existing E-class combustion turbines. The upgrades provide an estimated total of 21 MW of incremental winter capacity.
- Upgrade Rainey Units CT1A and CT1B by adding advanced gas-path equipment during the next major overhaul of these units. Units CT1A and CT1B are existing F-class combustion turbines that are part of the existing Rainey PB1 combined cycle facility. The upgrades provide an estimated total of 56 MW of incremental winter capacity.

SUPPLY AND DEMAND BALANCE THROUGH 2030

The resources mentioned above, when combined with existing and committed resources and resource options selected through the portfolio optimization evaluations, including BESS resources, opportunities for additional capacity at Rainey, and potential PPA additions or extensions, would satisfy Santee Cooper's reserve margin planning requirements prior to the retirement of Winyah by 2031. See Figure 4 for a representation of projected load, required planning reserves, existing resources, recently implemented and planned resources, and future capacity needs for 2024 through 2030.

Figure 4. Supply and Demand Balance 2024-2030, Winter Demand and Capacity



EVALUATION OF THE 2023 IRP PREFERRED PORTFOLIO

Consistent with the requirements of S.C. Code Ann. §58-37-40(D)(1), Santee Cooper evaluated the preferred portfolio identified in its 2023 IRP ("2023 Preferred Portfolio") to assess impacts of changes to base planning assumptions. This evaluation was prepared by re-optimizing the resource build assuming that the major 2031 NGCC resource and solar resources over 2026-2030 from the 2023 Preferred Portfolio are added but replacing the generic, short-term PPA resources that were modeled for 2023-2030 with the near-term resource additions described above. Table 2 provides a summary of resource additions and retirements through 2040 that were included for the 2023 Preferred Portfolio and those that were selected for the updated portfolio that has been re-optimized for changes in planning assumptions.

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Table 2. Re-optimization of the 2023 Preferred Portfolio

Resource Changes Through 2040	Additions/(Retirements) (MW)[4]	
	2023 Preferred Portfolio	2023 Preferred Portfolio Re-Optimized
Retirements • Winyah (2031) • MB and HH CTs (2034)	(1,150) (165)	(1,150) (165)
Rainey Upgrades • Rainey PB2 Conversion (2028) • Rainey NGCT Upgrades (2028) • Rainey PB1 Upgrades (2028)	0 0 0	178 21 56
Central PPAs • 2029	672	672
New NGCC • 2031	1,020	1,020
New Peaking • 2031 • 2032-2040	0 112	894 0
New Solar[5] • 2026-2031 • 2032-2040	1,800 900	1,800 1,650
New BESS • 2026-2031 • 2032-2040	0 350	250 200
New Wind • 2029-2031 • 2032-2040	0 0	100 500

Comparison of the 2023 Preferred Portfolio to the 2023 Preferred Portfolio Re-Optimized shows the impacts from updates made to key assumptions result in portfolio additions that are consistent with the 2023 Preferred Portfolio.

- For both portfolios, the new NGCC in 2031 is the key dispatchable replacement resource upon the retirement of Winyah.

[4] Capacity amounts shown herein reflect winter capacity for thermal resources and nameplate capacity for solar, wind, and BESS resources, unless otherwise noted.
[5] The amounts of New Solar capability shown are in addition to existing owned and purchased solar resources and the approximately 200 MW of solar PPAs procured by Santee Cooper and Central in 2021.

- Similar to the 2023 Preferred Portfolio, the 2023 Preferred Portfolio Re-Optimized adds considerable amounts of solar resources, totaling nearly 3,500 MW by 2040 (versus 2,700 MW in the 2023 Preferred Portfolio).
- The 2023 Preferred Portfolio Re-Optimized includes the upgrades to Rainey and accelerated implementation of BESS resources in the late 2020s. The Rainey upgrades would provide approximately 255 MW of additional NGCC and CT capacity to meet capacity needs beginning 2028, as well as providing value throughout the remainder of the study period.
- The 2023 Preferred Portfolio Re-Optimized reflects the addition of a greater amount of resources than contemplated in the 2023 Preferred Portfolio because of higher load projections. This includes the addition of 894 MW of new large frame NGCT resources in 2031 (versus a much smaller amount of peaking resources later in the 2030s), 750 MW of additional solar resources, 600 MW of new wind resources, and 100 MW of additional BESS resources by 2040.

PORTFOLIO EVALUATION AND RESULTS

In addition to the 2023 Preferred Portfolio Re-Optimized described above, Santee Cooper evaluated the following portfolio strategies for the 2024 IRP Update.

2024 Portfolio Update – A fully optimized, cost-effective, and reliable plan to meet resource needs caused by load growth and resource retirements.[6]

2024 Portfolio with PPAs – Same as the 2024 Portfolio Update but limiting the number of new large NGCTs in the early 2030s and instead relying on PPA resources during the 2030s. This portfolio permits an assessment of reduced capital and implementation risk and greater flexibility to adapt to changing load projections.

GHG Rule Portfolio – Optimized portfolio considering requirements of the EPA GHG Rule, including the retirement of Cross Generating Station by 2032 and operating limits on new natural gas-fired resources.

Table 3 below summarizes the resulting resource build plans for each portfolio through 2040.

[6] The analysis of the 2024 Portfolio Update differs from the 2023 Preferred Portfolio Re-Optimized by not assuming that a major NGCC resource is added in 2031, as was identified for the Preferred Portfolio for the 2023 IRP, and instead allowing the 2024 Portfolio Update to solve for the most optimal portfolio of resources.

Table 3. Summary of Optimized Portfolios

Resource Changes through 2040	Additions (Retirements) (MW)		
	2024 Portfolio Update	2024 Portfolio with PPAs	GHG Rule Portfolio
Retirements			
• Winyah (2031)	(1,150)	(1,150)	(1,150)
• HH and MB CTs (2034)	(165)	(165)	(165)
• Cross (2032)	0	0	(2,330)
Rainey Upgrades (2028)	255	255	255
Central PPAs			
• 2029	672	672	672
New NGCC			
• 2031	1,020	1,020	1,360
• 2032-2040	0	0	2,719
New Peaking			
• 2031	894	447	0
• 2032-2040	0	447	256
PPAs[7]			
• 2031	0	550	0
• 2039	0	(550)	0
New Solar[8]			
• 2026-2031	1,800	1,800	1,800
• 2032-2040	1,650	1,700	2,700
New BESS			
• 2026-2031	250	250	250
• 2032-2040	200	150	50
New Wind			
• 2029-2031	100	100	300
• 2032-2040	500	400	550

The resulting resource builds reflect the following key conclusions.

- The key resources identified in the 2023 Preferred Portfolio continue to be selected, including the 2031 NGCC and significant amounts of solar resources.
- Additional resources beyond the 2023 Preferred Portfolio are needed in both the near-term and long-term to meet the higher projections of system demand and energy requirements.

[7] Reflects the addition of PPAs, as needed, over the 2031 through 2038 period, and the replacement of the PPAs with other resources in 2039 as identified through the portfolio optimization process.
[8] The amounts of New Solar capability shown are in addition to the approximately 200 MW of solar PPAs procured by Santee Cooper and Central in 2021.

- The 2024 Portfolio Update is essentially identical to the 2023 Preferred Portfolio Re-Optimized. Hence, while the portfolio metrics discussed from this point refer to the 2024 Portfolio Update, it is important to recognize that results would be essentially the same for the 2023 Preferred Portfolio Re-Optimized.
- The GHG Rule Portfolio would result in significant resource additions that are needed upon retirement of Cross by 2032. Given the scale of the Cross Generating Station (2,330 MW), there is significant uncertainty and risk as to whether Santee Cooper can practically implement the generation resources, necessary fuel delivery infrastructure, and modifications to its transmission system to meet the schedule mandated by the current EPA GHG Rule.

Net present value ("NPV") Power Costs presented in Table 4 summarize the incremental power supply costs projected to result from the implementation of each Portfolio. Costs are presented in NPV 2024 dollars, computed over the 2024 through 2052 study period ("Study Period"), and represent only incremental costs that vary between alternative resource plans.

Table 4. Comparison of NPV Power Costs ($B)

Portfolios	NPV Power Costs
2024 Portfolio Update	$29.3
2024 Portfolio with PPAs	$29.2
GHG Rule Portfolio	$35.7
Difference to 2024 Portfolio Update	
2024 Portfolio with PPAs	($0.1)
GHG Rule Portfolio	$6.5

Results indicate that portfolios that rely on new NGCT builds in 2031 or limits NGCT builds by offering PPA options in the 2030s are projected to have similar costs. Decisions on which of these portfolio approaches are more appropriate for Santee Cooper will instead rely on business decisions regarding managing implementation and financial risk, maintaining flexibility for future resource additions as load projections change, transmission import capability, and additional information regarding PPA market depth and pricing, among others.

Results also indicate that power costs would be significantly higher under scenarios reflecting the EPA GHG Rule. Incremental NPV power supply costs under the 2024 GHG Rule Portfolio are projected to be $6.5 billion higher over the Study Period, much of this incremental cost being a direct result of resource and transmission additions due to the retirement of Cross.

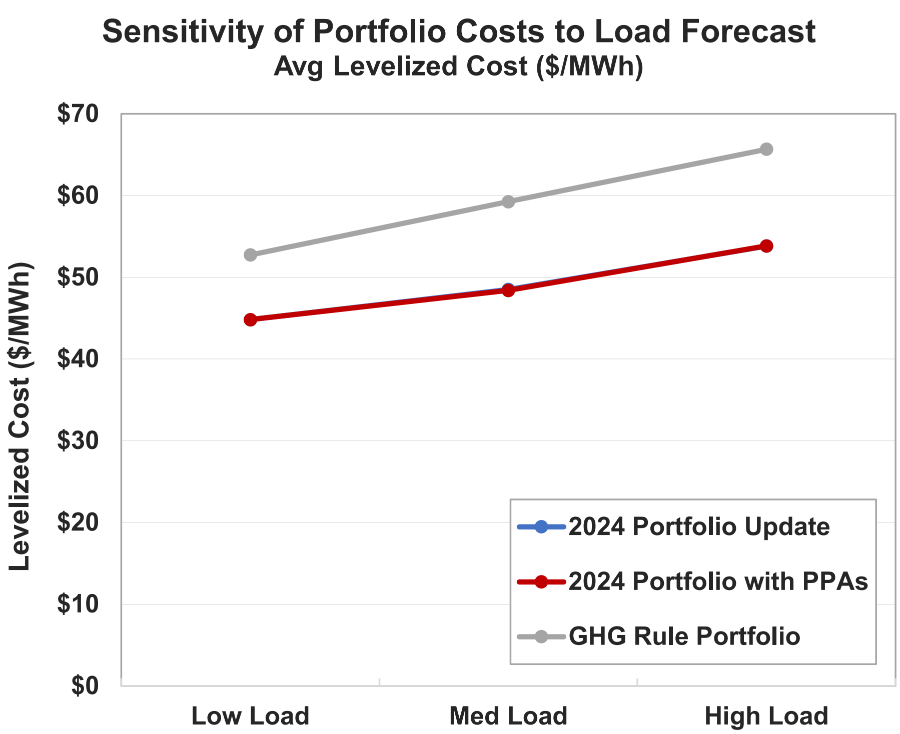
Table 5 provides a comparison of NPV costs under fuel price sensitivity assumptions and the range of NPV cost uncertainty for each portfolio. Results indicate that the 2024 Portfolio with PPAs and the 2024 Portfolio Update have nearly an identical response to changes in fuel prices. The GHG Rule Portfolio reflects a much larger range of uncertainty given much greater reliance upon NGCC resources.

Table 5. Fuel Price Sensitivity Results

Supplemental Portfolios	NPV Power Costs ($B)			Range of Uncertainty
	Reference Case	Low Fuel Price	High Fuel Price	
2024 Portfolio Update	$29.3	$27.6	$33.3	$5.7
2024 Portfolio with PPAs	$29.2	$27.5	$33.2	$5.7
GHG Rule Portfolio	$35.7	$33.4	$42.5	$9.1

Figure 5[9] illustrates average levelized costs for the portfolios under different load forecast sensitivity case assumptions. As can be seen in the chart, the 2024 Portfolio Update and the 2024 Portfolio with PPAs are projected to have nearly identical average levelized costs across the load forecast sensitivities, indicating similar sensitivity to changes in load. Importantly, the load sensitivity analysis confirms there is not significant risk to Santee Cooper's customers should projected load additions not materialize. However, the GHG Rule Portfolio is projected to result in an increase in levelized cost from approximately $8/MWh for the Low Load Forecast to approximately $12/MWh for the High Load Forecast, indicating that costs of the GHG Rule Portfolio are projected to be impacted much more significantly by changes in load.

Figure 5. Load Forecast Sensitivity Case Results



[9] The 2024 Portfolio Update and 2024 Portfolio with PPAs are indistinguishable in this chart.

Results of the fuel price and load forecast sensitivities demonstrate that the key resource decisions of both the 2024 Portfolio Update and the 2024 Portfolio with PPAs are robust under a wide range of assumptions and that the GHG Rule as written would make serving higher load levels more costly.

IMPACT OF THE 2024 IRP UPDATE ON FUTURE RESOURCE PLANNING DECISIONS

As stated previously, the 2024 IRP Update reinforces the key resource addition-related conclusions and recommendations from the 2023 IRP. As a result of higher forecasts for demand and energy, the 2024 IRP Update also identifies other near- and long-term resource additions to ensure reliability and meet system needs. As is demonstrated by the results of evaluations, each of the evaluated portfolios selects NGCC, NGCT, BESS, and solar resources whether the longer-term goal for the Combined System is to minimize costs as in the 2024 Portfolio Update, phase out coal resources under GHG regulations, or consider PPA options during the 2030s. Moreover, the NGCC and renewable resource options were found to be appropriate whether the future brings lower or higher load levels or lower or higher fuel prices.

Based on the evaluation and analysis presented in the 2024 IRP Update, Santee Cooper will use the 2024 Portfolio with PPAs to guide its resource planning decisions, pending any change in direction indicated by the 2025 IRP Update. This portfolio includes as a foundation the resources identified in the 2023 Preferred Portfolio, calls for additional resources to meet growing load, and maintains flexibility for future resource additions.

UPDATES TO SANTEE COOPER'S SHORT-TERM ACTION PLAN

Considering the results of the evaluations and conclusions above, Santee Cooper plans to proceed as follows, subject, where appropriate, to acceptance of the 2024 IRP Update by the Commission.

UPDATE THE LOAD FORECAST AND MONITOR CHANGES IN POTENTIAL NEW LARGE CUSTOMERS

Santee Cooper and Central will continue to work closely together to update the load forecast, including the potential for the addition of large new customer loads. Additionally, Santee Cooper will also continue to work with other stakeholders to refine the methodology used to quantify the probability of large new customers connecting to the Combined System.

IMPLEMENT NEAR-TERM RESOURCES

Santee Cooper and Central have worked together to identify changes to Rainey, short-term purchases, and the addition of BESS resources to meet the additional need for capacity in the short-term (prior to 2031). Santee Cooper plans to file with the Commission and seek approval for a Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN") application for the Rainey NGCC conversion project.

CONTINUE TOWARDS EXECUTING THE KEY RESOURCES IN THE 2023 PREFERRED PORTFOLIO

- Pursue additional solar resources beginning in 2026.
- Continue due diligence and evaluation of the NGCC resource needed in 2031 upon the retirement of Winyah, including potentially partnering with Dominion Energy South Carolina, Inc. ("DESC"). Santee Cooper will continue to evaluate the development schedule of this resource, particularly the timing under which the resource can be brought online and will update the Commission in subsequent IRPs and IRP updates.

CONTINUE TO REFINE OPTIONS FOR LARGE FRAME COMBUSTION TURBINES TO MEET GROWING LOAD

To further study these peaking resources, Santee Cooper will begin front-end engineering and design studies for NGCT resources to be added in the early 2030s.

MONITOR REGULATORY DEVELOPMENTS

We will continue to monitor changes in regulations and, through many of the items above, will continue to assess options for complying with existing or future GHG regulations.

CONTINUE STAKEHOLDER ENGAGEMENT AND STUDIES TO SUPPORT FUTURE FILINGS

Santee Cooper will continue to work towards completing the studies identified in the 2023 IRP Short-Term Action Plan and complying with the requirements of Order 2024-171. Stakeholders will be a critical part of these efforts, and we will continue a robust engagement process.

INTRODUCTION

The state of South Carolina requires Santee Cooper to file an Integrated Resource Plan ("IRP") every three years and an update in intervening years.[10] This report ("2024 IRP Update") provides an update to Santee Cooper's 2023 IRP approved by the Public Service Commission of South Carolina ("Commission") in Order No. 2024-171 ("Order 2024-171") issued March 8, 2024.

In preparing the 2024 IRP Update, Santee Cooper addressed four key topics—(i) addressing items identified in the 2023 IRP Short-Term Action Plan, (ii) addressing items required by Order 2024-171, (iii) continuing stakeholder engagement efforts, and (iv) reflecting trends that will impact utility operations and planning, including recent and unprecedented potential growth in load from large customers and the publication by the U.S. Environmental Protection Agency ("EPA") of a final rule regulating greenhouse gas emissions from power plants ("EPA GHG Rule").

As specified in the 2023 IRP Short-Term Action Plan, Santee Cooper is working with our largest customer, Central Electric Power Cooperative, Inc. ("Central"), to plan for the near-term needs of the combined system and to procure solar resources identified in the 2023 IRP. Additionally, Dominion Energy South Carolina, Inc. ("DESC") and Santee Cooper continue to evaluate the potential for jointly developing resources to serve the future energy needs of the Combined System.

Order 2024-171 directed Santee Cooper to consider improvements to its load forecast methodology to plan for future industrial load growth due to economic development, incorporate actual solar additions, continue evaluations of the natural gas combined cycle ("NGCC") recommended upon the retirement of Winyah, and discuss with stakeholders the seven recommendations made by the Office of Regulatory Staff ("ORS"). In this IRP Update, Santee Cooper provides a status update for each of these items.

The section titled Stakeholder Engagement Process provides an overview of the stakeholder engagement Santee Cooper is conducting leading up to the next triennial IRP, to be filed in 2026. Through this process, we will provide stakeholders with the opportunity to engage at their desired technical level and ensure that Santee Cooper's planning process considers all perspectives. The planned engagements will provide the opportunity to work with stakeholders to address the requirements laid out by the Commission in Order 2024-171.

The 2024 IRP Update reflects the careful consideration of the potential impacts of the trends identified below on the preferred portfolio identified in the 2023 IRP ("2023 Preferred Portfolio").

- Substantial growth in customer load and potential additional load from large customers
- Significant increases in capital costs for new generation, both fossil-fueled and renewable resources, as well as BESS resources
- Regulations related to greenhouse gas emissions

The 2024 IRP Update is intended to outline Santee Cooper's efforts to incorporate and address the critical issues and trends identified above and to lay out a roadmap for the 2025 update and

[10] S.C. Code Ann. Section 58-37-40.

subsequent 2026 Triennial IRP. Santee Cooper, through this Update, has worked to ensure all stakeholders and the Commission are aware of the critical drivers and issues that will impact Santee Cooper's near- and long-term resource decisions.

RECENT ACTIVITIES AND DEVELOPMENTS

This section provides an overview of Santee Cooper's activities related to the Short-Term Action Plan presented in the 2023 IRP and efforts to comply with Commission Order 2024-171. Additionally, information is provided related to environmental regulatory developments since the 2023 IRP, including the EPA GHG Rule.

SHORT-TERM ACTION PLAN ITEMS FROM THE 2023 IRP

In the 2023 IRP, Santee Cooper committed to addressing the following items in its Short-Term Action Plan:

- Work with Central to address system near-term capacity needs
- Begin NGCC implementation including engaging with DESC on the potential for jointly developing a project
- Conduct retirement evaluations to support future IRPs
- Begin solar implementation using the Commission-approved Competitive Procurement for Renewable Energy[11] process
- Work toward implementation of a BESS pilot project to enhance corporate familiarity with this technology

NEAR-TERM CAPACITY NEEDS

The 2023 IRP incorporated the results of a reserve margin study, which resulted in an increase in the winter planning reserve margin and indicated the need for additional near-term resources. Additionally, and as described in the Electric Load Forecast Overview section, Santee Cooper and Central are experiencing significant load growth from large customers and projecting a continuation of this above-normal growth for the next several years. Beginning in 2023 and continuing through 2024, Santee Cooper has worked with Central to identify options for meeting the near-term resource needs identified in the 2023 IRP and from potential large customers. The coordinated planning has resulted in the acquisition of the following resources:

- The Cherokee facility[12] providing 98 MW of NGCC generation, as identified in Table 9
- Four PPAs totaling 447 MW, as identified in Table 10

As described in the 2023 IRP, the Coordination Agreement between Santee Cooper and Central is a comprehensive, long-term agreement that provides for coordinated planning of generation resources needed to reliably and economically serve loads on the Combined System. Central and Santee Cooper have worked closely to comply with the Coordination Agreement in ensuring that sufficient resources are in place to meet the needs of the Combined System in the near term and in jointly planning for resources needed in the future. These coordinated planning efforts with Central have been appropriately incorporated into this IRP Update.

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[11] See Commission Order 2024-2 in Docket No. 2022-351-E.
[12] See Commission Order 2023-784 in Docket No. 2023-189-E approving the acquisition of the Cherokee facility.

NATURAL GAS COMBINED CYCLE IMPLEMENTATION INCLUDING POTENTIAL JOINT PROJECT WITH DESC

Santee Cooper continues to study and refine the NGCC resource that was a key element of the preferred plan identified in the 2023 IRP. Such refinements have focused on facility costs and fuel supply, permitting requirements, and project schedules. The modeling performed in the 2024 IRP Update is intended to objectively evaluate the resource need and whether an NGCC resource remains the preferred replacement resource when Winyah is retired.

Santee Cooper also continues to pursue the opportunity for jointly developing a facility with DESC. Santee Cooper would have to receive legislative authorization from the South Carolina General Assembly to partner with DESC in jointly owning the proposed NGCC.

The supply chain for combustion turbines, transformers, and other equipment continues to be constrained. As part of the NGCC resource evaluation Santee Cooper will continue to evaluate the timing under which the resource can be available and will update the Commission in subsequent IRPs and IRP updates.

RETIREMENT EVALUATIONS TO SUPPORT FUTURE FILINGS AND IRPS

Santee Cooper intends to perform evaluations related to Cross retirement options and retirement of older combustion turbines. Santee Cooper is working to scope and plan the necessary studies, including those related to transmission impacts, and engaging stakeholders. Results of the evaluations are expected to be ready for use in Santee Cooper's next triennial IRP. For this IRP Update, Santee Cooper assumed the same retirement dates as those in the 2023 IRP for all coal facilities and the Hilton Head and Myrtle Beach CTs.

SOLAR PROCUREMENT UPDATE

As discussed in the 2023 IRP, Santee Cooper issued a request for proposals ("RFP") in late 2020 for solar resources which resulted in 425 MW of PPAs. Currently, two projects totaling 200 MW are proceeding toward completion, with expected commercial operation in 2025. The remaining projects faced significant cost increases and schedule delays resulting in termination of those contracts.

On January 3, 2024, the PSC issued Order 2024-2 approving, pursuant to S.C. Code Ann. Section 58-31-227, the Competitive Procurement for Renewable Energy ("CPRE") Program for Santee Cooper. Immediately following the issuance of the Order, Santee Cooper and Central jointly began to work towards issuing an RFP ("2024 Solar RFP") under the approved CPRE guidelines for the procurement of solar resources.

Both the 2023 IRP and the 2024 IRP Update reflect the assumption that Santee Cooper will add solar resources averaging 300 MW per year over 2026 through 2030, depending on the results of solicitations. The 2024 Solar RFP is the first step towards procurement of additional solar resources, and Santee Cooper and Central anticipate acquiring solar resources through long-term PPAs with terms beginning in 2026. The actual amounts and terms of solar resources acquired through this process will be determined by Central and Santee Cooper based on the joint evaluation of responses received.

The CPRE guidelines approved by the PSC in Order 2024-2 include a process and timeline to be followed for each procurement. For the 2024 Solar RFP, Santee Cooper is following the process, including filing updates and quarterly reports with the Commission in Docket No. 2022-351-E. The 2024 Solar RFP was issued on June 10, 2024, with final proposals due on August 5, 2024. Santee Cooper and Central are currently evaluating the proposals and anticipate awarding contracts in the first quarter of 2025. Future IRPs will provide updates on the awarded contracts and actual resource additions from the 2024 Solar RFP.

STATUS OF BESS PILOT PROJECT

As discussed in the 2023 IRP, Santee Cooper is proceeding with plans to implement a BESS pilot project to enhance corporate familiarity with the technology. Learnings from this pilot will help the company gain development, construction, and operational experience for anticipated greater deployment of this technology across the Combined System.

The project is expected to be a 30-40 MW 4-Hour BESS located at the site of a retired Santee Cooper coal facility, allowing Santee Cooper to maximize federal incentives and streamline interconnection.

Santee Cooper has engaged a consultant to conduct preliminary engineering, project cost, and schedule estimates and expects to award a contract by year-end 2024, provided that the resulting projected cost and schedule are reasonable. Commercial operation is expected in late 2025 or early 2026.

COMMISSION REQUIREMENTS FROM ORDER 2024-171

In Order 2024-171, the Commission directed Santee Cooper to address the following issues in the 2024 IRP Update and future IRPs:

- Consider other approaches to load forecasting and resource portfolio analysis to plan for future industrial load growth due to economic development and provide updates to the Commission in future IRP filings
- Incorporate actual solar additions and any updates to future planned solar addition in its annual IRP updates
- Continue to evaluate the NGCC shared resource in the analyses conducted for future IRP Updates and IRPs
- Review and address the recommendations of the ORS witnesses to discuss seven issues with stakeholders no later than the 2026 IRP

The ORS recommendations regarding discussions with stakeholders include the following topics.

- Commodity price forecasts for natural gas, coal, and CO_2 and if the forecasts sufficiently consider variation and risk
- Higher penetration of renewable resources and Effective Load Carrying Capability studies
- Integration costs and associated modeling methodologies, including modeling operating reserves

- Impacts of EPA GHG regulations and the need for a sensitivity scenario to evaluate the rules impacts
- Scope for further studies to analyze any potential cost savings that might accrue to ratepayers from retirement of additional coal units
- Development of a quantitative reliability metric
- Methodology to study and evaluate transmission investment costs associated with the retirement of Cross coal-fired generating facility

See Appendix H: Cross Reference for Compliance With S.C. Code § 58-37-40(D) and Commission Order 2024-171 for a compliance table of requirements from Order 2024-171 with a cross reference where this 2024 IRP Update provides an update on each requirement.

ENVIRONMENTAL REGULATORY DEVELOPMENTS

In 2024, the EPA adopted two rules that impact current and future generating stations. On May 9, 2024, the EPA published the EPA GHG Rule in the Federal Register ("FR"), which became effective July 8, 2024, regulating the emission of GHGs from existing coal, oil, and natural gas fired steam generating units and new natural gas fired combustion turbine generating units. Also on May 9, 2024, the EPA published a rule in the FR, which became effective July 8, 2024, updating the effluent limitation guidelines ("ELG") for coal fired electric generating units.

EPA GREENHOUSE GAS RULE

Under the EPA GHG Rule, coal units must either cease operations before January 1, 2032 or choose one of two potential compliance pathways: 1) convert to co-fire with natural gas (at 40 percent or greater) before January 1, 2030 and cease operations before January 1, 2039 or 2) implement 90 percent carbon capture and sequestration before January 1, 2032.

The following three compliance pathways exist for new natural gas-fired electric generating units under the EPA GHG Rule.

1) Base load units, defined as those operating at greater than 40 percent capacity factor, must meet CO_2 emission standards for highly efficient combined cycle generation upon startup and then must comply with 90 percent CCS before January 1, 2032.
2) Intermediate load units, defined as those operating at a capacity factor between 20 and 40 percent, must meet CO_2 emission standards for highly efficient simple cycle generation (CO_2 emissions rate of less than 1,170 lbs/MWh).
3) Low load units, defined as those operating at less than 20 percent capacity factor, must utilize low-emitting fuels (CO_2 emissions rate of less than 160 lbs/MMBtu).

Existing combustion turbines (whether simple or combined cycle) are not addressed in the final rule.

EPA EFFLUENT LIMIT GUIDELINES RULE

The 2024 ELG rule provides the following potential pathways for compliance.

1) Cease Operation Options
    a. Cease operations by December 31, 2028 with no modifications required.

    b. Cease operations by December 31, 2034 in addition to compliance with the 2020 ELG[13] Best Available Technology ("BAT") standards requiring physical chemical and biological treatment of Flue Gas Desulfurization ("FGD") wastewater by December 31, 2025.
2) Continue Operation Options
    a. Voluntary Incentive Program ("VIP") Option – Comply by December 31, 2028 with the 2020 ELG VIP requiring physical chemical and membrane treatment for FGD wastewater and comply with 2024 ELG BAT standards requiring zero discharge of Bottom Ash Transport Water ("BATW") by December 31, 2029.
    b. BAT Option – Comply by December 31, 2029 with the 2024 ELG rule BAT standards requiring zero discharge of FGD (through installation of membrane treatment) and BATW in addition to compliance with the 2020 ELG BAT standards requiring physical chemical and biological treatment of FGD wastewater by December 31, 2025.

Santee Cooper previously submitted notification of its intention to comply with option 1a for Winyah and option 2a for Cross. However, both plants are currently on paths that would limit compliance to option 1b or option 2b given that construction of physical chemical and biological treatment systems for FGD wastewater is in progress to meet the December 31, 2025 compliance deadline for the 2020 ELG Rule. The 2024 ELG rule requires notification to permitting authorities no later than December 31, 2025 if compliance will be achieved through any option other than BAT.

[13] The 2024 ELG rule retains most of the 2020 ELG rule requirements and adds to the 40 CFR 423 Steam Electric Effluent Limitation Guidelines.

STAKEHOLDER ENGAGEMENT PROCESS

Santee Cooper is committed to undertaking a robust IRP process, which includes continually engaging stakeholders. In advance of the 2023 IRP, Santee Cooper facilitated a stakeholder process that informed the development of the IRP, and Santee Cooper has built on this foundation to improve and extend its stakeholder engagement for the 2024 IRP Update and future IRPs.

Several different engagement opportunities are available to stakeholders with the goal of providing the best opportunity to receive desired information and the most efficient means for providing feedback to Santee Cooper. These efforts include the formation of a stakeholder working group, general notice meetings, and technical meetings requested by interested stakeholders. The engagement process supported the development of the 2024 IRP Update and will continue after the 2024 IRP Update filing through the 2026 Triennial IRP and beyond.

Materials for the stakeholder engagement process can be found on the Santee Cooper IRP web page.[14]

OVERVIEW OF THE IRP STAKEHOLDER WORKING GROUP

Santee Cooper has formed a working group of interested stakeholders ("Stakeholder Working Group"), including all intervenors from the 2023 IRP proceeding at Docket 2023-154-E. The Stakeholder Working Group has a set membership that provides a wide range of perspectives and expertise to inform the development of IRPs. The working group engages through virtual meetings facilitated by an independent firm, Vanry Associates, and meets about every three to four months. Meetings include technical presentations from Santee Cooper subject matter experts and consultants and presentations from working group members who desire to share their information and opinions.

Below is a list of the current Stakeholder Working Group membership.

- South Carolina Office of Regulatory Staff
- South Carolina Department of Consumer Affairs
- South Carolina Department of Natural Resources
- South Carolina Department of Environmental Services
- Central Electric Power Cooperative, Inc.
- Industrial Customer Association, J. Pollock
- Century Aluminum
- Nucor
- Messer
- Google
- South Carolina Association of Municipal Power Systems
- 3 Individual Members representing Residential and Commercial customers
- Carolina Clean Energy Business Association
- Conservation Voters of South Carolina
- South Carolina Coastal Conservation League

[14] https://www.santeecooper.com/about/integrated-resource-plan/2026-irp-stakeholder-process/

- South Carolina Energy Justice Coalition
- Southern Alliance for Clean Energy
- Southern Environmental Law Center
- Sierra Club
- Vote Solar

Santee Cooper hosted the first working group meeting on April 25, 2024, a second meeting on June 27, 2024, and a third meeting on September 4, 2024. The meeting on April 25th introduced the working group members to each other and Santee Cooper and provided opportunity for discussions on how the Stakeholder Working Group would operate and the topics it would cover. The meeting on June 27th provided the opportunity for discussion with working group members regarding the major assumptions, portfolios, sensitivities, and metrics for the 2024 IRP Update. The meeting on September 4th provided an overview of and discussion on preliminary results and conclusions prior to filing the 2024 IRP Update. On the IRP web page and for each meeting to date, Santee Cooper posted the presentation and meeting summary and will continue to do so for future meetings.

OVERVIEW OF IRP GENERAL NOTICE MEETINGS

In addition to the Stakeholder Working Group, Santee Cooper periodically hosts meetings of a less technical nature intended to garner participation by a broader group of stakeholders ("General Notice Meetings"). A General Notice Meeting was held on July 18, 2024 and reflected a virtual format, also facilitated by Vanry Associates. The meeting followed the same public notice and registration process utilized during the 2023 IRP stakeholder process and allowed any interested person the opportunity to register. The agenda provided for discussion and feedback on the assumptions, portfolios, sensitivities, and metrics for the 2024 IRP Update. On the IRP web page, Santee Cooper posted the presentation, video recording, question and answer log, and meeting summary.

Santee Cooper will continue to host general notice meetings to support future IRPs including the 2025 IRP Update and 2026 Triennial IRP. The meetings will be scheduled prior to IRP filings and at a frequency designed to allow the public at large and all interested stakeholders the opportunity to provide input and feedback.

OVERVIEW OF IRP TECHNICAL MEETINGS

At the request of any stakeholder, Santee Cooper periodically hosts technical meetings on specific topics. The meetings provide the opportunity for in-depth conversations on highly technical topics. To support the 2024 IRP Update, Santee Cooper hosted the following technical meetings:

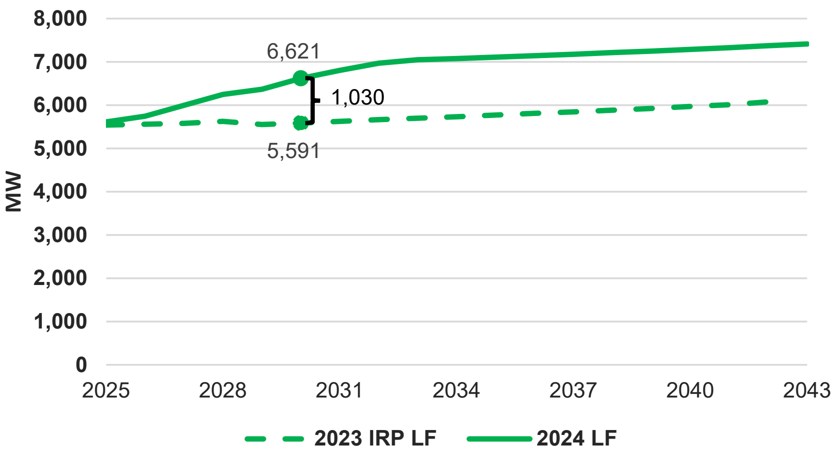
- May 2, 2024 – Technical Presentation on Load Forecast Methodology
- July 17, 2024 – Battery Energy Storage Systems

For each technical meeting, Santee Cooper posted a summary on the Santee Cooper IRP web page and will continue to do so for future meetings.

ELECTRIC LOAD FORECAST OVERVIEW

With assistance and input from Central, other customers, and consultants, Santee Cooper annually prepares a 20-year load forecast. The load forecast used in the 2024 IRP Update was finalized in May 2024 ("2024 Load Forecast"). It was developed using the same approach as that used in the 2023 IRP but incorporated updated assumptions and a post-modeling adjustment to capture economic development projects expected to occur in Central cooperative or Santee Cooper service territory.

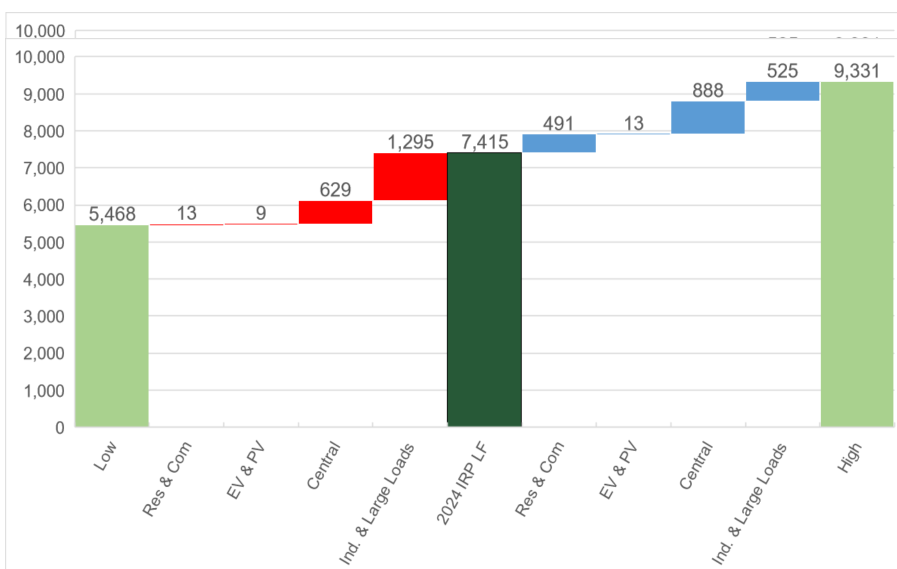
Figure 6. Comparison of Winter Peak Forecasts



These updates and the post-modeling adjustment result in a higher winter peak demand compared to the forecast used in the 2023 IRP by approximately 1,030 MW by 2030, as shown in Figure 6. Aggregate demand in the winter is forecasted to grow from 5,573 MW in 2024 to 7,415 MW in 2043. Energy sales are also projected to grow at a higher rate, from 28,121 GWh to 42,963 GWh over the same period. This represents a 1.5 percent compound annual growth rate ("CAGR") for coincident peak demand and a 2.3 percent CAGR for energy. This is a substantial increase from the projected load requirements in the 2023 IRP, which reflected 0.5 percent CAGR for both energy and demand. This is consistent with the statewide, regional, and national trend of increasing demand in the electric industry.

In addition to the base load forecast, Santee Cooper prepares load forecast scenarios to reflect the uncertainty inherent with forecasting over long periods of time and that are intended to incorporate a reasonable range of possible outcomes. These scenarios consider uncertainty related to economic activity, demographic shifts, customer photovoltaic ("PV") rooftop solar adoption, distributed battery storage, electric vehicle ("EV") penetration, large load siting, and other

Figure 7. High v. Low Case 2043 Winter Peaks



uncertainties that could affect Santee Cooper's energy and demand requirements, resulting in variations from the Base Case for 2043 winter peak demand shown in Figure 7. In the "High Case" scenario, assumptions were adjusted to reflect higher economic growth and other drivers of customer usage relative to the base scenario, resulting in forecasted winter demand growing to 9,331 MW and energy requirements growing to 53,577 GWh by 2043. In the "Low Case" scenario, in which the assumptions are adjusted to reflect lower economic growth and other drivers of customer usage relative to the base scenario, Santee Cooper forecasts winter peak demand to decline to 5,468 MW and energy requirements to increase slightly to 32,111 GWh by 2043.

2024 LOAD FORECAST METHODS AND RESULTS

DIRECT-SERVED RESIDENTIAL AND COMMERCIAL CLASSES

In developing the 2024 Load Forecast, Santee Cooper used similar modeling techniques and assumption sources as used in the 2023 IRP for the direct-served residential and commercial classes. The residential forecast is developed using "statistically-adjusted end use," or SAE, modeling. To support this, models are developed to forecast the number of customers and average use per customer, which are then multiplied to determine total energy sales to the class. The commercial forecast is developed using similar linear forecasting techniques.

Santee Cooper provides power directly to approximately 215,000 residential and commercial customers located in Berkeley, Georgetown, and Horry counties. The population growth in these areas continues to exceed previously forecasted levels. The accelerated growth is partially offset by the continued decline in individual customer usage, which is a continuation of the historical trend for this customer class. Over the 20-year forecast, the number of residential customers is expected to increase by approximately 1.5 percent on average annually, while use per customer is expected to decline by approximately 0.5 percent on average per year. This downward pressure on usage per customer offsets the increased number of customers, leading to an average annual residential energy increase of 1.1 percent.

Santee Cooper's direct-served commercial class continues to experience lower usage needs over time as the energy needs from new customers is offset by lower energy needs from the existing customers. Santee Cooper expects commercial energy use to decline, on average, by 0.3 percent annually. For the High Case and Low Case scenarios, Santee Cooper used the 95th and 5th percentile of outcomes of the stochastically derived residential and commercial forecasts.

The EV forecast and the rooftop PV solar forecast results were similar to the results in the load forecast used in the 2023 IRP. Santee Cooper used the same High Case and Low Case methodology as the 2023 IRP to create the EV and PV forecasts.

DIRECT-SERVED INDUSTRIAL CLASSES

Santee Cooper's direct-served industrial class grew to 31 customers from the 27 customers in the load forecast used in the 2023 IRP, offsetting some of the decline in sales to existing customers. These new customers represent about 40 MW of winter Coincident Peak ("CP") demand. Furthermore, in 2023, Santee Cooper executed a contract with an existing large industrial customer to convert approximately 150 MW of firm power to non-firm power. These new contract terms are reflected in the 2024 Load Forecast.

CENTRAL

Central prepares its own load forecast and provides the results to Santee Cooper for inclusion in the Combined System load forecast. Central's methodology remains substantially consistent with the methodology used in the 2023 IRP. Central's load forecast reflects many of the same trends as Santee Cooper's direct-served residential forecast as rapid population growth is occurring throughout much of South Carolina. Central's load forecast also includes the addition of several new large customer loads. Due to customer growth, Central's energy requirements are expected to increase from 16,928 GWh in 2024 to 21,820 GWh in 2043. Central's demand requirements are expected to increase from 3,709 MW in 2024 to 4,429 MW in 2043. This represents CAGRs of 1.3 percent and 0.9 percent for energy and demand, respectively. Central used similar methods as Santee Cooper for creating its High Case and Low Case scenarios by varying inputs to the 90th and 10th percentiles, respectively.

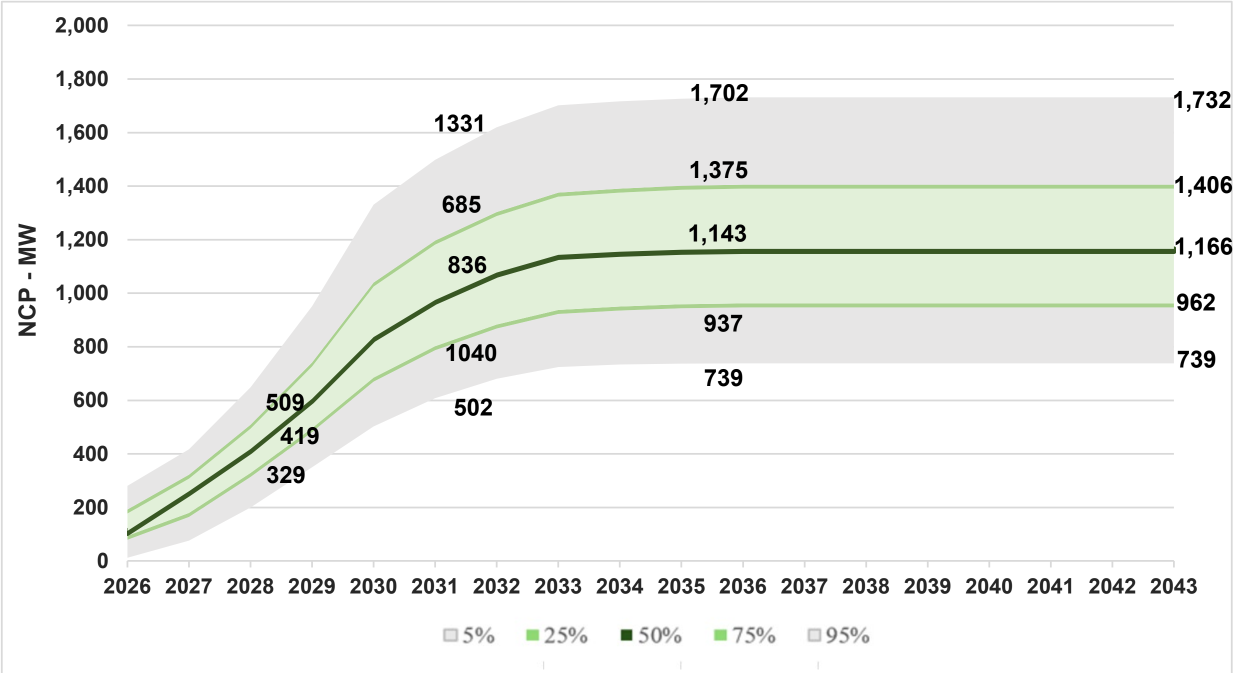
POTENTIAL NEW LARGE LOAD CUSTOMERS

Since the development of the load forecast used in the 2023 IRP, Santee Cooper and Central cooperatives have received a number of inquiries for potential service from industrial and other customers with substantial energy requirements. This is consistent with the trend in the Southeast and the United States as a whole, as data centers and other new industries are poised to rapidly grow and expand their energy requirements. The Commission recognized this trend and ordered Santee Cooper to "engage stakeholders to discuss the additional economic development in the state and how best to incorporate and anticipate new loads into its load forecast." In response, Santee Cooper made an adjustment in the 2024 Load Forecast to anticipate and plan for new loads. In addition, Santee Cooper sought, received, and incorporated input from stakeholders regarding the approach used to forecast new large loads.

All load forecasting inherently contains a degree of uncertainty and risk, and planning for specific customers who have large requirements but have not signed a service agreement creates additional risk. To mitigate the risk of forecasting discreet and large load events, Santee Cooper utilized stochastic forecasting techniques to probabilistically project potential new large loads. In the stochastic analysis, customers were assigned probabilities related to likelihood of connection, potential deviations in the ultimate requirements of the customer, and the date the customer may start service. Through many iterations of possible outcomes for the group, an expected distribution of outcomes was determined that is not dependent on any single customer's decision to initiate service from Santee Cooper. Results of the analysis are presented in Figure 8.

During development of the post-modeling adjustment, Santee Cooper and Central collectively tracked up to 30 potential customers. Ultimately, twenty-one potential projects were selected for inclusion in the analysis, with these customers varying in their maximum peak demand from 2 MW to over 500 MW. Of the 50,000 simulations conducted, Santee Cooper chose a result that was near the median case. The system level impact of projected potential new large loads was adjusted to reflect their impact at the coincident peak.

Figure 8. Range of Projected Potential New Large Loads



For purposes of the High Case scenario, Santee Cooper used the 95th percentile outcome, which reflected 525 MW of additional new large loads by 2043 for a total of 1,592 MW of new large loads (on a coincident peak demand basis). For the Low Case scenario, Santee Cooper used the results near the minimum stochastic outcome, which represents 200 MW of new large loads. Furthermore, the Low Case includes a 400 MW reduction representing the loss of a very large, or several medium to large, industrial customers in Santee Cooper or Central territory. These two adjustments net to a 200 MW reduction in industrial and new large loads. The Low Case results reflected a decrease of 1,295 MW compared to the Base Case.

SANTEE COOPER SYSTEM LOAD FORECAST

The 2024 Load Forecast Base Case reflects the growth that has been occurring on the system. Continued population growth and rapid economic development throughout the state leads to increased energy sales from Santee Cooper's direct served customers and Central. Santee Cooper's 2043 winter CP demand is forecasted to be approximately 1,300 MW higher in the 2024 Load Forecast compared to the 2023 IRP with an average annual growth rate of 1.4 percent compared to an expected growth rate of 0.5 percent in the 2023 IRP. Table 6 presents the forecasted winter peak demand, and Table 7 presents annual energy sales for the system from 2024-2043, including transmission and distribution losses and excluding future demand side management and energy efficiency.

Table 6. Forecasted System Peak Demand (Winter MW)

Year	Direct-Served Residential and Commercial[15]	Direct-Served Industrial	Municipal & Off-System	Central	Potential Large Load	Total	High Case	Low Case
2024	974	707	184	3,709	0	**5,573**	5,633	5,508
2025	980	743	186	3,705	0	**5,615**	5,724	5,116
2026	987	758	160	3,747	93	**5,745**	6,106	5,132
2027	994	759	147	3,855	243	**5,998**	6,383	5,211
2028	1,002	759	150	3,941	398	**6,251**	6,710	5,282
2029	1,010	759	36	4,016	550	**6,371**	7,017	5,268
2030	1,017	759	35	4,048	761	**6,621**	7,504	5,350
2031	1,025	759	35	4,078	909	**6,807**	7,718	5,373
2032	1,034	759	35	4,106	1,040	**6,975**	7,954	5,402
2033	1,042	759	35	4,128	1,086	**7,050**	8,091	5,400
2034	1,050	759	35	4,148	1,086	**7,078**	8,230	5,398
2035	1,057	759	35	4,171	1,086	**7,109**	8,331	5,398
2036	1,064	759	35	4,201	1,086	**7,145**	8,443	5,405
2037	1,071	759	35	4,228	1,086	**7,179**	8,554	5,410
2038	1,078	759	34	4,257	1,086	**7,215**	8,670	5,416
2039	1,086	759	34	4,287	1,086	**7,252**	8,794	5,424
2040	1,092	759	34	4,320	1,086	**7,292**	8,923	5,434
2041	1,098	759	34	4,352	1,086	**7,330**	9,052	5,443
2042	1,104	759	34	4,390	1,086	**7,373**	9,190	5,457
2043	1,110	759	30	4,429	1,086	**7,415**	9,331	5,468

[15] Gross of future demand side management/energy efficiency (“DSM/EE”) related to Santee Cooper’s retail customers but net of Central’s DSM/EE.

Table 7. Forecasted System Energy Sales (GWh)

Year	Direct-Served Residential and Commercial[16]	Direct-Served Industrial	Municipal & Off-System	Central	Potential Large Load	Total	High Case	Low Case
2024	4,236	6,285	672	16,928	0	**28,121**	28,439	27,802
2025	4,276	6,422	682	17,182	0	**28,562**	29,074	27,978
2026	4,314	6,547	512	17,830	752	**29,955**	32,311	28,513
2027	4,360	6,567	422	18,604	2,017	**31,970**	34,278	29,155
2028	4,406	6,567	435	19,350	3,327	**34,085**	36,776	29,858
2029	4,458	6,567	175	19,691	4,629	**35,520**	39,561	30,241
2030	4,515	6,567	174	19,915	6,435	**37,606**	43,410	30,995
2031	4,569	6,567	174	20,054	7,705	**39,069**	44,860	31,183
2032	4,621	6,567	173	20,223	8,826	**40,410**	46,557	31,461
2033	4,679	6,567	172	20,298	9,215	**40,931**	47,351	31,452
2034	4,715	6,567	172	20,410	9,215	**41,079**	48,143	31,463
2035	4,783	6,567	171	20,531	9,215	**41,267**	48,731	31,515
2036	4,830	6,567	171	20,718	9,215	**41,501**	49,323	31,611
2037	4,884	6,567	170	20,813	9,215	**41,649**	49,826	31,627
2038	4,937	6,567	170	20,959	9,215	**41,848**	50,397	31,690
2039	4,991	6,567	169	21,110	9,215	**42,052**	50,991	31,759
2040	5,039	6,567	168	21,322	9,215	**42,311**	51,654	31,876
2041	5,092	6,567	168	21,445	9,215	**42,487**	52,241	31,918
2042	5,142	6,567	167	21,632	9,215	**42,723**	52,900	32,013
2043	5,194	6,567	167	21,820	9,215	**42,963**	53,577	32,111

[16] Gross of future DSM/EE related to Santee Cooper's retail customers but net of Central's DSM/EE.

ASSESSMENT OF RESOURCE NEED

CURRENT RESOURCE OVERVIEW

Santee Cooper plans for firm power supply from its own generating capacity and firm power contracts to equal its firm load plus a reserve margin. Table 8 below details Santee Cooper's resource capacity classified by fuel type for both summer and winter peak power supply capability.

Table 8. Resource Capacity by Fuel Type (as of September 2024)

	Summer		Winter	
	(MW)	% of Total	(MW)	% of Total
Coal	3,465	60.1	3,480	59.4
Natural Gas and Oil	1,203	20.9	1,413	24.1
Long-Term Contracted Purchases	463	8.0	463	7.9
Nuclear	322	5.6	322	5.5
Owned Hydro Generation	142	2.5	142	2.4
Solar (1)	146	2.5	12	0.2
Landfill Methane Gas	26	0.5	26	0.4
Total	5,767	100.0	5,858	100.0

(1) Includes 5 MW of Santee Cooper's owned resources and 283 MW of purchased power on a nameplate basis. The capability shown in the table represents the effective load carrying capability of solar. See the section titled Effective Load Carrying Capability for further information.

OWNED GENERATING FACILITIES

Information regarding Santee Cooper's generating facilities is provided in Table 9 below. See Appendix G: Generation Fleet Data for data for current generating facilities.

Table 9. Existing Owned Generating Facilities

Generating Facilities	Location	Initial Date in Service	Winter Net Dependable Capacity (MW)	Summer Net Dependable Capacity (MW)	Energy Source
Jefferies Hydroelectric Generating Station	Moncks Corner	1942	140	140	Hydro
Wilson Dam Generating Station	Lake Marion	1950	2	2	Hydro
MB Combustion Turbines Nos. 1 and 2	Myrtle Beach	1962	20	16	Oil/Gas
MB Combustion Turbines Nos. 3 and 4 (1)	Myrtle Beach	1972	20	19	Oil
MB Combustion Turbine No. 5	Myrtle Beach	1976	25	21	Oil
HH Combustion Turbine No. 1	Hilton Head Island	1973	20	16	Oil
HH Combustion Turbine No. 2	Hilton Head Island	1974	20	16	Oil
HH Combustion Turbine No. 3	Hilton Head Island	1979	60	52	Oil
Winyah Generating Station	Georgetown				
No. 1		1975	280	275	Coal
No. 2		1977	290	285	Coal
No. 3		1980	290	285	Coal
No. 4		1981	290	285	Coal
Summer Nuclear Unit 1 (2, 3)	Jenkinsville	1983	322	322	Nuclear

Generating Facilities	Location	Initial Date in Service	Winter Net Dependable Capacity (MW)	Summer Net Dependable Capacity (MW)	Energy Source
Cross Generating Station...............................	Cross				
Unit 1..		1995	585	580	Coal
Unit 2..		1983	570	565	Coal
Unit 3..		2007	580	585	Coal
Unit 4..		2008	595	605	Coal
Horry Landfill Gas Station	Conway	2001	3	3	LMG (4)
Lee County Landfill Gas Station	Bishopville	2005	11	11	LMG
Richland County Landfill Gas Station	Elgin	2006	8	8	LMG
Georgetown County Landfill Gas Station........	Georgetown	2010	1	1	LMG
Berkeley County Landfill Gas Station	Moncks Corner	2011	3	3	LMG
Rainey Generating Station.............................	Starr				
Unit 1..		2002	520	460	Gas
Unit 2A		2002	180	146	Gas
Unit 2B		2002	180	146	Gas
Unit 3..		2004	90	75	Gas
Unit 4..		2004	90	75	Gas
Unit 5..		2004	90	75	Gas
Cherokee	Gaffney	1998	98	86	Gas
Solar (5)...	Various	2006-19	5	5	Solar
Total Capability			5,388	5,163	

(1) Myrtle Beach Combustion Turbine No. 4 is currently unavailable until further notice and is not included in the totals above.
(2) Virgil C. Summer Nuclear Generating Station Unit 1.
(3) Represents Santee Cooper's one-third ownership interest in Virgil C. Summer Nuclear Generating Station Unit 1.
(4) Landfill Methane Gas ("LMG").
(5) Capacity values here reflect the nameplate capacity.

RAINEY GENERATING STATION

As noted above, the Rainey Generating Station ("Rainey") consists of 6 natural gas-fired units, as follows.

- Unit 1 – A two-on-one F-class NGCC
- Units 2A and 2B – Simple cycle F-class combustion turbines
- Units 3, 4, and 5 – Simple cycle E-class combustion turbines

As part of the 2024 IRP Update, Santee Cooper evaluated options to upgrade Unit 1 and Units 3-5 to increase their capacity and the conversion of Units 2A and 2B into a two-on-one combined cycle configuration. These options are detailed in the Resource Option Assumptions section.

CHEROKEE FACILITY

Since the filing of the 2023 IRP, Santee Cooper has acquired and began to operate the Cherokee facility located in Gaffney, South Carolina. The facility provides reliable base load natural gas generation to the system. The 2024 IRP Update assumes that this facility will continue operations through 2052.

PLANNED RETIREMENTS

For the 2024 IRP Update, Santee Cooper assumes that Winyah retires at year end 2030 and that Hilton Head and Myrtle Beach Combustion Turbines retire at year end 2033. These are the same retirement dates assumed in the 2023 IRP. Actual retirement dates could be impacted by changes in load projections and the availability of replacement resources.

POWER PURCHASE AGREEMENTS

Santee Cooper has entered various PPAs for capacity and energy needs. Table 10, below, lists these existing PPAs.

Table 10. Power Purchase Agreements

Generating Facilities	Term End Date/Year	Nameplate Capacity (MW)	Winter Capacity (MW)	Energy Source
Long-term Contracts				
Domtar	2028	38	38	Biomass
EDF Renewables	2043	36	36	Biomass
Southeastern Power Administration (SEPA)	Indefinite	305	305	Hydro
St. Stephen Hydro [1]	2035	84	84	Hydro
Total Long-term Contracts		463	463	
Solar Purchases				
Solar Qualifying Facilities [2,3]	Various	287	12	Solar
Solar Power Purchase Agreements [3, 4]	2026-2046	200	8	Solar
Total Solar		487	20	
Purchase Contracts				
Purchase 1	2024-2028	200	200	System Purch.
Purchase 2	2024-2028	50	50	Natural Gas
Purchase 3	2025-2028	150	150	Nuclear
Purchase 4	2024	47	47	Natural Gas
Total Purchases		447	447	
Total PPAs [5]		1,397	930	

(1) Santee Cooper anticipates taking ownership of St. Stephens by 2035.
(2) Solar Qualifying Facilities contracts of varying lengths.
(3) Winter firm capacity based on the effective load carrying capability study discussed herein.
(4) Central is a counterparty for its share of solar resources as its NSR.
(5) Totals may not add due to rounding.

CENTRAL NON-SHARED RESOURCES

As discussed in the 2023 IRP, Central entered into three PPAs, described as follows, to meet its obligations under the Coordination Agreement to provide Non-shared Resources ("NSR") to supply a portion of the capabilities of the Proposed Shared Resource ("PSR") identified in 2021.

- Base Load PPA – 150 MW from the Catawba Nuclear Station

- NGCC PPA – 230 MW from a 1x1 NGCC resource on the Southern Company ("SOCO") system
- Peaking PPA – 292 MW from an NGCT resource, also on the SOCO system

All three PPAs have terms that begin no later than 2029.

In addition to the three PPAs above, Central has indicated it intends to procure BESS projects totaling 150 MW to meet the remainder of its NSR obligation.

PLANNING RESERVE REQUIREMENTS

In conjunction with the 2023 IRP, Santee Cooper retained Astrapé Consulting to perform a planning reserve margin ("PRM") study. The PRM study concluded that Santee Cooper's PRM requirement should reflect a winter requirement and that a winter reserve margin in the range of 17-18 percent was appropriate to ensure the target reliability levels. The study also concluded that a summer reserve margin requirement should be considered a secondary requirement and that a 14-16 percent range was appropriate. Accordingly, Santee Cooper has utilized minimum winter and summer PRM requirements for the 2024 IRP Update at 18 percent and 15 percent, respectively, consistent with the PRM requirements assumed for the 2023 IRP.

SUPPLY AND DEMAND BALANCE

Combining projections from the 2024 Load Forecast, existing owned and contracted resource capabilities, Central NSRs, planned retirement of Winyah and the Myrtle Beach and Hilton Head CTs, and reserve requirements yields projections of the future Santee Cooper supply-demand balance as depicted in Figure 9 below.

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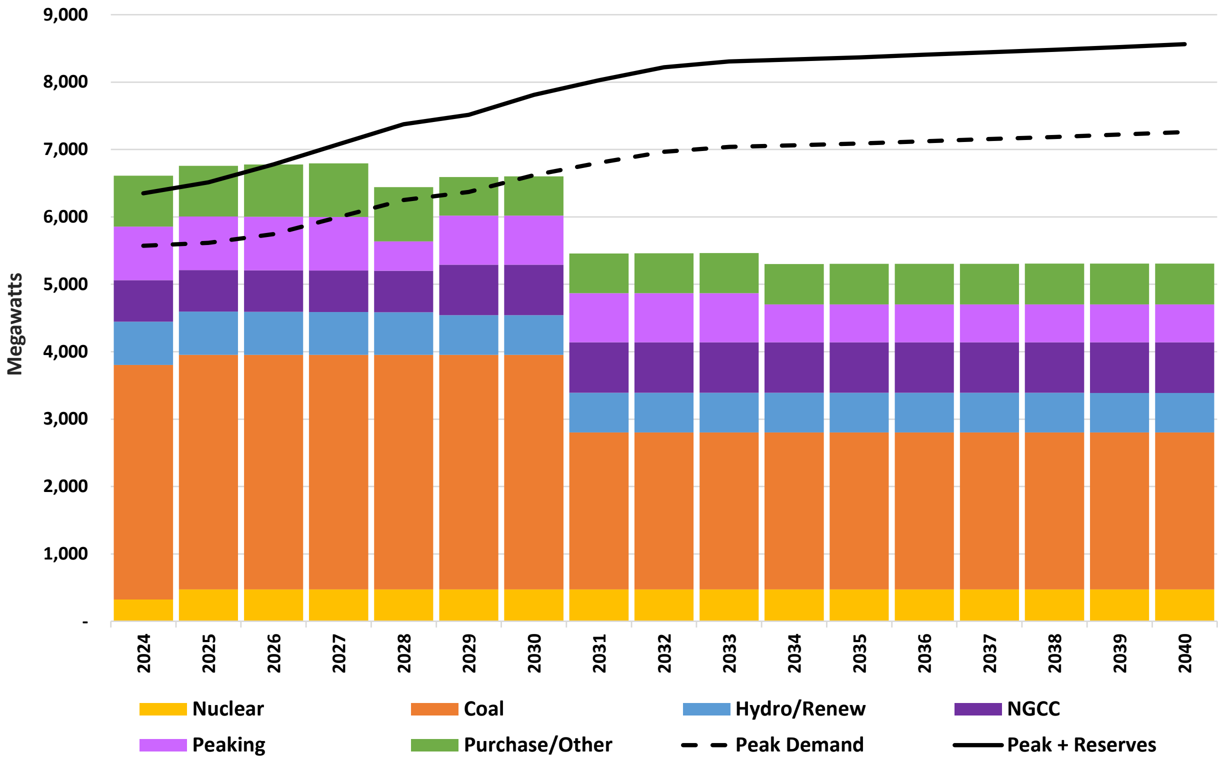
Figure 9. Projected Supply v. Demand Balance (Base Case)



DEMAND-SIDE MANAGEMENT OVERVIEW

SANTEE COOPER DIRECT-SERVE PROGRAMS

As outlined in Figure 14 of the 2023 IRP, Santee Cooper has been developing a new demand-side management ("DSM") program portfolio and a five-year implementation plan based on the achievable potential scenarios from the 2023 IRP.

In close collaboration with third-party consultant Resource Innovations ("RI") and our dedicated internal program managers and DSM planners, Santee Cooper developed a new recommended portfolio of DSM programs. This portfolio is based on the Energy Efficiency and Demand Response Market Potential Studies ("MPS") used in the 2023 IRP. The aim of this effort was to leverage the MPS results applied in IRP scenarios and build on Santee Cooper's existing DSM programs.

Our planning process built upon the successes and lessons learned from past DSM programs offered by Santee Cooper. We have also considered the challenges in the current marketplace and how we can expand to target additional customers who have not fully utilized Santee Cooper's historic DSM offerings. Santee Cooper, with RI's assistance, examined the end-use measures and technologies identified in the MPS to determine a recommended portfolio. This portfolio allowed us to bundle measures into programs that can be effectively offered to our direct-serve customers. A key assumption used throughout this program planning process was that the proposed program portfolio, including startup costs of the programs, would be cost-effective as measured by the Utility Cost Test ("UCT").

The proposed portfolio of DSM programs includes updates to current DSM programs and the addition of new DSM programs. In addition to creating the new portfolio, a five-year implementation plan will be developed with initial program implementation starting no later than 2025.

However, for purposes of this 2024 IRP Update, Santee Cooper has continued to utilize the Medium Case from the MPS.

Looking ahead, Santee Cooper expects to update the MPS beginning in 2025. The results of this study will be incorporated into the 2026 IRP and will shape our future strategies and programs.

CENTRAL PROGRAMS

Assumptions for Central's incremental DSM program impacts are consistent with those utilized for the 2023 IRP.

TRANSMISSION PLANNING

Santee Cooper invested $99 million in capital additions and improvements to its transmission system in 2023. Any projects that involved the reconstruction of existing transmission line facilities reflected replacing existing wood structures with steel. This increases the reliability and resiliency of these facilities under normal and severe weather conditions while also decreasing the overall cost of operation and maintenance. Santee Cooper also has several major transmission projects under way or otherwise expected to be completed within the next five years.

These projects are discussed in Appendix B: Transmission Projects.

MAJOR MODELING ASSUMPTIONS

This section details major modeling assumptions that underpin the 2024 IRP Update. These assumptions were developed based on industry best practices and in consultation with stakeholders.

FINANCING AND ECONOMIC ASSUMPTIONS

The 2024 IRP Update reflects assumptions regarding future general cost escalation and Santee Cooper cost of debt shown in Table 11 below. The NPV cost results shown herein reflect a discount rate set equal to Santee Cooper's assumed cost of debt.

Table 11. Financial Assumptions

General Inflation	2.3%
Santee Cooper Cost of Debt	5.0%
Weighted Cost of Short-term Debt	5.0%
Present Value Discount Rate	5.0%

The assumed long-term general inflation rate was developed based on periodic reviews of forecasts of inflation published by the Philadelphia Federal Reserve in its quarterly Survey of Professional Forecasters and is the same as the value assumed in the 2023 IRP. Escalation of certain nominal costs, including capital costs of generation facilities, reflect the combination of specific assumed real escalation rates and the general inflation rates. Fixed and variable operation and maintenance costs reflect the general inflation rate, unless otherwise noted.

The assumed cost of Santee Cooper long- and short-term debt to finance capital equipment, such as generation and transmission facilities, was determined in consultation with Santee Cooper's financial adviser, Public Financial Management™ ("PFM").

SYSTEM ENERGY AND PEAK DEMAND

Forecasts of monthly energy requirements and peak demand for the Santee Cooper system through 2043 were developed as discussed in the section titled Electric Load Forecast Overview. These values were taken on a gross of planned and potential new DSM energy efficiency ("DSM/EE") and DSM demand reduction ("DSM/DR") basis.

Future annual assumed DSM/EE impacts for Santee Cooper's Distribution system were taken from results of the EE MPS, referenced in the section titled Demand-side Management Overview and are modeled as load reductions. Monthly impacts were derived from annual and seasonal impacts based on the underlying load shape of the relevant segment of Santee Cooper's load. Assumptions regarding future DSM/EE impacts for Central were consistent with those assumed for the 2023 IRP.

Table 12 provides the resulting projected impacts of future DSM/EE program activity on annual energy requirements and winter peak demand for the Combined System, including losses, over the first 20 years of the Study Period. Projections beyond 2043 generally reflect a simple linear extrapolation.

Table 12. Combined System Demand-side Management/EE Impacts with Losses

Year	Energy (GWh)	Winter Peak Demand (MW)
2024	40	6
2025	62	9
2026	89	12
2027	117	16
2028	146	21
2029	175	25
2030	204	29
2031	231	33
2032	259	37
2033	285	41
2034	310	45
2035	334	48
2036	357	51
2037	379	54
2038	399	57
2039	422	60
2040	444	63
2041	466	66
2042	489	70
2043	511	73

System hourly load profiles were based on 2019 data.[17]

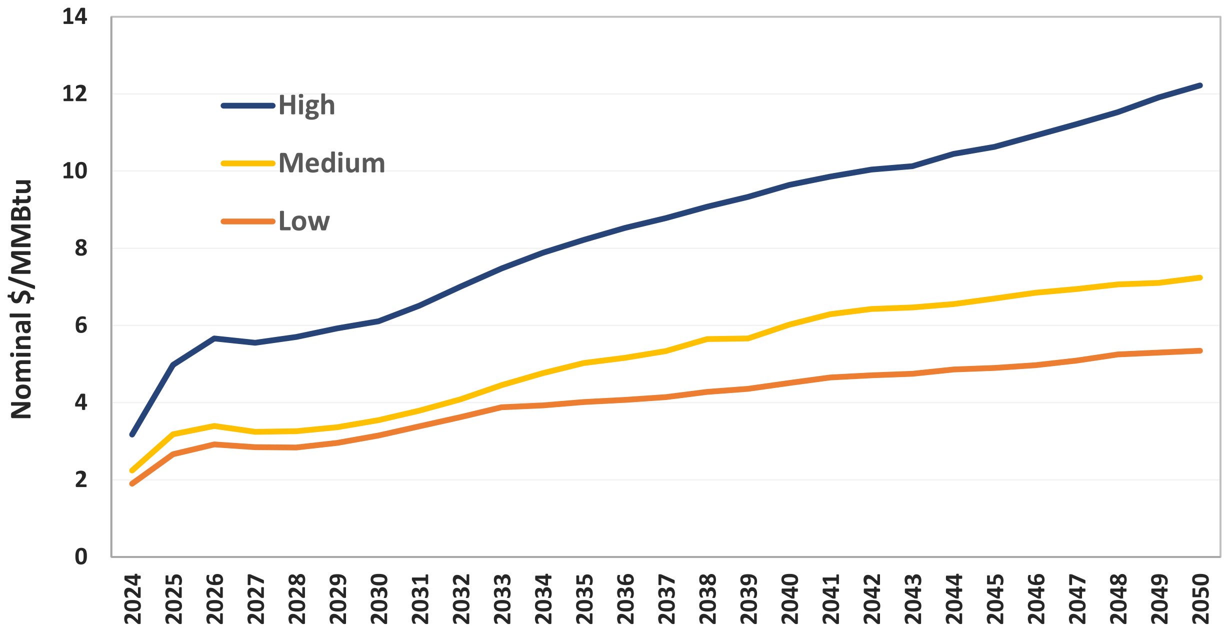
FUEL FORECASTS

Forecasted fossil fuel prices throughout the Study Period generally reflect forecasts taken from the Energy Information Administration's 2023 Annual Energy Outlook ("AEO") Reference Case, with prices for Henry Hub natural gas through 2026 based on forward prices. To study a reasonable range of uncertainty regarding future fuel prices, Low and High Cases were derived from this average adjusted by the relative percentage differences between the AEO Reference Case and the High and Low Oil and Gas Supply cases, respectively. The High Oil and Gas Supply Case reflects more accessible oil and natural gas resources and lower extraction costs than the Reference Case, while the Low Oil and Gas Supply Case reflects less accessible resources and higher extraction costs.

[17] For this purpose, hourly load profiles in September 2019 were adjusted to remove the estimated effects of Hurricane Dorian, which impacted South Carolina over September 4th through 6th.

Forecasts of Henry Hub natural gas prices are shown in Figure 10 below.

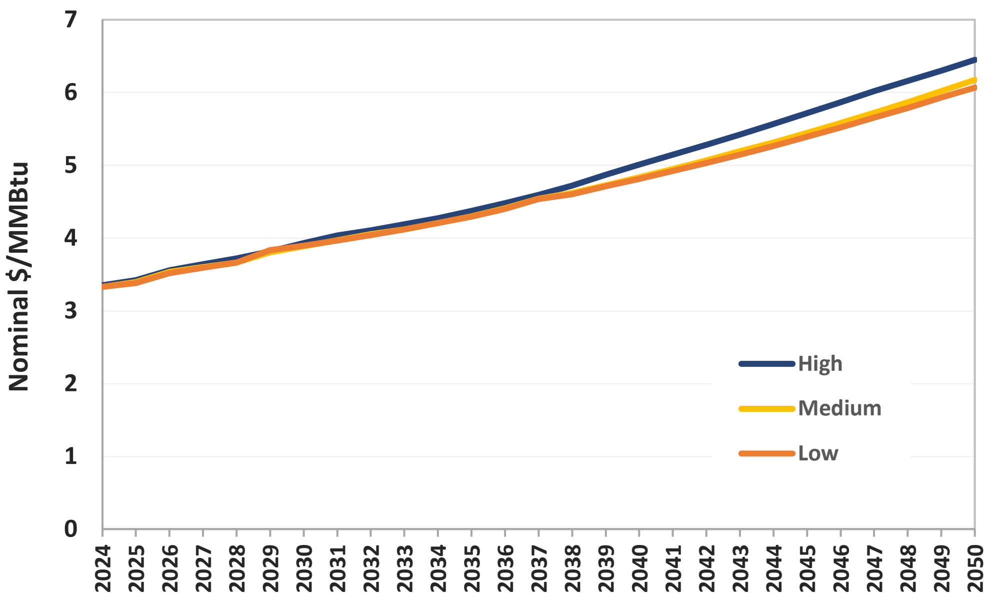
Figure 10. Natural Gas Price Forecasts



The natural gas prices used in the EnCompass simulations described herein include both Henry Hub commodity prices and costs to deliver the natural gas to each generating unit. Delivered costs reflect forecasted basis differentials from S&P Platts, and representative delivery costs, including charges for pipeline transportation. For prospective new natural gas-fired generation, Santee Cooper has assumed prices for new firm natural gas supply based on information that has been provided by natural gas system operators for delivery of natural gas to and within South Carolina.

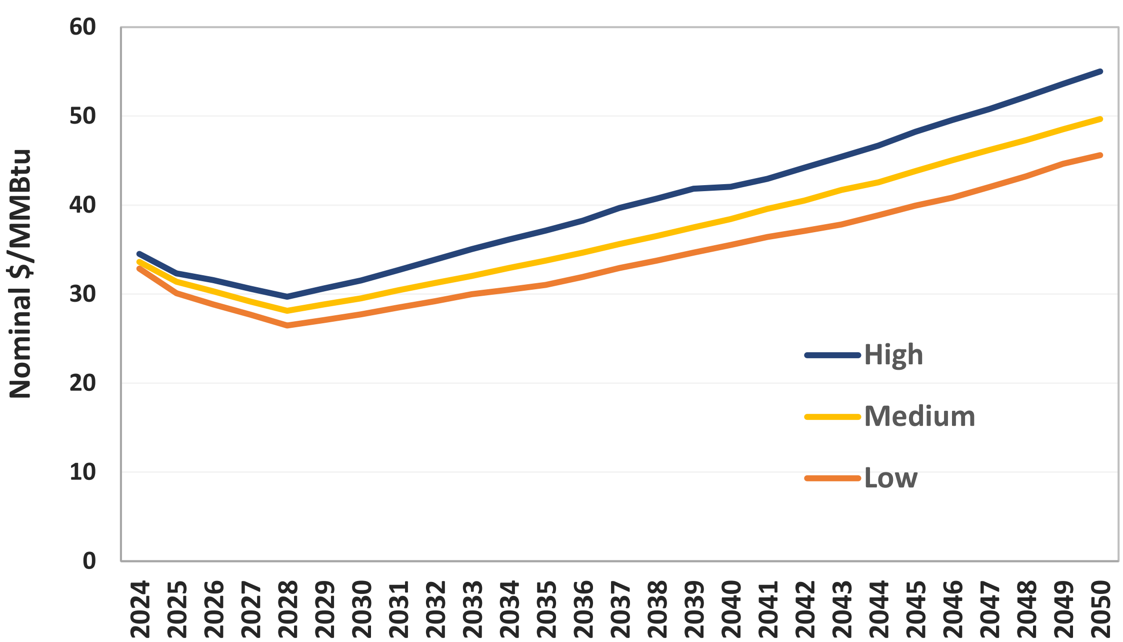
Forecasted coal prices are based on basin price forecasts from the 2023 AEO for Central Appalachian, Northern Appalachian, and Illinois basins and rail delivery costs to South Carolina based on Santee Cooper estimates and are shown in Figure 11 below. As the High and Low Cases were drawn from the relative differences in these projections in the AEO High and Low Oil and Gas Supply Cases, there is very little variation in coal supply costs among these cases. That is not to suggest that coal costs are not uncertain, but such uncertainty is not correlated with the factors that drive the Oil and Gas Supply Cases, as modeled by the EIA.

Figure 11. Coal Price Forecasts



Forecasted fuel oil prices, shown in Figure 12 below, were based on forecasts from the 2023 AEO, with High and Low sensitivity cases developed as discussed above, and were adjusted for regional delivery costs based on information developed by Santee Cooper.

Figure 12. Distillate Fuel Oil Price Forecasts

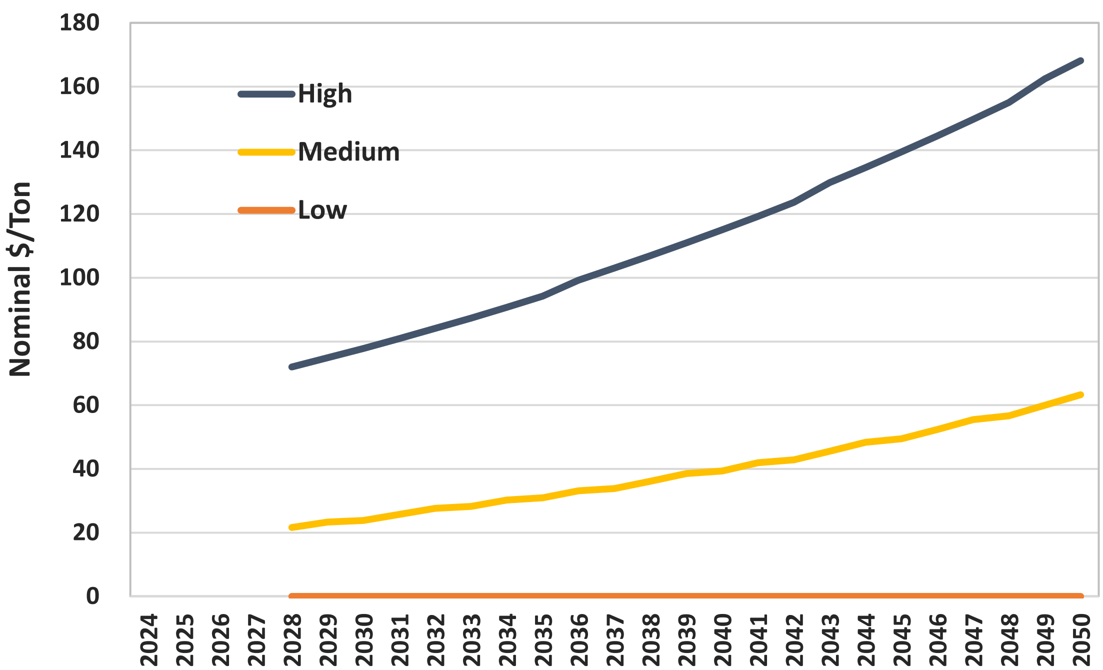


CARBON EMISSIONS PRICING

While CO_2 is not currently regulated by the federal government nor by the State of South Carolina, to assess the impact on Santee Cooper's future build plans and the sensitivity of power costs under various build plans to such regulation, Santee Cooper has developed three scenarios regarding the cost of CO_2 emissions over the coming decades, as described below and illustrated in Figure 13 below.

- **Low Case** – Reflecting no regulation or cost of CO_2 emissions over the Study Period
- **Medium Case** – Reflecting a CO_2 emissions price starting in 2028 at $22/ton and escalating at 5.0 percent per year
- **High Case** – Reflecting a CO_2 emissions price starting in 2028 at $72/ton and escalating at 3.9 percent per year

Figure 13. CO_2 Emissions Price Forecasts



These scenarios and the basis of assumptions are consistent with those utilized and described in the 2023 IRP. The 2024 IRP Update includes an analysis of a prospective portfolio under the EPA GHG Rule, as well as sensitivities for the cost of CO_2 emissions reflected above.

EXISTING RESOURCE OPERATING COSTS AND CHARACTERISTICS

Variable non-fuel operating costs and characteristics of Santee Cooper's existing resources modeled in EnCompass are based on historical data and developed jointly by Santee Cooper staff and consultants. Variable non-fuel operating costs reflect cost of consumables and allowances for start costs and impacts on long-term maintenance costs and are generally assumed to escalate with general inflation.

Fixed operation and maintenance costs and capital costs for existing resources are not included in the portfolio costs, except for costs associated with coal-fired resources that are avoided in portfolios in which such resources are assumed to be retired or are incurred for portfolios in which such resources are evaluated for continued operation beyond the retirement date reflected in other portfolios. Such costs are developed based on historical data, anticipated capital expenses, and reasonable estimates of long-term requirements to maintain such units, adjusted for inflation.

RESOURCE OPTION ASSUMPTIONS

Updated assumptions regarding capital and operating costs and characteristics for future resource options are discussed in the subsections below.

RAINEY STATION UPGRADE OPTIONS

The following upgrades to the existing Rainey Generating Station were included as resource options.

- Upgrades to Unit 1, the existing 520 MW NGCC, including advanced gas path modifications to improve the fuel efficiency of each combustion turbine for a total increase in winter capacity of approximately 56 MW[18]
- Upgrades to Units 3, 4, and 5, existing CTs rated at 90 MW each, including axial fuel staging modifications to each turbine, increasing total winter capacity by approximately 21 MW
- Conversion of Units 2A and 2B, currently simple-cycle CTs of 180 MW each, to a combined cycle unit, with two new heat recovery steam generators and a new steam turbine, for a total increase in winter capacity of approximately 178 MW and an improvement in efficiency

FOSSIL-FUELED AND NUCLEAR ASSETS

Base year capital costs, operating costs, and operating characteristics for CC, CT, aeroderivative CTs, and small modular reactor ("SMR") resource options were based on information from the Electric Power Research Institute's ("EPRI") Technology Cost and Performance Program (referred to as TAGWeb), equipment vendors, and engineering estimates developed by Santee Cooper and aligned with DESC's 2024 IRP Update. Capital cost escalation was generally based on National Renewable Energy Laboratory's ("NREL") 2023 Annual Technology Baseline ("ATB"),[19] while non-fuel operating costs are generally assumed to escalate at the general rate of inflation.

Capital costs, fixed and variable operating costs, and heat rates of the fossil-fueled and nuclear resources available as options in the resource optimization analyses underpinning the 2024 IRP Update are shown in Table 13 below. All costs are shown in 2024 dollars. Capacity ratings and per-unit capital costs reflect average ambient conditions; hence, the capacity ratings will not tie to other values reported herein on a winter rating basis. Capital costs include land and transmission and natural gas pipeline interconnection. Fixed O&M costs exclude property taxes (or payments in lieu of taxes) and insurance.

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[18] Upgrades to Rainey Unit 1 are contingent on a successful steam path audit that is planned to be performed in the 2024Q3-Q4 timeframe.

[19] While NREL's 2024 ATB was released prior to the 2024 IRP Update filing, most of the assumptions drawn from the ATB, including the projected trend in fossil technology capital costs, are similar between the two releases.

Table 13. Fossil-Fueled and Nuclear Resource Option Parameters

Technology	Net Capacity (MW; Avg. Ambient)	Base Year Capital Costs ($/kW)	Fixed O&M Cost ($/kW-yr.)	Variable O&M Cost ($/MWh)	Full Load Heat Rate (Btu/kWh)	Year First Available
Combined Cycle (2x1; H-class)	1,264	1,335	5.16	2.85	6,116	2031
Combined Cycle (Half of a 2x1; H-class; i.e., Shared Resource)	632	1,335	5.16	2.85	6,116	2031
Combined Cycle (1x1; H-class)	630	1,700	7.77	2.85	6,136	2031
Combined Cycle (1x1; F-class)	357	2,626	11.75	3.30	6,668	2031
Combustion Turbine (H-class)	402	1,674	5.10	9.80	9,386	2031
Combustion Turbine (F-class)	230	1,848	8.18	8.97	10,188	2031
Aeroderivative Turbine (LM6000)	40	2,511	46.55	11.30	9,346	2028
Small Modular Nuclear Reactors	683	7,033	101.51	12.38	10,900	2040

Capital costs are assumed to decline in real dollars by approximately 0.9 percent per year, based on projections taken from NREL's 2023 ATB for these assets. Hence, in nominal dollars, given the underlying general inflation assumption utilized in the 2024 IRP Update, capital costs are assumed to increase at approximately 1.4 percent per year. Fixed and variable O&M are assumed to escalate at the rate of general inflation, or 2.3 percent per year.

RENEWABLE AND ENERGY STORAGE RESOURCES

Utility-scale solar, wind (both onshore and offshore), and BESS resources have been reflected in EnCompass as PPA options based on estimates of the levelized cost of energy ("LCOE"), or in the case of BESS resources, levelized cost of capacity ("LCOC"), over their useful lives. Santee Cooper assumes, for purposes of the 2024 IRP Update, that renewable and BESS resources will be implemented through PPAs. However, Santee Cooper and Central will determine the implementation method that best meets their needs over time.

The 2024 IRP Update reflects the same annual planning limits on solar and onshore wind resource installations as assumed for the 2023 IRP. It should be noted that these limits are imposed for planning purposes, and Santee Cooper may work to acquire more or less renewable resources in any year. We will continue to evaluate the annual limits on solar and wind resources and will update the assumptions if warranted. The experience of the Stakeholder Working Group members and the results of procurement efforts, including the 2024 Solar RFP, will be helpful in considering these planning limits, and changes will be discussed with stakeholders as part of future IRP filings.

Capital and operating cost assumptions for solar, wind, and BESS resources have been taken from the NREL 2023 ATB. Capital costs for solar resources have been adjusted based on NREL's 2023Q1 Solar and Storage Cost Benchmark, which reflected approximately 10 percent higher costs for these resources relative to the values reflected in the 2023 ATB.[20] Capital and operating costs for wind resources have been adjusted to reflect higher costs for Southeast projects relative to those in more prevalent wind resource regions based on data from EPRI and, for onshore wind resources, to reflect potentially higher costs for development of such resources in South Carolina (as there are no existing or proposed large-scale projects in the state).

The resulting capital and operating costs (in 2024 dollars and reflecting 2024 online dates) assumed for the 2024 IRP Update are provided in Table 14 below.[21]

Table 14. Renewable Resource Option Parameters

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr.)	Operating Life (Years)	First Year Available
Solar (PV)	1,554	23.82	30	2026
BESS (4-Hour)	1,860	46.49	20	2026
BESS (8-Hour)	3,355	83.88	20	2026
On-shore Wind	1,951	48.34	30	2029
Off-shore Wind	3,556	119.46	30	2040

New solar and BESS resources are assumed to be available beginning January 2026, while on-shore wind resources are assumed to be available beginning January 2029. Due to the development and permitting timeframe of off-shore wind resources, such resources are assumed to be available beginning 2040.

Financing costs are based on the 2023 ATB, reflecting the cost structure of a taxable developer, with some adjustments to assumed after-tax return on equity, to maintain consistency with broader interest rate trends, and financing structure. Table 15 below provides the debt interest rates and approximate after-tax return on equity values that underpin renewable and BESS PPA pricing.

[20] Available at https://www.nrel.gov/docs/fy22osti/83586.pdf. This publication has typically been a key source of base year values in the following year's ATB, which is the case for the 2024 ATB. As discussed previously, the 2024 IRP Update relies on the 2023 ATB, as most assumptions drawn from the ATB are very similar between the two releases, and Santee Cooper does not believe that conclusions presented herein would be impacted in a noticeable way by updating assumptions for the 2024 ATB.

[21] As these technologies typically reflect declining real capital cost curves for future installations, the capital cost values for future install years will vary from these values.

Table 15. Renewable Resource Debt Interest and After-tax Return on Equity[22] Rates

Technology	Interest Rates
Debt Interest Rate	7.0%
Return on Equity:	
Solar	10.4%
Batteries	10.4%
Onshore Wind	11.6%
Offshore Wind	12.6%

Projected costs for renewable resources have been modeled assuming either investment or production tax credits ("ITC" and "PTC," respectively) available because of the Inflation Reduction Act of 2022 ("IRA"). Assumed PPA prices reflect the lesser of the projected costs under either credit regime and assume that 90 percent of facility costs will be eligible for the ITC and that tax credits, whether ITCs or PTCs, are sold for 90 percent of their value.[23] Solar, wind, and BESS resources are assumed to take advantage of the full tax credit rates—ITC at 30 percent and PTC at $27.50/MWh (2022 dollars; indexed to inflation). The IRA is scheduled to phase-out after the later of 2033 or the year after the U.S. achieves greenhouse gas reductions prescribed in the IRA. Because there is some uncertainty regarding whether greenhouse gas reductions prescribed in the IRA will be achieved, the 2024 IRP Update assumes the tax credits are available throughout the Study Period ending 2052.

Figure 14 provides resulting projections of the LCOE for solar, onshore wind, and offshore wind resources. [24] Differences in escalation are driven primarily by differing projections of capital costs reflected in NREL's 2023 ATB, offshore wind reflecting greater increases in capital cost than the other resource types shown below, and differing relative contributions from PTCs over time.

22 Assumed after-tax return on equity rates vary slightly across online years.
23 Industry estimates typically reflect that 85-90 percent of facility costs will be eligible and that tax credit sales are discounted by 5-15 percent versus the tax credit value (i.e., at 85-95 cents on the dollar).
24 The levelized cost shown would apply over the life of a resource placed into service in the year indicated.

Figure 14. Levelized Cost of Energy of Renewable Resources by COD Year

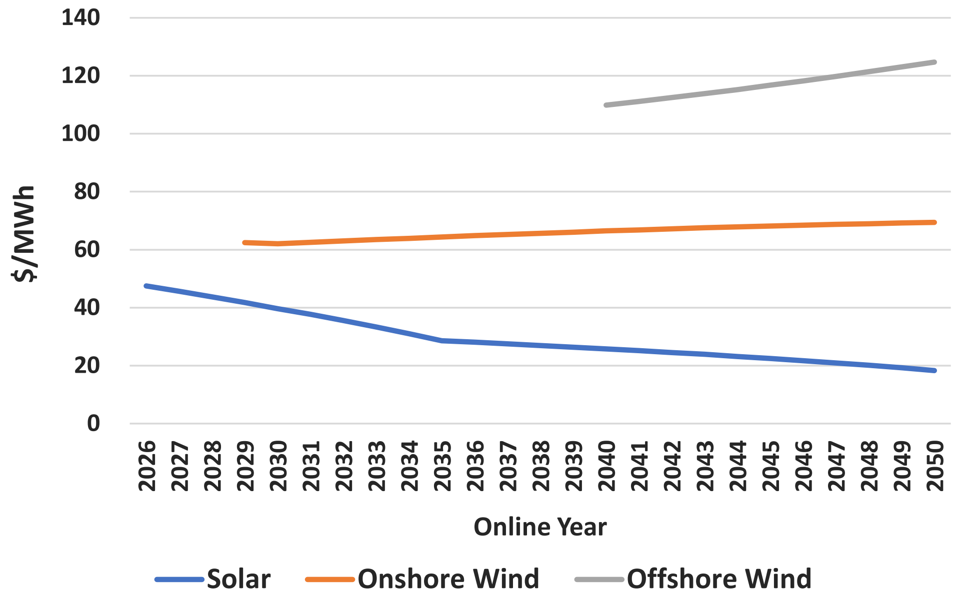
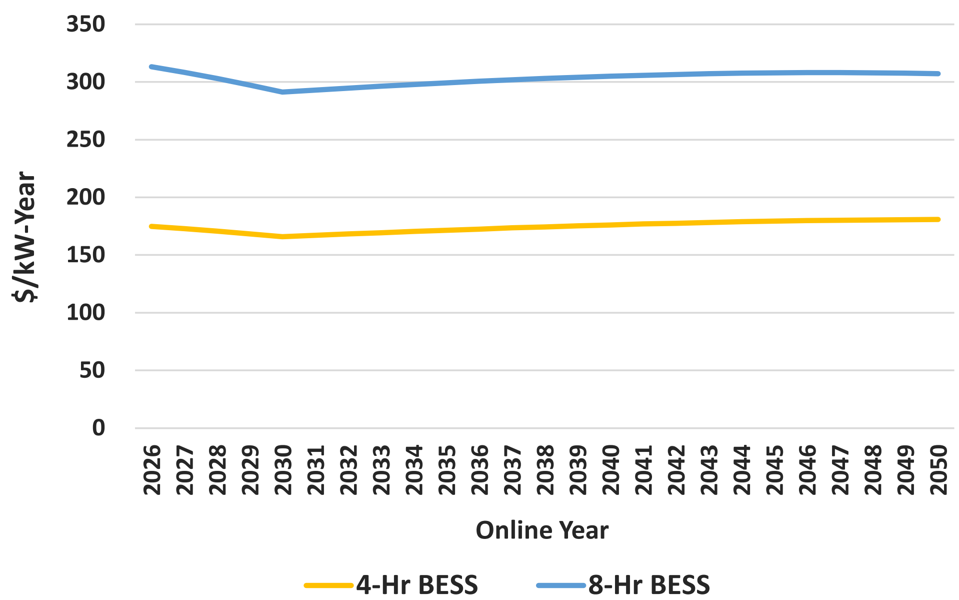


Figure 15[25] provides resulting projections of the LCOC for BESS resources, reflecting 4- and 8-hour durations.

Figure 15. Levelized Cost of Capacity of Battery Resources by COD Year



[25] The levelized cost shown would apply over the life of a resource placed into service in the year indicated.

Solar production profiles were developed from NREL's System Advisor Model ("SAM"), utilizing 2019 conditions, to represent a diversified aggregate profile based on several representative locations.

An onshore wind production profile was also developed from NREL's SAM but is represented as a typical 24-hour profile by month, as the latest year of available weather conditions for use in SAM was 2014. Offshore wind production profiles were provided by an offshore wind developer, representative of 2019 weather conditions as a typical 24-hour profile by month.

EFFECTIVE LOAD CARRYING CAPABILITY

Effective load carrying capability ("ELCC") represents the amount of dependable capacity from a given resource that can be counted on for resource adequacy purposes. The ELCC is determined by finding the amount of additional load that can be served by a given resource without adversely affecting system reliability as compared to a system without the resource. ELCC is represented as a percent of nameplate capacity and is calculated by dividing the amount of additional peak load that can be served with the resource in place by the nameplate capacity of the additional resource. For the 2024 IRP Update, Santee Cooper utilized the same ELCC assumptions as the 2023 IRP.

In 2025, Santee Cooper plans to work with Astrapé Consulting to update the ELCC results including scenarios with higher penetrations of renewable resources. This work will be done with stakeholder input and is expected to be complete for inclusion in future IRPs and no later than the 2026 IRP.

RENEWABLE AND STORAGE RESOURCE INTEGRATION

Renewable resources are valued for their ability to produce energy with no emissions and low to no fuel cost. Some renewable resources (e.g., hydro resources) are dispatchable and can be called upon to supply capacity and energy. Other renewable resources (e.g., wind and solar facilities without storage) are inherently intermittent. While they often supply significant energy into the system, because of the intermittent nature of their production, solar and wind generation resources tend to increase the level of operating reserves and ramping capability required for reliable electric system operation. These reserves support the system capacity and operational needs given the variability of solar and wind production.

Incremental integration costs for two representative periods and resource mix scenarios assumed for the 2024 IRP Update are the same as assumed for the 2023 IRP. Santee Cooper will continue to work with stakeholders to evaluate methodologies for integration costs for renewable resources, consistent with the ORS recommendation from the 2023 IRP proceeding and Commission Order 2024-171. Any changes to methodology will be reflected in the 2026 IRP.

TRANSMISSION SYSTEM REQUIREMENTS

Significant investment in the transmission system may be required to retire existing coal resources that support the Combined System and to integrate resource additions considered in the 2024 IRP Update, particularly if replacement generation of similar magnitude and with similar capabilities is not located at or near the sites of retiring coal facilities. Transmission upgrade requirements vary depending on the specific coal facility being retired and the type and location of replacement generation that are added in each potential resource plan. Separate estimates of required transmission investments are included in the NPV revenue requirements for each of the resource portfolios discussed in the next section. These cost estimates, in 2024 dollars, range from approximately $284 million for portfolios that do not retire the Cross Generating Station to $1.9 billion for the GHG Rule Portfolio, which requires the retirement of Cross by 2032. These transmission cost estimates should be viewed as high level planning estimates that could vary considerably, depending on the precise location and characteristics of resource additions, the amount of new resources being connected at each location, escalation in labor and material costs, changes in interest rates, and siting and permitting requirements.

OPERATING RESERVES

For the purposes of the 2024 IRP Update, the operating reserves modeled in EnCompass include regulating reserves, contingency reserves spinning (spinning reserves), and contingency reserves supplemental (non-spinning reserves). As a member of the Carolinas Reserve Sharing Group (CRSG), [26] Santee Cooper is required to carry 235 MWs of contingency reserves. Table 16 below provides the operating reserves modeled half as spinning and half as non-spinning reserves for the IRP analysis and collectively referred to as the Base Ancillary Services Requirements.

Table 16. Base Ancillary Services Requirements

Reserve Component	Requirement (MW)
Total Contingency Reserves	235
Minimum Spinning Reserves	117.5
Minimum Non-Spinning Reserves	117.5

[26] CRSG includes Santee Cooper, Duke Energy Carolina, Duke Energy Progress, and Dominion Energy South Carolina. Each participating member is required to carry its load ratio share of the total contingency reserve requirement for the combined systems based on the previous year's peak load.

RESOURCE PLAN EVALUATION

For the 2024 IRP Update, Santee Cooper has evaluated how changes in assumptions impact the resource recommendations from the 2023 Preferred Portfolio. Primary among the changes is the much higher load growth than forecasted in the 2023 IRP, requiring additional resource capacity beyond the levels contemplated in the 2023 IRP. In addition, the EPA GHG Rule, to the extent not stayed or overturned, would force considerable changes to Santee Cooper's resource mix including the retirement of its entire coal fleet early in the next decade and development of large amounts of replacement capacity.

Santee Cooper evaluated impacts to the 2023 Preferred Portfolio due to the updated planning assumptions discussed above by re-optimizing and determining the need for additional resources beyond certain key resources identified in the 2023 IRP. Results of the re-optimized build are presented herein and compared to the 2023 Preferred Portfolio.

Santee Cooper also evaluated full optimizations utilizing the updated planning assumptions for three portfolios with differing build and operating constraints, as detailed herein. Resulting resource builds and portfolio costs and other metrics are compared using an approach similar to that used for the 2023 IRP.

OVERVIEW OF METHODOLOGY

For the 2024 IRP Update, Santee Cooper has utilized the EnCompass power systems dispatch and optimization simulation software system from Anchor Power Solutions.

REFERENCE CASE

For purposes of resource optimization simulation, a Reference Case was developed reflecting assumptions for key variables described in Table 17 below.

Table 17. Reference Case Definition

Key Uncertainty	Reference Case Assumption	Assumption Basis
Fuel Prices	Medium Case	2023 AEO Reference Case
CO_2 Emissions Cost	Low Case	CO_2 emissions cost at $0/ton
Load Forecast	Medium Case	2024 Load Forecast Base Case, as discussed in section titled Electric Load Forecast Overview
Demand-side Management	Medium Case	As discussed in section titled Demand-side Management Overview
Resource Option Capital and Fixed costs	As described in the section above titled Resource Option Assumptions	

The optimization analysis was used to identify the optimum portfolio of resources to be analyzed further as described below.

PORTFOLIO COST ANALYSES

To project variable portfolio production costs (e.g., fuel costs, renewable energy costs, emissions costs, etc.), optimized resource plans for each portfolio were simulated in more detail using an hourly 8760 chronological representation, resource operating limitations (minimum up/down times, ramp rates, etc.), and resource commitment. The simulation considered implications of intermittency of renewable resources and limitations of dispatchable resources. Accordingly, it was not necessary to add allowances for renewable integration costs as was done in the optimization analyses.

Incremental fixed production and transmission costs and DSM program costs were then estimated and included with the projected variable portfolio costs to determine total portfolio costs.

MODELED POWER COSTS

As in the 2023 IRP, the power supply costs modeled in this analysis include only those categories that vary between alternative resource plans being evaluated. More specifically, the following categories of power supply costs were considered.

- Capital cost for new resources
- Differences in fixed O&M and capital expenses for existing resources evaluated for retirement at differing timeframes (i.e., Cross and Winyah)
- Natural gas transportation costs
- Fuel and purchased energy costs
- Variable O&M costs
- Emissions-related costs
- Demand-side management program costs
- Capital cost for required transmission system upgrades and expansion

For purposes of estimating the impact of variations in power costs on rates, additional categories of costs were estimated and extrapolated from historical values and combined with projected power costs, as described in the section titled Rate Impacts of Portfolios.

RISK ANALYSIS APPROACH

In addition to the Reference Case assumptions, sensitivity cases were evaluated for each portfolio for the following variables.

- **Fuel Prices** – High and Low Case projections drawn from variations reflected in the AEO High and Low Oil and Gas Supply Cases
- **CO_2 Emissions Costs** – Medium and High Case costs of CO_2 emissions drawn from estimates of the social cost of CO_2 developed by the Federal Government
- **Load Forecast** – High and Low Case forecast generally representing the 90th and 10th percentile of potential future conditions, based on Santee Cooper's 2024 Load Forecast

Detailed descriptions of the assumptions and associated projections are provided in the preceding sections. For each sensitivity simulation, all other variables remain at the Reference Case values.

Production costs for resource plans resulting from optimization under the Reference Case assumptions were simulated with the variations in fuel prices. For purposes of the load forecast sensitivities, however, given the variations in future load levels inherent in these cases, an additional optimization was run for each sensitivity allowing EnCompass flexibility beyond certain near-term build decisions (as discussed further below) to determine the most economic variations from the Reference Case optimization.

The sensitivity analyses do not reflect optimization of the resource additions under each sensitivity case, as the purpose of the evaluation is to understand the sensitivity of each portfolio to changes in certain key assumptions and the resulting impact on power costs and other metrics subsequent to the adoption of key initial resource decisions.

The resulting power costs across these sensitivities are utilized, in part, to inform some of the Portfolio Metrics discussed below.

PORTFOLIO METRICS

The evaluation of portfolios included development and review of the following metrics, guided by Act 90 and Commission direction in previous IRP proceedings.

- **NPV Cost** – Total cumulative NPV power supply costs over the 30-year study horizon
- **Mini-max Regret** – Assesses the potential for each resource plan to incur higher costs than other plans under the same sensitivity case
- **Fuel Cost Resiliency** – Measures the degree to which resource plan costs vary with respect to modeled variations in fuel prices
- **CO_2 Emissions** – Total emissions and emissions rate over the Study Period and at specific points in time
- **Generation Diversity** – Measure of the balance in the mix of sources of generation, with no single resource type dominating the generation sources
- **Clean Energy** – Percentage of generation that is from non-CO_2-emitting resources, including solar, wind, hydro, landfill methane gas, biomass, and nuclear facilities
- **Fixed Cost Obligations** – Cumulative capital and fixed costs, including firm natural gas reservation costs, PPA cost obligations, and fixed O&M costs
- **Reliability Factors** – Measures the extent to which resource plans incorporate resources and features that improve system reliability

It is important to recognize that several of the metrics inherently measure the same or highly related issues. For example, sensitivity to fuel cost variability represented by the fuel cost resiliency metric can have an effect on the mini-max regret metric. However, the metrics can provide useful information regarding the relative merits of potential resource portfolio directions.

In Order 2024-171, the Commission directed Santee Cooper to work with stakeholders to develop a quantitative reliability metric. This metric would be in addition to, or would improve upon, the current reliability metric. Santee Cooper will work with stakeholders and include the metric when available and no later than the 2026 IRP.

RE-OPTIMIZATION OF THE 2023 PREFERRED PORTFOLIO

As a first step in the 2024 IRP Update, Santee Cooper performed a portfolio optimization simulation "locking in" certain key resources from the 2023 Preferred Portfolio, including the 2031 NGCC and solar resources from 2026-2030. The EnCompass software optimization model then determined the optimal resource additions needed to meet the increased demand and energy forecasts. This portfolio is referred to as the 2023 Preferred Portfolio Re-Optimized.

Table 18 summarizes the resulting build plan through 2040 for the 2023 Preferred Portfolio Re-Optimized as compared to the 2023 Preferred Portfolio.

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Table 18. Re-optimization of the 2023 Preferred Portfolio

Resource Changes Through 2040	Additions (Retirements) (MW)[27]	
	2023 Preferred Portfolio	2023 Preferred Portfolio Re-Optimized
Retirements • Winyah (2031) • MB and HH CTs (2034)	(1,150) (165)	(1,150) (165)
Rainey Upgrades • Rainey PB2 Conversion (2028) • Rainey CT Upgrades (2028) • Rainey PB1 Upgrades (2028)	0 0 0	178 21 56
Central PPAs • 2029	672	672
New NGCC • 2031	1,020	1,020
New Peaking • 2031 • 2032-2040	0 112	894 0
New Solar[28] • 2026-2031 • 2032-2040	1,800 900	1,800 1,650
New BESS • 2026-2031 • 2032-2040	0 350	250 200
New Wind • 2029-2031 • 2032-2040	0 0	100 500

Comparison of the 2023 Preferred Portfolio to the 2023 Preferred Portfolio Re-Optimized shows that the updates in key assumptions still result in portfolio additions that are similar to the 2023 Preferred Portfolio.

- For both portfolios, the new NGCC in 2031 is the key dispatchable replacement resource upon the retirement of Winyah.

[27] Capacity amounts shown herein reflect winter capacity for thermal resources and nameplate capacity for solar, wind, and BESS resources, unless otherwise noted.
[28] The amounts of New Solar capability shown are in addition to the 200 MW of solar PPAs procured by Santee Cooper and Central in 2021.

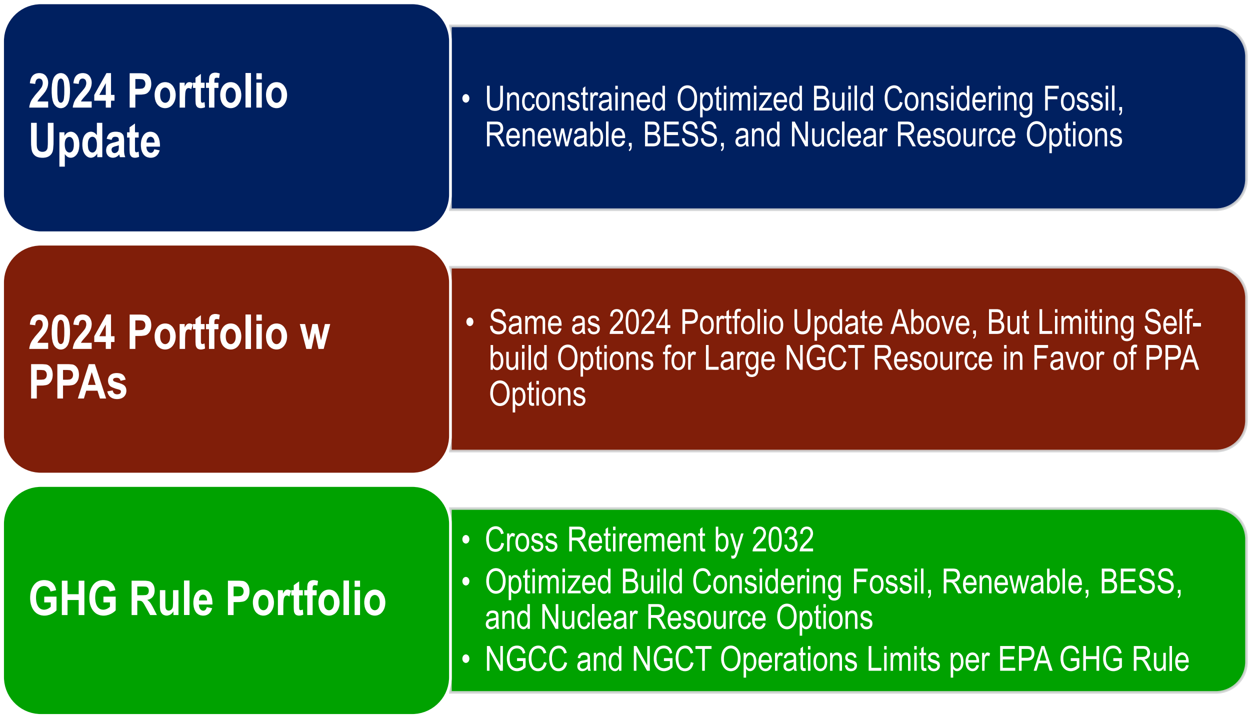
- The 2023 Preferred Portfolio Re-Optimized reflects the addition of a greater amount of resources than contemplated in the 2023 Preferred Portfolio because of higher load projections. The 2023 Preferred Portfolio Re-Optimized reflects generation additions through 2040 totaling approximately 7,300 MW of nameplate capacity versus approximately 4,700 MW in the 2023 Preferred Portfolio (approximately 1,500 MW of the 2,600 MW difference reflecting renewable and BESS resources).
- The 2023 Preferred Portfolio Re-Optimized includes the upgrades to Rainey and accelerated implementation of BESS resources in the late 2020s. The Rainey upgrades would provide approximately 255 MW of additional NGCC and CT capacity to meet capacity needs beginning 2028, as well as providing value throughout the remainder of the Study Period.[29]
- Similar to the 2023 Preferred Portfolio, the 2023 Preferred Portfolio Re-Optimized adds considerable amounts of solar resources, totaling nearly 3,500 MW by 2040 (versus 2,700 MW in the 2023 Preferred Portfolio).
- The 2023 Preferred Portfolio Re-Optimized also includes the development of 600 MW of onshore wind over 2030-2040, which was not reflected in the 2023 Preferred Portfolio.

2024 PORTFOLIOS EVALUATED

Santee Cooper performed additional optimization simulations that reflect Winyah's retirement by 2031 and allowed the EnCompass software to optimize the resource build plan to both replace Winyah's retiring capacity and to meet the projected higher load levels. In addition to an unconstrained optimization, the 2024 IRP Update includes a portfolio that incorporates PPAs as an alternative to self-build resources to mitigate financial risk and provide flexibility as load projections evolve. Finally, an optimization simulation was performed reflecting the impacts of the EPA GHG Rule. The three portfolios are shown in Figure 16 and described further below.

[29] As discussed in Near-term Capacity Needs, Santee Cooper also recently acquired a small NGCC facility, Cherokee, and has secured PPA capacity not captured in the table above. In the 2023 Preferred Portfolio, capacity needs through 2030 then-forecasted were fulfilled by generic, short-term PPAs that were offered to EnCompass.

Figure 16. Resource Portfolios Evaluated



2024 Portfolio Update –The EnCompass software optimizes the resource build plan to both replace Winyah, assumed to be retired by 2031, and add additional resources to meet higher demand and energy forecasts.

2024 Portfolio with PPAs – Same as the 2024 Portfolio Update but allowing EnCompass to add only a single large frame CT and replacing additional peaking resource needs in the 2030s with PPAs.

GHG Rule Portfolio – An optimized build plan considering requirements of the EPA GHG Rule including the retirement of all coal resources before January 2032 (Winyah retired by 2031 as above) and operating limits on new natural gas-fired resources.

PORTFOLIO OPTIMIZATION RESULTS

COMPARISON OF OPTIMIZED PORTFOLIOS

Table 19 summarizes the build plan for each of the portfolios through 2040. Detailed build plans for each portfolio are shown in Appendix C.

Table 19. Summary of Optimized Portfolios

Resource Changes Through 2040	Additions (Retirements) (MW)		
	2024 Portfolio Update	2024 Portfolio with PPAs	GHG Rule Portfolio
Retirements • Winyah (2031) • HH and MB CTs (2034) • Cross (2032)	(1,150) (165) 0	(1,150) (165) 0	(1,150) (165) (2,330)
Rainey Upgrades • Rainey PB2 Conversion (2028) • Rainey CT Upgrades (2028) • Rainey PB1 Upgrades (2028)	178 21 56	178 21 56	178 21 56
Central PPAs • 2029	672	672	672
New NGCC • 2031 • 2032-2040	1,020 0	1,020 0	1,360 2,720
New Peaking • 2031 • 2032-2040	894 0	447 447	0 256
CT PPAs[30] • 2031-2038 • 2039	0 0	550 (550)	0 0
New Solar[31] • 2026-2031 • 2032-2040	1,800 1,650	1,800 1,700	1,800 2,700
New BESS • 2026-2031 • 2032-2040	250 200	250 150	250 50
New Wind • 2029-2031 • 2032-2040	100 500	100 400	300 550

The resulting resource builds reflect the following key conclusions.

- All portfolios reflect the addition of a large NGCC resource in 2031 as the replacement resource upon the retirement of Winyah, which is consistent with the results of the 2023

[30]Reflects the addition of PPAs, as needed, over the 2031 through 2038 period, and the replacement of the PPAs with other resources in 2039 as identified through the portfolio optimization process.
[31] The amounts of New Solar capability shown are in addition to the approximately 200 MW of solar PPAs procured by Santee Cooper and Central in 2021.

IRP. The 2024 Portfolio Update and the 2024 Portfolio with PPAs select a 1,020 MW NGCC resource, developed jointly with DESC, in 2031. The GHG Rule Portfolio adds a greater amount of NGCC capacity beginning in 2031.

- All portfolios reflect the addition of significant amounts of solar resources.
- The 2024 Portfolio Update is essentially identical to the 2023 Preferred Portfolio Re-Optimized. Hence, while the portfolio metrics discussed from this point refer to the 2024 Portfolio Update, it is important to recognize that results would be essentially the same for the 2023 Preferred Portfolio Re-Optimized.
- The GHG Rule Portfolio results in dramatically greater need for NGCC capacity to replace the retirements of Santee Cooper's fleet of coal-fired assets despite the limitation on NGCC operation imposed by the EPA GHG Rule.
- The GHG Rule Portfolio relies on considerably larger amounts of renewable resources—approximately 1,200 MW more than the other portfolios.

PORTFOLIO METRICS

To evaluate the portfolios, Santee Cooper simulated each portfolio under the Reference Case assumptions and a series of sensitivity cases. The sensitivity cases represent a reasonably broad range of future conditions related to fuel prices, CO_2 emissions cost, and load levels. To allow for total costs and emissions to be comparable, results are separately provided for sensitivities reflecting Base Load Forecast load levels and those reflecting variations in the load forecast.

Projected NPV power costs are shown herein in billions of dollars. Some differences between portfolios can be within rounding and may impact comparisons that are illustrated as differences in color-coding of resulting values.

NPV POWER COSTS

The NPV Power Cost metric measures the costs to customers of each of the resource portfolios based on NPV modeled power costs in 2024 dollars of each portfolio over the Study Period. Table 20 compares the NPV power cost for the portfolios under the Reference Case Assumptions, with color-coding from green, gold, and then to a rose color indicating lowest to highest values.

Table 20.
Comparison of NPV Power Costs for the Reference Case ($B)

Portfolios	NPV Power Costs
2024 Portfolio Update	$29.3
2024 Portfolio with PPAs	$29.2
GHG Rule Portfolio	$35.7
Difference to 2024 Portfolio Update	
2024 Portfolio with PPAs	($0.1)
GHG Rule Portfolio	$6.5

The Reference Case results show that the 2024 Portfolio with PPAs results in the lowest NPV power cost followed very closely by the 2024 Portfolio Update. The GHG Rule Portfolio reflects considerably higher costs.

A summary of NPV power costs by portfolio over both the full Study Period and over a 20-year period from 2031-2050 is provided in Appendix D.

MINI-MAX REGRET

The Mini-Max Regret metric evaluates the potential to incur higher power costs by pursuing any resource portfolio relative to other plans as evaluated across the modeled sensitivities. The Mini-Max Regret first measures the difference in NPV power cost between each portfolio and the lowest cost portfolio for each sensitivity case. That difference can be referred to as the potential regret of choosing a portfolio if the specific scenario conditions were to occur. The maximum regret score for each portfolio is the maximum difference observed across all sensitivity cases. This metric indicates which portfolio minimizes the computed maximum regret.

Table 21 provides the NPV power costs for each portfolio across the fuel and CO_2 price sensitivities and computes the maximum regret by portfolio. The results reflect that the maximum regret is minimized by the 2024 Portfolio Update with PPAs, with the results for the 2024 Portfolio Update being essentially the same. The maximum regret for the GHG Rule Portfolio is considerably higher, driven from the much greater reliance on NGCC resources.

Table 21. NPV Power Costs Across Sensitivities and Maximum Regret ($B)

Portfolios	Reference Case	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
2024 Portfolio Update	$29.3	$27.6	$33.3	$36.6	$49.6
2024 Portfolio w PPAs	$29.2	$27.5	$33.2	$36.5	$49.6
GHG Rule Portfolio	$35.7	$33.4	$42.5	$40.8	$50.5

Max Regret by Portfolio	
2024 Portfolio Update	$0.1
2024 Portfolio with PPAs	$0.0
GHG Rule Portfolio	$9.2

FUEL COST RESILIENCY

Table 22 provides the results of the fuel price sensitivities comparing NPV fuel costs across the fuel price cases and the total range of uncertainty for each portfolio. Results reflect that the 2024 Portfolio with PPAs results in the lowest range of uncertainty followed closely by the 2024 Portfolio Update. The GHG Rule Portfolio reflects a much larger range of uncertainty, as discussed above. Importantly, while a portfolio with a greater reliance on renewables might tend to have lower fuel cost uncertainty, the future cost of renewable resources over the Study Period is also significantly uncertain, which is not captured in this metric.

Table 22. Fuel Price Sensitivity Results

Supplemental Portfolios	NPV Fuel Costs ($B)			Diff. to Reference ($B)		
	Reference Case	Low Fuel Price	High Fuel Price	Low Fuel Price	High Fuel Price	Uncertainty Range
2024 Portfolio Update	$16.4	$14.6	$20.4	-$1.8	$4.0	$5.8
2024 Portfolio with PPAs	$16.4	$14.6	$20.4	-$1.8	$4.0	$5.8
GHG Rule Portfolio	$15.0	$12.7	$21.7	-$2.3	$6.7	$9.0
Difference to 2024 Portfolio Update						
2024 Portfolio with PPAs	$0.0	$0.0	$0.0			
GHG Rule Portfolio	($1.4)	($1.9)	$1.3			

CO_2 EMISSIONS

Santee Cooper is committed to reducing the carbon footprint of its generating fleet. Table 23 compares CO_2 emissions in millions of tons ("MT") and CO_2 emissions rates in pounds per MWh of energy produced over the Study Period across the resource portfolios and fixed load sensitivities. Not surprisingly, given the intent of the portfolio, results reflect that the GHG Rule Portfolio would produce the lowest CO_2 emissions, considerably lower than the other portfolios on both a mass and rate basis.

Table 23.
Comparison of CO_2 Emissions Across Fixed Load Sensitivities

Portfolios	Reference Cases	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
Cumulative Emissions (MT)					
2024 Portfolio Update	503	477	613	461	432
2024 Portfolio with PPAs	504	478	612	463	435
GHG Rule Portfolio	349	347	379	346	343
Average Emissions (lbs/MWh)					
2024 Portfolio Update	896	852	1,086	827	778
2024 Portfolio with PPAs	896	854	1,085	830	783
GHG Rule Portfolio	643	639	704	637	633

GENERATION DIVERSITY

The extent to which a resource plan relies significantly upon a single type of resource or fuel can represent a significant source of risk for the system, both in terms of cost and reliability. A useful measure of diversity for this purpose is the coefficient of dispersion, which represents the standard deviation of a series of values divided by the average of the values. A lower coefficient of dispersion corresponds to a more uniform, equally distributed set of values.

Table 24 presents the coefficient of dispersion for capacity and energy by fuel type in the study end year, 2052, for each of the portfolios. The coefficient of dispersion here represents the standard deviation of the capacity and generation by fuel type divided by the average across the fuel types.[32] The 2024 Portfolio with PPAs reflects the lowest coefficient of dispersion, reflecting a lower reliance on any one fuel or resource type than the other portfolios.

Table 24.
Diversity of Generation Resources Across Portfolios at Study End Year

Portfolios	Coefficient of Dispersion		
	Capacity	Energy	Average
2024 Portfolio Update	1.22	1.08	1.15
2024 Portfolio with PPAs	1.22	1.07	1.15
GHG Rule Portfolio	1.51	1.47	1.49

CLEAN ENERGY PROPORTION

The Clean Energy Proportion metric measures the percentage of system energy that is derived from carbon-free resources, including solar, wind, nuclear, hydro, biomass, and landfill gas ("LFG") facilities. Table 25 provides the proportion of carbon-free generation across the portfolios over the Study Period. The GHG Rule Portfolio, not surprisingly, derives the highest proportion of system energy from carbon-free resources, but the other portfolios result in only slightly lower proportions of clean energy. This difference is fairly small across sensitivities despite the retirement of Santee Cooper's coal units and the operating limits on NGCC resources in the GHG Rule Portfolio.

Table 25.
Carbon-free Generation Proportion Across Portfolios over Study Period

Portfolios	Reference Case	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
2024 Portfolio Update	33.3%	33.4%	33.1%	33.5%	33.6%
2024 Portfolio with PPAs	33.4%	33.4%	33.2%	33.5%	33.6%
GHG Rule Portfolio	36.7%	36.7%	36.7%	36.7%	36.7%

FIXED COST OBLIGATIONS

The fixed cost obligations metric considers the total of fixed costs that would not vary based on energy provided from the resources. These would include debt service and fixed operating costs of new resources, payment obligations under take-or-pay PPAs, or other fixed costs directly attributable to resource decisions. Table 26 provides the total fixed cost obligations across the

[32] For this purpose, the generation is taken from the Reference Case.

portfolios on an NPV basis over the Study Period and reflects that the 2024 Portfolio Update with PPAs incurs the lowest burden of fixed costs of the portfolio options.

Table 26.
Fixed Cost Obligations by Portfolio Over the Study Period

Portfolios	NPV ($B)
2024 Portfolio Update	$9.7
2024 Portfolio with PPAs	$9.6
GHG Rule Portfolio	$18.4

This relative level of fixed cost obligations also provides some indication regarding the sensitivity of the portfolios to changes in capital costs. Variations in capital costs, driven from real escalation in the cost of raw materials (e.g., steel, copper) or equipment that spans all generating resource types will have the most impact on those portfolios with higher fixed cost obligations above. This implies that the cost of portfolios that reflect relatively large concentrations of renewable and BESS resources tend to be more sensitive to variations in capital costs.

RELIABILITY

As solar, wind, and BESS resources may not provide for as high a level of reliability as more dispatchable generating resources, Santee Cooper has developed a reliability metric that measures the annual quantity of solar, wind, and BESS nameplate capacity relative to the peak winter demand for 2026 through 2034. This period represents an initial period over which Santee Cooper is most concerned with future resource additions.

Table 27, below, provides a summary of the reliability metric computed for the portfolios under the Reference Case assumptions. This metric reflects that the 2024 Portfolio Update and 2024 Portfolio with PPAs have lower levels of BESS and intermittent solar and wind resources as compared to the GHG Rule Portfolio.

Table 27.
Renewable and BESS Capacity as a Percentage of Peak Demand

Portfolios	Percent (2026 - 2034)
2024 Portfolio Update	25%
2024 Portfolio with PPAs	25%
GHG Rule Portfolio	29%

Santee Cooper will continue to work with stakeholders to discuss further development of quantitative reliability metrics for use for future IRPs and IRP Updates.

FLEXIBILITY TO ADAPT TO LOWER OR HIGHER CUSTOMER LOADS

A key priority for the IRP has been to identify a portfolio that affords Santee Cooper the flexibility to adapt as conditions and levels of customer load changes. Accordingly, Santee Cooper performed sensitivity analysis that assumes variations in the load forecast to understand the flexibility of the portfolios to load levels and the sensitivity of levelized NPV power costs to such load variations. For this purpose, the assumption was made that the decisions to retire Winyah and develop a large NGCC upon Winyah's retirement and develop solar resources over 2026-2030 would not be affected by the assumed variations in load levels, thereby removing that flexibility that may exist in those scenarios to mitigate cost impacts.

Table 28 summarizes the resource build plan resulting from the optimization of the 2024 Portfolio Update across the load growth sensitivity cases. Under the Low Load case, significantly less solar is implemented, and the NGCT, wind, and BESS resources through 2040 are not implemented. In the High Load case, an additional NGCC resource is built in the 2030s and additional solar, CT, wind, and BESS resources are implemented.

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Table 28. 2024 Portfolio Update Build Across Load Sensitivities

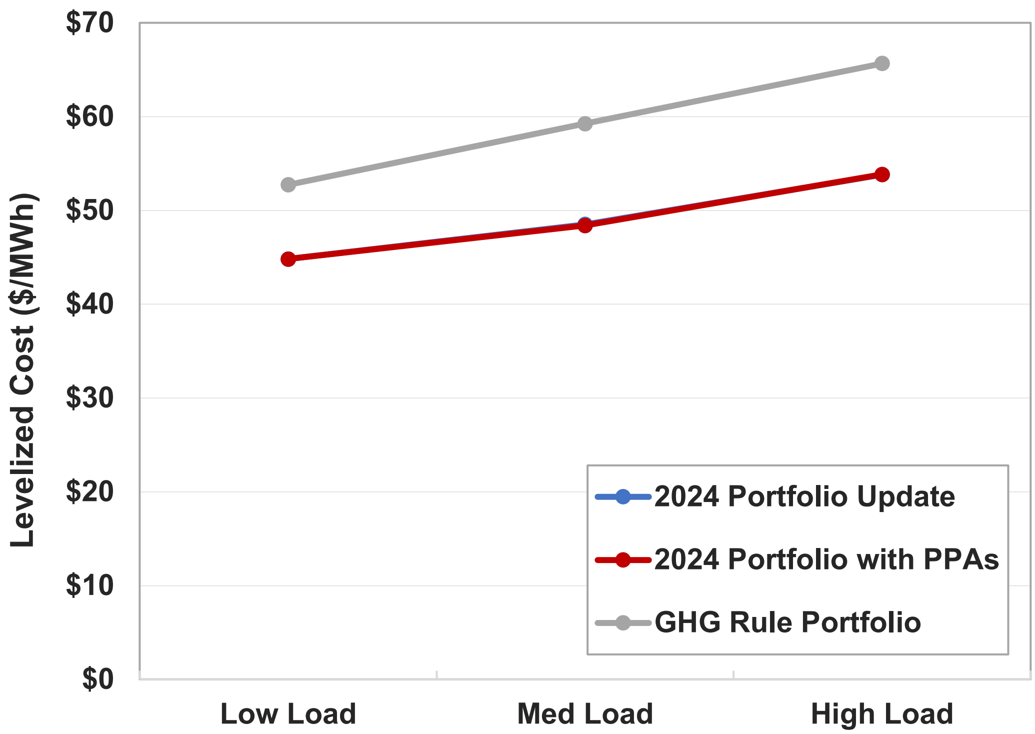
Resource Changes Through 2040	Additions (Retirements) (MW)		
	Low Load	Medium Load	High Load
Retirements • Winyah (2031) • HH and MB CTs (2034) • Cross (2032)	(1,150) (165) 0	(1,150) (165) 0	(1,150) (165) 0
Rainey Upgrades • Rainey PB2 Conversion (2028) • Rainey CT Upgrades (2028) • Rainey PB1 Upgrades (2028)	178 21 56	178 21 56	178 21 56
Central PPAs • 2029	672	672	672
New NGCC • 2031	1,020	1,020	2,379
New Peaking • 2031 • 2032-2040	0 0	894 0	0 2,044
CT PPAs[33] • 2031-2038 • 2039	0 0	0 0	0 0
New Solar[34] • 2026-2031 • 2032-2040	1,500 1,400	1,800 1,650	1,800 2,700
New BESS • 2026-2031 • 2032-2040	0 0	250 200	1000 0
New Wind • 2029-2031 • 2032-2040	0 0	100 500	0 200

Santee Cooper prepared re-optimized portfolios for the Low and High Load forecast sensitivity cases for the other two portfolios and computed total and levelized NPV costs for the reference and load sensitivity cases to provide a comparison of costs resulting from variations in load forecast assumptions. Figure 17, below, depicts the average levelized power cost over the Study

[33]Reflects the addition of PPAs, as needed, over the 2031 through 2038 period, the replacement of the PPAs with other resources in 2039 as identified through the portfolio optimization process.
[34] The amounts of New Solar capability shown are in addition to the approximately 200 MW of solar PPAs procured by Santee Cooper and Central in 2021.

Period for each of the portfolios under the three load forecast scenarios. The chart shows that the 2024 Portfolio Update values are virtually indistinguishable from the 2024 Portfolio with PPAs, indicating similar sensitivity to changes in load. Importantly, the load sensitivity analysis confirms that there is not a significant risk to Santee Cooper's customers should projected load additions not materialize. However, the GHG Rule Portfolio is projected to result in an increase in levelized cost from approximately $8/MWh for the Low Load Forecast to approximately $12/MWh for the High Load Forecast, indicating that costs of the GHG Rule Portfolio are projected to be impacted much more significantly by changes in load.

Figure 17. Sensitivity of Levelized Power Costs to Load Growth Variations[35]



RATE IMPACTS OF PORTFOLIOS

Portfolio costs refer to total fuel and purchased energy costs plus only the level of fixed costs that vary between portfolios (e.g., debt service and fixed O&M for resources added in the future). However, the portfolio costs that underlie the analyses presented elsewhere herein are only part of the total costs that must be recovered from future Santee Cooper charges to customers.

The information below places the projected portfolio costs compared elsewhere in the IRP in the context of the projected impact on Santee Cooper's average rates to customers. This analysis captures the rate impact of resource portfolio changes only and is based on the Reference Case Assumptions.

[35] The 2024 Portfolio Update and 2024 Portfolio with PPAs are indistinguishable in this chart.

To approximate Santee Cooper's average rate level, Santee Cooper's total cost-of-service[36] has been projected by adding to the portfolio costs allowances for other Santee Cooper costs that would be approximately the same for all portfolios. These other costs have been projected based on existing debt service schedules and by escalating other production, transmission, distribution, and customer costs at the rate of inflation. It should be noted that the cost-of-service projected for this purpose includes the impact of fuel cost escalation assumptions which Santee Cooper passes through to customers as actual fuel and purchased energy expense incurred.

Figure 18 below provides the resulting trend in projected rates indexed to 2026 for Santee Cooper's customers for each of the portfolios studied based on the Reference Case assumptions.[37]

Figure 18. Projected Rate Index Across Portfolios (Reference Case)

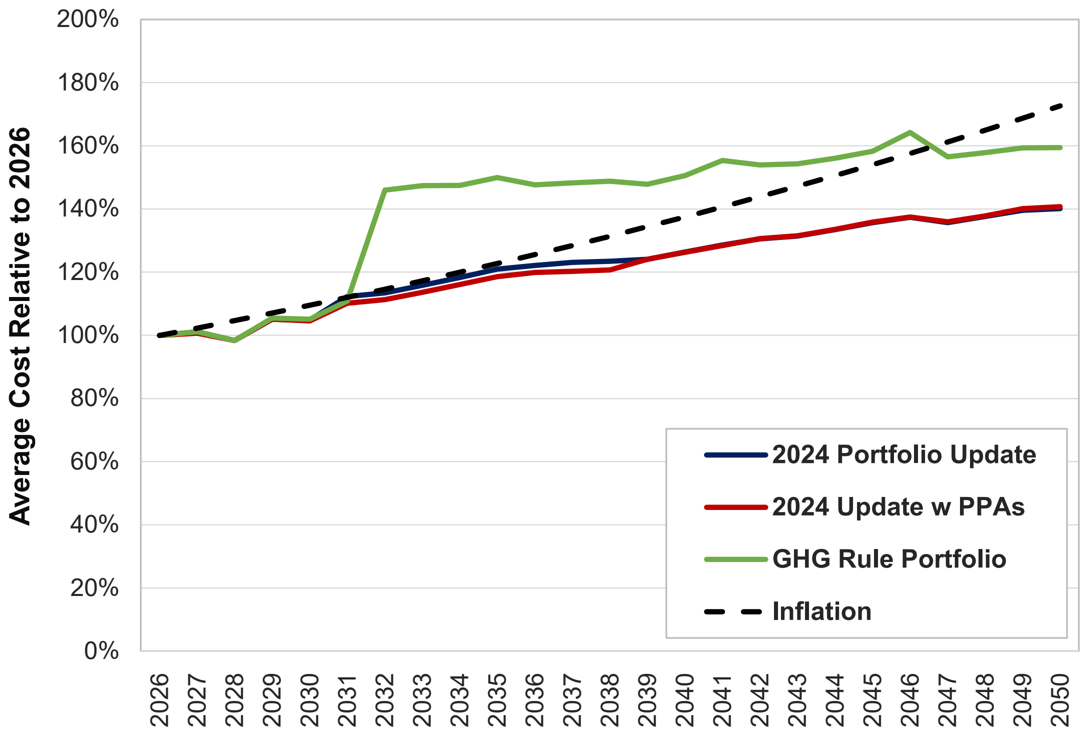


Figure 18 indicates that both the 2024 Portfolio Update and 2024 Update with PPAs result in projected cost rates that are well below the rate of inflation over the Study Period. The GHG Rule Portfolio, on the other hand, results in a large cost increase in 2032, the first major year of

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[36] The cost-of-service analysis prepared for this purpose is appropriate for assessing the difference in rate impacts of the portfolios analyzed in the 2024 IRP Update. However, the analyses do not consider the same level of information normally reflected in financial planning or rate setting studies. The analysis presented does not consider recovery of costs deferred due to Cook Settlement Exceptions, which costs would be the same or similar for all portfolios analyzed.

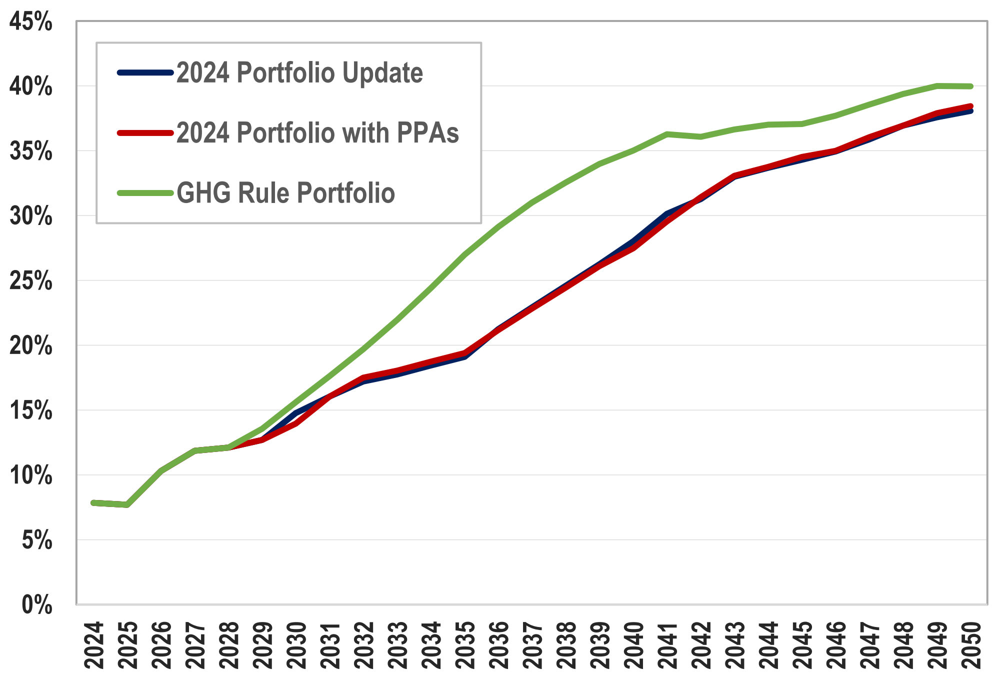
[37] Similar information for fuel and CO_2 price sensitivity cases is provided in Appendix F.

compliance with the Rule, and costs that generally escalate well above inflation over most of the Study Period.

RENEWABLE ENERGY FORECAST

Each of the portfolios reflect significant increases over the Study Period in the proportion of system energy requirement served from renewable resources. Figure 19 depicts the trend in this proportion over the Study Period. As should be expected, the GHG Rule Portfolio reflects considerably higher concentration of renewable resources over most of the Study Period. However, by the end of the Study Period, the other portfolios are only slightly below the level of GHG Rule Portfolio in proportion of renewable generation.

Figure 19. Percentage of System Energy Served from Renewables



Renewable generation amounts by year are provided in Appendix E.

ALTERNATIVE SELF-BUILD NGCC PORTFOLIO

At the request of stakeholders, Santee Cooper has performed an alternative optimization, similar to the 2024 Portfolio Update but constraining available resource options to exclude the joint-build NGCC, hence allowing only self-build NGCCs ("2024 Portfolio with Self Build NGCC"). Table 29 provides a comparison of the resulting resource build to the unconstrained build reflected in the 2024 Portfolio Update, which reflects a similar overall mix of resources.

Table 29. 2024 Portfolio Update v. Update Excluding Self-Build NGCC

Resource Changes Through 2040	Additions (Retirements) (MW)	
	2024 Portfolio Update	2024 Portfolio with Self Build NGCC
Retirements		
• Winyah (2031)	(1,150)	(1,150)
• MB and HH CTs (2034)	(165)	(165)
Rainey Upgrades		
• Rainey PB2 Conversion (2028)	178	178
• Rainey CT Upgrades (2028)	21	21
• Rainey PB1 Upgrades (2028)	56	56
Central PPAs		
• 2029	672	672
New NGCC		
• 2031	1,020	1,360
New Peaking		
• 2031	894	447
• 2032-2040	0	256
New Solar[38]		
• 2026-2031	1,800	1,800
• 2032-2040	1,650	1,650
New BESS		
• 2026-2031	250	200
• 2032-2040	200	100
New Wind		
• 2029-2031	100	0
• 2032-2040	500	450

Table 30 provides a comparison of NPV power costs for the 2024 Portfolio with Self Build NGCC to the unconstrained 2024 Portfolio Update and the 2024 Portfolio with PPAs.

[38] The amounts of New Solar capability shown are in addition to the 200 MW of solar PPAs procured by Santee Cooper and Central in 2021.

Table 30. Comparative NPV Power Costs of Self-Build NGCC Portfolio

Portfolios	NPV Power Costs
2024 Portfolio Update	$29.3
2024 Portfolio with PPAs	$29.2
2024 Portfolio with Self Build NGCC	$29.3
Difference to 2024 Portfolio Update	
2024 Portfolio with PPAs	($0.1)
2024 Portfolio with Self Build NGCC	$0.1

Santee Cooper anticipates that undertaking the 2031 NGCC resource jointly with DESC will significantly reduce risk and costs for customers relative to the Self-Build option. In this analysis, fixed costs per kW are based on DESC's estimates for a 2x1 NGCC resource under both the joint-build and Self-Build options, and therefore economies of scale likely to be realized through the joint-build option are not reflected in this analysis. Should the option of jointly undertaking the 2031 NGCC with DESC not materialize, this analysis shows that Santee Cooper would likely move toward a full 2x1 NGCC in an effort to maximize economies of scale for the project.

CONCLUSIONS

The results of the resource plan analyses presented in the previous section support and reinforce the key conclusions reached in the 2023 IRP and the key elements of the 2023 Preferred Portfolio. These include the following.

Portfolio Element	Conclusions
2031 NGCC Resource	▪ The 2031 NGCC provides a cost-effective resource addition upon Winyah's retirement by 2031 in the 2024 Portfolio Update and 2024 Portfolio with PPAs. ▪ The GHG Rule Portfolio suggests that, even under the restrictive greenhouse gas regulations in the current final rule, significant NGCC resources are a key feature of the optimal portfolio.
Solar Resources	▪ Solar resources are a key element of all portfolios. While solar resources totaling 1,500 MW through 2030 are added to all portfolios, the portfolio optimization simulations select additional solar immediately thereafter. ▪ Because solar costs are assumed to decline in real cost terms through 2035, solar is more economical in the later years of the Study Period. However, limitations and risks to implementing large magnitudes of solar in later periods supports a phased implementation of solar starting relatively early in the Study Period, if available at a reasonable cost.
BESS Resources	▪ BESS resources are selected across all portfolios and are an important element of any portfolio with significant solar and wind resources.
Onshore Wind	▪ Onshore wind resources are selected across all portfolios. However, as no such resources have been developed in South Carolina, their viability in the state is uncertain. Santee Cooper intends to investigate the viability of onshore wind for future IRPs.

The 2024 Portfolio with PPAs tended to perform as well or better than the 2024 Portfolio Update across the portfolio metrics. The use of PPAs to meet some of Santee Cooper's peaking resource needs in the 2030s would yield other benefits to Santee Cooper, including reducing risk and limiting capital outlay.

Figure 20 depicts Santee Cooper's projected winter peak demand and winter peak with reserve margin requirement versus the winter peak contribution of Santee Cooper's existing resources and the incremental resource build for the 2024 Portfolio with PPAs over the Study Period. The chart shows the Rainey NGCT upgrades and NGCC conversion in 2028,[39] the retirement of Winyah and installation of the replacement NGCC resource by 2031, and the addition of a mix of peaking resources and BESS over the Study Period. Not visible in this chart are significant amounts of solar resources being added over the Study Period, as these do not contribute significantly to the winter peak requirement.

Figure 20. Incremental Resource Additions under the 2024 Portfolio with PPAs

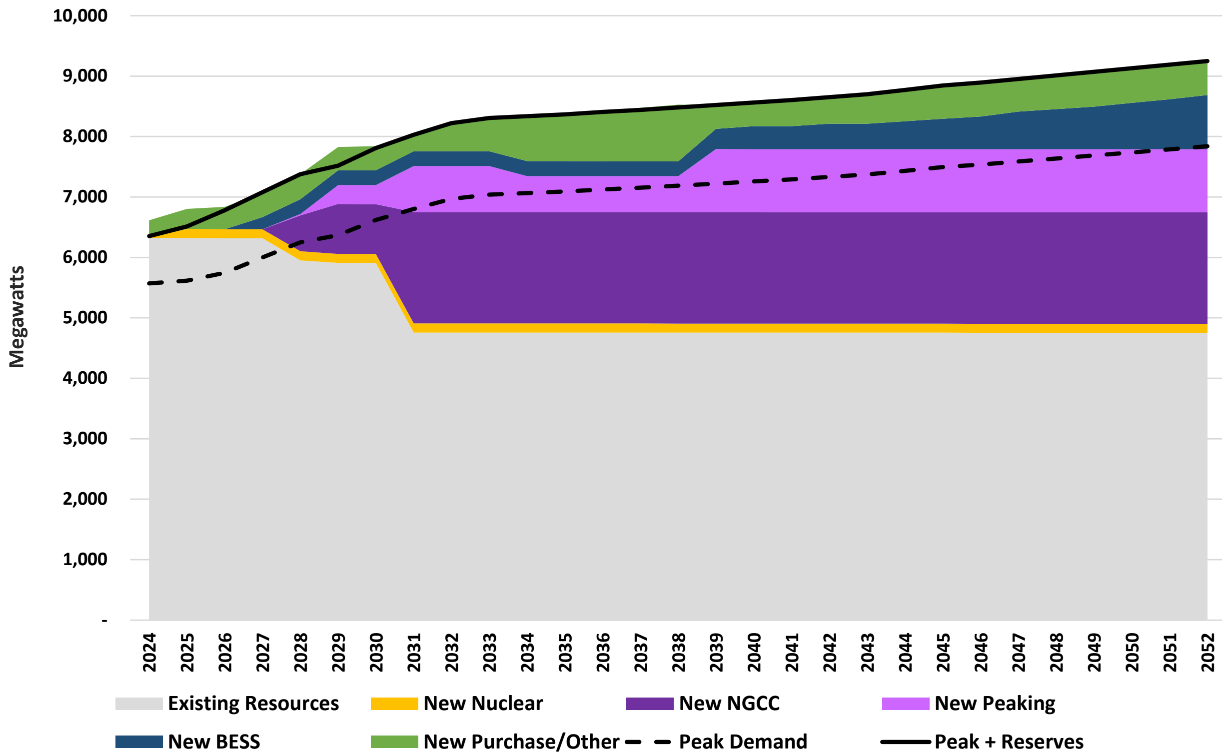


Figure 21 depicts a similar representation of the 2024 Portfolio with PPAs over the Study Period but shows resources by category without differentiating between existing resources and the new builds included in the 2024 Portfolio with PPAs.

39 Note that the chart reflects a drop in Existing Resources and a large amount of a new NGCC capacity in 2028 due to the conversion of a large portion of the Rainey NGCT capacity to NGCC capacity. Only 178 MW of capacity is added to the system as a result of this conversion.

Figure 21. Supply and Demand Balance under the 2024 Portfolio with PPAs

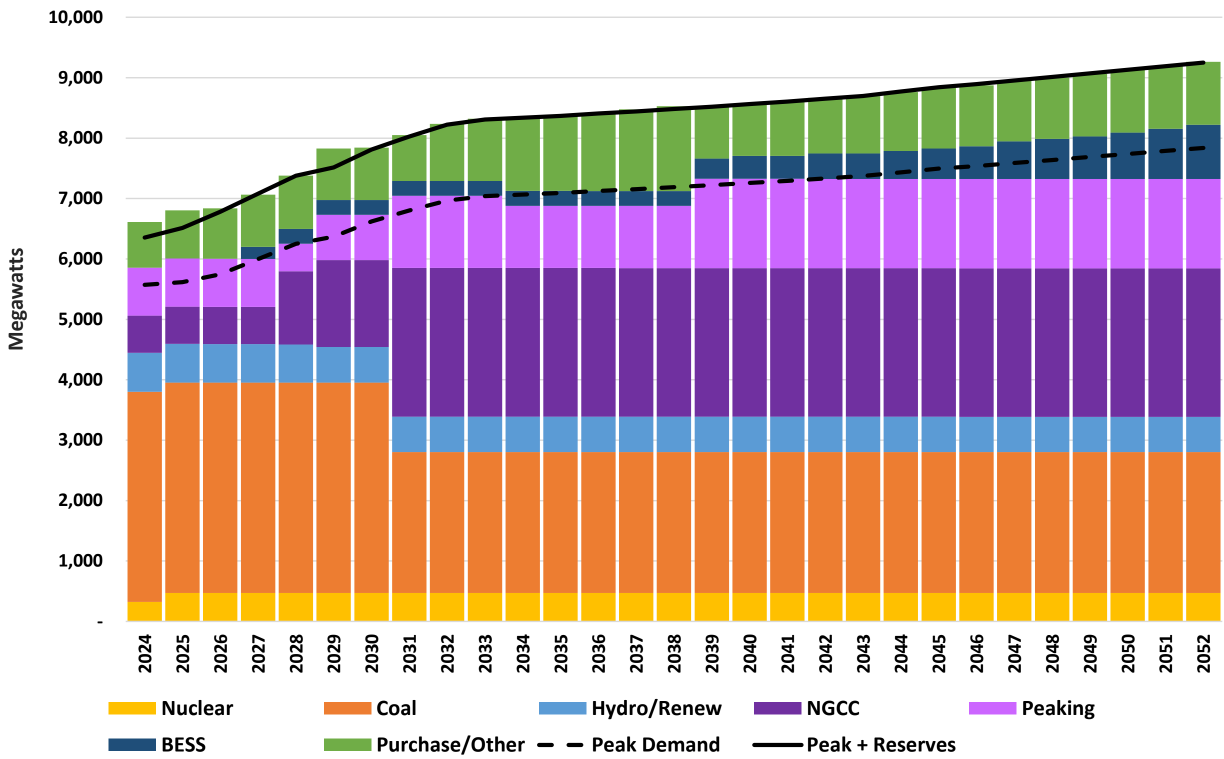


Figure 22 compares the generation mix for 2025 and 2040 for the 2024 Portfolio with PPAs, reflecting significantly improved portfolio diversity that is achieved by 2040 through the resource changes and additions reflected in the build plan. Reliance on coal would be reduced to less than half of the level projected for 2025, and the proportion of energy provided from sustainable resources would more than triple, mostly due to additions of solar resources. Instead of being largely reliant on coal, the portfolio would rely on a diverse mix of natural gas, sustainable, and coal resources, which reduces risk to customers. The build plan also offers flexibility to adjust as conditions change or if customer demand for electricity is higher or lower than currently projected.

Figure 22. Generation Mix Under the 2024 Portfolio with PPAs

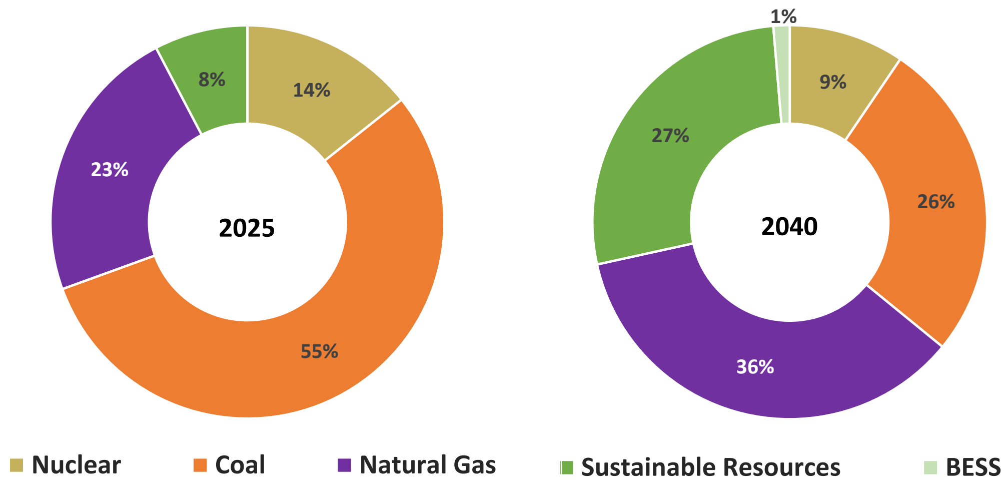
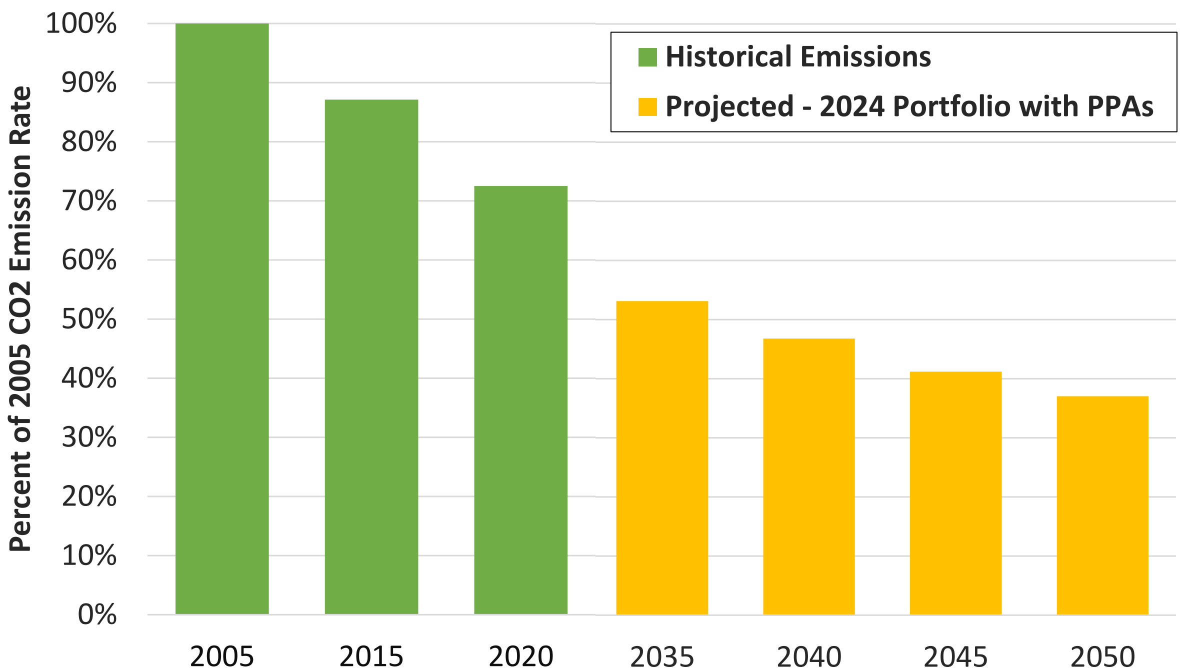


Figure 23 depicts historical and projected CO_2 emissions under the 2024 Portfolio with PPAs for representative years as a percent of 2005 emissions. Projected CO_2 emissions resulting from the significant transition in generation mix above reflect a reduction to approximately 47 percent of 2005 levels by 2040 and below 40 percent by 2050.

Figure 23. Projected CO_2 Emissions as a Percent of 2005



Based on a careful review of the needs of the Combined System and the evaluations discussed in this 2024 IRP Update, Santee Cooper has determined that the 2024 Update with PPAs will be used to guide its resource planning decisions until the 2025 IRP Update. The portfolio changes in the 2024 Update with PPAs are consistent with the key elements in the 2023 Preferred Portfolio and include additional resources to meet the system's growing load projections over the Study Period.

In making this determination, Santee Cooper recognizes that portfolio evaluation results for the 2024 Portfolio Update and the 2024 Portfolio with PPAs are very similar. Decisions on which of these portfolio approaches are more appropriate for Santee Cooper will instead rely on business decisions regarding managing implementation and financial risk, maintaining flexibility for future resource additions as load projections change, and transmission import capability, among others.

Santee Cooper respectfully submits this 2024 IRP Update to the Commission for consideration and acceptance.

SHORT-TERM ACTION PLAN

Considering the results of the planning analyses summarized above and explained further in the body of the 2024 IRP Update report, Santee Cooper plans to proceed as follows, subject, where appropriate, to acceptance of the 2024 IRP Update by the Commission.

CONTINUE TOWARDS EXECUTING THE 2023 PREFERRED PORTFOLIO AND SHORT-TERM ACTION PLAN

This IRP Update has confirmed the key resources identified in the 2023 IRP, including solar and a large NGCC resource in 2031 upon the retirement of Winyah. Santee Cooper will continue to work towards implementing these resources.

For solar, Santee Cooper and Central are currently evaluating bids received through the 2024 Solar RFP and expect to award contracts in early 2025. Updates will be provided to the Commission in Docket No. 2022-351-E and in future IRP filings.

For the NGCC, Santee Cooper will continue to refine project costs and schedule, including natural gas pipeline and transmission infrastructure, and will continue discussions with DESC on the possibility of jointly executing a project. As noted previously, Santee Cooper would have to receive legislative authorization from the South Carolina General Assembly to partner with DESC in jointly owning the proposed NGCC. Santee Cooper will continue to evaluate the development schedule of this resource, particularly the timing under which the resource can be brought online, and will update the Commission in subsequent IRPs and IRP updates.

UPDATE THE LOAD FORECAST AND MONITOR CHANGES IN POTENTIAL NEW LARGE CUSTOMERS

As discussed throughout this IRP Update, the potential for the addition of new large customers to the Combined System of Santee Cooper and Central drives the need for additional resources beyond those identified in the 2023 Preferred Portfolio. Meeting this increasing demand is important for the State of South Carolina to ensure a reliable electric system and the opportunity for robust economic development.

Santee Cooper and Central will continue to work closely together to update the load forecast including the potential for the addition of new customer loads. Additionally, Santee Cooper will also continue to engage with stakeholders in reviewing the methodology used to quantify the probability of large new customers joining the Combined System. The 2025 IRP Update and 2026 IRP will reflect updated load forecasts and, if warranted, changes to recommended resources or implementation schedules.

IMPLEMENT NEAR-TERM RESOURCES

An increase in Santee Cooper's planning reserve margin and the growth in load identified in the 2024 Load Forecast drive the need for resources that can be available in the near term. These resources are discussed below and are critical for meeting the near-term demands but also serve as cost effective and reliable long-term resources for customers of the Combined System. Santee Cooper intends to work closely with Central in implementing these resources while complying with the requirements in the Coordination Agreement.

- Conversion of Rainey Units 2A and 2B from Simple Cycle NGCTs to an NGCC – The project presents a unique opportunity to bring highly-efficient combined cycle energy and capacity to the system. Santee Cooper intends to pursue this project and will file a Certificate of Environmental Compatibility and Public Convenience and Necessity under the "Utility Facility Siting and Environmental Protection Act"[40] with the Commission in September of this year.
- Rainey Units 1 and 3-5 Upgrades – Santee Cooper is conducting engineering studies and plans to pursue these upgrades, which can be completed and ready to meet the 2028 winter peak.
- Additional BESS – The 2024 IRP Update has identified the potential need for BESS resources beginning in 2027. A portion of this need may be met through Santee Cooper's pilot project and Central's NSR. Santee Cooper intends to work with Central on finalizing a joint BESS solicitation strategy and will update the Commission in the 2025 IRP annual update.

REFINE OPTIONS FOR LARGE FRAME COMBUSTION TURBINES TO MEET GROWING LOAD

This IRP Update has identified large frame NGCTs as cost-effective and reliable resources to meet growing load and resource needs in the early 2030s. Santee Cooper will continue to monitor and update the load forecast which will impact the need for and the timing of these dispatchable resources. To further study these peaking resources, Santee Cooper will begin front-end engineering and design studies for NGCT resources in the early 2030s.

MONITOR REGULATORY DEVELOPMENTS

As demonstrated by this IRP Update, the EPA GHG Rule has potentially dramatic cost implications and implementation risks for Santee Cooper and Central's customers. We will continue to monitor these regulations and through many of the items above we will continue to refine the options for complying with existing or future GHG regulations.

CONTINUE STAKEHOLDER ENGAGEMENT AND STUDIES TO SUPPORT FUTURE FILINGS

Santee Cooper will complete studies identified in the 2023 IRP Short-Term Action Plan and comply with the requirements of Order 2024-171. Santee Cooper will continue to engage with stakeholders and share the scope and results of these studies as they are prepared.

[40] S.C. Code Ann. §58-33-10 et seq.

APPENDIX A: ABBREVIATIONS

AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BAT	Best available technology
BESS	Battery energy storage system
CAGR	Compound average growth rate
CC	Combined cycle generator
CO_2	Carbon dioxide
CRSG	Carolinas Reserve Sharing Group
CT	Combustion turbine generator
CVR	Conservation voltage reduction
DEC	Duke Energy Carolinas, LLC
DESC	Dominion Energy South Carolina
DG	Distributed generation
DOE	Department of Energy
DR	Demand response
DSM	Demand-side management
EE	Energy efficiency
EFOR	Equivalent forced outage rate
EIA	Energy Information Administration (of the Department of Energy)
ELCC	Effective load carrying capability
ELG	Effluent limitation guidelines
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
GHG	Greenhouse gas
GWh	Gigawatt-hour (i.e., 1,000 MWh)
IRA	Inflation Reduction Act
IRP	Integrated resource plan
ITC	Investment tax credit
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized cost of energy
LCOC	Levelized cost of capacity
LFG	Landfill gas
LOLE	Loss of load expectation
MMBtu	1 million British thermal units
MPS	Market potential study
MW	Megawatt
MWh	Megawatt-hour
NCP	Non-coincident peak
NERC	North American Electric Reliability Corporation
NGCC	Natural gas-fired combined cycle
NGCT	Natural gas-fired combustion turbine
NOAA	National Oceanic and Atmospheric Administration
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSR	Non-Shared Resource
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance
PCT	Production tax credit
PMPA	Piedmont Municipal Power Agency
PO	Planned maintenance outage
PPA	Power purchase agreement
PRM	Planning reserve margin
PSR	Proposed Shared Resource
PVRR	Present value revenue requirement
RFP	Request for proposal

SAE	Statistically-adjusted end-use
SAM	NREL System Advisory Model
SCC	Social cost of carbon (CO_2)
SERC	SERC Reliability Corporation
SERVM	Astrapé's Strategic Energy and Risk Evaluation Model
SEPA	Southeastern Power Administration
SMR	Small modular reactor
UCT	Utility cost test

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APPENDIX B: TRANSMISSION PROJECTS

ACTIVE PROJECTS

Johns Island – Queensboro (DESC) 115 kV Line

Currently, Johns Island has a single 230 kV transmission line providing service to the island and surrounding area. Backup service is available through a normally open 115 kV tie line with DESC, but it is not sufficient to serve all of the load in the area (Johns Island, Kiawah Island, Seabrook Island, and Wadmalaw Island) during high load periods. The backup tie line utilizes the same transmission corridor and structures as the 230 kV line for approximately 6 miles, making it vulnerable to outages during local weather events and making certain major maintenance activities impractical without a sustained outage. This new 115 kV project provides a transmission path from a separate source on a diverse route, or corridor, and will improve the electric reliability and increase resiliency for the James Island and Johns Island areas.

Wassamassaw 230-115 kV Substation

The Wassamassaw 230-115 kV Substation is expected to provide support for load growth in the Dorchester and Berkeley County area and is necessary to mitigate thermal loading issues under contingency conditions. Initial plans for the substation involve folding in the existing Carnes – Cross 230 kV line and Jefferies – Harleyville 115 kV Line with the addition of two 230-115 kV transformers. The Wassamassaw 230-115 kV Substation will be configured such that additional facilities can be added to provide support for continued load growth in the area.

Conway 230 kV Switching Station

The Conway 230 kV Switching Station is expected to provide support for load in the Horry County area and mitigate voltage and thermal loading issues under contingency conditions. Initial plans involve folding in the Hemingway – Red Bluff 230 kV Line and termination of the new Marion – Conway 230 kV Line to the new 230 kV switching station. The site is located adjacent to the existing Conway 115-34.5 kV Substation and will be configured to allow for additional 230 kV network expansion in the area and future 230-115 kV transformation.

Marion – Conway 230 kV Line

The Marion – Conway 230 kV Line is expected to provide an additional 230 kV source to support load in Horry County and mitigate voltage and thermal loading violations which could occur under contingency conditions. This project involves constructing approximately 34 miles of double circuit 230/115 kV from the Marion 230-115-69 kV Substation to the proposed Conway 230 kV Switching Station. This construction is expected to be within the existing Marion – Conway 115 kV right-of-way and will result in the rebuild of the Marion-Conway 115 kV Line for 230/115 kV double-circuit, which increases the reliability of delivery points served directly from this line.

Carolina Forest 230-115 kV Transformer #1 Addition

This project is expected to mitigate the existing Carolina Forest transformer thermal loading violations that could occur with the loss of both Perry Road 115 kV buses. This second transformer will increase the power flow through the Carolina Forest 230-115 kV Substation and will reduce loading on the Perry Road 230-115 kV transformers.

Conway – Perry Road 230 kV Line

This project will establish a new 230 kV line between the Conway 230 kV Switching Station and Perry Road 230-115 kV Substation and is intended to be constructed on existing rights-of-way. This line provides an additional path into the load center in the Myrtle Beach area and alleviates thermal loading under contingency conditions.

Wassamassaw-Pringletown #1 & #2 115 kV Line

This transmission project will provide additional load serving capability for the anticipated load growth at Camp Hall and surrounding areas. The scope of this project includes the construction of a 230/115 kV double circuit line, to be initially operated at 115 kV, from the Pringletown 115 kV switching station to the Wassamassaw 230-115 kV substation.

Cross – Wassamassaw 230 kV Line #2

This 230 kV circuit provides an additional path from Cross to Wassamassaw to provide network support under contingency conditions. This project will use existing structures on the Cross - Jefferies 230 kV line for 15 miles from Cross and then use existing right-of-way to construct the remaining 3-mile section to the Wassamassaw 230-115 kV Substation.

Reconductor Purrysburg – McIntosh 230kV Tie Lines

Reconductoring the Purrysburg – McIntosh #1 and #2 230kV tie lines is necessary to maintain transmission reliability and mitigate thermal loading under contingency conditions. Reconductoring the tie lines is also important for improving transfer capability with neighboring utilities.

Kingstree – Hemingway 230 kV Line #2

This 230 kV line will provide an additional path from generating resources in the western part of the state toward load centers in the east and alleviates multiple thermal and voltage violations identified under contingency conditions. This project rebuilds the existing Kingstree – Hemingway 115 kV line as a double circuit 230/115 kV line, which will increase the reliability to delivery points served from this line.

Indian Field 230-115kV Substation

This substation will support 230 kV network expansion plans and future load growth in this area. The scope of this project includes folding in the existing Harleyville – St. George 115kV line to a new Indian Field 230-115kV substation and constructing a new 115kV transmission line from the new Indian Field 230-115kV Substation to the existing St. George 115kV Switching Station.

Indian Field – Wassamassaw 230kV Line

This project along with the Varnville-Indian Field 230 kV line project are necessary to add an additional 230 kV transmission path from the Southern region of the system to the Eastern region of the system. Planning assessments indicate that the existing Southern path will be constrained under contingency conditions. The scope of this project includes the construction of a 230kV transmission line (approximately 22 miles in length) from the new Indian Field 230-115kV substation to the Wassamassaw 230-115kV substation.

Varnville – Indian Field 230 kV Line

This 230 kV line project is necessary to add an additional 230 kV transmission path from the Southern region of the system to the Eastern region of the system. Planning assessments indicate that the existing Southern path will be constrained under contingency conditions. The scope of this project includes the construction of a 230 kV transmission line (approximately 38 miles in length) from the Varnville 230-115 kV Substation to the new Indian Field 230-115 kV Substation as well as rebuilding the existing Bells Crossroads – Varnville 115 kV Line for 230/115 kV double-circuit on the existing right-of-way. The scope also includes rebuilding the St. George – Bells Crossroads 115 kV Line #2 for 230/115 kV double-circuit on the existing right-of-way.

Marion - Red Bluff 230 kV Line

The Marion – Red Bluff 230 kV line provides voltage stability and mitigates thermal loading issues in the eastern part of Santee Cooper's service territory under contingency conditions. This project would result in constructing a 230 kV line from the Marion 230-115-69 kV Substation to the Red Bluff 230-115 kV Substation using a combination of existing right-of-way and new right-of-way and would result in rebuilding portions of the Marion – Latta #2 69 kV Line, the Allen – Pine Level #2 115 kV line and the Pine Level – Red Bluff 115 kV Line for double circuit 230/115 kV construction, which would increase reliability to delivery points served from these lines.

Varnville 230-115 kV Substation

A new Varnville 230-115 kV Substation will facilitate the addition of new 230 kV transmission lines to support future transmission network expansion plans. The existing Varnville Substation has space limitations and cannot accommodate additional 230 kV line terminals or other facilities required to provide reliable long-term service to the area.

Jefferies – Charity 230 kV Line Rebuild

This project will provide an additional network 230 kV path to maintain transmission reliability and mitigate thermal and voltage violations identified under contingency conditions. The existing Jefferies – Charity 230 kV line will be rebuilt for 230/230 kV double circuit construction along the existing transmission corridor.

PLANNED PROJECTS

Wassamassaw – Carnes #2 & Jefferies – Wassamassaw 230 kV Lines

These new 230 kV lines will provide additional network support to the Wassamassaw Substation and are expected to mitigate thermal loading issues on the Wassamassaw 230-115 kV transformers and Wassamassaw-Jefferies 115 kV line under contingency conditions. This project is expected to support load growth in this area and to maintain transmission reliability. These 230 kV lines will be constructed utilizing double circuit construction with one configured as 230/230 kV double circuit with the Cross – Wassamassaw 230 kV #2 Line, and the other configured as 230/115 kV double circuit with the Wassamassaw – Jefferies 115 kV Line along the existing transmission corridor.

Bucksville – Conway 230 kV Line

This project will add an alternate path to deliver power from Hemingway to Bucksville via Conway and mitigate identified thermal loading conditions in the area. The scope of this project includes the construction of a 7-mile 230 kV line from the Bucksville 230-115 kV substation to the Conway 230 kV Switching Station along the existing transmission corridor.

Rebuild Perry Rd – Myrtle Beach #2 115 kV Line

This project will alleviate thermal loading identified under contingency conditions and maintain transmission reliability in the area. The project scope includes rebuilding the existing 556 ACSR section of the Perry Road-Myrtle Beach #2 115 kV Line with 1272 ACSR conductor.

Nixons Crossroads – Red Bluff #1 115 kV Line

This project will provide support to the north Myrtle Beach area and help to maintain system reliability under contingency conditions. The scope of this project includes the construction of a 115 kV transmission line from Nixon’s Crossroads 115-12 kV Substation to the Brooksville Cooperative Delivery Point Substation.

Cedar Knoll 230-69kV Substation

This project will support load growth in the Blythewood and Columbia areas and alleviate transformer loading in the area identified under contingency conditions. The scope of this project includes the construction of the new 230-69 kV Cedar Knoll substation as well as the fold in of the Pomaria – Sandy Run 230kV Line, the Bythewood-Pomaria 69 kV line, and the Blythewood-Columbia 69 kV lines into the new substation.

APPENDIX C: OPTIMIZED PORTFOLIO BUILDS

Table C-1: 2024 Portfolio Update Additions and Retirements (MW)

Year	Changes in Existing Resources				New Resources								Total
	Coal	NGCC	NGCT	Solar	PPAs	Central NSR	NGCC	NGCT	Solar	Wind	BESS	SMR	
2024	0	0	0	0	291	0	0	0	0	0	0	0	291
2025	0	0	0	0	150	0	0	0	0	0	0	0	150
2026	0	0	0	125	0	0	0	0	300	0	0	0	425
2027	0	0	0	0	0	0	0	0	300	0	250	0	550
2028	0	594	(339)	(75)	0	0	0	0	300	0	0	0	480
2029	0	0	0	(130)	(199)	672	0	0	300	0	0	0	643
2030	0	0	0	0	0	0	0	0	300	100	0	0	400
2031	(1,150)	0	0	0	(195)	0	1,020	894	300	0	0	0	869
2032	0	0	0	0	0	0	0	0	150	100	0	0	250
2033	0	0	0	0	0	0	0	0	0	100	0	0	100
2034	0	0	(165)	0	0	0	0	0	0	100	0	0	(65)
2035	0	0	0	0	0	0	0	0	0	100	0	0	100
2036	0	0	0	0	0	0	0	0	300	50	0	0	350
2037	0	0	0	0	0	0	0	0	300	0	100	0	400
2038	0	0	0	0	0	0	0	0	300	0	0	0	300
2039	0	0	0	0	0	0	0	0	300	0	50	0	350
2040	0	0	0	0	0	0	0	0	300	50	50	0	400
2041	0	0	0	0	0	0	0	0	300	100	0	0	400
2042	0	0	0	0	0	0	0	0	300	0	50	0	350
2043	0	0	0	0	0	0	0	0	300	100	0	0	400
2044	0	0	0	0	0	0	0	0	0	100	50	0	150
2045	0	0	0	0	0	0	0	0	0	100	0	0	100
2046	0	0	0	(200)	0	0	0	0	300	0	100	0	200
2047	0	0	0	0	0	0	0	0	300	0	50	0	350
2048	0	0	0	0	0	0	0	0	300	0	100	0	400
2049	0	0	0	0	0	0	0	0	200	0	100	0	300
2050	0	0	0	0	0	0	0	0	150	0	100	0	250
2051	0	0	0	0	0	0	0	0	150	0	100	0	250
2052	0	0	0	0	0	0	0	0	150	0	100	0	250
Total	**(1,150)**	**594**	**(504)**	**(280)**	**47**	**672**	**1,020**	**894**	**5,900**	**1,000**	**1,200**	**0**	**9,393**

Table C-2: 2024 Portfolio with PPAs Additions and Retirements (MW)

Year	Changes in Existing Resources				New Resources								Total
	Coal	NGCC	NGCT	Solar	PPAs	Central NSR	NGCC	NGCT	Solar	Wind	BESS	SMR	
2024	0	0	0	0	291	0	0	0	0	0	0	0	291
2025	0	0	0	0	150	0	0	0	0	0	0	0	150
2026	0	0	0	125	0	0	0	0	300	0	0	0	425
2027	0	0	0	0	0	0	0	0	300	0	200	0	500
2028	0	594	(339)	(75)	0	0	0	0	300	0	50	0	530
2029	0	0	0	(130)	(199)	672	0	0	300	0	0	0	643
2030	0	0	0	0	0	0	0	0	300	0	0	0	300
2031	(1,150)	0	0	0	(145)	0	1,020	447	300	100	0	0	572
2032	0	0	0	0	150	0	0	0	200	100	0	0	450
2033	0	0	0	0	50	0	0	0	0	100	0	0	150
2034	0	0	(165)	0	150	0	0	0	0	100	0	0	85
2035	0	0	0	0	0	0	0	0	0	100	0	0	100
2036	0	0	0	0	50	0	0	0	300	0	0	0	350
2037	0	0	0	0	50	0	0	0	300	0	0	0	350
2038	0	0	0	0	50	0	0	0	300	0	0	0	350
2039	0	0	0	0	(550)	0	0	447	300	0	100	0	297
2040	0	0	0	0	0	0	0	0	300	0	50	0	350
2041	0	0	0	0	0	0	0	0	300	100	0	0	400
2042	0	0	0	0	0	0	0	0	300	100	50	0	450
2043	0	0	0	0	0	0	0	0	300	100	0	0	400
2044	0	0	0	0	0	0	0	0	0	100	50	0	150
2045	0	0	0	0	0	0	0	0	0	100	50	0	150
2046	0	0	0	(200)	0	0	0	0	300	0	50	0	150
2047	0	0	0	0	0	0	0	0	300	0	100	0	400
2048	0	0	0	0	0	0	0	0	300	0	50	0	350
2049	0	0	0	0	0	0	0	0	200	50	50	0	300
2050	0	0	0	0	0	0	0	0	150	0	100	0	250
2051	0	0	0	0	0	0	0	0	150	0	100	0	250
2052	0	0	0	0	0	0	0	0	100	0	150	0	250
Total	**(1,150)**	**594**	**(504)**	**(280)**	**47**	**672**	**1,020**	**894**	**5,900**	**1,050**	**1,150**	**0**	**9,393**

Table C-3: GHG Rule Portfolio Additions and Retirements (MW)

Year	Changes in Existing Resources				New Resources								Total
	Coal	NGCC	NGCT	Solar	PPAs	Central NSR	NGCC	NGCT	Solar	Wind	BESS	SMR	
2024	0	0	0	0	291	0	0	0	0	0	0	0	291
2025	0	0	0	0	150	0	0	0	0	0	0	0	150
2026	0	0	0	125	0	0	0	0	300	0	0	0	425
2027	0	0	0	0	0	0	0	0	300	0	250	0	550
2028	0	594	(339)	(75)	0	0	0	0	300	0	0	0	480
2029	0	0	0	(130)	(199)	672	0	0	300	100	0	0	743
2030	0	0	0	0	0	0	0	0	300	100	0	0	400
2031	(1,150)	0	0	0	(195)	0	1,360	0	300	100	0	0	415
2032	(2,330)	0	0	0	0	0	2,719	0	300	100	0	0	789
2033	0	0	0	0	0	0	0	256	300	100	0	0	656
2034	0	0	(165)	0	0	0	0	0	300	100	0	0	235
2035	0	0	0	0	0	0	0	0	300	100	0	0	400
2036	0	0	0	0	0	0	0	0	300	100	0	0	400
2037	0	0	0	0	0	0	0	0	300	50	50	0	400
2038	0	0	0	0	0	0	0	0	300	0	0	0	300
2039	0	0	0	0	0	0	0	0	300	0	0	0	300
2040	0	0	0	0	0	0	0	0	300	0	0	0	300
2041	0	0	0	0	0	0	0	0	100	100	50	0	250
2042	0	0	0	0	0	0	0	0	50	0	0	0	50
2043	0	0	0	0	0	0	0	0	0	100	50	0	150
2044	0	0	0	0	0	0	0	0	0	50	50	0	100
2045	0	0	0	0	0	0	0	0	0	0	100	0	100
2046	0	0	0	(200)	0	0	0	0	300	0	50	0	150
2047	0	0	0	0	0	0	0	0	300	0	0	0	300
2048	0	0	0	0	0	0	0	0	200	0	100	0	300
2049	0	0	0	0	0	0	0	0	200	0	100	0	300
2050	0	0	0	0	0	0	0	0	0	0	100	0	100
2051	0	0	0	0	0	0	0	0	150	0	50	0	200
2052	0	0	0	0	0	0	0	0	200	100	100	0	400
Total	**(3,480)**	**594**	**(504)**	**(280)**	**47**	**672**	**4,079**	**256**	**6,000**	**1,200**	**1,050**	**0**	**9,633**

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Table C-4: 2024 Portfolio with Self-build NGCC Additions and Retirements (MW)

Year	Changes in Existing Resources				New Resources								Total
	Coal	NGCC	NGCT	Solar	PPAs	Central NSR	NGCC	NGCT	Solar	Wind	BESS	SMR	
2024	0	0	0	0	291	0	0	0	0	0	0	0	291
2025	0	0	0	0	150	0	0	0	0	0	0	0	150
2026	0	0	0	125	0	0	0	0	300	0	0	0	425
2027	0	0	0	0	0	0	0	0	300	0	200	0	500
2028	0	594	(339)	(75)	0	0	0	0	300	0	0	0	480
2029	0	0	0	(130)	(199)	672	0	0	300	0	0	0	643
2030	0	0	0	0	0	0	0	0	300	0	0	0	300
2031	(1,150)	0	0	0	(195)	0	1,360	447	300	0	0	0	762
2032	0	0	0	0	0	0	0	0	150	100	0	0	250
2033	0	0	0	0	0	0	0	0	0	50	0	0	50
2034	0	0	(165)	0	0	0	0	256	0	100	0	0	191
2035	0	0	0	0	0	0	0	0	0	100	0	0	100
2036	0	0	0	0	0	0	0	0	300	0	0	0	300
2037	0	0	0	0	0	0	0	0	300	0	0	0	300
2038	0	0	0	0	0	0	0	0	300	0	0	0	300
2039	0	0	0	0	0	0	0	0	300	0	50	0	350
2040	0	0	0	0	0	0	0	0	300	100	50	0	450
2041	0	0	0	0	0	0	0	0	300	100	0	0	400
2042	0	0	0	0	0	0	0	0	300	100	0	0	400
2043	0	0	0	0	0	0	0	0	200	100	0	0	300
2044	0	0	0	0	0	0	0	0	50	100	50	0	200
2045	0	0	0	0	0	0	0	0	0	0	100	0	100
2046	0	0	0	(200)	0	0	0	0	300	0	50	0	150
2047	0	0	0	0	0	0	0	0	300	0	100	0	400
2048	0	0	0	0	0	0	0	0	300	0	50	0	350
2049	0	0	0	0	0	0	0	0	200	0	50	0	250
2050	0	0	0	0	0	0	0	0	100	0	100	0	200
2051	0	0	0	0	0	0	0	0	150	0	100	0	250
2052	0	0	0	0	0	0	0	0	100	0	100	0	200
Total	**(1,150)**	**594**	**(504)**	**(280)**	**47**	**672**	**1,360**	**703**	**5,750**	**850**	**1,000**	**0**	**9,041**

APPENDIX D: NPV POWER COST SUMMARY

Table D-1: Net Present Value Power Costs by Portfolio Across Sensitivities ($B; 2023$)

Portfolio	Sensitivity Case	Study Period (2024-52)	20 Years (2031-50)
2023 Preferred Portfolio (Reoptimized)	Reference	$29.3	$21.0
2024 Portfolio Update	Reference	$29.3	$21.0
2024 Portfolio with PPAs	Reference	$29.2	$21.0
GHG Rule Portfolio	Reference	$35.7	$27.2
2024 Portfolio Update	Low Fuel	$27.6	$19.6
2024 Portfolio with PPAs	Low Fuel	$27.5	$19.6
GHG Rule Portfolio	Low Fuel	$33.4	$25.2
2024 Portfolio Update	High Fuel	$33.3	$24.1
2024 Portfolio with PPAs	High Fuel	$33.2	$24.0
GHG Rule Portfolio	High Fuel	$42.5	$32.8
2024 Portfolio Update	Med CO2	$36.6	$26.8
2024 Portfolio with PPAs	Med CO2	$36.5	$26.8
GHG Rule Portfolio	Med CO2	$40.8	$30.9
2024 Portfolio Update	High CO2	$49.6	$36.9
2024 Portfolio with PPAs	High CO2	$49.6	$36.9
GHG Rule Portfolio	High CO2	$50.5	$37.9
2024 Portfolio Update	High Load	$38.2	$28.5
2024 Portfolio with PPAs	High Load	$38.2	$28.5
GHG Rule Portfolio	High Load	$46.6	$36.6
2024 Portfolio Update	Low Load	$21.8	$14.8
2024 Portfolio with PPAs	Low Load	$21.8	$14.8
GHG Rule Portfolio	Low Load	$25.6	$18.5
2024 Portfolio with Self Build NGCC	Reference	$29.3	$21.1

APPENDIX E: RENEWABLE GENERATION FORECAST

Table E-1: Renewable Generation by Portfolio (GWh)[41]

Year	2024 Portfolio Update	2024 Portfolio with PPAs	GHG Rule Portfolio
2024	2,199	2,199	2,199
2025	2,189	2,189	2,189
2026	3,078	3,078	3,078
2027	3,779	3,779	3,779
2028	4,112	4,112	4,111
2029	4,494	4,494	4,799
2030	5,530	5,225	5,837
2031	6,240	6,240	6,854
2032	6,913	7,034	7,886
2033	7,228	7,349	8,926
2034	7,529	7,649	9,946
2035	7,830	7,950	10,954
2036	8,759	8,724	11,999
2037	9,483	9,433	12,815
2038	10,215	10,149	13,514
2039	10,953	10,893	14,167
2040	11,764	11,536	14,684
2041	12,698	12,453	15,242
2042	13,249	13,312	15,271
2043	14,059	14,086	15,587
2044	14,424	14,452	15,828
2045	14,770	14,859	15,932
2046	15,120	15,146	16,251
2047	15,613	15,690	16,759
2048	16,169	16,162	17,200
2049	16,532	16,670	17,564
2050	16,848	17,009	17,653
2051	17,244	17,403	18,035
2052	17,553	17,710	18,698

[41] Renewable generation includes solar, hydro, wind, and biomass.

APPENDIX F: RATE IMPACTS

Figure F-1: Projected Rate Index for the Portfolios Studied Under Low Fuel Prices

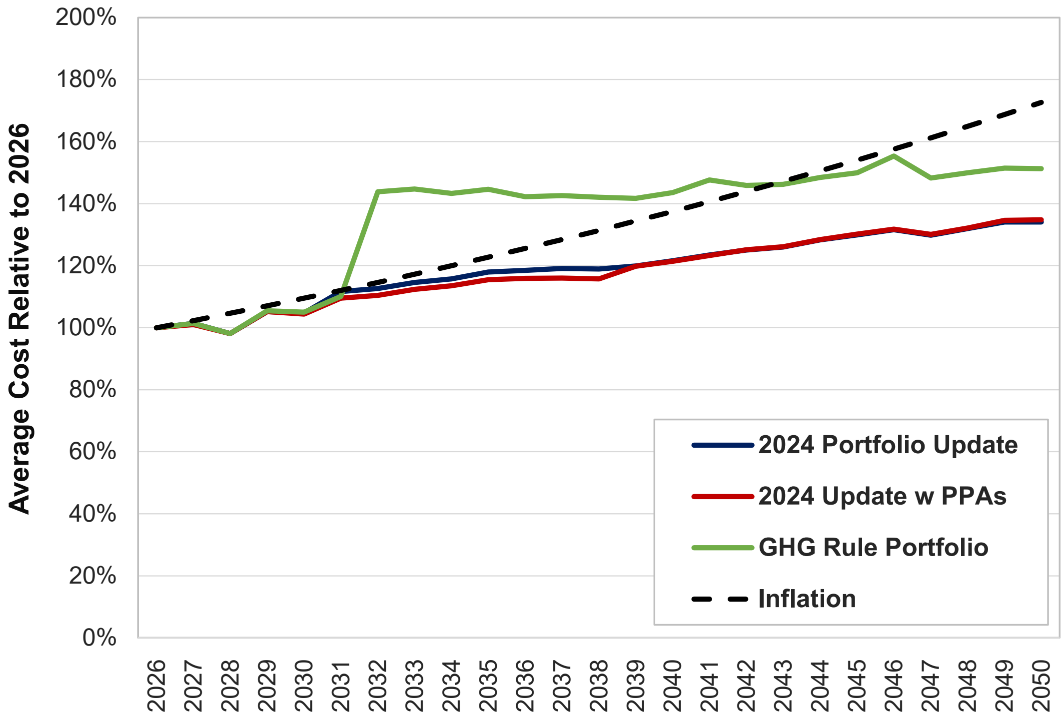


Figure F-2: Projected Rate Index for Foundational Portfolios Under High Fuel Prices

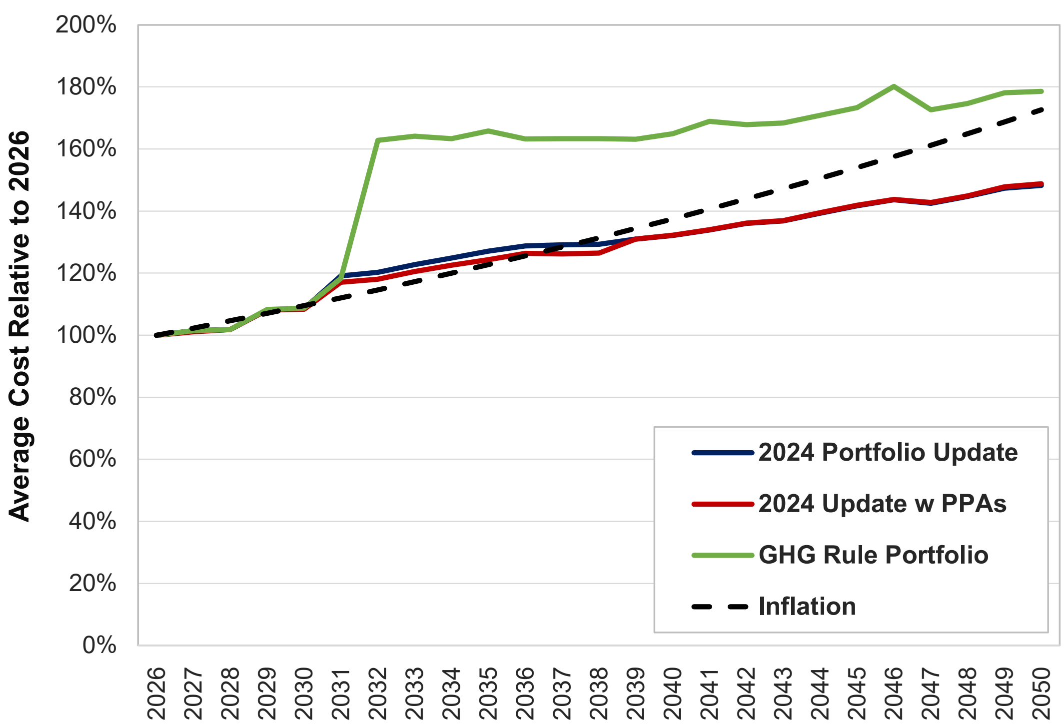


Figure F-3: Projected Rate Index for Foundational Portfolios Under Medium CO_2 Prices

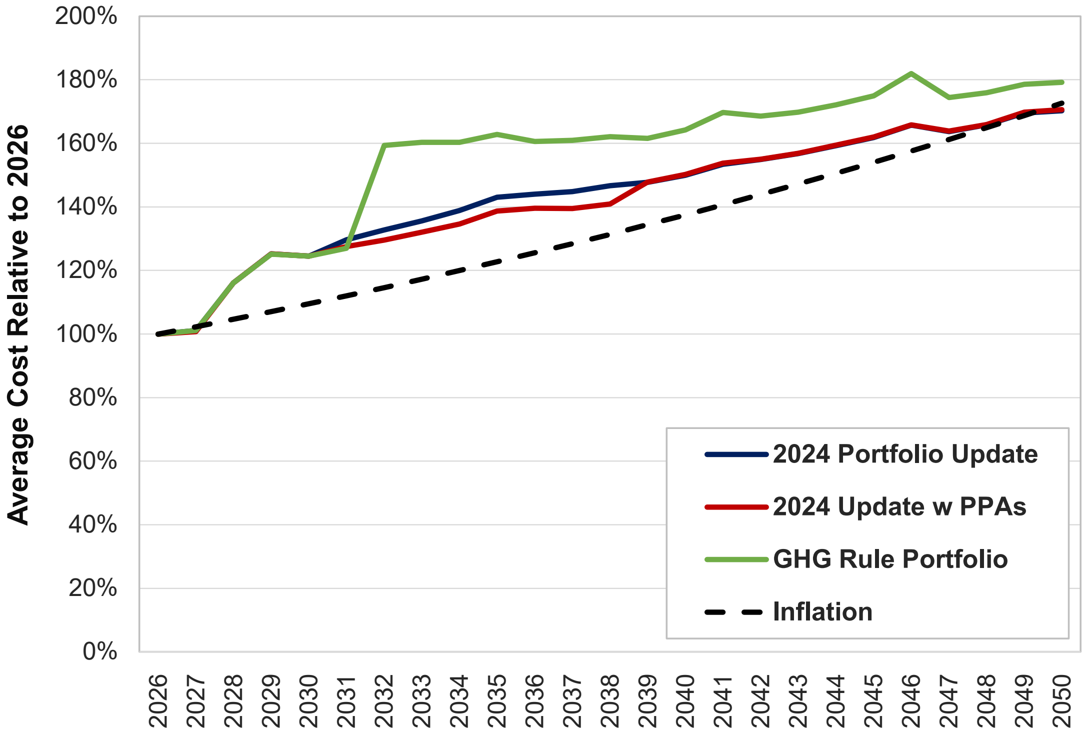
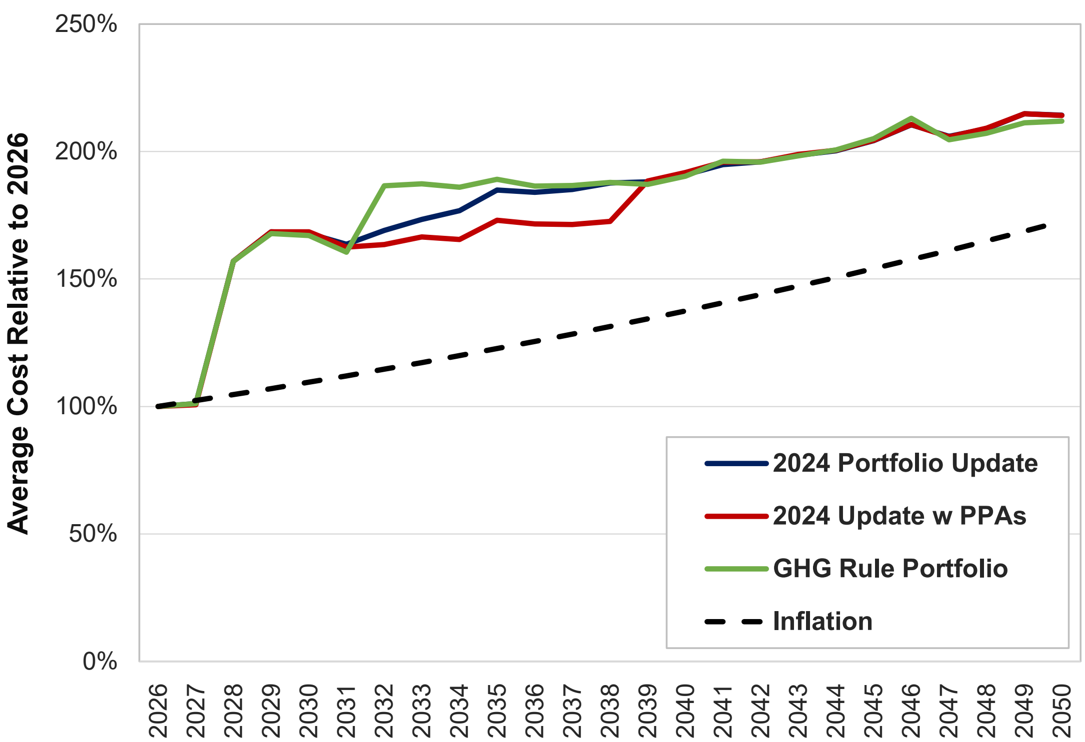


Figure F-4: Projected Rate Index for Foundational Portfolios Under High CO_2 Prices



APPENDIX G: GENERATION FLEET DATA

Table G-1: Generation Fleet Summary

Generating Station	Unit #	Service Date	End of Useful Life[1]	Fuel Type	Technology	Winter Rating[2] (MW)	Summer Rating[2] (MW)
Cross Pineville, SC	1	1995	2055	Coal	ST	585	580
	2	1983	2053	Coal	ST	570	565
	3	2007	2067	Coal	ST	580	585
	4	2008	2068	Coal	ST	595	605
Winyah Georgetown, SC	1	1975	To be retired as soon as replacement resources can be implemented	Coal	ST	280	275
	2	1977		Coal	ST	290	285
	3	1980		Coal	ST	290	285
	4	1981		Coal	ST	290	285
Rainey Iva, SC	1[3]	2002	2052	NG	CC	520	460
	2A	2002	2052	NG	CT	180	146
	2B	2002	2052	NG	CT	180	146
	3	2004	2054	NG	CT	90	75
	4	2004	2054	NG	CT	90	75
	5	2004	2054	NG	CT	90	75
Cherokee Gaffney, SC	1	2023[4]	2052	NG	CC	98	86
Myrtle Beach	1	1962	2034	NG	CT	10	8
	2	1962	2034	NG	CT	10	8
	3	1962	2034	NG	CT	20	19
	4	1962	2034	NG	CT	20	19
	5	1963	2034	NG	CT	25	21
Hilton Head	1	1973	2034	Oil	CT	20	16
	2	1973	2034	Oil	CT	20	16
	3	1973	2034	Oil	CT	60	52
V.C. Summer Nuclear Unit 1 Jenkinsville, SC	1	1983	2062[5]	Uranium	NUC	322	322
Jefferies Lake Moultrie	1	1942	2062	Water	Hydro	30	30
	2	1942	2062	Water	Hydro	36	36
	3	1942	2062	Water	Hydro	30	30
	4	1942	2062	Water	Hydro	36	36
	6	1942	2062	Water	Hydro	8	8
Spillway Lake Marion	-	1950	2070	Water	Hydro	2	2
Landfill Gas (multiple sites)	-	2001 - 2011		LFG	CT, IC	26	26
Total Capacity						5403	5177

1) Referenced end of useful life of resources were developed for use for IRP planning and modeling and are based on specific retirement dates proposed by Santee Cooper, industry data on actual and planned retirement dates for generating resources in the U.S. reported by S&P Global Capital IQ (S&P) and Energy Velocity/ABB (EV), industry data on operating lives of existing resources in the U.S. reported by S&P and EV, and information contained in recent Duke and Dominion Energy IRPs filed in South Carolina. Estimated potential lives are not based on any information on the condition of Santee Cooper facilities.
2) Ratings shown are Net Dependable Capacity values
3) Rainey 1 denotes the combined capacity of combustion turbine Units 1A and 1B combined with steam turbine Unit 1S in a combined cycle configuration.
4) Purchased by Santee Cooper in 2023.
5) Current operating license expires 2042; however, plans reflects seeking license extention to 2062.

Table G-2: Annual Forced Outage Rate

Generating Station	Unit	2019	2020	2021	2022	2023
Cross Pineville, SC	1	0.54%	1.51%	1.31%	3.15%	3.60%
	2	25.48%	0.00%	5.37%	35.50%	8.16%
	3	6.26%	1.30%	8.52%	1.67%	2.19%
	4	6.68%	1.00%	1.84%	4.41%	2.20%
Winyah Georgetown, SC	1	0.46%	4.93%	5.08%	2.75%	3.42%
	2	4.59%	3.26%	4.92%	3.72%	3.90%
	3	5.83%	0.91%	0.69%	1.81%	3.22%
	4	1.82%	6.99%	0.00%	8.99%	3.29%
Rainey Iva, SC	1	0.65%	0.50%	0.38%	0.10%	0.91%
	2A	2.40%	0.01%	0.11%	0.01%	0.10%
	2B	0.08%	0.22%	0.14%	0.02%	0.00%
	3	0.46%	0.27%	0.59%	0.00%	0.72%
	4	0.23%	22.54%	5.91%	0.00%	0.36%
	5	0.00%	0.67%	1.71%	0.93%	0.00%
Cherokee Gaffney, SC	1	0.24%	6.41%	0.29%	0.56%	8.25%
Myrtle Beach	1	40.33%	0.00%	99.76%	90.90%	99.17%
	2	100.00%	66.31%	70.21%	47.19%	99.80%
	3	0.00%	52.12%	98.87%	12.32%	0.00%
	4	100.00%	100.00%	100.00%	N/A	N/A
	5	99.95%	99.12%	0.00%	93.19%	99.98%
Hilton Head	1	0.00%	0.00%	0.00%	99.05%	0.00%
	2	0.00%	0.00%	0.00%	0.00%	99.92%
	3	19.08%	97.07%	26.37%	79.62%	75.28%
Summer Nuclear Unit 1 Jenkinsville, SC	1	4.08%	0.73%	8.36%	0.00%	4.20%
Jefferies Lake Moultrie	1	0.00%	0.00%	4.35%	46.24%	0.16%
	2	0.01%	0.10%	0.17%	0.12%	0.80%
	3	0.73%	0.00%	24.77%	0.45%	0.33%
	4	0.27%	0.01%	0.15%	3.24%	0.08%
	6	6.55%	0.00%	0.00%	0.00%	0.00%

Table G-3: Annual Availability Factor

Generating Station	Unit	2019	2020	2021	2022	2023
Cross Pineville, SC	1	89.7%	97.8%	91.5%	67.4%	91.5%
	2	72.1%	96.3%	89.3%	66.4%	54.8%
	3	93.0%	96.9%	61.3%	95.9%	89.7%
	4	82.1%	97.1%	75.8%	92.6%	93.0%
Winyah Georgetown, SC	1	88.4%	89.7%	91.4%	90.0%	77.4%
	2	94.8%	69.2%	71.7%	93.1%	91.9%
	3	97.9%	92.5%	75.3%	95.1%	89.2%
	4	86.1%	97.3%	43.2%	86.4%	71.1%
Rainey Iva, SC	1	94.0%	94.2%	92.9%	96.8%	85.3%
	2A	96.5%	96.5%	95.1%	97.7%	93.9%
	2B	83.3%	96.3%	95.7%	98.8%	98.4%
	3	97.3%	98.0%	96.2%	98.3%	97.9%
	4	97.2%	94.2%	97.1%	96.8%	98.0%
	5	98.5%	96.0%	92.9%	99.1%	98.1%
Cherokee Gaffney, SC	1	85.7%	86.2%	90.9%	93.4%	90.7%
Myrtle Beach	1	94.3%	100.0%	96.7%	94.9%	95.0%
	2	92.8%	99.9%	99.9%	99.3%	96.2%
	3	99.8%	99.9%	75.9%	99.8%	99.8%
	4	0.0%	0.0%	0.0%	N/A	N/A
	5	79.8%	94.2%	100.0%	81.4%	72.8%
Hilton Head	1	100.0%	100.0%	100.0%	41.5%	99.8%
	2	0.0%	0.0%	100.0%	99.9%	77.3%
	3	96.9%	92.1%	95.5%	93.5%	99.4%
Summer Nuclear Unit 1 Jenkinsville, SC	1	95.9%	91.1%	82.5%	99.4%	87.9%
Jefferies Lake Moultrie	1	99.9%	95.8%	99.1%	79.6%	89.4%
	2	95.3%	96.0%	99.6%	100.0%	99.5%
	3	98.5%	99.9%	86.5%	98.8%	88.1%
	4	97.9%	99.8%	99.2%	96.8%	93.4%
	6	99.6%	100.0%	99.7%	99.1%	100.0%

Table G-4: Annual Capacity Factor

Generating Station	Unit	2019	2020	2021	2022	2023
Cross Pineville, SC	1	41.9%	20.1%	39.0%	17.5%	22.2%
	2	2.9%	-0.6%	9.5%	0.5%	10.6%
	3	61.2%	40.5%	41.8%	67.7%	64.1%
	4	54.4%	62.2%	54.4%	62.3%	66.4%
Winyah Georgetown, SC	1	8.5%	36.3%	55.5%	36.9%	32.8%
	2	12.4%	30.8%	36.9%	30.6%	35.7%
	3	5.1%	16.7%	31.1%	22.9%	16.7%
	4	4.6%	8.2%	1.5%	3.6%	21.2%
Rainey Iva, SC	1	59.9%	58.6%	53.9%	61.0%	78.3%
	2A	58.0%	57.3%	45.4%	53.8%	69.6%
	2B	52.3%	55.3%	48.2%	54.5%	74.9%
	3	6.9%	5.0%	7.4%	13.4%	6.0%
	4	7.6%	4.3%	7.0%	13.3%	9.1%
	5	7.7%	3.7%	6.4%	13.0%	7.2%
Cherokee Gaffney, SC	1	71.4%	44.6%	47.1%	53.6%	14.8%
Myrtle Beach	1	-0.2%	-0.2%	-0.2%	0.1%	-0.1%
	2	-0.2%	-0.2%	-0.1%	0.3%	-0.2%
	3	-0.1%	-0.1%	-0.1%	0.5%	-0.1%
	4	0.0%	0.0%	0.0%	N/A	N/A
	5	-0.1%	-0.1%	0.0%	0.2%	-0.1%
Hilton Head	1	0.0%	0.0%	0.0%	0.3%	0.0%
	2	0.0%	0.0%	0.0%	0.4%	0.0%
	3	0.1%	0.0%	0.1%	0.5%	0.0%
Summer Nuclear Unit 1 Jenkinsville, SC	1	97.5%	91.1%	82.7%	101.5%	88.8%
Jefferies Lake Moultrie	1	6.2%	6.1%	5.6%	4.7%	7.0%
	2	34.6%	35.1%	34.4%	34.5%	34.4%
	3	5.4%	5.2%	5.5%	5.6%	6.8%
	4	35.2%	37.1%	34.4%	33.1%	32.4%
	6	-0.7%	-1.1%	-1.3%	-0.8%	-1.3%

APPENDIX H: CROSS REFERENCE FOR COMPLIANCE WITH S.C. CODE § 58-37-40(D) AND COMMISSION ORDER 2024-171

In Commission Order 2024-171 approving Santee Cooper's 2023 IRP, the Commission directed Santee Cooper to reflect available updates on a variety of assumptions and information and infuse certain activities into the 2024 IRP Update. The following table provides the requirements of S. C. Code § 58-37-40(D) and Order 2024-171 and a reference to the section and page number of this 2024 IRP Update report demonstrating compliance.

S.C. Code § 58-37-40(D) and Order 2024-171	Requirement	2024 IRP Update Section Satisfying Requirement
(D)(1)	An annual update must include an update to Santee Cooper's base planning assumptions relative to its most recently accepted integrated resource plan.	2024 IRP Update, pp. 24-48
(D)(1)	An annual update must include an update to Santee Cooper's base planning assumptions relative to its most recently accepted integrated resource plan, including: - Energy and demand forecast	Electric Load Forecast Overview, pp. 24-29
(D)(1)	An annual update must include an update to Santee Cooper's base planning assumptions relative to its most recently accepted integrated resource plan, including: - Commodity fuel price inputs	Major Modeling Assumptions: Fuel Forecasts, pp. 38-40
(D)(1)	An annual update must include an update to Santee Cooper's base planning assumptions relative to its most recently accepted integrated resource plan, including: - Renewable energy forecast	Resource Plan Evaluation: Renewable Energy Forecast, p. 66; Appendix E
(D)(1)	An annual update must include an update to Santee Cooper's base planning assumptions relative to its most recently accepted integrated resource plan, including: - Energy efficiency and demand-side management forecasts	Demand-Side Management Overview, p. 35; Major Modeling Assumptions: System Energy and Peak Demand, p. 37
(D)(1)	An annual update must include an update to Santee Cooper's base planning assumptions relative to its most recently accepted integrated resource plan, including: - Changes to projected retirement dates of existing units	Recent Activities and Developments, p. 17 (no changes); Assessment of Resource Need, p. 30 (same)

S.C. Code § 58-37-40(D) and Order 2024-171	Requirement	2024 IRP Update Section Satisfying Requirement
(D)(1)	Santee Cooper's annual update must describe the impact of the updated base planning assumptions on the selected resource plan.	Executive Summary, p. 13; Resource Plan Evaluation pp. 49-68; Conclusions, pp. 69-73
Order No. 2024-171, p. 99, Ordering Paragraph 3	Santee Cooper is directed to consider other approaches to load forecasting and resource portfolio analysis to plan for future industrial load growth due to economic development and provide updates to the Commission in future IRP filings.	Electric Load Forecast Overview, pp. 24-29
Order No. 2024-171, p. 99, Ordering Paragraph 4	Santee Cooper is directed to incorporate actual solar additions and any updates to future planned solar additions in its annual IRP Update.	Recent Activities and Developments: Solar Procurement Update, pp. 17-18
Order No. 2024-171, p. 92	[T]he Commission concludes that Santee Cooper has provided sufficient justification for its 300 MW target of solar additions per year from 2026-2030 and instructs Santee Cooper to work with stakeholders if revisions to the assumption are warranted for future IRPs and IRP Updates.	Major Modeling Assumptions: Resource Option Assumptions: Renewable and Energy Storage Resources, p. 42
Order No. 2024-171, p. 99, Ordering Paragraph 5, and p. 66	Santee Cooper is directed to continue to evaluate the natural gas combined cycle shared resource in the analyses conducted for future IRP Updates and IRPs; Santee Cooper must continue to consider the NGCC and alternatives to the NGCC in the analyses conducted for future IRP Updates and IRPs.	Introduction, p. 15; Recent Activities and Developments: NGCC Implementation including Potential Joint Project with DESC, p. 17; Resource Plan Evaluation pp. 49-68; Conclusions, pp. 69-73; Short-Term Action Plan, p. 74
Order No. 2024-171, p. 94	The Commission does not find it necessary to require Santee Cooper to update or revise its capital or operating cost assumptions utilized for its proposed NGCC resource for the purposes of this IRP. . . Santee Cooper has committed to updating stakeholders and the Commission, through future IRPs and IRP Updates, as well as compliance with all requirements of [the Siting Act].	Major Modeling Assumptions: Existing Operating Costs and Characteristics, pp. 41-42; Major Modeling Assumptions: Resource Option Assumptions, pp. 42-46
Order No. 2024-171, p. 99,	Santee Cooper is directed to review and address the recommendations of the ORS witnesses to	Introduction, pp. 15-16; Stakeholder Engagement Process, pp. 22-23

S.C. Code § 58-37-40(D) and Order 2024-171	Requirement	2024 IRP Update Section Satisfying Requirement
Ordering Paragraph 2	discuss seven issues with stakeholders no later than the 2026 IRP.	
Order No. 2024-171, p. 95; ORS Recommendation D1	ORS recommends all commodity forecasts, including coal and carbon dioxide (“CO_2”) forecasts, should continue to be discussed in the Stakeholder Working Group.	Major Modeling Assumptions, p. 37; Major Modeling Assumptions: Fuel Forecasts, pp. 38-40; Major Modeling Assumptions: Carbon Emissions Pricing, pp. 40-41
Order No. 2024-171, p. 95; ORS Recommendation E1	Santee Cooper intends to expand its future ELCC studies to address more resource types and to evaluate higher resource implementation levels. The Commission concludes that the ELCC values utilized in this IRP are reasonable and instructs Santee Cooper to discuss this topic with stakeholders.	Major Modeling Assumptions: Effective Load Carrying Capability, p. 47
Order No. 2024-171, p. 95; ORS Recommendation E3	ORS recommends integration costs and associated modeling methodologies, including modeling operating reserves, be discussed further in the Stakeholder Working Group.	Major Modeling Assumption: Renewable and Storage Resource Integration, p. 47
Order No. 2024-171, p. 99, Ordering Paragraph 2; ORS Recommendation E4	Santee Cooper discuss potential impacts of the United States Environmental Protection Agency (EPA) Section 111 proposed rule in the Stakeholder Working Group and consider including a sensitivity scenario in the 2024 IRP Update to address the proposed rule if adopted and not stayed; it is appropriate for Santee Cooper to model the proposed Section 111 Rules in future IRPs and IRP Updates upon finalization of the rules and resolution of any stays of the rules.	Resource Plan Evaluation, pp. 54-66
Order No. 2024-171, p. 99, Ordering Paragraph 2; ORS Recommendation F2	Santee Cooper discuss in the Stakeholder Working Group the scope for further studies to analyze any potential cost savings from the retirement of remaining coal generation assets.	Recent Activities and Developments: Retirement Evaluations to Support Future Filings and IRPs, p. 18

S.C. Code § 58-37-40(D) and Order 2024-171	Requirement	2024 IRP Update Section Satisfying Requirement
Order No. 2024-171, p. 95; ORS Recommendation G1	ORS recommends Santee Cooper discuss the development of a quantitative reliability metric in the Stakeholder Working Group.	Resource Plan Evaluation, pp. 51-52
Order No. 2024-171, p. 95; ORS Recommendation G2	ORS recommends Santee Cooper discuss the methodology it will use to estimate transmission investment associated with the retirement of the Cross Unit in the Stakeholder Working Group.	Recent Activities and Developments: Retirement Evaluations to Support Future Filings and IRPs, p. 18; Major Modeling Assumptions: Transmission System Requirements, pp. 47-48