Santee Cooper

2023 Integrated Resource Plan

[Page Left Intentionally Blank]

santee cooper®

TABLE OF CONTENTS

ATTACHMENTS TO THE IRP

TABLE OF FIGURES

TABLE OF TABLES

EXECUTIVE SUMMARY

Santee Cooper's 2023 Integrated Resource Plan ("IRP") identifies a Preferred Portfolio that will reliably and affordably meet the electric power needs of Santee Cooper's retail and wholesale customers, dramatically reduce Santee Cooper's carbon footprint, and add flexibility and innovation to support a growing state economy. This IRP also includes a Short-term Action Plan to provide a sound basis for near-term resource decisions, planning, and implementation activities. Santee Cooper respectfully submits this IRP for Public Service Commission of South Carolina (the "Commission") consideration and approval.

Santee Cooper appreciates the input received from stakeholders during preparation of this IRP through an extensive public engagement process and additional technical discussions requested by stakeholder groups. Santee Cooper has consulted with Central Electric Power Cooperative, Inc. ("Central"), municipal wholesale customers, and retail customers in preparing this IRP. The planning process has benefited from the input received from all interested parties.

KEY CONCLUSIONS

The Preferred Portfolio proposed in the IRP supports the following changes to the Combined System's[1] portfolio of resources:

1. Adding substantial new solar resource capacity annually from 2026 through the 2030s to levels totaling approximately 1,500 megawatts ("MW") by 2030 and over 3,000 MW by 2040,
2. Retiring the 1,150 MW Winyah Coal Generating Station ("Winyah") by year-end 2030,
3. Developing a natural gas combined cycle ("NGCC") resource of approximately 1,000 MW to 1,400 MW to coincide with the retirement of Winyah, and
4. Adding several hundred MWs of combustion turbine ("CT") generating units and battery energy storage systems ("BESS") in the late 2020s and into the 2030s.

In preparing this IRP, Santee Cooper evaluated several portfolio strategies including an unconstrained portfolio, another that assumes retirement of the coal fired Cross Generating Station ("Cross"), and one that targets achieving Net Zero CO_2 emissions by 2050. The portfolio changes to the resource mix listed above are common elements in the least-cost approach to achieve each of these unique portfolio strategies. They reflect a cost-effective approach under a wide range of assumptions and will also position Santee Cooper to adapt to policy changes related to CO_2 emissions.

These changes would provide several benefits as described below.

[1] The term "Combined System" refers to the power supply resources and bulk transmission network of Santee Cooper and Central.

- Reduce CO_2 emissions rates to approximately 44% of 2005 levels by the mid-2030s as shown in Figure ES-1, reflecting a continuation of Santee Cooper's successful efforts in this regard.
- Significantly increase portfolio diversity and therefore reduce risk to customers. Figure ES-2[2] illustrates that the Preferred Portfolio would, by 2040, significantly diversify resources used to serve Santee Cooper customer loads. Reliance on coal would be reduced to less than half of the level in 2025, and the proportion of energy provided from sustainable resources would almost triple, mostly due to additions of renewable solar power resources. Instead of being largely reliant on coal, the portfolio would balance use of natural gas, coal, and sustainable resources, which reduces risk to customers.

Figure ES - 1. Projected CO_2 Emissions Rate as Percentage of 2005 Rate

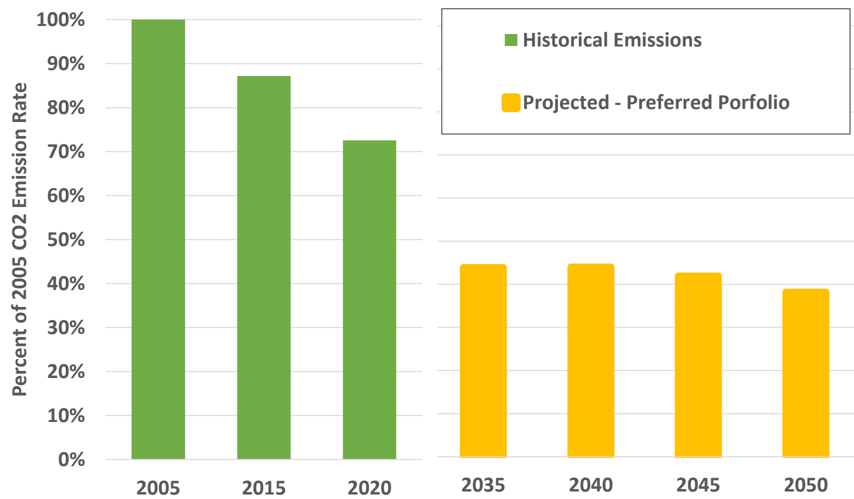
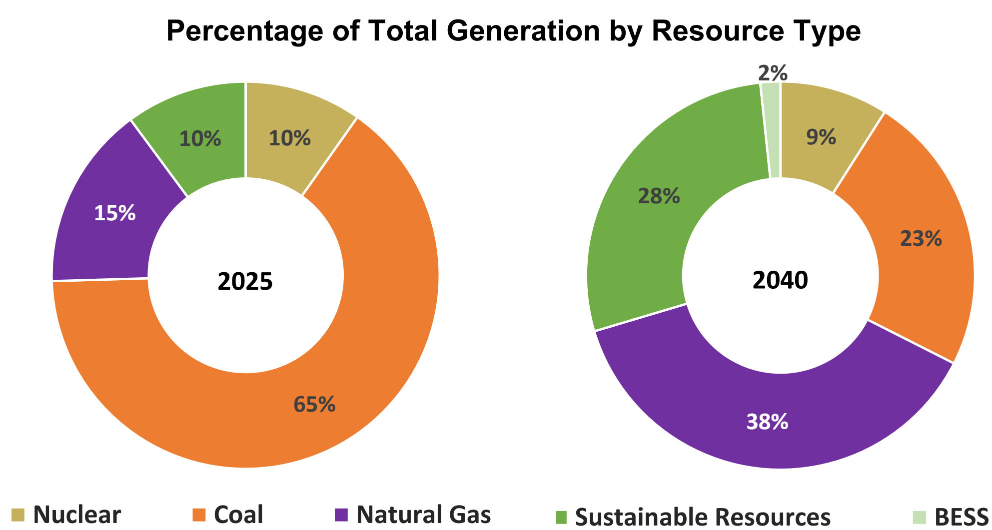


Figure ES - 2. Preferred Portfolio Resource Mix



[2] Total generation used for this Figure includes energy produced to charge BESS resources and load met from BESS resources.

- The Preferred Portfolio is projected to be the least cost portfolio in most scenarios, compared to other portfolios evaluated and has been structured to maintain the highly reliable service Santee Cooper's customers expect.
- The Preferred Portfolio offers flexibility to further adjust as conditions change or if customer demand for electricity is higher or lower than now projected. For instance, Santee Cooper could add additional BESS or CT resources, and in the early- to mid-2030s, add additional NGCC capacity to serve additional load expected to result from ongoing economic development initiatives.

The Short-term Action Plan presented in this IRP includes the following key steps.

1. Subject to approval of Santee Cooper's proposed competitive procurement process[3] by the Commission, procure new power purchase agreements under which additional solar power would be provided to the system beginning in 2026, with further additions thereafter.
2. Identify the best option for implementing a new NGCC resource, including the opportunity to partner with Dominion Energy South Carolina, Inc. ("DESC"), and proceed with further planning, approvals, permitting, and procurement processes for developing the NGCC project.
3. Gather further information concerning, and experience in integrating, renewable and BESS resources.
4. Conduct further evaluations of the retirement of the Cross Generating Station to determine the best transmission and resource portfolio solutions that would ensure reliable power supply for Combined System customers if Cross were to be retired. The results of the further evaluations will provide valuable information for consideration in future IRPs.
5. Proceed with further implementation of attractive demand-side management ("DSM") programs and perform additional studies to further evaluate demand-side options.

[3] Santee Cooper has submitted its *Application of the South Carolina Public Service Authority for Approval of Competitive Procurement Program Pursuant to S.C. Code Ann. § 58-31-227,* Docket No. 2022-351-E.

PLANNING OBLIGATIONS AND PORTFOLIO PRIORITIES

Figure ES-3 provides a high-level summary of Santee Cooper's key planning priorities.

Figure ES - 3. Santee Cooper Planning Priorities

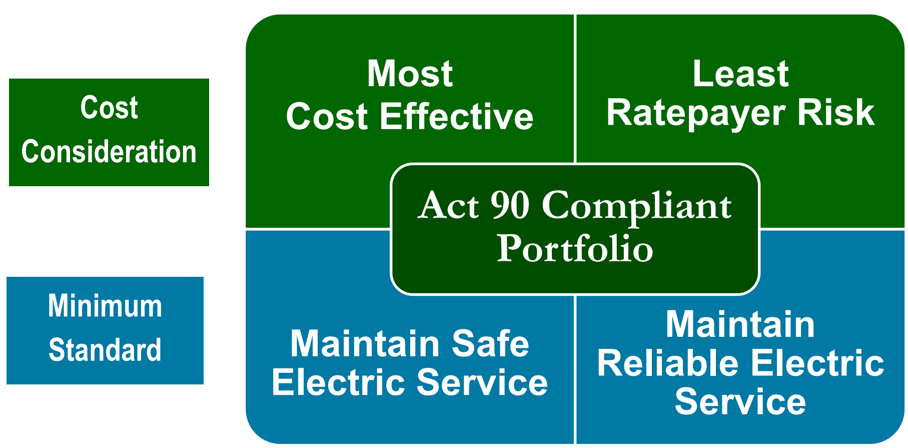
The Preferred Portfolio should:

1. Appropriately address statutory and Coordination Agreement obligations,
2. Afford Santee Cooper flexibility to adapt as conditions and forecasted levels of customer load change,
3. Diversify the Combined System's resource portfolio to reduce environmental impact and risk, especially to lessen dependence on coal, and
4. Be environmentally responsible.

Santee Cooper's resource planning has been structured to meet statutory obligations, comport with requirements of the Power System Coordination and Integration Agreement, dated December 31, 1980, and most recently amended in 2013 ("Coordination Agreement") with Central Electric Power Cooperative ("Central"), and comply with Commission directives as to metrics and analyses to be included in IRPs.

The Preferred Portfolio identified by Santee Cooper's 2023 IRP meets Santee Cooper's statutory planning obligation, illustrated in Figure ES-4, to identify the "most cost-effective and least ratepayer risk resource portfolio to meet the Public Service Authority's total capacity and energy requirements while maintaining safe and reliable electric service."[4]

Figure ES - 4. Key Statutory Planning Obligation



Further, the South Carolina Code and the Coordination Agreement with Central require Santee Cooper to plan to serve the <u>total</u> capacity and energy requirements of the customers served from the Combined System—whether those customers are served directly by Santee Cooper or by Central's Members or the Municipal systems that are wholesale customers of Santee Cooper.

[4] S.C. Code Ann. § 58-37-40(A)(4)(a).

Accordingly, Santee Cooper's planning has been structured to identify the most cost-effective, least-customer-risk portfolio of supply- and demand-side resources, considering transmission upgrade cost estimates and considering that the portfolio must include sufficient planning and operating reserves and other system capabilities (e.g., load following, etc.) to serve the Combined System load effectively and reliably.

Santee Cooper is a not-for-profit entity and due to its nature as a public power utility, Santee Cooper's planning and capital investment decisions reflect the highest priority it places on affordable rates and lowering risk to customers.

PLANNING IN A TIME OF EXCEPTIONAL UNCERTAINTY

As illustrated by Figure ES-5 below, in preparing its IRP, Santee Cooper has been navigating a complex set of uncertainties and considerations, over many of which Santee Cooper has limited or no control and some of which are unique to Santee Cooper.

Figure ES - 5. Key Santee Cooper Planning Issues and Uncertainties

Central Electric Power Cooperative Resource Decisions	Opportunities to Consider Joint Options to Achieve Economies of Scale	Potential Near-term Load Increases
Uncertainty Regarding Renewable Resource Costs	Changes in Societal Preferences and Governmental Policy toward Greenhouse Gases, Renewables, and Electric Uses	Need for Capabilities to Integrate Intermittent and Energy Limited Resources Ecomomically and Reliably
Heightened Concerns about System Resiliency	Record Inflation and Pressures on the Economy	Tightening Energy Markets
Pending CO_2 and Other Environmental Regulations	Exponentially Increasing Pace of Technology Change	Increasing Customer Interest in Resource Decisions and in "Fuel" Supply Source Choices

The most significant uncertainties of those presented include implementation of resource decisions being made by Central, potential for major shifts in governmental policy aimed at reducing carbon dioxide (“CO_2”) and other emissions from coal and natural gas fueled resources, tightening energy markets, increasing future customer demand due to economic development initiatives and shifts toward electrification, record inflation and concerns about the potential for recession, and reliability-related concerns heightened by recent electric system outages during adverse weather in various portions of the U.S. These important considerations and trends all have impacted Santee Cooper’s planning and have been considered in this IRP.

IRP PROCESS

Santee Cooper’s 2023 IRP has benefited from input provided by Central, municipal customers, retail customers, and other stakeholders. Santee Cooper’s process included multiple stakeholder meetings open to the public and technical sessions requested by certain stakeholders. As required by the Coordination Agreement, Central and Santee Cooper coordinated several actions through a joint planning committee that were reflected in the IRP, including the development and adoption of the Combined System load forecast and approval of the reserve margin requirement following the completion of the Reserve Margin Study, discussed later herein.

Santee Cooper held five public, virtual stakeholder meetings, as depicted in Figure ES-6 below, and posted extensive materials on an IRP website available to the public.[5] Santee Cooper received and responded to numerous questions for clarification and requests throughout that process.

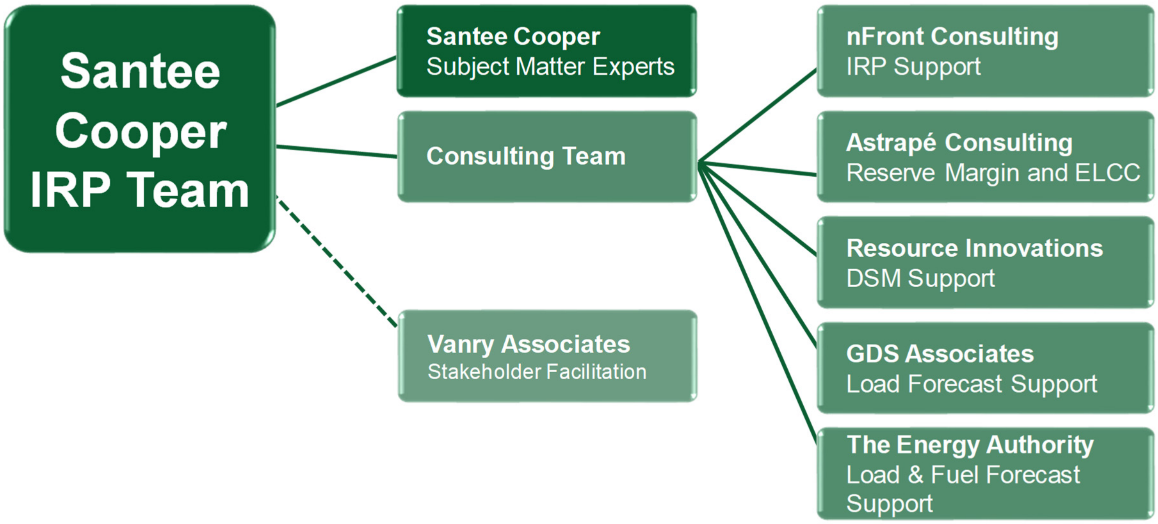
Figure ES - 6. Public Stakeholder Engagement Sessions

Session 1 March 2022	Session 2 April 2022	Session 3 June 2022	Session 4 December 2022	Session 5 April 2023
Introduction and Overview	Assumptions, Sensitivities & Portfolios	Technical Detail Assumptions, Sensitivities & Portfolios	Final Assumptions & Initial Learnings	Final Updates

As shown in Figure ES-7 below, Santee Cooper assembled a diverse team of staff and external consultants with expertise necessary to properly consider the myriad of issues that impact planning of resources in today’s complex and rapidly changing environment.

[5] www.santeecooper.com/IRP

Figure ES - 7. Santee Cooper's IRP Team



Importantly, the IRP analyses presented in this report are underpinned and informed by a series of studies performed by the above team members and Central to:

- Project loads on the Combined System,
- Determine potential effects and economics of demand-side resource programs,
- Determine reasonable fuel and purchased power price assumptions,
- Establish planning reserve margin requirements, and
- Determine load carrying capability of renewable and energy storage resources.[6]

Overall, Santee Cooper's IRP process was structured to comply with procedural requirements established by S.C. Act 90 of 2021 ("Act 90").[7] These include requirements regarding stakeholder involvement, portfolios to be considered, robust and thorough analyses necessary to inform significant resource decisions, and provision of information to stakeholders and the Commission.[8]

SCOPE OF EVALUATIONS

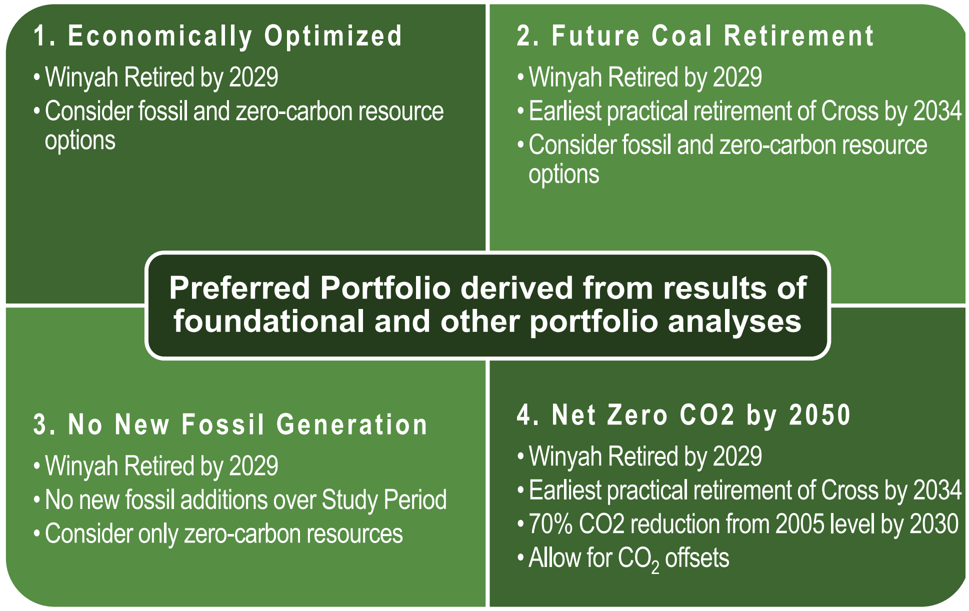
As shown in Figure ES-8, Santee Cooper considered four major foundational portfolio alternatives and several sensitivity and side case analyses to gain an understanding of the relative impacts on costs, reliability, and emissions of alternative resource options and plans.

[6] See the attachments to this report for additional information and copies of these studies, where applicable.
[7] *S.C. Code Ann. § 58-37-40(A)(3).*
[8] *S.C. Code Ann. § 58-37-40(A)(4)(c).*

Based on those analyses, Santee Cooper formulated its Preferred Portfolio.

All four foundational portfolios studied assume that the entire Winyah Generating Station would be retired.

Figure ES - 8. Foundational Portfolios



Portfolio 1 identifies the lowest-cost portfolio based on the Reference Case, assuming the Cross continues to operate over the Study Period through 2052 and without considering potential policy interventions related to CO_2 emissions.

Portfolio 2 was analyzed to assess impacts on costs, risks, and emissions of retiring Cross by 2034, relative primarily to Portfolio 1.

Portfolio 3 was analyzed to assess impacts on costs, risks, and emissions of a policy of only adding renewable and BESS resources after the retirement of Winyah, relative primarily to Portfolio 1.

Portfolio 4 was analyzed in compliance with specific Act 90 requirements to assess impacts of a policy that would achieve Net Zero CO_2 by 2050.

Each of the four major foundational portfolio alternatives were evaluated under a set of Reference Case assumptions and under sensitivity cases to evaluate a wide range of assumptions concerning fossil fuel prices and costs due to changes in CO_2 emissions regulations.

Generally, the Reference Case set of assumptions reflect or assume:

- Combined System load forecast finalized in late spring of 2022;
- Projections of natural gas and coal commodity prices prepared using fundamental projections published during 2022;[9]
- Utilities are not assessed taxes, charges, or other costs based on CO_2 emissions;
- Long-term inflation would average approximately 2.3%;
- Santee Cooper's average cost of capital and discount rate would be 5.25%;

[9] Current fuel price projections from the same sources and forward curves suggest the fuel prices assumed in this IRP are conservatively high.

- Projections of capital and operating costs of dispatchable resources prepared referring to various sources, including data from the Electric Power Research Institute ("EPRI") Technical Assessment Guide ("TAG"); and
- Cost of purchasing renewable energy under power purchase agreements from solar and wind projects and capacity from BESS resources are projected including the effects of the Inflation Reduction Act of 2022 ("IRA") and by reference to 2022 data and projections from the National Renewable Energy Laboratory ("NREL").[10] Projections may not fully capture upward cost pressures of higher future demand for renewable resources, availability of suitable land, or supply chain issues.

See the section of this IRP titled Major Modeling Assumptions for more in-depth discussion of Reference Case assumptions.

Sensitivity and side cases were then performed to assess impacts of variations in key assumptions as compared to the Reference Case.

In the fossil fuel price sensitivity cases, both coal and natural gas prices were varied. The variation in coal prices assumed was a small fraction of the variation in assumed natural gas prices at Henry Hub shown in Figure ES-9. As a result, the fuel price sensitivity cases test impacts on the relative costs of the portfolios of significantly higher or lower differentials between natural gas and coal commodity prices, as well as the impact of changes in fuel prices relative to the cost of renewable resources.

Sensitivity assumptions regarding the cost of CO_2 emissions range from the "No CO_2 Cost" assumption used in the Reference Case to mid-range and high-range CO_2 prices based on estimates of the social cost of CO_2 released in February 2021 by the Interagency Working Group on Social Cost of Greenhouse Gases, established by Executive Order of the President. As shown in Figure ES-10 below, the range of CO_2 cost assumptions is substantial.

[10] Projections used assume solar power purchase agreement ("PPA") prices will decline from today's levels through 2030 considering technological improvements and resolution of current high inflation levels and supply chain issues. As a result, the optimization models tend to select solar PPAs beginning in the late 2020s.

Figure ES - 9. Fuel Prices

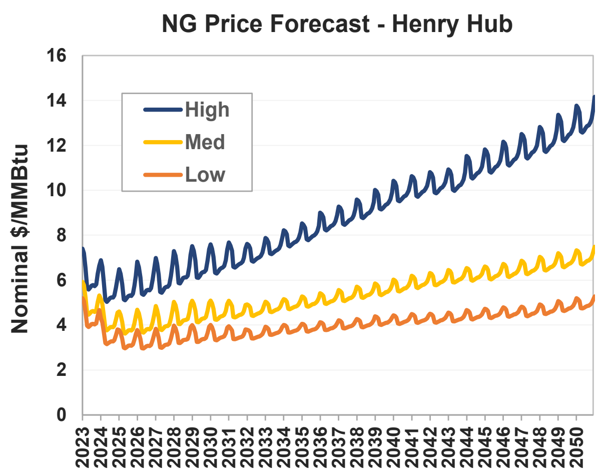
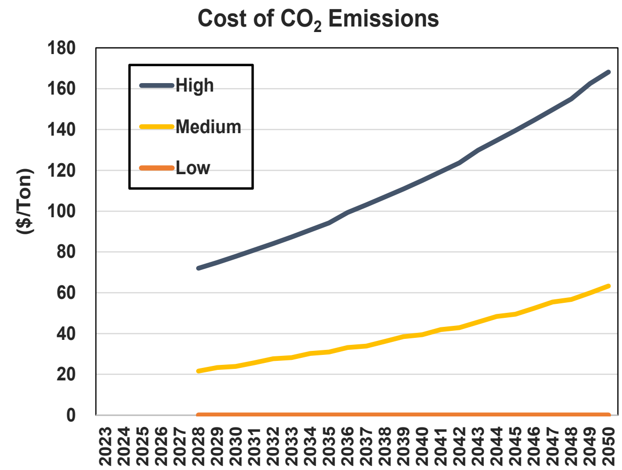


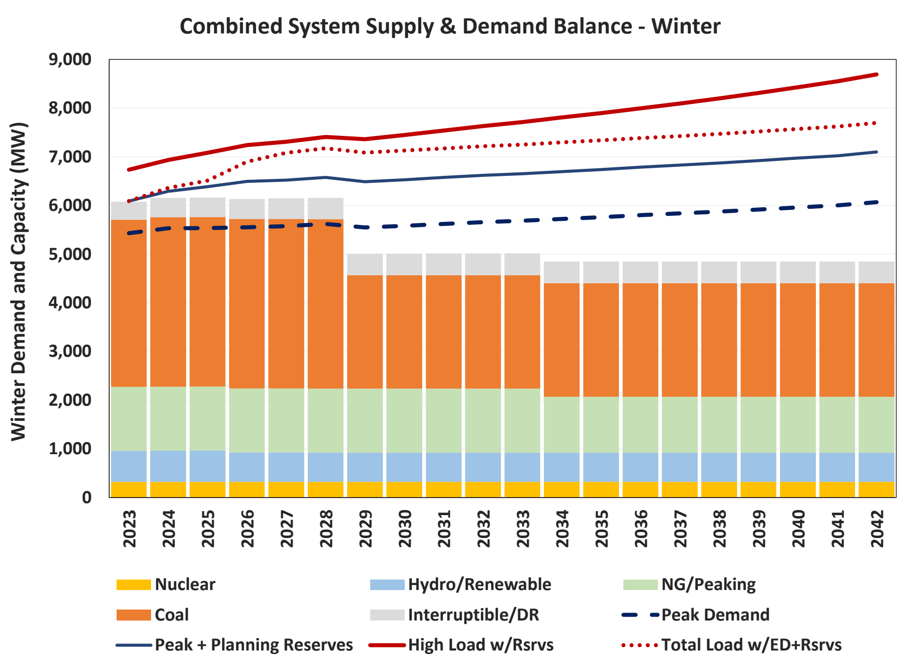
Figure ES - 10. CO_2 Emissions Costs



RESOURCE NEED

Upon retirement of Winyah, the Combined System[11] would have a significant need for new generation capacity as shown in Figure ES-11.

Figure ES - 11. Resource Need



Approximate Need for New Capacity (MW)	
Case	**Upon Retirement of Winyah**
Base Load Forecast	**1,500**
Base with Potential New Loads	**2,100**
High Load Forecast	**2,400**

[11] Combined System loads include the customer loads served directly by Santee Cooper and loads of Central's Members.

The bar heights in Figure ES-11 represent capacity available to the Combined System from existing resources. The solid and dotted lines represent capacity requirements, which is the sum of forecasted customer demand during winter peak demand periods plus the amount of capacity necessary to provide reserve margins required to achieve system reliability standards. The dashed line represents the projected Combined System winter peak demand under the Base Load Forecast.[12] The solid black line represents capacity requirements under Santee Cooper's Base Load Forecast.

The dotted red line in Figure ES-11 shows capacity requirements under the medium case load forecast (solid black line) adjusted to include additional customer loads that would potentially result from recent economic development initiatives (noted as "ED" in the figure). The solid red line represents projected capacity requirements under the High Load Forecast.

Figure ES-11 illustrates that the Combined System's need for new generation capacity upon retirement of Winyah by 2029 is projected to be approximately 1,500 MW under the Base Load Forecast to 2,400 MW under the High Load Forecast sensitivity. The figure also indicates that recent economic development initiatives expected to provide a wide range of benefits in terms of jobs and economic activity also could potentially increase loads significantly toward the High Load Forecast sensitivity (the red solid line), all other things being equal. Santee Cooper's resource plans include the flexibility needed for Santee Cooper to support these new economic opportunities. As discussed later, a Low Load Forecast sensitivity has also been analyzed.

[12] The "Base Load" forecast discussed in this section is consistent with the Medium Load assumptions used in the Reference Case and discussed in reference to load forecast sensitivities.

DEMAND-SIDE MANAGEMENT

Santee Cooper anticipates that new demand-side resources will "serve" a portion of, or reduce, Combined System capacity and energy requirements. The capacity requirements shown in Figure ES-11 above are net of the medium-case projection of the effect on winter peak demands of Santee Cooper's and Central's demand-side programs.

Figure ES-12 shows the low, medium, and high projections of DSM program impacts on winter peak demand and energy to be served from supply side resources considered in developing Santee Cooper's IRP.

In addition, medium case effects of Santee Cooper's and Central's demand response ("DR") programs shown in Figure ES-13 are factored into the analyses as resources.

Please see the Demand-side Management Overview section in the body of the report for more information on demand-side programs.

Figure ES - 12. DSM/EE Load Impacts

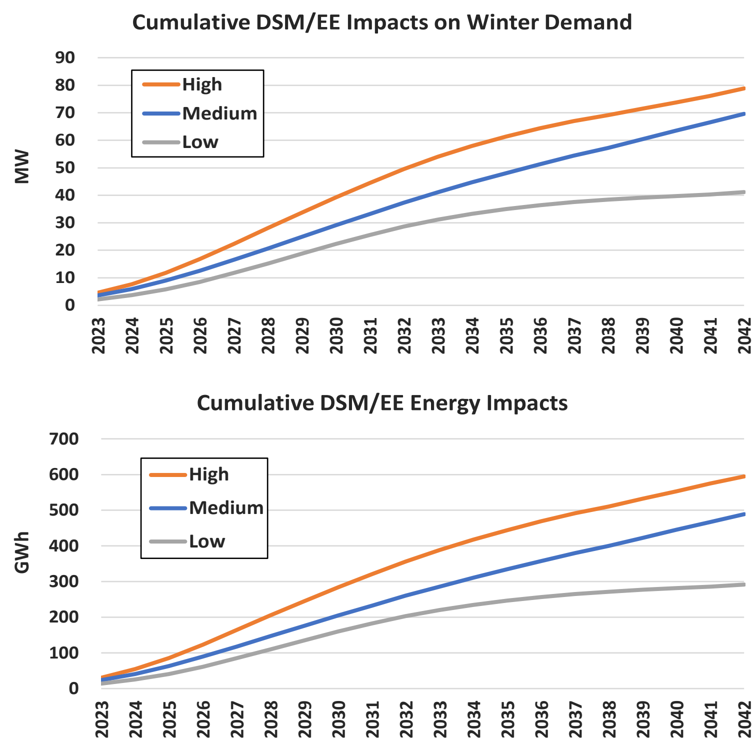
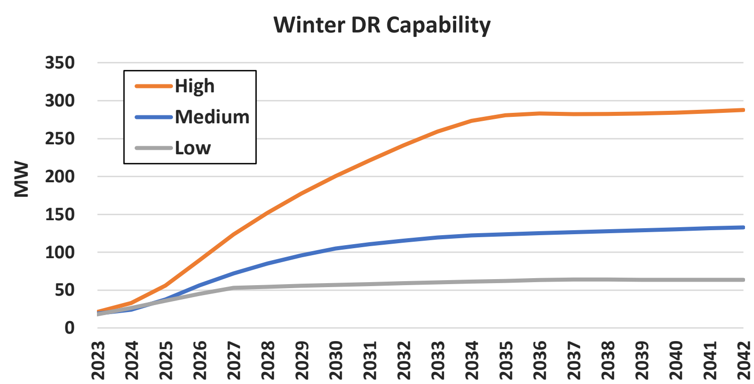


Figure ES - 13. Demand Response Resources



ANALYTICAL METHODS AND METRICS

Santee Cooper's team selected the EnCompass™ power system simulation software based on its capabilities and industry acceptance. EnCompass was used to first identify optimum portfolios and then to perform hourly resource dispatch simulations of the optimized portfolios over 2023 through 2052 (the "Study Period"). Projected variable costs (i.e., fuel, variable operation and maintenance ("O&M"), and emissions costs) are based on the hourly simulations of the portfolios.

Incremental fixed costs under each portfolio are then combined with variable cost impacts to project the total cost of each of the portfolios.

Importantly, the hourly simulation of resource commitment and dispatch performed includes simulation of operating reserves, limits on resource cycling, minimum loading, generation unit ramp rates, and solar and wind curtailment in hours when the renewable energy could not be integrated into the system. Therefore, projected costs include costs of achieving similar system reliability under each portfolio.[13]

The modeling resulted in projections of costs through 2052 for each of the portfolios studied. Outputs of the analytical process were used to develop the metrics shown in the following Figure ES-14, which were selected to:

1. Conform to Commission policy, requirements, and precedence,
2. Provide information needed to comply with statutory obligations, and
3. Inform stakeholders and decision-makers.

Figure ES - 14. Metrics

Cost	Risk	Environmental Considerations	Reliability
• Net Present Value Power Costs • Rate Impacts	• Mini-Max Regret • Cost Range • Fuel Cost Resiliency • Generation Diversity • Fixed Cost Obligations	• CO_2 Emissions • Clean Energy	• Production Cost Simulation • Qualitative Assessment

Projected portfolio costs reported herein consider allowances for: (i) fixed production and transmission costs (debt service and fixed O&M) expected to vary between portfolios[14], and (ii) total system fuel and non-fuel variable O&M costs. Generally, costs reported represent cumulative net present value ("NPV") amounts over the 30-year Study Period in billions of dollars, unless otherwise stated.

[13] For the 2023 IRP, resource operation was simulated using a "normal" historical load shape for the system. To further assess system reliability for portfolios that include intermittent renewable resources, energy-limited storage systems, and limited dispatchable resource capacity, Santee Cooper plans to perform additional analyses of portfolio performance during extended adverse weather periods and on a sub-hourly basis and has included in its proposed Short-term Action Plan preparation of additional reliability-focused analyses for applicable portfolios.

[14] Fixed costs of Cross that would be avoided if the resource is retired are included in the analyses. Fixed costs of Winyah that would be incurred if retirement of Winyah is delayed also are included in the analyses. Fixed costs that would not vary between portfolios were not included, such as costs associated with general office functions, other existing generation resources, other transmission facilities, distribution plant and operations, or customer service. This approach is consistent with other recent IRP filings in South Carolina.

RESULTS AND CONCLUSIONS

OPTIMIZED PORTFOLIOS

The optimization model determines the mix of resources that would result in the lowest cost over the 30-year Study Period, considering the directives for each portfolio shown in Figure ES-15.

Figure ES - 15. Portfolio Description and Directives

Portfolio Directives				
Portfolio Name	Also Retire Cross[15] by 2034	Allowed Types of New Resources		Other Directives
		All Fossil and Zero Carbon Resources	*Only Zero Carbon Resources*	
1. **Economically Optimized**		√		
2. **Future Coal Retirement**	√	√		
3. **No New Fossil Generation**			√	
4. **Net Zero CO_2 by 2050**	√	√		Achieve 70% CO_2 Reduction by 2030 and Net Zero CO_2 by 2050

The data provided to the optimization model included capital and operating costs, capacity ratings, and performance and operating parameters for a wide range of potential resources. In addition to the types of resources shown in Table ES-1 and discussed below in identifying the most optimal portfolios, the model had the option to, but did not, select offshore wind, small modular nuclear reactors ("SMR"), reciprocating internal combustion engines (i.e., diesel engine driven generators also referred to as "RICE" units), and aeroderivative gas turbine generators.

Table ES-1 below summarizes the optimized portfolios through 2040 for each of the four foundational portfolios. Regarding Table ES-1:

- "Solar" refers to utility-scale photovoltaic solar powered resources. The capacity shown is the sum of the capacity ratings (i.e., maximum potential output of the plant during peak solar conditions for the year) of the solar resources added within a portfolio.
- "NGCC" refers to natural gas fueled combined cycle generating resources (with diesel fuel back-up).

[15] Winyah is assumed retired in all portfolios.

- "Frame CT" refers to simple-cycle combustion turbine ("CT") generating resources made for utility service, fueled by natural gas with diesel fuel back-up.
- "BESS" refers to battery energy storage systems. The capacity shown is the sum of the capability ratings of the BESS resources added within a portfolio. BESS resources include both 4-hour and 8-hour duration systems, with 4-hour system being generally favored in the optimization runs. However, both 4-hour and 8-hour systems are indicated in the No New Fossil and Net Zero CO_2 by 2050 portfolios.
- "Wind" as used in the table below refers to onshore wind electric generation resources. The capability shown is the sum of the capacity ratings of the wind resources included in a portfolio.

The load-carrying capability of solar, BESS, and wind resources during peak load periods on the Combined System are less than the capacity ratings shown in Table ES-1.

[Left Intentionally Blank]

Table ES - 1. Resources in Foundational Optimized Portfolios

Resource Changes	Optimized Portfolios – Additions (Retirements) - MW			
	Economically Optimized	Future Coal Retirement	No New Fossil Generation	Net Zero CO_2 by 2050
Coal Retirement • By 2029: Winyah • By 2034: Cross	(1,150)	(1,150) (2,330)	(1,150)	(1,150) (2,330)
New Solar[16] • 2029 • 2030-2040	2,200 750	2,250 750	3,550 1,350	2,250 1,100
New NGCCs • 2029 • 2034	1,360 0	1,360 1,360	None by policy	1,360 0
New Frame CTs • 2029 • 2030-2040	447 0	0 1,341	None by policy	0 1,597
New BESS • 2029 • 2030-2040	0 250	100 300	1,550 900	100 1,100
New Wind • 2029 • 2030-2040	0 50	0 50	1,000 500	0 2,650

Setting aside the "No New Fossil" policy-based portfolio, Table ES-1 shows the following common elements to each of the other three portfolios.

1. Addition of over 2,000 MW of New Solar capacity in 2029 and then substantial additional amounts of new Solar capacity in the 2030s.
2. Addition of a 2x1 NGCC[17] resource (1,360 MW) upon retirement of Winyah, even in the Net Zero CO_2 by 2050 Portfolio.
3. Addition of CT (and/or BESS)[18] capacity by 2029 and thereafter.

[16] The amounts of New Solar capability shown are in addition to the solar procured by Santee Cooper and Central in the 2020/2021 timeframe through power purchase agreements with third parties.
[17] The large NGCC would have two gas turbine electric generators (essentially CTs), a heat recovery steam generator, and a steam turbine generator with a total capacity of 1,360 MW in the winter season.
[18] Analyses indicate that projected costs of new CTs are marginally more cost-effective than costs of BESS over the Study Period. Compared to BESS, CTs have certain benefits in terms of operating flexibility and system reliability. Although BESS can only "produce" energy to the extent stored, BESS may have certain

4. Addition of substantial wind resources only in the No New Fossil and Net Zero CO_2 by 2050 portfolios.

The Future Coal Retirement Portfolio includes a second 1,360 MW NGCC and additional CTs to replace retired Cross capacity.

The No New Fossil Generation Portfolio relies on large renewable resource and BESS capacity additions upon retirement of Winyah to reliably serve system loads. More specifically, the No New Fossil Generation Portfolio includes a total of 6,100 MW of renewable resources and BESS capacity additions in 2029 in contrast to the approximately 4,000 MW of New Solar, NGCC, and CT additions in the Economically Optimized Portfolio.

COST COMPARISONS

Table ES-2 below compares the projected costs under the four foundational portfolios. The values shown in Table ES-2 are NPV power costs (discounted to 2023 dollars) in billions of dollars. In Table ES-2, the most cost-effective results for the Reference Case Assumptions and each sensitivity case are shaded in green.

The key conclusions that can be drawn from the data in Table ES-2 include:

1. The Economically Optimized Portfolio has the lowest projected costs of the portfolios studied under the Reference Case assumptions and remains the least-cost under each of the sensitivity analyses, except the High CO_2 Price sensitivity case under which both the Coal Retirement and Net Zero CO_2 by 2050 portfolios are projected to be lower cost portfolios.
2. Retiring Cross is currently projected to result in significantly higher costs than the Economically Optimized Portfolio whether the replacement resources are assumed to be the more economic resources available (as in the Coal Retirement Portfolio) or only zero-CO_2 resources (as in the Net Zero Portfolio), which would result in less affordable prices for customers, except under the High CO_2 Price sensitivity case.
3. A Net Zero CO_2 Portfolio is currently projected to result in significantly higher costs, which would result in less affordable prices for customers, under the Reference Case and remains among the highest cost portfolios under the sensitivity cases, except for the High CO_2 Price sensitivity case. Special considerations regarding costs shown for the Net Zero Portfolio include the following.
   - Costs shown for the Net Zero CO_2 Portfolio include costs to reduce CO_2 emissions to below 10% by 2050 but do not include projections of costs of CO_2 mitigation technologies or obtaining CO_2 offsets to achieve “Net Zero” CO_2 emissions. Currently, projecting costs of CO_2 mitigation technologies and offsets would be

advantages over CTs in terms of shorter implementation schedules. Santee Cooper has concluded that further consideration should be given to balancing addition of CTs and BESS instead of concluding that predominately CTs should be added as indicated by the optimization model.

speculative, but such costs are expected to increase costs under the Net Zero Portfolio significantly toward the 2050 timeframe.

- The Net Zero Portfolio has been analyzed with the capabilities necessary to serve electric system loads, both capacity and energy, and to meet planning reserve margins and regional reliability criteria. However, Santee Cooper plans to perform additional studies to assess resiliency of the resulting system during extended adverse weather and further evaluate effects of the intermittent nature of renewable resources. Solutions to any issues identified may add to the cost of the Net Zero Portfolio.

4. Imposition and implementation by the government of policy that would impose on utilities additional costs related to CO_2 emissions would materially increase projected future Combined System costs and therefore increase charges to customers under all four foundational portfolios by amounts ranging from approximately $2 billion to $5 billion under the Medium CO_2 Price sensitivity cases and $7 billion to $13 billion under the High CO_2 Price sensitivity cases. Should the level of costs imposed reach the levels assumed in the High CO_2 Price case, portfolios that assume retirement of Cross may become more cost effective. However, further evaluation is needed to determine if additional costs would be incurred to maintain system reliability as discussed in the Short-term Action Plan section.

Table ES - 2. Projected Foundational Portfolio Costs

NPV Portfolio Cost (2023 $B)

Portfolio	Reference Case	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price	Range of Uncertainty: Fuel Price	Range of Uncertainty: CO2 Price
Economically Optimized	$23.5	$22.1	$26.6	$28.2	$36.6	$4.5	$13.1
Coal Retirement	$25.3	$23.5	$30.0	$28.8	$35.6	$6.5	$10.3
No New Fossil	$25.3	$24.6	$26.6	$29.5	$37.2	$2.0	$11.9
Net Zero	$26.7	$25.5	$29.8	$28.9	$33.3	$4.3	$6.6
Diff from Economically Optimized							
Coal Retirement	$1.8	$1.4	$3.4	$0.6	-$1.0		
No New Fossil	$1.8	$2.5	$0.0	$1.2	$0.5		
Net Zero	$3.2	$3.4	$3.2	$0.7	-$3.3		

RISK METRICS

Table ES-3 below compares key risk-related metrics for the four foundational portfolios. The key conclusions drawn from the data in Table ES-3 are:

1. The Economically Optimized Portfolio compares to the other portfolios as follows:
    a. A similar or lower level of risk based on the Mini-max Regret metric,
    b. Significantly lower fixed cost obligations than other portfolios, and
    c. More diverse mix of resources in the portfolio.

2. Over the 30-year Study Period, the No New Fossil and Net Zero CO_2 by 2050 Portfolios are more favorable than the Economically Optimized and Coal Retirement portfolios in the following respects:
    a. A higher percentage of energy (over 50% versus over 30%) used by customers would be provided from zero-carbon emitting resources, and
    b. Costs would be less dependent on fuel prices (i.e., lower fuel cost resiliency metric).

Table ES - 3. Key Risk Metrics

Portfolio	Mini-max Regret (2023 $B)	Total Fixed Cost Obligations (2023 $B)	Fuel Cost Resiliency (2023 $B)	Portfolio Diversity (Rank)	Clean Energy Production (Study Period)
Economically Optimized	$3.3	$6.2	$4.8	1	33%
Coal Retirement	$3.4	$9.0	$6.6	4	34%
No New Fossil	$3.8	$10.3	$2.2	2	52%
Net Zero	$3.4	$13.1	$4.4	3	54%

Risk Metric	Description
Mini-max Regret	Incremental cost exposure of choosing one portfolio over another.
Fixed Cost Obligations	Total fixed cost obligations due to ownership of new resources or purchase of resource output (and other attributes) under power purchase agreements. Fixed costs included are obligations that would not vary based on energy provided from the resources.
Fuel Cost Resiliency	Uncertainty of fuel costs across fuel price sensitivities.
Generation Diversity	Diversity of installed capacity and energy production by major fuel type (average coefficients of dispersion by end of Study Period).
Clean Energy Production	Portion of energy produced from non-emitting resources over the IRP Study Period.

CO_2 EMISSIONS

As shown in Table ES-4 below, all portfolios studied would result in significantly lower Combined System CO_2 emissions as compared to historical[19] levels.

For instance, by 2050 the Economically Optimized Portfolio would result in a 61% lower CO_2 emissions rate than in 2005. The Net Zero CO_2 by 2050 Portfolio would result in a 91% lower CO_2

[19] In 2005, Combined System CO_2 emissions were approximately 23 million tons and 1,785 lbs./MWh. By 2020, CO_2 emissions were approximately 15 million tons and 1,300 lbs./MWh.

emissions rate than in 2005 by 2050, with the remaining roughly 10% of CO_2 emissions addressed at additional cost through CO_2 mitigating technologies or offsets to achieve net zero CO_2 emissions. CO_2 emissions under the other portfolios studied are projected to be between these values by 2050.

Table ES - 4. Projected CO_2 Emissions Across the Foundational Portfolios

CO2 Emissions by Year (lb/MWh)						% Reduction v. 2005 CO2 Emiss. Rate (1,785 lb/MWh)				
Portfolio	Reference Case	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price	Reference Case	High Fuel Price	Low Fuel Price	Med CO2 Price	High CO2 Price
Year 2035										
Economically Optimized	812	786	991	772	709	-55%	-56%	-44%	-57%	-60%
Coal Retirement	479	479	479	479	479	-73%	-73%	-73%	-73%	-73%
No New Fossil	693	671	791	663	608	-61%	-62%	-56%	-63%	-66%
Net Zero	339	339	339	339	340	-81%	-81%	-81%	-81%	-81%
Year 2050										
Economically Optimized	696	647	895	629	591	-61%	-64%	-50%	-65%	-67%
Coal Retirement	430	431	430	430	430	-76%	-76%	-76%	-76%	-76%
No New Fossil	582	535	703	531	509	-67%	-70%	-61%	-70%	-71%
Net Zero	153	153	153	153	153	-91%	-91%	-91%	-91%	-91%

FLEXIBILITY TO ADAPT TO LOWER OR HIGHER CUSTOMER LOADS

A key priority for the IRP has been to identify a portfolio that will "afford Santee Cooper flexibility to adapt as conditions and levels of customer demand forecast to be served changes." (See Figure ES-3).

Accordingly, Santee Cooper has performed sensitivity analyses that vary the load forecast above and below the Base Load Forecast to determine (a) whether the identification of the most-cost effective portfolio is particularly sensitive to load levels and (b) the risk that average portfolio cost per MWh would vary due to variations in the volume of sales over which to spread Santee Cooper's fixed costs. The average portfolio cost per MWh is an indicator of the sensitivity of rate levels to load forecast levels for the portfolio.

Figure ES - 16. Winter Demand Sensitivity Cases

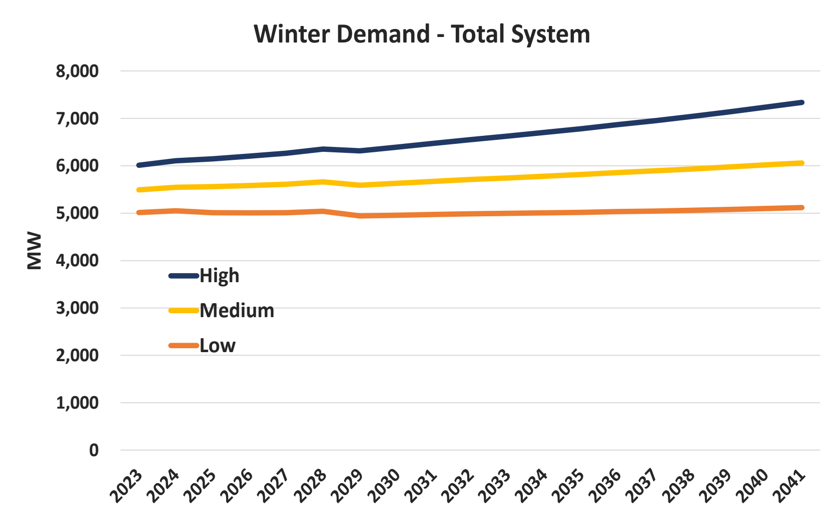


Figure ES-16 illustrates the range of variance in winter peak demand forecasts considered. Energy requirements and summer peak demand were also assumed to vary from the Medium Load Forecast to a similar extent. Figure ES-16 shows that, in the 2020s, the range of demand forecasts varied by plus or minus approximately 500 MW to 600 MW from the Medium

Load Forecast. By the end of the 2030s, the variance from the Medium Load Forecast was approximately plus or minus approximately 1,000 MW.

The analysis of portfolio costs under the high and low load forecasts assumes decisions to retire Winyah and develop a large NGCC would not change due to the shift assumed in load forecast. Even though Santee Cooper may have flexibility under many circumstances to modify those decisions in response to a load forecast shift, the conservative assumption was made to determine the impacts of different load levels without reflecting those cost mitigating options.

Figure ES - 17. Sensitivity of Power Costs to Load Growth

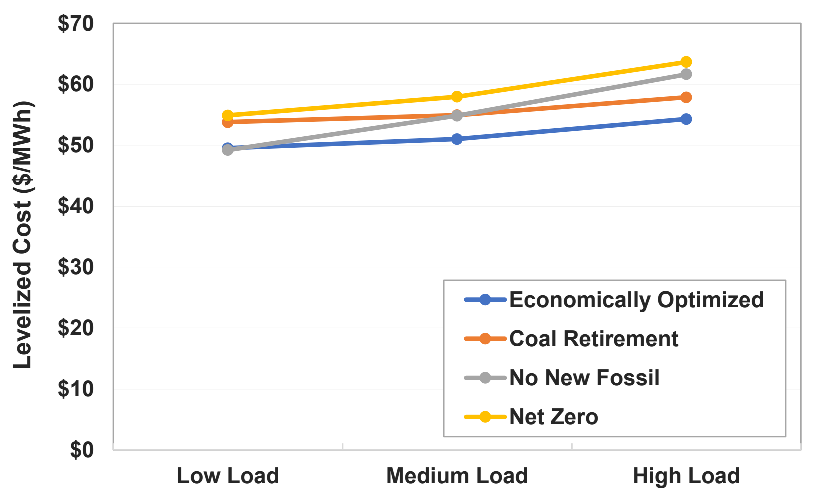


Figure ES-17 shows the average levelized portfolio cost on a $/MWh of customer load basis for each of the four foundational portfolios for the Low Load through High Load Forecasts.

The key conclusions drawn from Figure ES-17 are:

1. The Economically Optimized Portfolio average cost per MWh is relatively flat across the range of load forecasts tested. This indicates a relatively low level of load forecast-related risk.
2. The Coal Retirement Portfolio shows a similar level of load forecast risk to the Economically Optimized Portfolio—the average cost per MWh is relatively flat under that portfolio also.
3. The average cost per MWh under the Coal Retirement Portfolio remains above the Economically Optimized Portfolio across the forecast range, indicating that the conclusion that continuing to operate Cross remains cost-effective is not particularly sensitive to load forecast levels.[20]
4. Average costs per MWh under the No New Fossil Portfolio are much more sensitive to the load forecast than costs under the other two portfolios just discussed. Under the Low Load forecast, the average costs per MWh for the Economically Optimized and No New Fossil portfolios are projected to be very close. However, the No New Fossil Portfolio becomes

[20] Note that in Table ES-5 below, under the Low Load Forecast Case, Santee Cooper would have the flexibility to consider retirement of a one or more Cross Units if needed to right-size its portfolio of resources.

increasingly more costly as the load forecast moves higher, with average cost per MWh moving toward a level that is approximately 20% higher under the High Load Forecast.

5. Costs of the Net Zero CO_2 by 2050 Portfolio remain higher than costs for the other three foundational portfolios for the range of load forecasts considered and are more sensitive to load forecast levels than the Economically Optimized and Coal Retirement portfolios.

These results confirm that the Economically Optimized Portfolio has the flexibility to be adjusted in response to variations in future load levels with limited variation in resulting average power costs. This implies lower load forecast-related risk to customers and that the Economically Optimized Portfolio remains the most cost-effective of the four foundational portfolios under a wide range of future load levels.

Table ES-5 summarizes the variations in the optimized resource build under the load sensitivities for the Economically Optimized Portfolio.

Table ES - 5. Load Sensitivity of Economically Optimized Portfolio

Resource Changes	Economically Optimized Portfolio Load Sensitivity – Additions (Retirements) – MW		
	Low Load Forecast	Medium Load Forecast	High Load Forecast
Coal Retirement • Winyah – by 2029 • Cross	(1,150) Also Would Consider Mothballing or Retiring One or More Cross Units	(1,150) Cross Continues	(1,150) Cross Continues
New Solar[21] • In 2029 • 2030-2040	1,700 300	2,200 750	2.800 650
New Large NGCCs • 2029 • 2036	1,360 0	1,360 0	1,360 1,360
New Frame CTs • 2029 • 2030-2040	0 0	447 0	894 703
New BESS • 2029 • 2030-2040	0 0	0 250	50 50
New Wind • 2029 • 2030-2040	0 0	0 50	0 0

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

EVALUATION OF VARIATIONS IN DEMAND-SIDE RESOURCES

The NPV power cost comparisons elsewhere in this IRP reflect Central and Santee Cooper's medium case DSM program implementation, based on information provided by Central generally consistent with Central's 2020 IRP and based on Santee Cooper's EE and DR Market Potential Studies, as discussed in the Demand-side Management Overview section. To understand the economics of variations in demand-side resources, a sensitivity analysis that assumes variations in Central and Santee Cooper's DSM programs has been prepared as discussed below, based on assumptions discussed in detail in the Demand-side Management Overview section.

For this sensitivity, the Economically Optimized Portfolio was re-optimized under both Low DSM and High DSM cases, with all other assumptions consistent with the Reference Case. Variations in assumed DSM implementation resulted in differences in the optimized resource build, as additional demand-side resources can substitute, to some degree, for supply-side resources or allow the timing to be delayed in the High DSM case and reduced DSM can result in supply-side resources being brought forward or increased in magnitude in the Low DSM case. Under the Low DSM case, aside from minor differences in the timing of solar implementation, somewhat more BESS is implemented. In the High DSM case, the CT resource is delayed from 2029 to 2030 and significantly less solar and BESS resources are implemented, though some additional wind is selected. See the Evaluation of Variations in Demand-side Resources section for details on the optimized build plan impacts.

Table ES - 6 compares the NPV power costs for the Economically Optimized Portfolio under the Low DSM and High DSM cases to those under the Reference Case. As shown, the Reference and Low DSM Cases reflect very close to the same NPV total portfolio costs. In other words, the total supply-side and DSM program cost differences between the two cases are negligible. Accordingly, comparing the Low DSM to the Reference Case would suggest targeting the Medium DSM Case implementation rather than the Low DSM Case, because, while resulting power costs would be similar, the resulting portfolio would result in lower emissions.

However, projected costs under the High DSM Case are higher than under the Reference DSM Case indicating that the cost to obtain additional DSM impacts and DR capability beyond the Medium DSM implementation may be greater than the avoided cost of supply-side resources.

Table ES - 6. NPV Power Costs Across Demand-side Management Sensitivities

Sensitivity Case	NPV Power Costs
Low DSM	$23.5
Reference Case (Medium DSM)	$23.5
High DSM	$23.7
<u>Diff to Reference Case</u>	
Low DSM	$0.0
High DSM	$0.2

Based on these DSM Sensitivity Case results, Santee Cooper has assumed the medium DSM assumptions in the other analyses included in this IRP. As noted in the section titled Short-term Action Plan, Santee Cooper plans to proceed with further implementation of attractive DSM programs and perform additional studies to further evaluate demand-side options. Central also plans to continue DSM studies and implementation activities. These additional efforts will provide valuable information for use in future IRPs.

SANTEE COOPER'S PREFERRED PORTFOLIO

Based on analyses of the four fundamental portfolios discussed above, Santee Cooper identified that its Preferred Portfolio should reflect the concepts summarized in Figure ES-18 below.

Figure ES - 18. Characteristics of Preferred Portfolio

Topic	Conclusions
Portfolio Direction	▪ The Economically Optimized Portfolio provides cost and risk advantages over the other foundational portfolios studied. ▪ Resource additions that need to be planned for in the near term (NGCC, CT, solar) are similar under the Economically Optimized, Future Coal Retirement, and Net Zero CO_2 by 2050 portfolios.
Viability of a New NGCC	▪ Analyses support the NGCC as an attractive new resource upon retirement of Winyah and demonstrate that adding an NGCC is an important component of future portfolio development. ▪ Adding a new NGCC would be an important step to position the system for integrating solar resources in a cost effective and reliable manner.
Timing of Winyah Retirement	▪ Continuing to operate Winyah through 2030 provides the following benefits. – Added near term flexibility and reliability to effectively manage higher load cases. – Opportunities to collaborate with DESC to achieve greater economies of scale.
Solar Additions	▪ Solar additions can be phased-in, through a future competitive procurement RFP. ▪ The Preferred Portfolio assumes 300 MW per year from 2026 through 2030, then as optimized by the model.
BESS Additions	▪ BESS resources may be a viable alternative to CTs installed in the late 2020s and early 2030s

As noted above, the Preferred Portfolio reflects a two-year delay in Winyah retirement, from 2029 to 2031. While Santee Cooper continues to pursue retirement of this facility, it was decided, with support from Central, to upgrade the station to comply with the Best Available Technology ("BAT") by the end of 2025 as defined in the 2020 Effluent Limitation Guidelines ("ELG") Rule. There are uncertainties around permitting timelines for new resources, as well as the potential for significant new loads on the Combined System. Upgrading Winyah to comply with the BAT under the 2020 ELG Rule retains the option to delay the retirement to serve the best interest of Santee Cooper's customers.

Table ES - 7 below compares Santee Cooper's Preferred Portfolio to the Economically Optimized Portfolio.

Table ES - 7. Preferred Portfolio Compared to Economically Optimized Portfolio

Resource Changes	Portfolios – Additions (Retirements) in MW	
	Economically Optimized	Preferred Portfolio
Coal Retirement • Winyah • Cross	by 2029 (1,150) Continue to Operate	by 2031 (1,150) Continue to Operate
New Solar[22] • 2029 • 2030-2040	All in 2029: 2,200 750	2026-2029: 1,200 1,850
New NGCCs upon Winyah Retirement • 2029 • 2031	1,360 0	0 1,360
New Frame CTs • 2029: • 2030-2040	447 0	0 447
New BESS • 2029: • 2030-2040	0 250	350 50
New Wind • 2029: • 2030-2040	0 50	0 0

Projected costs for the Preferred Portfolio are marginally higher than costs for the Economically Optimized Portfolio under Reference Case assumptions as discussed in the section below titled Impact on the Preferred Portfolio.

However, the Preferred Portfolio has lower risks as follows:

1. Procurement of solar power would be phased in from 2026 through 2029 instead of a large addition in 2029 to reduce implementation, reliability, and price risk and to allow for Santee

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

Cooper to better manage effects of increasing amounts of solar resources on system operations.

2. Retirement of Winyah and the addition of the NGCC would be delayed two years, from 2029 to 2031, providing time needed for evaluating implementation options, obtaining approvals, and project development.
3. Substituting BESS for a portion of the CTs indicated by the Economically Optimized Portfolio would reduce permitting risks and involve shorter implementation schedules, making implementation of the portfolio more flexible and adaptable, but will require further consideration of the limited duration of the energy that can be provided to the system by BESS in comparison to CTs. This decision will also be made after validating pricing of BESS and CTs (and potentially other alternatives) through an all-source RFP.
4. Continuing to operate Winyah beyond 2028 would better position the Combined System to reliably serve higher loads expected to result from ongoing economic development efforts and which may result from accelerated electrification.
5. Continuing to operate Winyah through 2030 also presents Santee Cooper with greater optionality to consider a joint NGCC project with DESC, as discussed below, and other resource alternatives.

POTENTIAL PREFERRED PORTFOLIO ADJUSTMENTS

Central's PPAs - During Santee Cooper's IRP preparation process, Central announced decisions to enter into three power purchase agreements, or "Central PPAs." Central PPAs have been proposed by Central to meet a portion of Central's obligations under the Coordination Agreement to provide Non-Shared Resources ("NSRs") to supply a portion of the capabilities of the 2029 NGCC Proposed Shared Resource ("PSR") identified in 2021. At that time, following joint planning with Central, Santee Cooper identified the PSR as needed by the Combined System, subject to approval of Santee Cooper's 2023 IRP by the Commission. Central has indicated that it has already executed two of the contracts and is awaiting counterparty approval for the third. Central has also indicated that the greatest outstanding risk to the PPAs is obtaining transmission to deliver the resources to the Santee Cooper Balancing Authority.

The Central PPAs would supply a substantial portion of the NSR capacity Central is obligated to provide. Santee Cooper's IRP reflects that the Central PPAs do not provide the same system support and capabilities that an NGCC located within the Santee Cooper Balancing Authority would provide. Under each of the Central PPAs, Central would purchase power from resources interconnected with other bulk transmission systems. The Central PPAs would be must-run or scheduled by Santee Cooper but not dispatched automatically by Santee Cooper's Energy Control Center. Central indicated it would provide firm electric transmission over adjacent systems to deliver the power to the Santee Cooper Balancing Authority.

A summary of information concerning the Central PPAs based on information provided by Central is shown in Table ES - 8. Central advises it cannot release certain information to Santee Cooper due to obligations under non-disclosure agreements. Therefore, Santee Cooper has not been provided access to Central's PPAs and has incomplete information concerning cost and emissions profiles of the PPAs.

Table ES - 8. Overview of Central's 30-Year PPAs

	Base Load PPA	NGCC PPA	Peaking PPA
Approximate Winter Capacity Entitlement	150 MW	230 MW	292 MW
Fuel Type	Not natural gas or coal	Natural Gas (No backup fuel)	Natural Gas (No backup fuel)
Resource Type	Not specified	NGCC	CTs
3rd Party Transmission	Duke	SoCo	SoCo

To analyze potential adjustments to the Preferred Portfolio assuming all three Central PPAs are finalized and implemented, Santee Cooper has prepared estimates of the cost of power to be supplied to the Combined System under the Central PPAs. The projections have been prepared based on the limited information Central has been able to provide and other available information deemed to be reasonable for this limited purpose.

The capacity pricing assumptions used were deemed to be toward the low-end range of expected prices. Also, the projections do not include an allowance for cost of Combined System transmission system upgrades that may be required to import the power supplied under the three Central PPAs into the Combined System. Reliable estimates of the cost of resulting transmission system upgrades are not currently available to Santee Cooper.

Based on these optimistic estimates, incorporating the three Central PPAs into the Preferred Portfolio causes the projected cost of the Preferred Portfolio to be higher by an amount approaching $400 million on a cumulative present worth basis over the Study Period. Santee Cooper will refine these estimates, as needed, when more information regarding the PPAs is available, and the transmission studies are completed. See the Preferred Portfolio section of this IRP report for more information.

DESC Joint Project Opportunity – Santee Cooper and DESC have begun working together to consider a joint NGCC project. Santee Cooper anticipates that a joint project with DESC could result in lower costs and reduce project risk. Key considerations are expected to include impacts of the joint project approach on the amount of NGCC capacity that would be provided to the Combined System, costs and risks of firm natural gas transportation arrangements and required electric transmission modifications, and operational considerations relative to other alternatives, including developing an NGCC project dedicated to the Combined System. DESC has stated in its most recent IRP filing that its preferred portfolio includes a joint project with Santee Cooper involving a 2x1 NGCC. Subsequently, DESC also has indicated interest in studying two NGCC project configurations that, based on the assumptions used in this IRP, would range in winter capacity from 1,360 MW to 2,040 MW.

Based on a 50% share of the proposed joint project, analyses presented in this IRP assume the joint project could provide approximately 680 MW to 1,020 MW of NGCC capacity to the Combined System. Santee Cooper plans to further explore joint development of its NGCC resource with DESC.

Examples of potential advantages to developing a joint NGCC project with DESC include:

- Greater economies of scale (i.e., reduced average capital and O&M costs on a unit basis),
- Reduced implementation risks,
- Obtaining firm natural gas supply on more favorable terms,
- Optimizing transmission impacts holistically, and
- Appropriately considering economic development impacts in South Carolina.

Below, Santee Cooper has analyzed NGCC size likely to result from a joint project with DESC using the same planning cost and performance assumptions otherwise used in the IRP for 2x1 NGCC resources.

[Left Intentionally Blank]

IMPACT ON THE PREFERRED PORTFOLIO

Santee Cooper has made initial assessments of potential impacts of the Central PPAs and a joint NGCC project, as may result from the opportunity to collaborate with DESC, on the Preferred Portfolio as summarized below in Table ES - 9. As shown, the Preferred Portfolio may readily be modified to address Central's PPAs and/or the opportunity to jointly develop an NGCC project with DESC.

Table ES - 9. Preferred Portfolio Adjusted for Joint DESC Project and Central PPAs

Resource Changes	Portfolios – Additions (Retirements) - MW		
	Economically Optimized	**Preferred Portfolio**	**Preferred Portfolio** Adjusted for DESC Joint Project Size[23] and Central PPAs
Coal Retirement • Winyah • Cross	2029 (1,150) Cross Continues	2031 (1,150) Cross Continues	2031 (1,150) Cross Continues
New Solar[24] • 2029 • 2030-2040	All in 2029: 2,200 750	2026-2029: 1,200 1,850	2026-2029: 1,200 1,800
New NGCCs upon Winyah Retirement • 2029 • 2031	1,360 0	0 1,360	0 1,020
New Frame CTs • 2029 • 2030-2040	447 0	0 447	0 0
Central's PPAs • by 2029	0	0	672
New BESS • 2029: • 2030-2040	0 250	350 50	0 450
New Wind • 2029: • 2030-2040	0 50	0 0	0 0

[23] Assumed to involve 50% of a NGCC Project consisting of a 2x1 NGCC and a 1x1 NGCC (i.e., 2x1 is two gas turbine generators, plus one steam generator and 1x1 is one steam turbine and only one gas turbine with the single steam generator and steam turbine.) A 3x1 configuration may also be considered.

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

Table ES - 10 shows the impact on costs of the Preferred Portfolio with and without impacts of the Central PPAs and a smaller NGCC project size as may be expected to occur through a joint project with DESC.

Table ES - 10. Potential Impacts of Adjustments on Preferred Portfolio Costs

Impacts of the Preferred Portfolio With, and Without, Adjustment for Central PPAs and the DESC Joint Project Sized NGCC[25]

NPV Portfolio Costs -- $ Billion	Reference Case	Higher Cost than Economically Optimized Portfolio	Higher Cost than Preferred Portfolio Without Adjustment
Economically Optimized	$23.5		
Preferred Portfolio			
Without Adjustment	$23.6	$0.1	
With Adjustment	$24.0	$0.5	$0.4

OTHER POTENTIAL RESOURCES

Santee Cooper is considering short-term power supply alternatives to meet the potential higher loads that are expected to result from ongoing economic development activities. Those short-term resources have been modeled in the IRP analyses as short-term capacity purchases from 2024 through 2028. One of the resources, an NGCC plant with a capacity of approximately 100 MW, identified through a planning process to identify resources needed in the near term, may be acquired by Santee Cooper. On May 10, 2023, Central notified Santee Cooper that the resource would be treated as a Shared Resource under the Coordination Agreement. Santee Cooper is preparing to seek other approvals necessary for the acquisition, including from the Commission. Should that acquisition occur, Santee Cooper would evaluate its impact on the Preferred Portfolio, which is expected to be minimal.

SHORT-TERM ACTION PLAN SUMMARY

Considering the results of the planning analyses summarized above and explained further in the body of this IRP report, subject, where appropriate, to approval of this IRP by the Commission, Santee Cooper plans to take the following actions to meet its customers' needs.

1. ***Near-term Capacity Needs:***

   Santee Cooper would continue to work with Central and engage with market participants to identify options and transmission arrangements that would allow purchases to meet capacity needed prior to 2029.

[25] The increase in projected costs of approximately $400 million due to the Central PPAs, discussed above, is offset slightly by a reduction in portfolio costs due to other adjustments related to the assumed DESC joint project. However, the net impact rounds to $0.4 billion.

2. ***NGCC Planning and Implementation:***

   Santee Cooper would proceed with further actions and investigations to determine how best to implement the NGCC resource the IRP demonstrates would be an economical and valuable resource for the Combined System.

   Santee Cooper would engage further with DESC regarding the potential for jointly developing a project. Santee Cooper would also engage with Central regarding implementation of the project, Central's expressed interest in participating in the project, and its treatment under the Coordination Agreement. Santee Cooper would proceed with steps to:

   a. Confirm critical cost information (such as processes to confirm costs of project development, transmission system upgrades, and RFPs regarding firm natural gas transportation to the project),
   b. Seek further approvals and permits, and
   c. Take other appropriate actions toward implementing the NGCC, working with Central and DESC to the extent appropriate.

3. ***Evaluations to Support Future IRP Updates and Filings:***

   The following studies and investigation are expected to prove valuable for future resource planning processes.

   <u>*Cross Generating Station Retirement Options*</u>***:*** This IRP indicates that scenarios under which it would become economic to retire Cross are most likely to involve governmental policy changes aimed at reducing CO_2 emissions. Under those scenarios, Santee Cooper would likely be constrained to establish a reliable system using primarily renewable and BESS resources.

   Accordingly, Santee Cooper intends to perform additional evaluations of future portfolios that assume Cross is retired and only zero-carbon resources are added to the system.

   Initial studies indicate that retirement of Cross may require major upgrades to the Combined System transmission network, including potentially developing 500 kV transmission corridors. Another approach is to evaluate the extent to which system needs can be met from extensive, strategically sited fossil resources, renewable resources and BESS, thereby reducing or avoiding the need for major transmission upgrades due to retirement of Cross. Such future evaluations to be performed will be structured to better inform future IRPs regarding these issues.

   Other utilities have identified reliability issues that could arise during extended periods of adverse weather as portfolios become more dependent on intermittent renewable resources. In addition, sub-hourly impacts of renewable intermittency may impact reliability. Accordingly, Santee Cooper intends to perform analysis to identify issues regarding how adverse weather could impact the Combined System and the most economic solutions to those issues.

Retirement of Older CTs: Santee Cooper has assumed for purposes of this IRP that its Hilton Head (approximately 100 MW) and Myrtle Beach (approximately 56 MW) combustion turbine plants would continue to operate through 2033. Santee Cooper plans to further evaluate retirement options for those resources.

Update Reserve Margin and Related Studies: This IRP reflects reserve margin, solar integration cost, and effective load-carrying capability studies conducted in 2022. The results of those studies are dependent on the resources assumed available to meet Combined System load and therefore will be updated considering the portfolio plans and options identified in this IRP.

DSM Implementation: Santee Cooper plans to proceed with further implementation of attractive DSM programs and perform additional studies to further evaluate demand-side options. Santee Cooper understands that Central also intends to perform additional DSM studies soon.

BESS Pilot Project: Santee Cooper plans to proceed with implementation of a BESS resource as a pilot project to enhance corporate familiarity with that technology. The knowledge and experience gained from this pilot will inform future planning and ensure Santee Cooper is ready to integrate this type of resource into the Combined System at a larger scale in the future.

Wind Resources: The current IRP indicates that onshore wind may be an economical component of certain portfolios. Accordingly, Santee Cooper plans to undertake additional investigations of cost and appropriate locations for future wind projects.

Stakeholder Engagement: Santee Cooper plans to continue to appropriately engage stakeholders as Santee Cooper proceeds with the above-described evaluations.

4. ***Solar Implementation:***

This IRP, and prior planning studies, have indicated it would be cost effective to add substantial solar resources through the remainder of the 2020s and into the 2030s.

Santee Cooper has submitted its *Application of the South Carolina Public Service Authority for Approval of Competitive Procurement Program Pursuant to S.C. Code Ann. § 58-31-227,* Docket No. 2022-351-E. Upon approval of Santee Cooper's "CPRE" process, Santee Cooper anticipates working with Central to procure additional solar resources for the Combined System targeting addition of new solar capacity in 2026 or as soon thereafter as may prove reasonable. Santee Cooper plans to phase-in large additions of solar resources targeted in its Preferred Portfolio through multiple procurements.

Santee Cooper plans to gather additional information on locations within the Combined System footprint that may have the characteristics necessary to maximize benefits of certain provisions of the IRA. Santee Cooper also may examine approaches other than PPAs for providing a portion of the solar capacity needed for the Combined System to determine if other approaches may be more beneficial to Combined System customers.

5. Regulatory Developments

The current Federal administration has placed a high priority on reducing carbon emissions from the generation of electricity from coal and natural gas fueled resources. Regulatory developments in this area can impact future IRPs and resource planning more generally.

Accordingly, Santee Cooper plans to continue monitoring regulatory processes and identifying and evaluating potential impacts of new regulations on Santee Cooper's resource plans.

CLOSING COMMENTS

This IRP supports adding substantial solar resource capacity commencing in 2026, adding a large NGCC resource in the range of up to 1,400 MW upon retirement of coal capacity from Winyah, and adding a balance of CTs and BESS to meet other resource needs in the late 2020s and into the 2030s. The proposed Short-term Action plan focuses on resources common to the foundational portfolios studied and the Preferred Portfolio for which implementation activities should proceed prior to the next IRP. Implementation of Central's PPAs is not expected to alter the types of resources for which implementation steps are needed in the near term (i.e., NGCC, solar, and BESS).

The remainder of this report provides greater detail on the methodology, data sources, and conclusions of the IRP process and significant background information on Santee Cooper's electric system.

Santee Cooper respectfully submits this IRP for the Commission's consideration and approval and looks forward to discussing and explaining the IRP further in the proceeding before the Commission.

INTRODUCTION

Santee Cooper's 2023 Integrated Resource Plan ("IRP") builds on the power supply roadmap Santee Cooper first presented in its 2019 Reform Plan for changing its generation and transmission system to provide more affordable and competitive service to its wholesale and retail electric customers. The 2019 Reform Plan was intended to enhance the diversity of Santee Cooper's resource portfolio and better position Santee Cooper to adapt as conditions change in the future. The 2023 IRP reflects those same goals and will improve the affordability of Santee Cooper electricity, preserve the reliability of its power supply, and significantly reduce the carbon footprint of its generation fleet.

Santee Cooper's 2023 IRP was developed through stakeholder engagement and analytical processes that comply with S.C. Act No. 90 of 2021 ("Act 90"), which amended certain provisions in South Carolina law applicable to Santee Cooper.

- Section 21 of Act 90 amended S.C. Code Ann. § 58-37-40, relating to the content, development, submittal, and review of triennial IRPs by electrical utilities, electric cooperatives, and municipally owned electric utilities in South Carolina, as well as Santee Cooper.
- Act 90 also amended S.C. Code Ann. §58-37-40(A)(3) to require that "[t]he Public Service Authority shall develop a public process allowing for input from all stakeholders prior to submitting the integrated resource plan. Further, the integrated resource plan must be developed in consultation with the electric cooperatives and municipally owned electric utilities purchasing power and energy from the Public Service Authority and consider any feedback provided by retail customers and shall include the effect of demand side management activities of the electric cooperatives and municipally owned electric utilities that directly purchase power and energy from the Public Service Authority or sell power and energy generated by the Public Service Authority."
- Act 90 also provided in S.C. Code Ann. §58-37-40(A)(4)(a) that the Public Service Authority's IRP shall include an analysis of long-term power supply alternatives and enumerate the cost of various resource portfolios over various study periods including a 20-year study period and, by comparison on a net present value basis, identify the most cost effective and least ratepayer-risk resource portfolio to meet the Public Service Authority's total capacity and energy requirements while maintaining safe and reliable electric service.

Santee Cooper's 2023 IRP was developed during a period of unprecedented change and uncertainty. Key activities and emerging issues that have impacted the 2023 IRP and will impact future Santee Cooper planning processes include the following.

1. Resource decisions being made by Central Electric Power Cooperatives, Inc. ("Central") that, if implemented, would import 225 to 230 MW of combined cycle capacity, 292 MW of peaking capacity, and approximately 150 MW of baseload capacity into the Combined System. The resources would be acquired through power purchase agreements ("PPA"). Central has not provided the PPAs or detailed information about the transactions to Santee

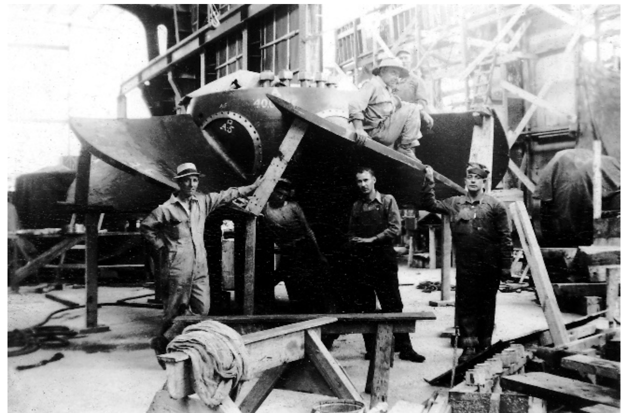
Cooper citing obligations under non-disclosure agreements. Santee Cooper was informed that two of the PPAs were executed and one is pending the counterparty's review. Central PPAs are sourced from existing resources, which reduces implementation risk. Central has indicated that an outstanding risk to the PPAs is obtaining transmission to deliver the resources to the Santee Cooper balancing authority.

2. Discussions between Santee Cooper and Dominion Energy South Carolina, Inc. ("DESC") on collaborating to develop new natural gas-fueled combined cycle resources to achieve greater economies of scale and efficiencies and reduce risks.
3. Significant potential for step increases in system load in the near term due to economic development initiatives ongoing in areas served from the Combined System and the potential need for new resources to reliably meet that increased load, which is significantly greater than what was projected in the 2022 Load Forecast Base Case presented herein.
4. Material changes in projected costs of renewable resources resulting from supply chain issues and the passage of the Inflation Reduction Act.
5. Rapid societal and government policy changes that emphasize reduction of the carbon footprint of electric energy production using intermittent renewable resources and would increase electric demand through the adoption of electric transportation and electrification to reduce reliance on fossil-fueled end-uses.
6. Increasing need for system capabilities to reliably and economically integrate large amounts of intermittent renewable energy resources and energy limited resources into power systems.
7. Elevated concerns regarding system reliability in the wake of Winter Storm Elliott and other major weather events that have impacted other parts of the U.S.
8. Domestic and international developments, which have resulted in record inflation and abrupt increases in fuel prices, costs of fuel transportation, and costs of potential new resources and transmission system changes.
9. Tightening power markets with reduced opportunities to obtain capacity and energy from other entities by entering long-term power purchase agreements.

Santee Cooper's 2023 IRP identifies a roadmap for future decisions that aggressively transitions toward greater renewable energy resources and a significant reduction in carbon emissions while balancing the critical importance of system reliability and low-cost power. Maintaining system reliability and low-cost power can be expected to grow in importance as our society moves toward greater reliance on the electric system in our lives and businesses, including greater electric demand due to transportation and other end use electrification. The roadmap identified provides a framework that will allow Santee Cooper to press forward with further input from stakeholders and direction from the Public Service Commission of South Carolina ("Commission") to make important near-term resource-related decisions. The roadmap established in this 2023 IRP is also specifically structured to allow Santee Cooper to quickly adapt as conditions change.

The remainder of this report provides more information regarding the above-listed developments and the data sources, assumptions, methodology, and results of Santee Cooper's 2023 IRP, including Santee Cooper's identification of a Preferred Portfolio.

COMPANY OVERVIEW


Initial turbine install at Jefferies Hydro Station

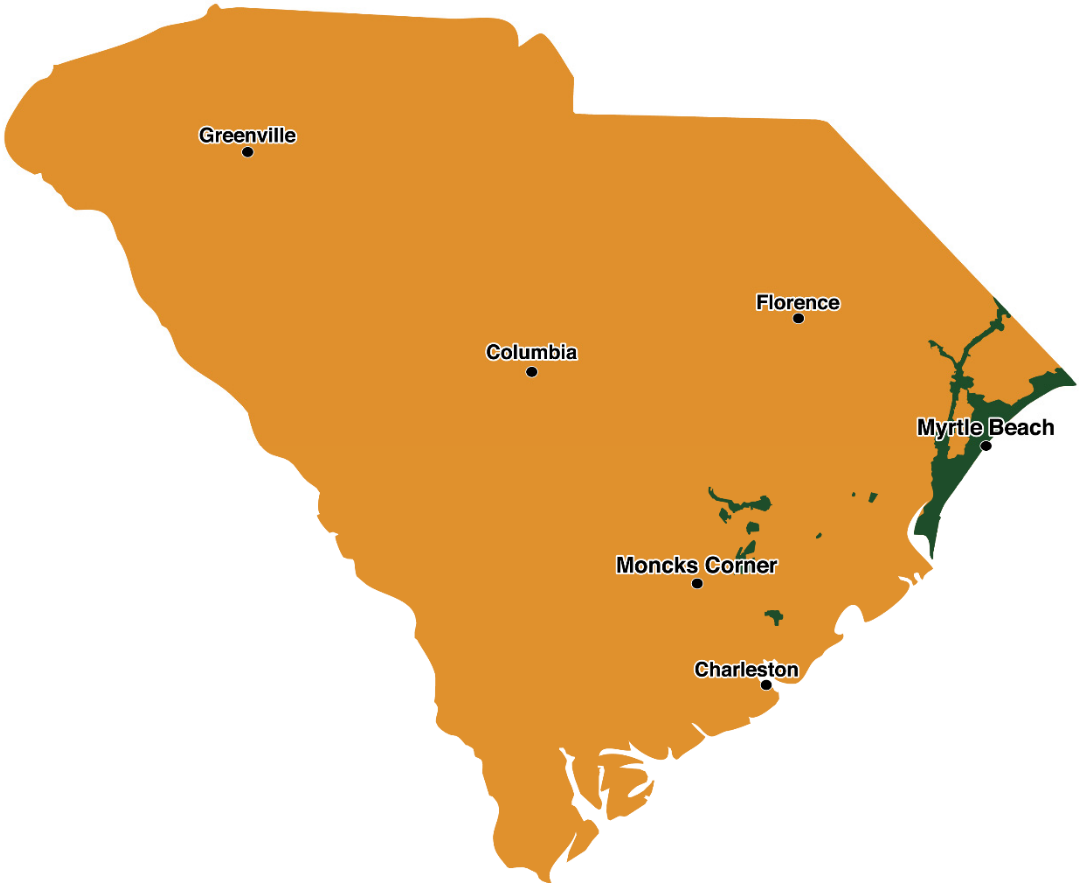
Santee Cooper is South Carolina's state-owned electric and water utility. Santee Cooper is a not-for-profit entity authorized to produce, distribute, and sell electric power and to acquire, treat, transmit, distribute, and sell wholesale water within various portions of the state. Santee Cooper was created in 1934 as a rural electrification and public works project and first generated electricity in February 1942. Santee Cooper's primary business operation is the production, transmission, and distribution of electrical energy, both at wholesale and retail, to citizens of the State of South Carolina, which is the focus of this IRP. Santee Cooper is one of the nation's largest municipal wholesale utilities, directly or indirectly serving approximately two million South Carolinians in all 46 counties of the State.

Santee Cooper owns and operates several large generating facilities, a high voltage transmission network, and over 3,000 miles of distribution lines and associated facilities through which it directly serves more than 200,000 retail customers in Berkeley, Georgetown and Horry counties, including 27 large industrial retail customers. Santee Cooper also serves several wholesale customers, including Central, Santee Cooper's largest customer, and two municipal electric systems located in South Carolina, the Town of Bamberg and the City of Georgetown, all of which are directly interconnected to the Santee Cooper transmission system. Other wholesale customers, not interconnected to Santee Cooper, include the City of Seneca, South Carolina, Piedmont Municipal Power Agency, Alabama Municipal Electric Authority, and the Town of Waynesville, North Carolina.

SANTEE COOPER AND CENTRAL RETAIL SERVICE AREAS

While Santee Cooper serves load throughout most of the state through its wholesale service to Central as described further below, the retail service territory for Santee Cooper consists of two non-contiguous areas covering portions of Berkeley, Georgetown, and Horry counties, as illustrated as the green-colored areas in Figure 1 below.

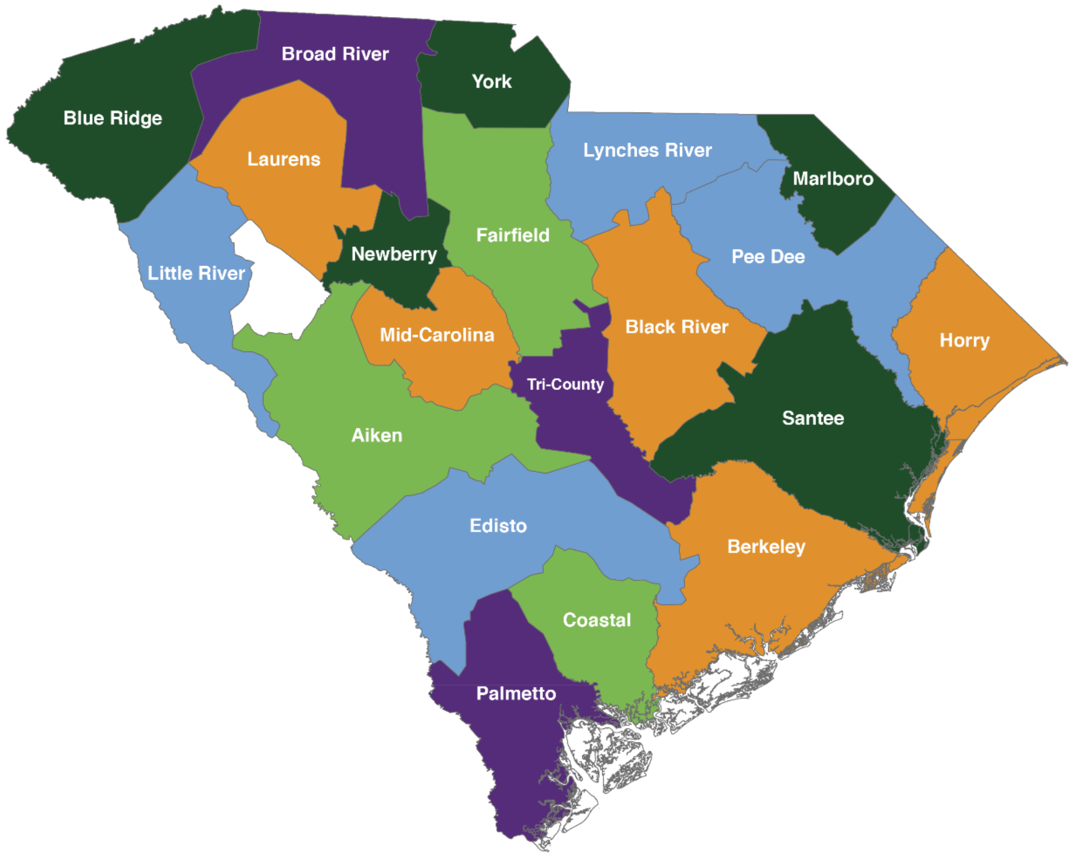
Figure 1. Santee Cooper Retail Service Areas



Central is a wholesale electric generation and transmission cooperative headquartered in Columbia, South Carolina. The terms of Central's wholesale purchase of power from Santee Cooper are governed by the Power System Coordination and Integration Agreement, dated December 31, 1980, and most recently amended in 2013 ("Coordination Agreement"). Santee Cooper and Central coordinate resource planning under the terms of this agreement, as discussed in the section titled Proposed Shared Resources and Non-Shared Resources.

Central provides power to the state's 20 electric distribution cooperatives ("Central Members") with more than 1.5 million customers in all 46 counties of the state. The cooperatives served by Central are illustrated in Figure 2 below.

Figure 2. Central Retail Cooperative Service Areas



Santee Cooper supplies the total power and energy requirements in the territories served by the fifteen (15) Central Members connected to the Combined Authority-Central System ("Combined System") as of January 2013, less any amounts which Central purchases directly from Southeastern Power Administration of the United States Department of Energy ("SEPA"), amounts supplied by Central Non-Shared Resources, and amounts supplied by allowed alternative purchases in accordance with the Coordination Agreement.

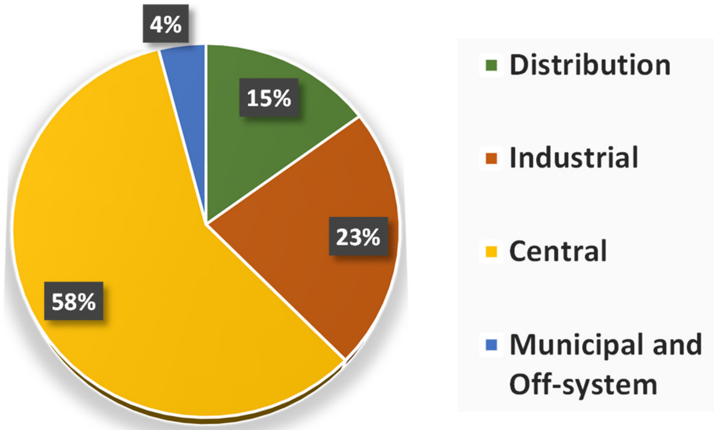
Central purchases, primarily from Duke Energy Carolinas, LLC ("DEC"), requirements service needed to supply the power and energy requirements of the five (5) Central Members not served under the Coordination Agreement with Santee Cooper.[26]

SANTEE COOPER SYSTEM

Figure 3 below provides the breakdown of calendar year 2022 electricity sales volume by customer class, reflecting that sales to Central represent well over half of system sales, while sales to residential and commercial customers from the distribution system and to industrial customers represent approximately 15% and 23%, respectively, of the total.

[26] These Central Members include Blue Ridge, Broad River, Laurens, Little River, and York.

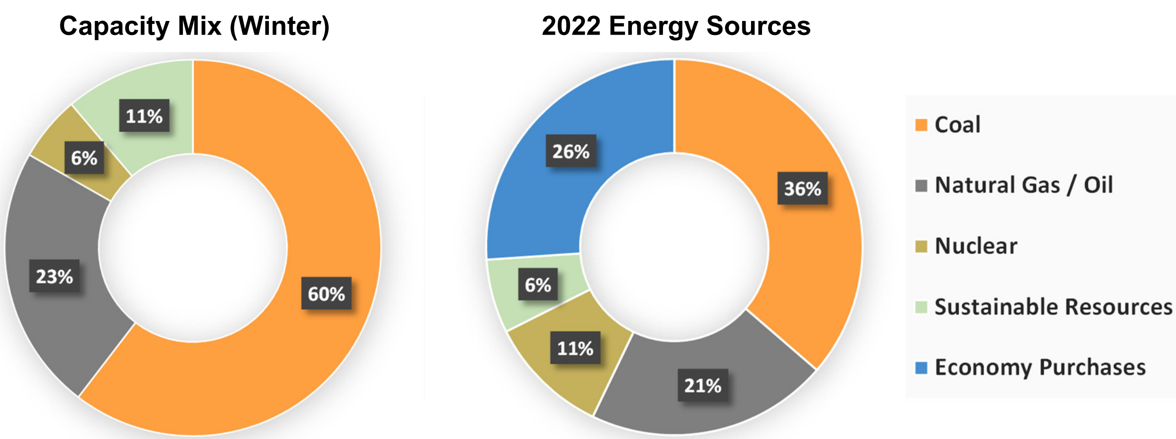
Figure 3. 2022 Electricity Sales Volume by Major Customer Classification



Santee Cooper serves its load through a mixture of generating assets that include wholly-owned and ownership interests in a variety of coal, natural gas, nuclear, hydro, biomass, landfill, and solar generating units totaling approximately 5,100 MW, based on peak output ratings under summer conditions, and approximately 5,300 MW during the winter, as detailed in the section titled Current Resource Overview. In addition, Santee Cooper has entered into various power purchase arrangements through which Santee Cooper purchases approximately 460 MW of firm capacity and associated energy. The territorial peak demand for 2022 was approximately 5,300 MW. Santee Cooper typically peaks during the winter season.

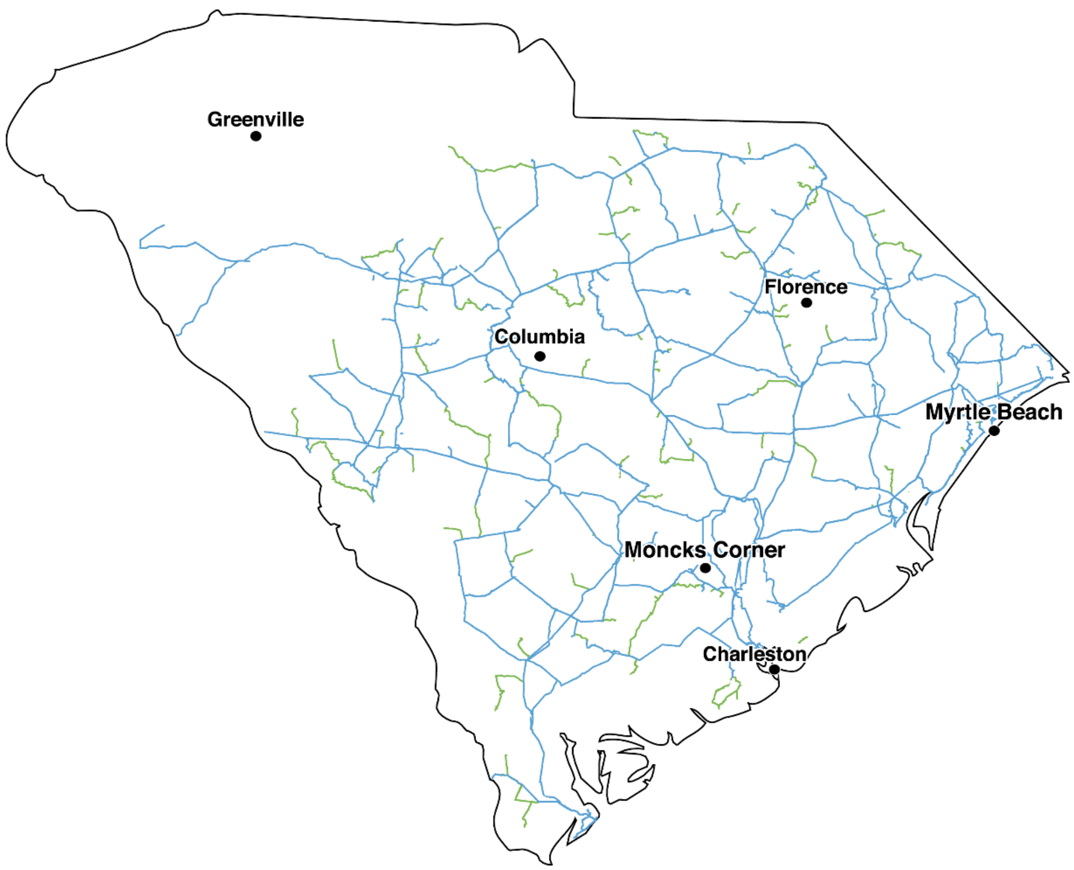
Figure 4 below illustrates the current mix of Santee Cooper's resources by primary fuel source on a winter capacity and total energy basis, based on current capacity resources and calendar 2022 energy. "Sustainable Resources" in these charts include solar, landfill methane gas, biomass, and hydroelectric resources, whether owned or purchased.

Figure 4. Current Capacity and Energy Mix of Resources



Santee Cooper operates an integrated transmission system, illustrated in Figure 5 below, which includes lines owned by Santee Cooper, as well as those owned by Central and maintained by Santee Cooper. The transmission system includes approximately 5,223 miles of overhead and underground lines primarily rated between 69 kV and 230 kV. Additionally, the system includes 93 transmission substations and switching stations serving 59 distribution substations owned by Santee Cooper and 421 Central delivery points. Santee Cooper plans the transmission system to operate during normal and contingency conditions that are outlined in electric system reliability standards adopted by the North American Electric Reliability Corporation ("NERC").

Figure 5. Santee Cooper Transmission System



Santee Cooper's transmission system is interconnected with neighboring electric utilities in the region. It is directly interconnected with DESC at twelve locations (with one additional interconnection currently under construction); with Duke Energy Progress, LLC ("DEP"), at eight locations; with Southern Company Services, Inc. ("Southern Company") at one location; and with DEC at two locations. Santee Cooper is also interconnected with DESC, DEC, Southern Company, and the SEPA through a five-way interconnection at the SEPA J. Strom Thurmond Hydroelectric Project, and with Southern Company and SEPA through a three-way interconnection at the SEPA R. B. Russell Hydroelectric Project. Through these interconnections, the Santee Cooper transmission system is integrated into the regional transmission system serving the Southeastern region of the United States and the Eastern Interconnection (one of the three major electrical grids in the continental U.S. power transmission grid, the others being the Western Interconnection and the Electric Reliability Council of Texas). Santee Cooper has separate interchange agreements with each of the companies with which it is interconnected to provide for mutual exchanges of power.

The electric generation, transmission, and distribution facilities owned by Santee Cooper, as well as certain transmission facilities owned by Central, are operated and maintained by Santee Cooper as a fully integrated electric system.

GOVERNANCE

Santee Cooper is governed by a Board of Directors appointed by the Governor of South Carolina with the advice and consent of the Senate. Candidates for appointment to the Board, including the Ex Officio Directors appointed by Central's board, must be screened by the State Regulation of Public Utilities Review Committee ("PURC") and, prior to confirmation by the Senate, must be found qualified by PURC as meeting the minimum requirements described in Santee Cooper's enabling act. An Advisory Board, comprised of the Governor, Attorney General, State Treasurer, Comptroller General and Secretary of State, receives annual reports from the Board. These reports are to be submitted to the General Assembly by the Governor. The South Carolina Legislature's Joint Bond Review Committee approves Santee Cooper's real estate and financing transactions.

Santee Cooper submits annual payments to the state equal to one percent of its projected annual operating revenues, such payments totaling approximately $17 million annually over 2020-2022. Santee Cooper also makes payments in lieu of taxes to local governments.

ECONOMIC DEVELOPMENT ACTIVITIES

Santee Cooper's enabling statute requires its Board to consider economic development as part of its mission. To accomplish this mission, Santee Cooper works with many economic development partners, most notably the electric cooperatives and the South Carolina Power Team, to bring jobs and capital investment to South Carolina. Together with the cooperatives, Santee Cooper has helped bring more than $22 billion in investment and more than 89,000 new jobs to South Carolina since 1988. Notable examples include Volvo, Nucor, Samsung, and Century Aluminum.

Camp Hall Industrial site

RESOURCE PLANNING CONSIDERATIONS

Santee Cooper is committed to planning its generation, transmission, and distribution systems in a manner that will result in low-cost and competitively priced electricity service to customers, while maintaining system safety and reliability. In compliance with S.C. Code Ann. § 58-37-40(A)(4)(a) as established by Act 90, Santee Cooper has conducted this 2023 IRP in a manner to "identify the most cost effective and least ratepayer risk resource portfolio to meet the Public Service Authority's total capacity and energy requirements while maintaining safe and reliable electric service."

Santee Cooper's planning process has evaluated alternative portfolios using the metrics shown in Table 1 below, consistent with direction from the Commission in other IRP proceedings.

Table 1. Metrics for Evaluating Portfolios

Metric	Explanation
Levelized Cost	Net present value ("NPV") incremental cost of each portfolio within each sensitivity case
Mini-Max Regret	NPV cost difference to lowest cost portfolio within each sensitivity case
Fuel Cost Resiliency	NPV of fuel costs by portfolio within each sensitivity case
Generation Diversity	Proportion of total system capacity allocated to the most common resource type
CO_2 Emissions	CO_2 emissions (cumulative) by portfolio and within each sensitivity case
Clean Energy	Quantity of energy produced from non-emitting generating sources (solar, wind, hydro, nuclear) by portfolio and within each sensitivity case
Reliability	Reliability attributes provided by each resource type, including black start capability, fast start capability, geographic diversity, and proximity to load
Compiled Risk Metric Scores	Ranking of each portfolio by metric (qualitative consideration of all scores, not a composite score)

Fixed Cost Obligations	Cumulative capital and fixed costs, including firm natural gas reservation costs, PPA cost obligations, and fixed O&M costs.
Rate Impacts	Portfolio and scenario impact on retail rates (incremental cost impact on existing rates)

In this 2023 IRP, Santee Cooper used the above metrics to evaluate multiple portfolios considering appropriate available power supply and demand-side management ("DSM") technologies and options under wide ranges of assumptions about future conditions.

Santee Cooper has concluded that the Preferred Portfolio best balances the considerations of cost, risk, safety, and reliability as mandated by Act 90 while significantly reducing the carbon footprint of the Combined System's generation fleet and positioning Santee Cooper to respond in the most effective manner to potential increases in industrial electricity demands to support South Carolina's continued economic development efforts. Therefore, Santee Cooper would, subject to Commission approval, use the conclusions of this IRP process to guide the short-term action plan set forth herein and future planning activities.

DISCUSSION REGARDING ACT 90

On June 15, 2021, South Carolina Governor Henry McMaster signed into law Act 90, which amended certain provisions of South Carolina law applicable to Santee Cooper. Section 21 of Act 90 amended S.C. Code Ann. § 58-37-40, relating to the content, development, submittal, and review of triennial IRPs by electrical utilities, electric cooperatives, and municipally owned electric utilities in South Carolina, as well as by Santee Cooper.

Prior to the enactment of Act 90, S.C. Code Ann. § 58-37-40 had last been amended by Act 62 of 2019 ("South Carolina Energy Freedom Act" or "Act 62"). In addition to changing the periodicity of IRPs from annual to triennial with annual updates, Act 62 expanded the requirements of the previously existing IRP processes by requiring utilities to consider, among other factors, analyses of alternative futures, including futures with higher levels of renewable energy and energy efficiency.

Immediately prior to the enactment of Act 90, Santee Cooper was required to develop an IRP with the same content and based on the same analysis as those prepared by electrical utilities under Act 62. However, unlike electrical utilities who filed their IRPs with the Commission for approval and subject to a full evidentiary proceeding, Santee Cooper, like electric cooperatives and municipally owned electric utilities, filed its Board-approved IRP with the South Carolina State Energy Office ("SEO"). IRPs filed with the SEO were subject neither to evidentiary proceedings nor to the approval of the SEO. Santee Cooper filed its 2020 Integrated Resource Plan ("2020 IRP") with the SEO on December 23, 2020.

The primary change that Act 90 made to S.C. Code Ann. § 58-37-40 was to require Santee Cooper to submit its IRP to the Commission for approval subject to a full evidentiary proceeding. In addition, Act 90 requires Santee Cooper to (i) implement a public process to obtain input from all stakeholders prior to submitting the IRP and (ii) develop its IRP in consultation with the electric cooperatives and municipally owned electric utilities purchasing power and energy from it, while incorporating any feedback provided by retail customers. In addition, Act 90 amended S.C. Code Ann. § 58-37-40 to require specific evaluations and requirements associated with long-term power supply alternatives.[27] Act 90 also amended S.C. Code Ann. § 58-37-40 to require Santee Cooper to submit to the Commission an annual update to its IRP, including updates to Santee Cooper's base planning assumptions relative to its most recently accepted IRP.[28]

Finally, Act 90 made several other changes to the South Carolina Code relative to Santee Cooper including, but not limited to the following.

- Putting Santee Cooper under the Utility Facility Siting and Environmental Protection Act[29]

[27] S.C. Code Ann. §58-37-40(A)(4)(a),(b).
[28] S.C. Code Ann. §58-37-40(D)(1)
[29] S.C. Code Ann. §58-33-10 *et seq.*

- Requiring Santee Cooper to obtain Commission approval for the construction[30] or acquisition[31] of a major utility facility[32]
- Requiring Santee Cooper to obtain Commission approval to enter a contract for the purchase of power with a duration of longer than ten years[33]
- Requiring Santee Cooper to implement a program for the competitive procurement of energy, capacity, and environmental attributes from renewable energy facilities.[34]

[30] S.C. Code Ann. §58-33-180.
[31] S.C. Code Ann. §58-33-185.
[32] S.C. Code Ann. §58-33-20(2).
[33] S.C. Code Ann. §58-33-190.
[34] S.C. Code Ann. §58-31-227.

RECENT RESOURCE PLANNING ACTIVITIES

Historically, Santee Cooper has periodically developed IRPs as part of its broader planning process. The IRP process entails an evaluation of Santee Cooper's existing generation resources and its projected load and energy needs over an extended period and the establishment of a plan for the supply- and demand-side resources needed to serve those needs. Each IRP establishes a roadmap for how Santee Cooper expects to meet the projected load of its customers, in a cost-effective and reliable manner and requires a balancing of multiple objectives, including system reliability, environmental responsibility, maintaining low cost of service, and minimizing risks.

The 2020 IRP and 2021 Proposed Shared Resource Due Diligence planning process were developed balancing the following priorities.

- **Reliability:** Operate and plan the Santee Cooper system to ensure that all retail and wholesale customers are provided reliable electric power — reliability is the number one product of any electric utility
- **Customer Focus:** Provide safe, reliable, and affordable power, and provide customers with new opportunities as markets change
- **Cost Management:** Develop resource plans that provide effective cost management over the long-term
- **Environmental Stewardship:** Responsibly manage the environmental impact of Santee Cooper operations
- **Long-Term View:** Develop a long-term portfolio to ensure flexibility and optionality over a wide range of possible future conditions
- **Reduce Financial and Planning Risk:** Develop resource plans that can readily adapt as future conditions change and, when possible, add resources in increments that closely match resources to needs
- **Embrace Innovation:** Identify potential developing technologies and incorporate in resource plans when reasonable and cost-effective
- **Transparency:** Engage customers, stakeholders, Board Members, and elected officials in a transparent resource planning process that is responsive to questions and input

These principles are consistent with required metrics outlined in Act 90 and included in the analyses and results described herein.

2020 INTEGRATED RESOURCE PLAN

In December 2020, Santee Cooper filed its 2020 IRP with the SEO. The 2020 IRP was developed consistent with S.C. Code Ann. § 58-37-40 as amended by Act 62 and was developed collaboratively with Central. Through the 2020 IRP, a preferred power supply plan was developed reflecting the following.

- Retirement of 1,150 MW of coal resources at Winyah by the late 2020s
- Addition of 1,500 MW of new solar resources over 2023-2032
- Addition of 200 MW of utility-scale battery storage over 2026-2036

- Addition of a 552 MW natural gas combined cycle ("NGCC") resource in the late 2020s, as well as identification of opportunities for long-term purchases to flexibly meet future load growth and resource need
- Implementation of demand response resources totaling 106 MW over 2020-2034
- Addition of quick-start peaking generating resources near the Santee Cooper retail load centers
- Upgrading of the transmission system as needed to accommodate the above resource additions and ensure reliability

These changes to Santee Cooper's generation portfolio, driven from the resource planning principles identified earlier, were intended to transform the Santee Cooper system from one that was expected to rely heavily on coal-fired resources to one reflecting a more balanced energy supply mix from fossil-fueled, nuclear, and renewable resources.

2021 PROPOSED SHARED RESOURCE DUE DILIGENCE

During 2021, building from the work underpinning the 2020 IRP, Santee Cooper engaged in various resource optimization and related analyses, resulting in the development of a generation expansion plan that included a portfolio of diverse generation resources, including an NGCC facility to become operational in the late 2020s. Throughout this process, Santee Cooper and Central staff participated in numerous, regular joint planning meetings to share and refine assumptions and preliminary conclusions. The 2021 Proposed Shared Resource ("PSR") Due Diligence process culminated in the development of a Generation Expansion Plan prepared by Santee Cooper in accordance with the terms of the Coordination Agreement which identified that a large NGCC resource would be an economical alternative to provide capacity, energy, and system support capabilities needed upon retirement of Winyah (then scheduled for the beginning of 2029) and expansion of solar resources on the system toward 1,500 MW by the early 2030s.

Accordingly, in January 2022, Santee Cooper, as provided in the Coordination Agreement, proposed a NGCC generation facility, to be in operation upon Winyah's retirement, as a PSR to meet the system needs demonstrated by the Generation Expansion Plan, as discussed further in the section below titled Near-term Joint Planning Activities with Central. Santee Cooper communicated to stakeholders during the 2023 IRP process that implementation of any such resource is subject to Commission approval. Santee Cooper also emphasized the need to remain flexible and Santee Cooper's desire to collaborate with Central to adapt the PSR in conjunction with the 2023 IRP process.

PRE-ACT 90 COMPETITIVE PROCUREMENT PROCESS

In late 2020, Santee Cooper and Central jointly conducted a solicitation for solar resources, yielding offers from approximately 20 different proposers for nearly 60 different projects ranging in size from 8 MW to 150 MW. The solicitation resulted in 425 MW of PPAs for five solar projects with four counterparties. Central and Santee Cooper entered separate contracts for their respective share of the output from selected projects that ranged in size from 75 to 100 MW at locations across the state. The projects were scheduled to be operational in 2023 and would supply solar energy to Santee Cooper and Central for the terms of the contracts, which range from 15 to 20 years.


Large solar facility in the final stages of construction

These purchases were collectively considered a PSR. Central opted out of this resource. As a result, Santee Cooper is entitled to 27.5% of the capabilities and output of these projects, and Central is entitled to the remaining 72.5%. See Central Relationship and Coordination Agreement for further description of Opt-Out and the methodology for determining the percentages.

Due to recent challenges faced by the solar industry, the project developers notified Santee Cooper and Central that the projects could not be completed at the agreed-upon prices and schedules as reflected in the PPAs. One of the project developers terminated its PPAs with Santee Cooper and Central for one 75 MW project, and Santee Cooper and Central have agreed to amend the PPAs with another project developer for two 100 MW projects. As of the timing of this report, Santee Cooper and Central are involved in discussions with the other two project developers to understand the challenges specific to each of the two remaining 75 MW projects and to evaluate measures to take related to their PPAs.

NEAR-TERM JOINT PLANNING ACTIVITIES WITH CENTRAL

Economic development is increasing in South Carolina. Significant new industrial loads are being added to the Combined System, and other loads are being discussed. For purposes of the IRP, this anticipated load increase is sufficiently addressed over the long-term by considering the High Load Case. Santee Cooper and Central recognized that these announced load additions coupled with increased Planning Reserve Margins (see section titled Planning Reserve Requirements) will require additional resources as early as the winter of 2024 (December 2023-February 2024), and the system could require over 1,000 MW of new resources prior to the retirement of Winyah Generating Station.

Santee Cooper is assessing several resource options. The Coordination Agreement describes the process by which Santee Cooper and Central will assess these options, either as Shared or Non-Shared Resources. At the time of this filing, that process is underway. The options currently under consideration are as follows:

- Santee Cooper has been evaluating the purchase of an existing in-state natural gas-fired generating facility and has determined to move forward with the purchase. This action requires approval by the Commission under S.C. Code Ann. § 58-33-185, and the Commission will receive this request for approval in 2023 before the IRP hearings.
- Santee Cooper has issued a Request for Proposals ("RFP") for PPAs through 2028. The responses to this solicitation are currently being evaluated.

Pending the outcome of these actions, other options that may be considered include the following:

- Options may exist to increase capacity at Rainey Generating Station ("Rainey") as vendor technology permits and as part of Santee Cooper's ongoing operating and maintenance program. These options have been identified, but a decision to proceed with any has not yet been made.
- Limited research indicates some potential availability of trailer-mounted CT facilities to purchase or lease, but at the time of this filing no action has been taken.
- There is a potential that the Non-Shared Resources ("NSR") that Central intends to bring to the system in 2029 may be available sooner than 2029. When information is available to assess these options, advancing one or more of the PPAs will be evaluated.

POTENTIAL JOINT PROJECT WITH DOMINION

Santee Cooper has signed a Memorandum of Understanding ("MOU") with DESC to evaluate the joint development of an NGCC facility within South Carolina. Both utilities recognize the benefits to be gained from economies of scale and are interested in exploring a potential jointly developed facility. The MOU is only to evaluate the potential for a joint build and does not include commitments by either utility to a joint project. At the time of IRP filing, the evaluation is in its initial stages.

CENTRAL RELATIONSHIP AND COORDINATION AGREEMENT

As noted earlier in the Company Overview section, since 1981, Santee Cooper has served Central under the terms of the Coordination Agreement, most recently amended in 2013.[35] This section provides certain details regarding the Coordination Agreement so that its influence on the IRP process can be understood.

The term of the Coordination Agreement currently extends through at least December 31, 2058. Under the Coordination Agreement's 10-year rolling notice provision, a party must give notice of termination no later than December 31, 2048, to terminate the Coordination Agreement as of the end of 2058. Failing a notice to terminate by either party, the Coordination Agreement will renew for additional periods.

Central has entered into all-requirements agreements with Central's 20 member cooperatives that extend through December 31, 2058, and such agreements obligate those members to pay Central's costs, including costs paid under the Coordination Agreement.

Generally, Santee Cooper supplies the total power and energy requirements in the territories served by the fifteen (15) Central Member Cooperatives connected to the Combined System as of January 2013, less (i) any amounts Central purchases directly from SEPA, amounts supplied by Central NSRs, and (ii) any amounts supplied by allowed alternative purchases in accordance with the Coordination Agreement.

COORDINATED PLANNING REQUIREMENTS

The Coordination Agreement is a comprehensive, long-term agreement that provides for coordinated planning of generation resources needed to serve loads on the Combined System reliably and economically, allocation of a portion of Santee Cooper's production and transmission costs to Central, accounting for new resources undertaken by Santee Cooper and Central, and other related matters. The Coordination Agreement requires Santee Cooper and Central to cooperate and coordinate in the joint planning of future resources and outlines how the parties will determine the need for and plan new resources.

The Coordination Agreement provides for Santee Cooper to dispatch power supply resources provided by Santee Cooper and Central to economically serve loads on the Combined System without respect to ownership much as a power pool would be dispatched to serve multiple parties' loads. The Coordination Agreement also provides for Santee Cooper to operate the integrated transmission system owned by Santee Cooper and Central. The Coordination Agreement recognizes Santee Cooper operates the balancing authority on behalf of the Combined System.

[35] Since 2013, the parties have also executed multiple Memoranda of Understanding that clarify certain aspects of the administration of the Coordination Agreement.

PROPOSED SHARED RESOURCES AND NON-SHARED RESOURCES

When new Major Resources[36] are needed to serve Combined System load, the Coordination Agreement requires Santee Cooper to propose to undertake PSRs to serve loads on the Combined System. Once a PSR is identified, Central must decide whether it will "Opt In" or "Opt Out" of the resource within 120 days after the date such PSR is identified.

If Central chooses to Opt In, the PSR becomes a Shared Resource under the Coordination Agreement, and Santee Cooper would undertake the needed resource and recover a portion of the costs of the new Shared Resource through charges to Central under the Coordination Agreement. Santee Cooper would have the right to refine plans for the new Shared Resource as needed during the implementation of the resource, with Central review and input as allowed for under the Coordination Agreement.

If Central chooses to Opt Out of the PSR under the Coordination Agreement, Central and Santee Cooper are then each obligated to provide their respective pro rata share ("Load Ratio Share") of the capabilities the PSR would have provided by providing NSRs to the Combined System.

NSRs typically would be "Pooled Resources," meaning Santee Cooper would dispatch the resources to meet the "Pooled Loads" of Santee Cooper and Central without regard to ownership. Under Appendix F of the Coordination Agreement, the output of NSRs, entitlements to Shared Resources, and Interchange Transactions are accounted for in serving the respective hourly demands of each party.

Santee Cooper and Central also have the option to meet their respective obligations to provide capacity to the Combined System by providing for a NSR to meet load on Designated Delivery Points moved to another Balancing Authority. If Central elects the Designated Delivery Point option, Central's NSR would not be dispatched by Santee Cooper and therefore is referred to as a Non-Pooled Resource. If Central were to elect that option, Central would have the obligation to serve all future loads on the Designated Delivery Points, Santee Cooper would no longer have the obligation to plan to serve that load, and Central would have the obligation to supply capabilities to the Combined System to the extent not provided from removing load from the system and its NSRs.

The decision by Central to Opt Out of a PSR does not reduce the portion of existing Shared Resource fixed costs or transmission costs allocated to Central under the Coordination Agreement.

As mentioned above in the section entitled Recent Resource Planning Activities, during 2021, Santee Cooper worked with Central in joint planning for future resources. Following several months of joint diligence, Santee Cooper developed a Generation Expansion Plan that included a portfolio of diverse generation resources, including a NGCC facility to become operational upon

[36] Under the Coordination Agreement, generally, a Major Resource is a new resource with Net Dependable Capacity of 50 MW or more, a purchase price or aggregate lease payments of $50 million or more, an agreement or series of related agreements with terms of 5-years or more or providing for capacity or energy in excess of 50 MW in any hour, or certain Major Resource Modifications to existing resources that increase the resource's capability by 50 MW or more or extend the resource's life by 5-years or more.

the retirement of Winyah Generating Station. In January 2022, Santee Cooper identified a NGCC generation facility to be in operation by the end of 2028 as a PSR to provide capacity and other capabilities needed due to the planned retirement of Winyah and planned additions of solar power to the Combined System. On April 28, 2022, Central notified Santee Cooper that it would Opt Out of the PSR. Accordingly, both Central and Santee Cooper are now each contractually required to develop and share plans to provide NSRs as required to provide their respective Load Ratio Share of the capabilities the PSR would have supplied to the Combined System. Each party's Load Ratio Share is determined by a formula in the Coordination Agreement and based on projected contribution to Combined System monthly firm demands over the five years after the PSR is planned to be placed into service. The Load Ratio Share will vary with each PSR. Santee Cooper and Central's Load Ratio Share of the 2029 natural gas PSR is 31.2% and 68.8%, respectively.

Central has notified Santee Cooper that it intends to fulfill a portion of its obligation to provide a share of the capacity the PSR would have provided to the Combined System through power purchase agreements for baseload and peaking capacity and energy from resources located in adjacent systems. Central has also expressed interest in procuring other resources, including potential participation in the NGCC being evaluated jointly with DESC, as well as a BESS project.

To fulfill its obligation, Santee Cooper proposed developing a 1x1 NGCC as its NSR. Santee Cooper noted that its NSR plans will be updated following the approval of this IRP and has not made any contractual commitments related to its NSR.

In contrast, Central has executed or is in the process of finalizing certain contracts. In the IRP, Santee Cooper evaluated three non-shared PPAs proposed by Central as modifications to the Preferred Portfolio, utilizing information provided by Central and other available information deemed to be reasonable. Santee Cooper did not constrain the model with other NSRs proposed by Central or Santee Cooper. This approach allowed Santee Cooper to propose the most cost effective and least risk portfolio to serve the Combined System and avoided redundancy. Following approval of this IRP, Santee Cooper will identify resources that Central and Santee Cooper might consider developing as their respective NSRs, consistent with the Preferred Portfolio, and in collaboration with Central.

The Coordination Agreement establishes a process that obligates Santee Cooper to plan and implement resources as deemed necessary and appropriate to maintain a reliable system based on studies completed. Further, the Coordination Agreement provides for resource decisions to be made by both parties according to a specific lengthy timeline. Act 90 now places obligations on Santee Cooper to conduct a resource planning process in coordination with Central and along a different timeline. Santee Cooper has endeavored to meet both obligations through its development of the 2023 IRP.

STAKEHOLDER PROCESS FOR 2023 IRP

S.C. Code Ann. §58-37-40(A)(3) requires that:

> The Public Service Authority shall develop a public process allowing for input from all stakeholders prior to submitting the integrated resource plan. The integrated resource plan must be developed in consultation with the electric cooperatives and municipally owned electric utilities purchasing power and energy from the Public Service Authority and consider any feedback provided by retail customers and shall include the effect of demand side management activities of the electric cooperatives and municipally owned electric utilities that directly purchase power and energy from the Public Service Authority or sell power and energy generated by the Public Service Authority.[37]

To provide interested parties an opportunity to engage in the development of the 2023 IRP and to meet the statutory requirements referenced in the paragraph above, Santee Cooper initiated a stakeholder process which began in the first quarter of 2022 and continued the process through 2023, up to the finalization and filing of the IRP. As described in this section, Santee Cooper developed multiple avenues for stakeholder engagement throughout the process.

The primary form of engagement was through five public meetings, held virtually. The stakeholder meetings were facilitated by a third party, Vanry & Associates, Inc. ("Vanry Associates"), which has substantial experience managing stakeholder processes in the energy sector. Each of these meetings were noticed through multiple media outlets including print and social media, bill notices, customer mailing lists, and web site notices. In addition, prior to each meeting, Santee Cooper personnel reached out directly to individuals representing cooperatives, municipal electric utilities, industrial customers, state agencies, local governments, and non-governmental organizations ("NGO"). Registration records for the meetings demonstrate that the relevant stakeholders were aware of and notified well in advance of each meeting.

Meetings were held in March, April, June, and December of 2022 and in April of 2023. Meeting materials were shared on the Santee Cooper IRP web page prior to each meeting allowing stakeholders the opportunity to review and develop questions and comments prior to the meeting date. Meetings were hosted through the Zoom™ platform, and attendees had the opportunity to engage Santee Cooper presenters and experts through both live verbal interaction and a chat feature in which stakeholders could type their questions and receive either a written response in the chat, or have their question answered live by one of the Santee Cooper presenters. Participation and engagement were high and resulted in extensive input and feedback from stakeholders.

The content of the meetings progressed in conjunction with the work being carried out in developing the IRP. The initial meeting included topics related to company overview and past planning activities, as well as the plan for the analysis and preparation of the IRP. In each of the

[37] S.C. Code Ann. §58-37-40(A)(4)(c)

subsequent meetings, Santee Cooper discussed results to date for each of the input analyses (load forecast, fuel forecasts, reliability analyses, model software, resource options, etc.) as well as analyses that would be undertaken next. This afforded stakeholders the opportunity to provide input on the work to date as well as to ask questions and make suggestions regarding future analyses. In each meeting, the stakeholders and Santee Cooper discussed sources and perspectives on input assumptions and resource portfolios. In the final meeting, the stakeholders and Santee Cooper reviewed and discussed the preliminary indicative results and Santee Cooper's views on the range of portfolio results including the preferred portfolio direction.

After each meeting, materials including presentations, question and answer logs, meeting summaries, and video recordings were posted to the Santee Cooper IRP web page.[38] In addition, a summary of each public meeting was filed with the Commission in Docket No. 2022-23-E. Each summary filed with the Commission included a link to the IRP web page, which is still active at the time of this filing and available for reference throughout the 2023 IRP proceeding.

In response to requests for technical sessions from stakeholders, Santee Cooper held meetings with several different groups covering topics requested by each stakeholder group. A summary of the meetings was posted to the Santee Cooper IRP web page, including topics discussed and any decisions made relevant to the IRP analysis.

To enable and increase engagement outside of formal stakeholder meetings, Santee Cooper created a Forum linked to the IRP web page. The Forum went live in mid-2022 and allowed stakeholders the ability to post questions or feedback for Santee Cooper to consider in the development of the 2023 IRP. Usage of the Forum was robust, with engagement from a variety of stakeholders. Santee Cooper evaluated each suggestion and piece of feedback and promptly posted responses. Each meeting summary filed with the Commission in Docket No. 2022-23-E included a link to the Forum which is still active at the time of this filing.

In response to stakeholder requests for information and data, Santee Cooper created a data sharing site and made the first files available in early February of 2023. Data shared included:

- Coal and natural gas pricing forecasts
- Load and resource tables
- Data related to the reserve margin and ELCC Studies

Santee Cooper also shared several reports prior to filing the IRP, including the following:

- Reserve Margin and ELCC Study Report (December 2022)
- EE MPS Residential and Commercial Measures (December 2022)
- Solar Integration Study Report (January 2023)
- Santee Cooper EE Market Potential Study Report (February of 2023)
- Santee Cooper DR Market Potential Study Report (March of 2023)

Santee Cooper also held several meetings with Central to coordinate regarding development of the 2023 IRP. Topics covered included modeling assumptions and inputs, initial results, and a

[38] www.santeecooper.com/IRP

review of the preliminary Preferred Portfolio. Central and several retail cooperative representatives also participated in the five public stakeholder meetings.

Finally, Santee Cooper communicated with its municipal customers about the IRP development and met with one municipality at its request.

The stakeholder process for Santee Cooper's 2023 IRP resulted in a valuable, robust, and collaborative engagement. As demonstrated above, Santee Cooper developed multiple avenues for stakeholder engagement including the five public meetings facilitated by Vanry Associates, hosting several technical meetings as requested by stakeholder groups, providing the Forum for stakeholders to submit input and feedback, and coordinating with Central through several meetings. Santee Cooper experts considered and evaluated all feedback received and, where appropriate or feasible, incorporated material changes to inputs, assumptions, and methodologies as a result of this interaction. A few examples of material changes to the IRP include: the addition of and modeling configuration for the No Fossil Portfolio, the inclusion of multiple durations for energy storage, and updated renewable cost assumptions after the passage of the Inflation Reduction Act of 2022, P.L. 117-169 ("IRA").

Attachment 5 contains a letter from Vanry Associates providing their opinion of the stakeholder process conducted for the 2023 IRP. As the letter states, Vanry Associates found the stakeholder process conducted by Santee Cooper to be best-in-class regarding engagement.

ELECTRIC LOAD FORECAST OVERVIEW

With assistance and input from Central, other customers, and consultants, Santee Cooper annually prepares a forecast of the total capacity and energy requirements of the Combined System by projecting each customer class's energy use and contribution to system peak demand for a period of twenty years under normal weather conditions. The 2023 IRP relies on the 2022 Load Forecast, completed in June 2022 and reflecting projections through 2041. The 2022 Load Forecast reflects that total system winter peak demand will grow from 5,392 in 2023 to 5,912 MW by 2041, primarily driven by growth of the distribution and Central customer classes. Similarly, energy sales are projected to grow from 27,698 GWh to 30,290 GWh over the same period. This represents a compound annual growth rate ("CAGR") of 0.5% growth rate for both peak demand and energy. The 2022 Load Forecast Report is attached to this IRP filing as Attachment 3.

In addition, Santee Cooper prepares various alternate scenarios, namely high and low cases, to reflect different potential outcomes due to changes in economic activity, demographic shifts, customer rooftop solar adoption, distribution level battery storage, electric vehicle penetration, and other relevant variables that would drive changes in Santee Cooper's future energy and demand requirements. These scenarios reflect the uncertainty inherent with forecasting over long periods of time and are intended to incorporate a range of possible outcomes for Santee Cooper.

DISTRIBUTION FORECAST

Santee Cooper develops the residential and commercial forecasts 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. Santee Cooper currently serves approximately 175,000 residential customers. Residential energy sales are expected to grow at a CAGR of approximately 1.4% per year over 2023-2041. The forecast for the commercial class is developed by modeling energy sales and number of customers independently, with separate regression analyses. This class consists of approximately 30,000 commercial customers and is expected to grow at a CAGR of 0.6% per year over 2023-2041. Key driving variables for the residential and commercial class forecasts include weather, market share and efficiency of electric appliances, price of electricity, and many others. The combined residential and commercial load is forecasted to grow at a CAGR of 0.8% for energy and 0.7% for demand. Stochastic methods are applied to these models to capture what the 90th and 10th percentile outcomes are for the high and low scenarios.

In addition, Santee Cooper made post-modeling adjustments to capture the impact of two significant trends that are not yet sufficiently reflected in historical data, and thus are not captured in the backward-looking regression analysis that underpins the forecast. First, Santee Cooper developed three electric vehicle ("EV") forecasts to model the impact of how different EV adoption scenarios would impact the load forecast. Santee Cooper currently has approximately 900 EVs on its distribution system. Over time, this number is expected to grow in a significant but manageable way, with 48,570 vehicles expected in the service territory consuming 274 GWh and adding 6 MW to the winter peak demand by 2041. Second, Santee Cooper developed three rooftop photovoltaic ("PV") forecasts to capture various growth trajectories of rooftop solar installations in the service territory, with the base case growing from 1,348 rooftop solar customers in 2023 to 3,249 by 2041.

EV charging station at Santee Cooper headquarters in Moncks Corner

Altogether, the base case residential and commercial SAE results, plus adjustments made for future EV and rooftop PV growth, indicates the combined class will grow from 4,208 GWh and 912 MW winter peak demand in 2023 to 5,149 GWh and 1,048 MW in winter peak demand by 2041, representing a 1.1% CAGR for energy and 0.8% CAGR for winter peak demand.

INDUSTRIAL FORECAST

Santee Cooper's current direct-served industrial class is composed of 27 customers whose operations involve industrial, manufacturing, and other energy-intensive economic activities and are typically directly interconnected to the transmission system. The forecast of demand and energy requirements for this class is based on an analysis of historical load and contractual quantities and consultations to determine any potential changes to their loads. While some customers anticipated near-term growth at the time the 2022 Load Forecast was completed, which was included in the forecast, the forecast reflects no other changes in load for this class, as no new industrial customers had approached Santee Cooper for bundled retail service at the time. This near-term growth for some existing customers will cause Santee Cooper's total forecasted industrial energy and winter peak demand requirements to grow from 6,434 GWh to 6,531 GWh and 748 MW to 765 MW by 2041, representing a 1.5% and 2.4% cumulative increase in energy and demand, respectively. Santee Cooper evaluated the potential range of industrial customer load by adjusting demand and energy upward or downward by the equivalent of 400 MW for the High and Low Cases, respectively, for the Combined System to account for future variations in load from industrial customers. This represents the addition or loss of a very large, or several medium to large, industrial customers on the Combined System.

Santee Cooper serves approximately 340 MW of non-firm Industrial customer load through Economy Power and Interruptible service contracts. Interruptible service allows Santee Cooper to disrupt power service during times of peak demand. Economy power service represents electricity that Santee Cooper offers to customers only on an as-available basis, and the pricing for the service typically reflects market pricing. For the purposes of the IRP, the non-firm load is considered a resource available to the EnCompass model to dispatch during peak demand periods.

CENTRAL FORECAST

Central's forecast is prepared by Central staff and Central Members. Details regarding Central's forecast methodology can be found in Central's 2020 Integrated Resource Plan ("Central IRP"). Central's service territory includes several densely populated areas, such as Hilton Head; however, Central's service territory generally tends to be more rural. The aggregate total retail customers served by Central through the member-cooperatives is large, with over 824,000 active accounts, and geographically diverse, as Central Members touch every county in South Carolina. The forecast represents the aggregate forecast for the loads of the Central Members within Santee Cooper's Balancing Authority. Central's forecast is developed using a similar method as Santee Cooper's distribution forecast described above. Based on the 2022 Load Forecast, Central's energy requirements are expected to grow from 16,141 GWh in 2023 to 18,397 GWh in 2041, while winter peak demand is expected to grow from 3,512 MW to 4,061 MW in 2041. This represents annual CAGRs of 0.7% and 0.8% for energy and peak demand, respectively. Similar to Santee Cooper's residential and commercial classes, Central's growth is expected to be driven primarily by the growth in the number of households in South Carolina. The Central IRP describes Central's methodology in the following manner:

> *"Residential and Small Commercial classes are forecasted using the industry standard Statistically Adjusted End-Use (SAE) modeling…Residential energy is modeled by forecasting the number of residential member-owners and the average use per member-owner. Due to energy efficiency trends, residential growth comes from new residential member-owners on the system. Similarly, Small Commercial growth is driven by additional member-owners. The Industrial subset of Large Commercial and Industrial is forecasted individually in close consultation with member- cooperatives. The remaining classes (Seasonal, Irrigation, Lighting, and Other) are forecasted using linear trends and historical averages."* [39]

Central also prepares high and low load scenarios for planning using a statistical approach similar to Santee Cooper's method:

> *"The low-growth scenario uses economic growth that is one standard deviation below the IHS Markit base forecast. (Standard deviation measures the variability of individual values from the average.) The growth rates for all economic and demographic categories are reduced by the standard deviation calculation. For example, a standard*

[39] Source: Central IRP

> *deviation estimate of 0.5% and a growth estimate of 1.2% yields 0.7% growth in the low-growth scenario. Residential member-owner forecasts are also one standard deviation below projections.*
>
> *High-growth scenarios are calculated similarly, but one standard deviation is added for economic growth and the member- owner forecasts."* [40]

Importantly, Central's load forecast reflected projected load determinants that were net of DSM impacts, under a "business-as-usual" case (as discussed further in the section entitled Demand-side Management Overview). For purposes of the 2023 IRP, projected impacts of *new* Central DSM resources (i.e., activity beyond 2022) for this case were added back to the projections. As discussed later herein, projected DSM impacts across a range of scenarios were netted away from these gross load determinants to test the cost effectiveness of progressively higher levels of DSM activity.

MUNICIPAL AND OFF-SYSTEM FORECASTS

Forecasts of wholesale sales to the Town of Bamberg, South Carolina, the Town of Georgetown, South Carolina, Alabama Municipal Energy Authority ("AMEA"), Piedmont Municipal Power Authority ("PMPA"), the City of Seneca, South Carolina, and the Town of Waynesville, North Carolina, are based on forecasts provided to Santee Cooper by each of these entities. If any of the customers does not provide a forecast, Santee Cooper uses an SAE approach to develop a forecast for that customer in a manner similar to the residential forecast developed for the direct-served residential customers. Santee Cooper has contracted to provide full requirements service to all of these customers except PMPA and AMEA. PMPA is a partial owner of Duke's Catawba nuclear unit, so Santee Cooper's service to PMPA includes only the portion in excess of their entitlement to that unit. AMEA receives the majority of its requirements from Southern Company, while Santee Cooper is obligated to supply up to 50 MW.

Municipal and Off-system customers are included in the load forecast through their contract termination date, at which point they are assumed to discontinue receiving service from Santee Cooper. If a contract with a wholesale customer has no termination date or includes an evergreen provision, Santee Cooper assumes the customer will continue to take service in perpetuity, similar to the assumption for industrial customers. The removal of Off-System customers from the forecast at their contract termination date leads to a substantial reduction in load over time, causing Municipal and Off-system Sales to shrink from 915 GWh and 220 MW (winter peak demand contribution) in 2023 to 213 GWh and 38 MW in 2041, which would represent about 1% of the total system load.

For the Low Case, beginning 2025, Santee Cooper removed the load of a customer with whom Santee Cooper has an evergreen agreement but recently issued a request for proposals for power supply, assuming that customer will select an alternative supplier.

[40] Ibid.

SANTEE COOPER SYSTEM FORECAST

The Combined System forecast synthesizes the results of each class forecast and indicates the total system energy and capacity requirements, reflecting that Santee Cooper peaks in the winter. Population growth in South Carolina, as well as a vibrant economy in energy-intensive fields, drive Santee Cooper's forecasted energy and peak demand requirements higher by a CAGR of approximately 0.5% annually over the twenty-year forecast horizon. Tables 2 and 3 present forecasted annual energy sales and winter peak demand for the system over 2023-2041, excluding transmission losses.[41]

Table 2. Forecasted System Energy Sales (GWh)

	Base Case						
Year	Distribution	Industrial	Central	Municipal & Off System	Total	High Case Total	Low Case Total
2023	4,209	6,434	16,141	915	27,699	31,247	24,231
2024	4,248	6,472	16,599	686	28,005	31,704	24,438
2025	4,282	6,531	16,506	605	27,924	31,751	24,113
2026	4,322	6,531	16,616	533	28,002	31,964	24,089
2027	4,367	6,531	16,735	447	28,080	32,178	24,060
2028	4,416	6,531	16,897	463	28,307	32,544	24,173
2029	4,469	6,531	16,989	214	28,203	32,573	23,953
2030	4,518	6,531	17,102	197	28,348	32,870	23,986
2031	4,569	6,531	17,142	199	28,441	33,124	23,965
2032	4,621	6,531	17,294	200	28,646	33,505	24,056
2033	4,674	6,531	17,356	201	28,762	33,809	24,065
2034	4,728	6,531	17,468	203	28,930	34,190	24,115
2035	4,784	6,531	17,584	204	29,103	34,593	24,163
2036	4,840	6,531	17,753	206	29,330	35,051	24,266
2037	4,898	6,531	17,837	207	29,473	35,427	24,285
2038	4,957	6,531	17,969	209	29,666	35,872	24,358
2039	5,017	6,531	18,108	210	29,866	36,325	24,436
2040	5,072	6,531	18,288	212	30,103	36,839	24,547
2041	5,151	6,531	18,397	213	30,292	37,277	24,603

[41] Values exclude transmission losses and are gross of future Santee Cooper DSM program impacts; Central forecast values reflect projections provided by Central that are net of expected impacts of their DSM programs.

Table 3. Forecasted System Peak Demand

Year	Base Case: Distribution	Base Case: Industrial	Base Case: Central	Base Case: Municipal & Off System	Base Case: Total	High Case Total	Low Case Total
2023	912	748	3,512	220	5,392	5,901	4,927
2024	918	759	3,592	174	5,443	5,986	4,952
2025	925	765	3,579	177	5,446	6,022	4,909
2026	932	765	3,608	159	5,465	6,073	4,903
2027	940	765	3,639	144	5,488	6,130	4,902
2028	947	765	3,674	148	5,534	6,211	4,923
2029	954	765	3,706	34	5,460	6,171	4,824
2030	962	765	3,734	34	5,495	6,242	4,834
2031	969	765	3,765	35	5,534	6,318	4,847
2032	976	765	3,794	35	5,571	6,394	4,860
2033	984	765	3,817	35	5,601	6,465	4,867
2034	992	765	3,843	35	5,636	6,542	4,878
2035	1,000	765	3,871	36	5,672	6,619	4,888
2036	1,008	765	3,904	36	5,713	6,704	4,905
2037	1,015	765	3,931	36	5,748	6,784	4,914
2038	1,023	765	3,962	37	5,787	6,873	4,930
2039	1,030	765	3,995	37	5,828	6,965	4,947
2040	1,039	765	4,029	37	5,871	7,065	4,967
2041	1,048	765	4,061	38	5,912	7,166	4,988

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. Santee Cooper's territorial peak demand for 2022 was 5,342 MW. As discussed further in the subsection titled Planning Reserve Requirements, Santee Cooper currently plans for a 15% summer reserve margin and a 12% winter reserve margin, the latter increasing incrementally to 17% by winter 2025/2026 (i.e., December 2025). Table 4 below details Santee Cooper's resource capacity classified by fuel type for both summer and winter peak power supply capability.

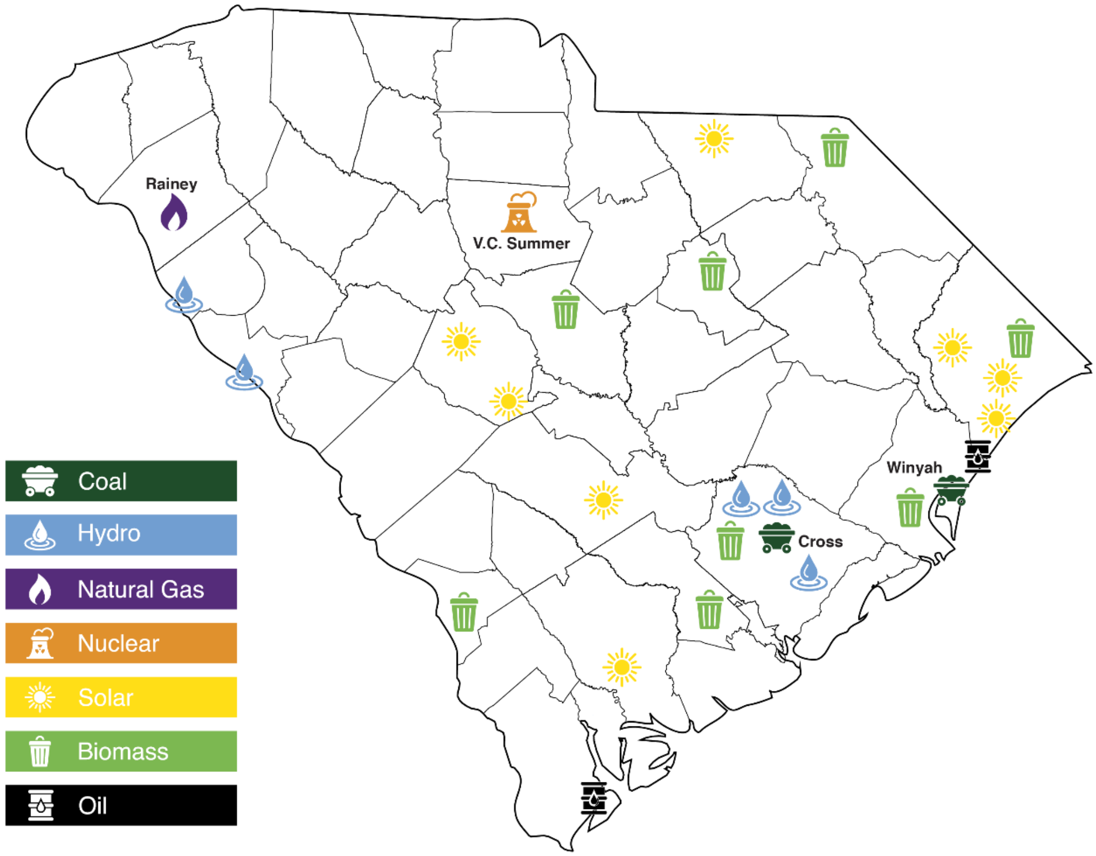
Table 4. Resource Capacity by Fuel Type

	Summer		Winter	
	(MW)	% of Total	(MW)	% of Total
Coal	3,460	61.6	3,480	60.5
Natural Gas and Oil	1,117	19.9	1,315	22.9
Long-Term Contracted Purchases	463	8.2	463	8.0
Nuclear	322	5.7	322	5.6
Owned Hydro Generation	142	2.5	142	2.5
Solar [(1)]	88	1.6	7	0.1
Landfill Methane Gas	26	0.5	26	0.5
Total	5,617	100.0	5,753	100.0

(1) Includes 5 MW of Santee Cooper's owned resources and 227 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.

Figure 6 below illustrates the locations of Santee Cooper's generating resources, including owned and contracted resources in South Carolina.

Figure 6. Locations of Santee Cooper Generating Resources



While Santee Cooper is currently not subject to a renewable portfolio standard, Santee Cooper, through its Distributed Generation Rider, purchases excess power produced by retail customers who install solar systems on their homes or businesses. Santee Cooper also encourages renewable energy adoption in its service area through Solar Share, its Community Solar program, in which Santee Cooper contracts with customers to provide them a portion of the output from an existing solar power purchase agreement. This program allows customers to participate in solar generation even if they choose not to install solar systems on their homes or businesses.

Information regarding Santee Cooper's generating facilities is provided in Table 5 below.

Table 5. 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
Combustion Turbines Nos. 1 and 2	Myrtle Beach	1962	20	16	Oil/Gas
Combustion Turbines Nos. 3 and 4 (1)	Myrtle Beach	1972	20	19	Oil
Combustion Turbine No. 5	Myrtle Beach	1976	25	21	Oil
Combustion Turbine No. 1	Hilton Head Island	1973	20	16	Oil
Combustion Turbine No. 2	Hilton Head Island	1974	20	16	Oil
Combustion Turbine No. 3	Hilton Head Island	1979	60	52	Oil
Winyah Generating Station (2)	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 (3, 4)	Jenkinsville	1983	322	322	Nuclear
Cross Generating Station	Cross				
Unit 1		1995	585	580	Coal
Unit 2		1983	570	565	Coal
Unit 3		2007	580	580	Coal
Unit 4		2008	595	605	Coal
Horry Landfill Gas Station	Conway	2001	3	3	LMG (5)
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
Solar (6)	Various	2006-19	5	5	Solar
Total Capability			5,290	5,072	

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

ENVIRONMENTAL COMPLIANCE

Both the Environmental Protection Agency ("EPA") and the Department of Health and Environmental Control ("DHEC") have imposed various environmental regulations and permitting requirements affecting Santee Cooper's generating facilities. These regulations and requirements relate primarily to airborne pollution, the discharge of pollutants into waters and the disposal of solid and hazardous wastes, although the addition of new facilities and other projects and operations can also bring about impacts associated with land disturbance, wetlands, wildlife, and threatened and endangered species regulations. Santee Cooper closely monitors these regulatory requirements and considers compliance costs associated with existing regulations in the development of its Integrated Resource Plans.

GREENHOUSE GAS REGULATION

Emission stacks at Winyah Generating Station, located in Georgetown County, SC

Santee Cooper continues to review proposed greenhouse gas regulations and legislation to assess potential impacts to its operations. The latest Final Rule addressing Greenhouse Gas Regulation was issued by the EPA on June 24, 2019, the final Affordable Clean Energy ("ACE") Rule, which replaced the Clean Power Plan ("CPP"). The ACE Rule was subsequently vacated and remanded by the D.C. Circuit Court of Appeals on January 19, 2021. On October 29, 2021, the U.S. Supreme Court granted a request for certiorari to review the D.C. Court of Appeals January 19, 2021, decision. On June 30, 2022, the U.S. Supreme Court issued a landmark decision in West Virginia vs. EPA, which reversed the DC Circuit and held that Congress did not give the EPA authority under the Clean Air Act ("CAA") to regulate CO_2 emissions based on generation shifting (outside the fence). The EPA will be issuing a proposed rulemaking package that will include the following regulatory actions.

- Repeal of the ACE rule
- Establishment of CO_2 performance standards for existing coal-fired and new and existing natural gas-fired EGUs

This rulemaking package is expected to be issued by mid-May 2023. Santee Cooper is closely following this development. As draft and final rules become available, their impacts on Santee Cooper's system and resource plan will be evaluated and appropriate changes incorporated in future IRPs and IRP updates.

The 2023 IRP evaluated several sensitivities that considered the impact of carbon regulation on Santee Cooper's generation fleet and potential new resources, based upon the Social Cost of Carbon developed by the Interagency Working Group on Social Cost of Greenhouse Gases in February 2021 (see the subsection titled Carbon Emissions Pricing in the section titled Major Modeling Assumptions).

STEAM ELECTRIC EFFLUENT LIMITATIONS GUIDELINES RULE

The Clean Water Act ("CWA") prohibits the discharge of pollutants, including heat, from point sources into waters of the United States, except as authorized in the National Pollutant Discharge Elimination System ("NPDES") permit program. A revision to the NPDES Steam Electric Effluent Limitation Guidelines ("ELG") rule became effective on January 4, 2016, followed by another rule published on October 13, 2020. These revised ELG rules included stricter performance standards that required upgrades and installation of additional wastewater treatment systems for the Winyah and Cross Generating Stations. The 2020 rule established several new subcategories for compliance. The standard best available technology ("BAT") compliance option requires compliance by 12/31/2025, and Santee Cooper has been planning to pursue this option at Cross. Another compliance subcategory is to elect to retire the impacted units no later than 12/31/2028, which is the option Santee Cooper had initially pursued for Winyah. Santee Cooper has since, with support from Central, elected to begin work to install equipment necessary for the standard BAT compliance option at Winyah. This would provide the Combined System with a valuable resource option to meet the State's growing electricity needs and allows Santee Cooper the ability to align its schedule with a potential joint resource development with DESC. It significantly mitigates risks associated with the time required to permit and construct new generating resources to replace Winyah. As this capital cost will be incurred in the near term, it is treated similarly in all portfolios and, as a result does not impact differences in net present value costs among the portfolios studied. However, O&M cost estimates associated with the upgraded wastewater treatment facilities are included in evaluating a Winyah retirement extension for the relevant extension period.

It should be noted that, while the current rule remains in force at this time, the EPA announced a new proposed rule on March 8, 2023, which was published in the Federal Register on March 29, 2023. The proposed rule, should it become final, would mandate zero liquid discharge of flue-gas desulfurization wastewater by December 31, 2029, and would be more expensive than the biological treatment technology that formed the basis of the 2020 rule's BAT compliance targets. Santee Cooper is evaluating its path forward given the uncertainty posed by EPA's decision to propose a new rule while stating that the 2020 rule remains in place. Given the uncertainty surrounding this developing regulation, Santee Cooper has not made any assumptions about the content of a new rule in this IRP.

PERFORMANCE OF CURRENT GENERATING ASSETS

Santee Cooper's generation portfolio includes a variety of coal, natural gas, nuclear, hydro, biomass, landfill and solar generating units (both wholly owned and representing ownership interests). Maintaining optimum performance and reliability is of utmost importance to Santee Cooper, and Santee Cooper continues to invest in its generation resources through capital replacements, major component maintenance, efficiency improvement projects, and control system upgrades to achieve low-cost, reliable power over the long term. As a result of these investments, along with the efforts of a talented and engaged team, Santee Cooper maintains a high

Cross Generating Station, located in Berkeley County, SC level of reliability for its fleet of generators. Santee Cooper's weighted equivalent forced outage rate ("WEFOR")[42] for its largest assets (Cross, Winyah, and Rainey) averaged 4.9% over the five-year period 2017-2021, which was 32% lower than the industry average[43] of 7.3%.

Table 6 and Table 7 below provide recent historical availability and forced outage statistics, respectively, for Santee Cooper's major generating units.

Table 6. Santee Cooper Generator Availability Factors

Generating Unit(s)	2020	2021	2022
Cross	97%	80%	81%
Winyah	87%	72%	91%
Rainey CC	91%	89%	90%
Rainey CT	96%	95%	98%
VC Summer [1]	91%	83%	99%

[1] Reflects refueling outages in spring 2020 and fall 2021 and a 26-day unscheduled outage to replace a failed step-up transformer in 2021.

Table 7. Santee Cooper Generator Forced Outage Rates

Generating Unit(s)	2020	2021	2022
Cross	1.2%	3.9%	3.6%
Winyah	3.9%	3.8%	3.1%
Rainey CC	0.1%	0.2%	0.1%
Rainey CT	1.3%	0.7%	0.1%
VC Summer	0.7%	8.4%	0.0%

SYSTEM RELIABILITY

System reliability is essential to the core mission and responsibilities of Santee Cooper. Santee Cooper continually works to maintain and improve its system, including its generation, transmission, and distribution assets. Reliability for the Santee Cooper distribution system as measured by the System Average Interruption Duration Index ("SAIDI") was 23.7 minutes in 2022. Using data reported to and compiled annually by the U.S. Energy Information Administration ("EIA"), Santee Cooper's reliability ranks in the top 2% nationally compared to investor-owned utilities ("IOU") and Cooperatives.[44] The top tier distribution rating demonstrates our commitment and ability to deliver the reliable service our customers require and expect.

---

[42] WEFOR reflects a weighted average of forced outage rates based on the capacity of the generating units in question.

[43] Industry Average WEFOR Source: NERC 2022 GADS State of Reliability Report.

[44] Based on 2021 data reported by electric utilities to the EIA on Form EIA-861 and compiled by the EIA, available at www.eia.gov. The comparison is made to IOUs and cooperatives as these types of utilities have service areas most similar to Santee Cooper.

Santee Cooper works to identify both potential risks and mitigation projects for its electric system assets. Severe weather or natural disasters, such as hurricanes, tropical storms, winter storms, floods, wildfires, or earthquakes, can adversely affect Santee Cooper's operations. These events can cause physical property damage or otherwise impede Santee Cooper's ability to generate, transmit, and/or distribute power.

The severe winter storm that impacted much of the continental United States in February of 2021 (the "Winter Storm Uri") is an example of a recent weather event that resulted in substantial impacts on utilities and their customers, especially within the state of Texas, and on other utilities within the Midwest and South-Central states that were affected by abnormally high natural gas prices. Santee Cooper, as a Generator Owner, Generator Operator, and a Balancing Authority under the NERC Reliability Functional Model, developed cold weather preparedness plans in accordance with three revised NERC Reliability Standards that became effective on April 1, 2023. The purpose of these standards is to enhance the reliability of the Bulk Electric System during cold weather events by ensuring registered entities prepare for extreme cold weather conditions.

Following Winter Storm Uri, the Governor of South Carolina requested that the South Carolina Office of Regulatory Staff ("ORS") "undertake a comprehensive review of the State's public and private power grid to evaluate its ability to withstand potential ice storms and other dangerous winter weather conditions." On December 31, 2021, the ORS submitted its Final Report to the Commission on this matter. The Final Report concluded that the South Carolina energy system and utility providers are adequately prepared to prevent and respond to outages caused by ice storms and winter weather events. However, the Final Report recommended that a number of actions be considered by utility providers to enhance their ability to respond to extreme winter weather events and to meet peak customer demand. In furtherance of the Final Report, on August 31, 2022, the ORS created the South Carolina Winter Storm Task Force, the objectives of which are to (i) review winter weatherization standards and incorporate those expected to enhance the reliability and resiliency of the electric and gas systems in the state, (ii) adopt the current codes and industry best practices for hardening for greater storm resiliency, and (iii) establish a voluntary, self-sustaining task force. Santee Cooper is a participant in this Task Force.

More recently, in December 2022, Winter Storm Elliott brought extremely cold conditions during the period surrounding the Christmas weekend to South Carolina and the entire Southeast. In the week leading up to Christmas, Santee Cooper forecasted increasing system load as temperature forecasts continued to drop, and load was projected to peak Christmas Eve morning. Santee Cooper undertook several proactive measures to prepare for the peak load event.

Through Friday night and into Christmas Eve morning, load increased, as forecasted, as Winter Storm Elliott moved into the state. Due to various resource availability issues, Santee Cooper had to initiate measures to stabilize the system.

Santee Cooper is undergoing additional review of the events around Winter Storm Elliott to further detail causes and identify mitigations.

Through its planning and the evaluations in this IRP, Santee Cooper works to ensure system reliability is maintained in a cost-effective manner for its customers. The portfolios identified in this

IRP meet reliability standards for the target reserve margin and satisfy shared regional contingency reserves for spinning and quick-start operating reserves.

POWER PURCHASE AGREEMENTS

Santee Cooper has entered various power purchase arrangements for capacity and energy needs.

Santee Cooper presently receives 84 MW of firm hydroelectric power from the U.S. Army Corps of Engineers and 305 MW of firm hydroelectric power from SEPA. The SEPA allocation consists of 154 MW for wheeling to the SEPA preference customers served by Santee Cooper (including Central) and 151 MW purchased directly by Santee Cooper for its customers. Santee Cooper's contract with SEPA is subject to termination only after Santee Cooper delivers a written termination notice to SEPA at least twenty-five (25) months prior to the termination date, or SEPA delivers a written termination notice to Santee Cooper at least twenty-four (24) months prior to the termination date.

Santee Cooper also receives 74 MW of biomass capacity and associated energy under three power purchase agreements—the first commenced in September 2010 and the most recent in November 2013, with varying terms from 15 to 30 years. There is also an agreement to purchase the output from a 2.5 MW solar facility that started producing power in December of 2013, with a 20-year term. Santee Cooper has entered into four solar PPAs totaling 280 MW, each for five-year terms, under Section 210 of the Public Utilities Regulatory Policies Act of 1978 ("PURPA").[45] Three projects associated with these agreements, each having a nameplate capacity of 75 MW, have reached commercial operation. A fourth project is expected to achieve commercial operation by Q3 2023. In addition, in 2020, Santee Cooper and Central conducted a competitive procurement process for solar resources to be contracted for through PPAs. The results and status of this process are discussed in the section titled Pre-Act 90 Competitive Procurement Process, and resulting purchases are not included in the tables below.

Table 8 below, lists existing power purchases made by Santee Cooper and Central, including information on the type of resource, purchase term, nameplate capacity rating, and winter firm capacity rating.

[45] 16 U.S. Code § 824a–3

Table 8. Power Purchase Agreements

Generating Facilities	Term End Date/Year	Nameplate Capacity (MW)	Winter Capacity (MW)	Energy Source
Long-term Contracts				
Domtar [(1)]	2025	38	38	Biomass
EDF Renewables	2043	36	36	Biomass
Southeastern Power Administration (SEPA)	Indefinite	305	305	Hydro
St. Stephen Hydro [(2)]	2035	84	84	Hydro
Total Long-term Contracts		463	463	
Solar Power Purchase Agreements [(3)]	2025-2033	227	7	Solar
Total PPAs [(4)]		690	469	

(1) Domtar PPA can be extended beyond 2025 with notice.
(2) Santee Cooper anticipates taking ownership of St. Stephens by 2035.
(3) Winter firm capacity based on the effective load carrying capability study discussed herein.
(4) Totals may not add due to rounding.

SOUTHEAST ENERGY EXCHANGE MARKET

On November 9, 2022, Santee Cooper and twelve other utilities (collectively, “SEEM Members”) began trading energy in the Southeast Energy Exchange Market (“SEEM”). SEEM is considered an energy-only market and does not impact resource planning from a capacity or reserves perspective. SEEM provides an automated, intra-hour trading platform allowing members to buy and sell energy in 15-minute blocks. Transactions utilize excess transmission capacity, at zero cost other than losses. The SEEM Members collectively own approximately 160,000 MW of generating capacity and serve about 640 terawatt hours of energy across ten balancing authority areas and two time zones. Transactions are priced at the midpoint between the offer and bid price, creating value for customers on both sides of the transaction. Santee Cooper is taking a methodical and careful approach to entering this new market by continuously analyzing system conditions to take full advantage of each 15-min trade interval.

NUCLEAR RELICENSING

In 2004, the Nuclear Regulatory Commission (“NRC”) extended the operating license for Summer Nuclear Unit 1 an additional twenty years to August 6, 2042. On December 16, 2021, Dominion filed an “Intent to Pursue License Renewal” notification to the NRC on behalf of itself and Santee Cooper to extend the operating license from August 2042 to August 2062. Dominion anticipates submitting the license application to the NRC by the fourth quarter of 2023.

FERC HYDRO RELICENSING


Jefferies Hydroelectric Station, located in Berkeley County, SC

Santee Cooper operates Jefferies Hydroelectric Station and certain other property, including the Pinopolis Dam on the Cooper River and the Santee Dam and hydroelectric facility on the Santee River under a license issued by the Federal Energy Regulatory Commission ("FERC") pursuant to the Federal Power Act ("FPA"). The FERC license includes oversight of project activities such as Dams and Dikes Maintenance, Shoreline Management, Forestry Management, Water Quality Monitoring, Aquatic Plant Management, and Endangered Species Protection within the Project Action Area. These activities are conducted in cooperation and partnership with DHEC, the South Carolina Department of Natural Resources, the U.S. Fish and Wildlife Service, the National Marine Fisheries Service, and the United States Army Corps of Engineers.

The Santee Cooper Hydroelectric Project was issued a new 50-year FERC license for continued operation on January 20, 2023, ensuring that Santee Cooper's existing hydroelectric generation resources will continue to be available for the foreseeable future. New compliance obligations include implementation of increased minimum flows into the Santee River, enhanced fish passage facilities, and a number of other environmentally focused measures, all of which Santee Cooper is prepared to complete in accordance with the terms of the license.

PLANNED RETIREMENTS

Santee Cooper announced the planned retirement of Winyah in the late 2020s in Santee Cooper's 2019 Reform Plan. Retirement of coal capacity, in conjuction with other components of the plan, which included substantially more solar and addition of a flexible natural gas resource, would substantially improve the carbon footprint and diversity of Santee Cooper's generation resources.

While Santee Cooper continues to pursue retirement of Winyah, it was decided, with support from Central, to upgrade the station to comply with the Best Available Technology by the end of 2025 as defined in the 2020 Effluent Limitation Guidelines ("ELG") Rule. There are uncertainties around permitting timelines for new resources, as well as the potential for significant new loads on the Combined System. Upgrading Winyah to comply with the BAT under the 2020 ELG Rule retains the option to delay the retirement if in the best interest of Santee Cooper's customers.

Power block at Winyah Generating Station

A draft revised ELG rule was issued in March 2023, with comments requested by May 30, 2023. Santee Cooper is closely following the development of revisions to the ELG Rule and its impact on this decision.

For purposes of the 2023 IRP, the combustion turbines units 1-5 at Myrtle Beach and units 1-3 at Hilton Head are assumed to retire at the end of 2033. Santee Cooper intends to conduct an evaluation of these units, including any transmission impacts, before making final determination to retire the units, in collaboration with Central.

ENVIRONMENTAL JUSTICE AND SUSTAINABILITY

Santee Cooper is committed to sustainability in its operations and in the communities in which it operates. Those sustainability efforts include environmental justice initiatives focused on the communities impacted by Santee Cooper's transition to cleaner energy sources.

To support its enterprise-wide sustainability efforts, Santee Cooper established the position of Director of Sustainability in late 2022. This position is responsible for Santee Cooper's broad sustainability initiatives as well as leading the company's community transition efforts in the Georgetown area in conjunction with the planned retirement of Winyah.

Santee Cooper's Sustainability group is currently engaged in meaningful dialogue with individual stakeholders and stakeholder groups impacted by the retirement of Winyah to identify a third-party facilitator to assist with its community transition efforts. Direct stakeholder input was used to create a request for information through which Santee Cooper and stakeholders educated themselves on methodologies and best practices for community transition programs. Based on the request for information responses and additional feedback from stakeholders a request for proposals is being formulated and Santee Cooper expects to retain a facilitator by the end of 2023.

It is Santee Cooper's position that an open and interactive process like that being undertaken in conjunction with the retirement of Winyah provides an opportunity for the fair treatment and meaningful involvement of people of all races, cultures, and income levels. The Winyah/Georgetown community transition process creates a model Santee Cooper intends to revise and refine for use not only in the retirement of projects but in the construction of new projects.

PLANNING RESERVE REQUIREMENTS

The planning reserve margin ("PRM") of a system represents the amount of additional firm capacity above forecasted peak load that a system would need in order to maintain an acceptable level of system reliability. Santee Cooper retained Astrapé Consulting to perform a PRM study, detailed in the report included in Attachment 1, titled Reserve Margin and Effective Load Carrying Capability Study, filed with this IRP. In this study, PRM estimates were developed through iterative simulations of the Santee Cooper system to determine the amount of capacity that would be necessary to maintain a Loss of Load Expectation ("LOLE") of 0.1 days per year. This level of reliability corresponds to an expectation of one loss of load event every 10 years, which is consistent with standard industry practice.

The base case PRM for the Santee Cooper system was performed for two different study years, 2026 and 2029, assuming availability of market purchases. The 2026 study year represents the near-term condition of the Santee Cooper system, while the 2029 study year corresponds with the retirement and subsequent replacement of the Winyah coal-fired generating facility. In addition to the base case analyses, several sensitivities were evaluated to test the robustness of the base case results. See Attachment 1 for more information.

The 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% was appropriate to ensure the target reliability levels. Based on these results, Santee Cooper has set its minimum winter PRM requirement at 17%. The study also concluded that a summer reserve margin requirement should be considered a secondary requirement and that a summer reserve margin requirement in the 14-16% range is appropriate. Santee Cooper has therefore set its summer PRM requirement at 15%.

Prior to conducting the recent reserve margin study, Santee Cooper utilized a winter and summer PRM of 12% and 15%, respectively. Hence, updating the winter PRM reflects a significant increase in the winter reserve margin. Santee Cooper will phase into this higher requirement, until it reaches the target 17% requirement by 2026.

Santee Cooper intends to reassess PRM requirements periodically and plans to conduct another reserve margin study no later than its next triennial IRP filling in 2026.

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. In conjunction with the PRM study, Astrapé Consulting also performed an analysis of the ELCC of solar and battery energy storage systems ("BESS"), detailed in the same report from Astrapé included with this filing. 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.

The tables below show the winter and summer ELCCs that were determined as part of this analysis.[46] Rows or columns showing a singular ELCC provide the ELCC values across a range of capacity for utility-scale solar or BESS resources in isolation. Where two ELCCs are shown, the BESS ELCC precedes that for solar. Hence, as shown in Table 9, at 2,000 MW of solar and 400 MW of BESS resources, BESS and solar resources are estimated to have winter peak ELCCs of 91.5% and 2.0%, respectively.

Table 9. Winter Peak Effective Load Carrying Capability of Solar and BESS

BESS Capacity (MW)	Solar Capacity (MW)				
	0	1,000	1,250	1,500	2,000
0		2.9%	2.8%	2.4%	1.9%
200	100%			100%, 3%	
400	88.8%				91.5%, 2.0%

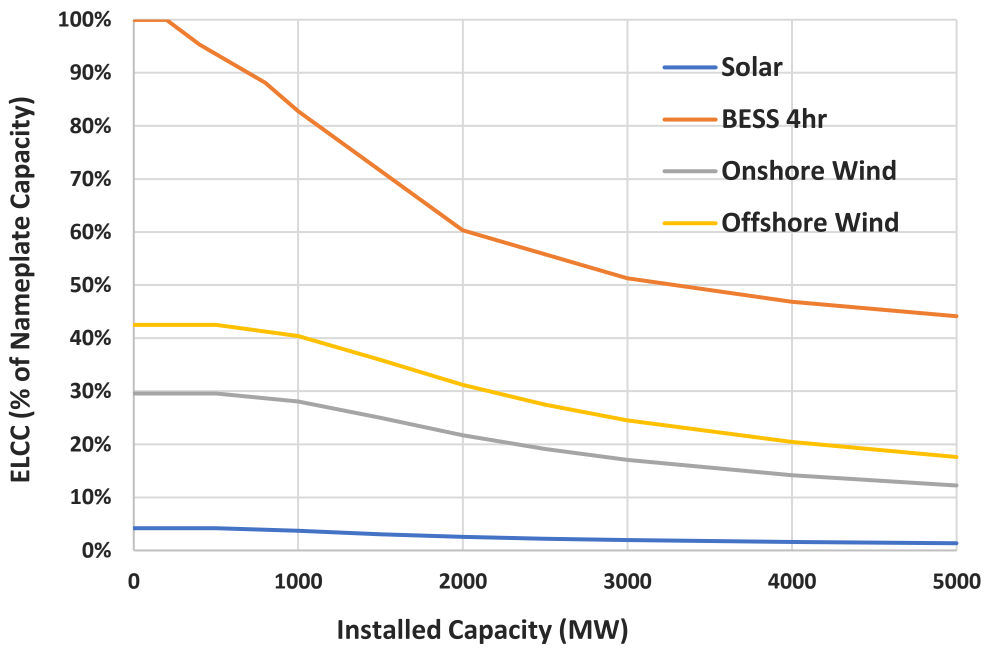
Table 10. Summer Peak Effective Load Carrying Capability of Solar and BESS

BESS Capacity (MW)	Solar Capacity (MW)				
	0	1,000	1,250	1,500	2,000
0		37.7%	35.0%	31.5%	25.5%
200	100%			100%, 32%	
400	93%				96%, 26%

For this IRP, Santee Cooper has evaluated the implementation of solar and BESS resources that exceed the implementation levels analyzed within the Astrapé ELCC analysis. To develop estimates for ELCC beyond the level modeled by Astrapé, Santee Cooper reviewed a recent ELCC analysis prepared by Astrapé for DEP that considered higher levels of solar and BESS implementation. Santee Cooper applied the ELCC estimates contained in the DEP study, relative to the peak demand of the DEP system, to extrapolate the ELCC values prepared for the Santee Cooper system. For wind resources, ELCC values were derived from the same DEP ELCC study prepared by Astrapé. Figure 7 provides the winter peak ELCC values assumed for the IRP for solar, BESS, and onshore and offshore wind resources.

[46] The ELCC studied 4-hour BESS resources only. ELCC of 8-hour BESS resources was approximated from the results for 4-hour BESS resources. ELCC values beyond these capacity ranges were extrapolated from these results.

Figure 7. Cumulative Winter Peak Effective Load Carrying Capability



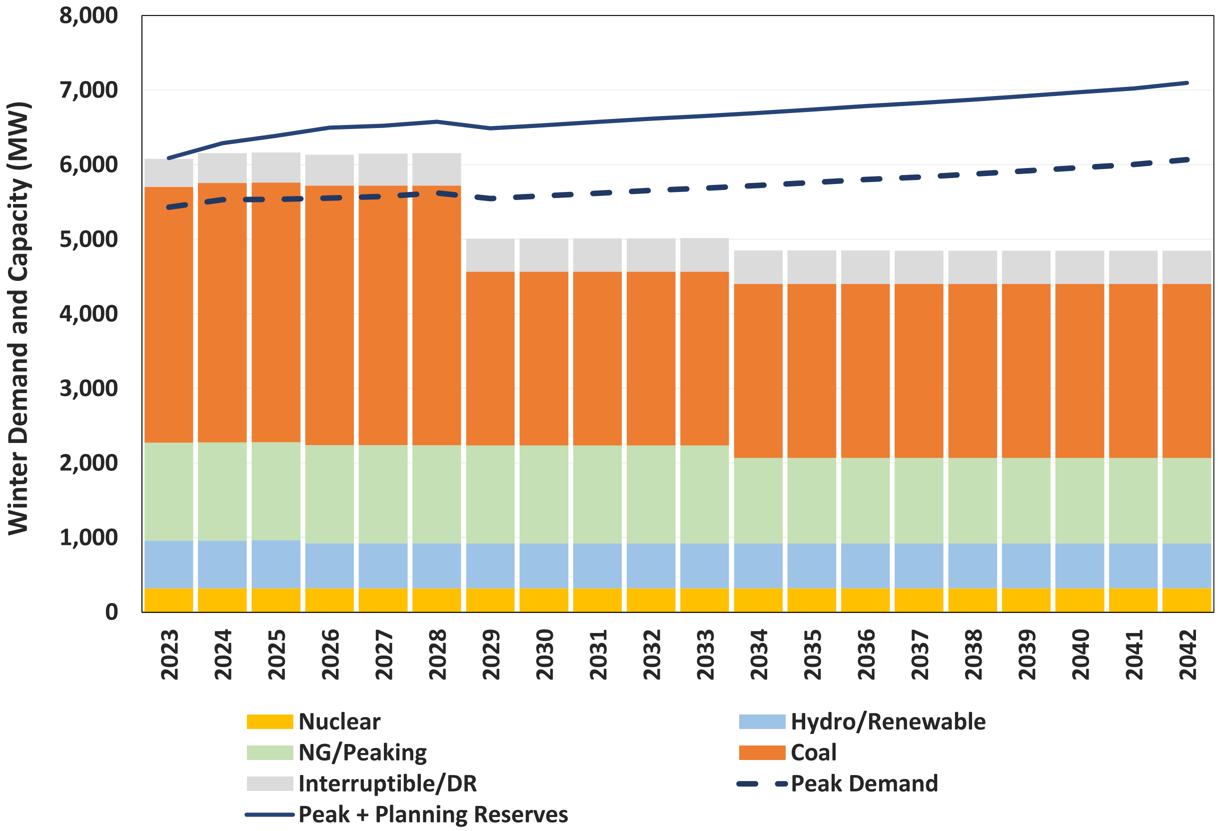
OPERATING RESERVE REQUIREMENTS

Operating reserves are reserves that a utility maintains on a real-time basis to ensure system reliability. Santee Cooper is part of the Carolinas Reserve Sharing Group ("CRSG") along with DEC, DEP, and DESC. These entities agree to pool operating reserves in the total amount of 1.2 times the Most Severe Single Contingency ("MSSC") on any member's system or 1.5 times the second MSSC on any other member's system, whichever is greater. Contingency reserves are recalculated annually or when there is a material change to the MSSC. 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. Currently, Santee Cooper is required to carry 212 MW of contingency reserves as part of the CRSG agreement.

SUPPLY AND DEMAND BALANCE

Combining projections from the Load Forecast, existing owned and contracted resource capabilities, 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 8 below. Supply resources reflected below include only existing owned and purchased resources. Under Base Case projections, some additional capacity resources are needed over 2023 through 2028. Santee Cooper has released an RFP for capacity resources to address this near-term shortfall under Base Case projections and potentially higher near-term load growth arising from inquiries by specific large industrial prospects. A much larger capacity need is triggered by the retirement of Winyah, respectively, at which time the Santee Cooper system is expected to require approximately 1,500 MW of new resources to reliably serve the winter peak, under the Medium Case projections.

Figure 8. Projected Supply v. Demand Balance (Base Case)



DEMAND-SIDE MANAGEMENT OVERVIEW

DSM is an important component of the services that Santee Cooper and Central Members provide to their customers and an important component of Santee Cooper's IRP. DSM focuses on reducing electricity demand and consumption through the development of incentive programs offered to retail customers to improve the efficiency of their end uses or otherwise affect their energy consumption.

SANTEE COOPER PROGRAMS

Santee Cooper's DSM offerings are broken down into Energy Efficiency ("EE") and Demand Response ("DR") programs. EE programs are primarily designed to achieve reductions in energy consumption, while DR programs are primarily designed to reduce system demand during peak periods. This section provides background on Santee Cooper's existing and planned DSM programs, as well as a summary of the EE and DR Market Potential Studies, developed by Resource Innovations, Inc. ("RI"), which have been included with the IRP filing as attachments.

EXISTING PROGRAMS

Santee Cooper has been providing DSM programs to its retail customers since the early '80s. In 2009, a new portfolio of EE programs was launched for Santee Cooper's residential and commercial customers.

In 2019, Santee Cooper refreshed and rebranded the existing portfolio of DSM programs and created "EmpowerSC." EmpowerSC was designed to brand DSM as well as other customer-facing programs at Santee Cooper. In 2022, Santee Cooper launched a DR switch program which also fell under the EmpowerSC brand. This program allows Santee Cooper to activate a switch on a customer's all-electric HVAC and/or electric water heater to cycle usage during periods of high demand.

EmpowerSC includes three umbrellas of DSM programs. Table 11 below provides a listing of the categories of measures included in each of these program umbrellas. Additional information about the individual DSM measures under each umbrella can be found in Appendix B.

Table 11. Current Demand-side Management Program Measures

Umbrella Program in EmpowerSC	Categories of Measures Included in Programs
EmpowerHome for Residential EE empower HOME	- HVAC - Whole Home Duct Replacement - Smart Thermostats - Heat Pump Water Heaters - Energy Efficient Pool Measures - ENERGY STAR Appliances - Lighting - Home Energy Rating System ("HERS") Scores

Umbrella Program in EmpowerSC	Categories of Measures Included in Programs
EmpowerBusiness for Commercial EE	- Lighting - HVAC - Smart Thermostats - Refrigeration - Kitchen Equipment - Domestic Hot Water - Pumps/Motors
SmartRewards for Residential DR	- HVAC Switches - Water Heater Switches - Combo (HVAC + Water Heater) Switches

In addition, Santee Cooper has installed a Conservation Voltage Reduction ("CVR") application, which allows for the reduction of distribution system peak demand through controlled reduction of voltage across the distribution system. The CVR application and the associated supervisory control and data acquisition ("SCADA"), regulator controls, and metering upgrades have been in operation since 2020 in the Horry, Georgetown, and Berkeley areas. There are a total of 270 feeders that are capable of running CVR. Of those, 254 are routinely utilized when CVR is required. When CVR is initiated, SCADA will direct the substation regulators to lower the feeder voltage until the end-of-line meters reach the lower end of the American National Standard Institute ("ANSI") required range. If voltage starts to drift too close to the lower limit, SCADA directs the regulators to increase the voltage. Voltage delivered to service points must fall within an acceptable ANSI range, and the voltage regulation application configures the system to deliver the lowest possible voltage while staying within that range. This operational efficiency results in an overall reduction of electric demand. Results from Santee Cooper's CVR pilot study support an expected demand reduction on the order of 2% of our distribution system's peak load, or between 15 MW and 19.5 MW on a typical monthly peak. These anticipated reductions are not reflected in the forecast of Santee Cooper's retail loads being utilized for the 2023 IRP and are instead reflected within the demand response capability shown as a supply-side resource.

MARKET POTENTIAL STUDIES

In 2022, Santee Cooper retained RI to conduct comprehensive EE and DR market potential studies ("MPS"). RI has significant expertise in conducting similar studies for utilities across the country, including recent potential studies for several Southeast utilities.

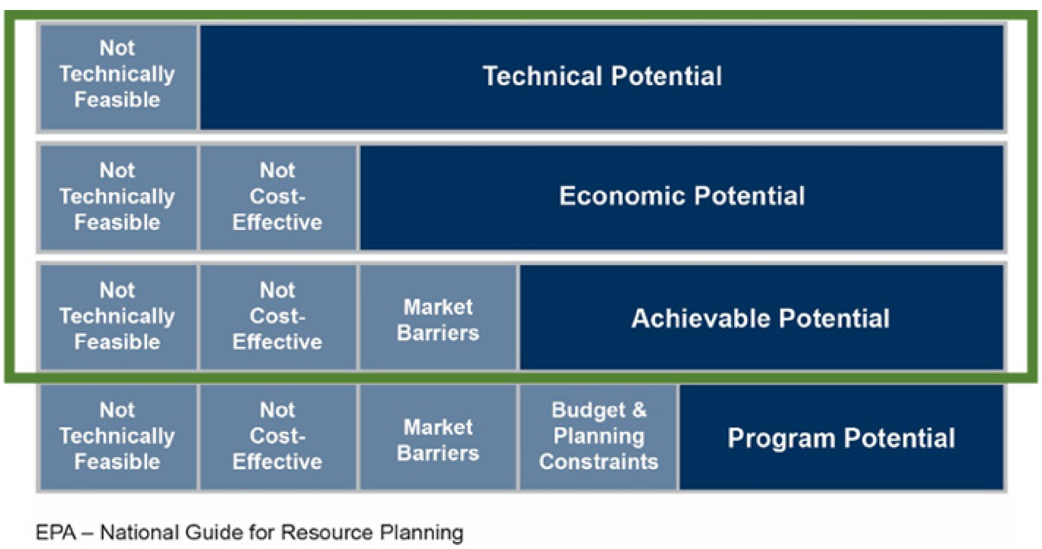
ENERGY EFFICIENCY MARKET POTENTIAL STUDY

The objective for the EE MPS was to determine the maximum amount of energy and demand savings from EE measures that are achievable over the next twenty years. The 2022 Demand Side Management Market Potential Study ("EE MPS"), dated February 2023 and filed with this IRP in Attachment 4, provides estimates of technical, economic, and achievable potential for EE savings among Santee Cooper's residential and commercial customers. Definitions of each type of potential are as follows.

- Technical potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- Economic potential is the amount of energy and capacity that could be reduced by efficiency measures that are considered cost-effective. This study used the Utility Cost Test ("UCT") perspective, which includes cost and benefits from the viewpoint of the utility. The UCT is calculated by dividing Santee Cooper's avoided supply cost by the estimated EE program costs (including administrative and customer acquisition costs).
- Achievable potential is the energy savings that can feasibly be achieved through program and policy interventions.
- Program potential reflects the application of utility program spending, the estimated impacts of incentives, and resulting customer response to specific EE program offerings.

Figure 9 provides an illustration of this progression of EE potential.

Figure 9. Demand-side Management Potential Categories



In the EE MPS, RI focused on estimates of achievable potential for 2023-2042 based on the following three scenarios.

- **Low Case**. The low scenario is based on Santee Cooper's current program incentives (ranging from 25% to 30% of incremental cost of the energy efficient measure) and current program administration and outreach costs, expressed in terms of dollar per annual kWh saved. Measures were screened from the UCT perspective, with a threshold of 1.0.

- **Medium Case**. The medium scenario increased incentives offered up to 50% of incremental measure costs and reduces the benefit-cost screening threshold for each measure to a UCT value of 0.7. This approach allows some marginally cost-effective measures to be included in the portfolio and potentially boosts savings while maintaining an overall portfolio that is cost-effective from the UCT perspective, when balancing some marginal measures with those that are more cost effective.
- **High Case**. The high scenario increases incentives to 75% of the incremental measure costs to boost participation, and the avoided marginal energy costs were increased by 50% to accommodate for higher fuel, environmental cost adders, etc. The benefit-cost screening threshold was held to a UCT value of 0.7 for this scenario also.

Figure 10. EE Annual Incremental Energy Savings (5-yr, 10-yr, 20-yr)

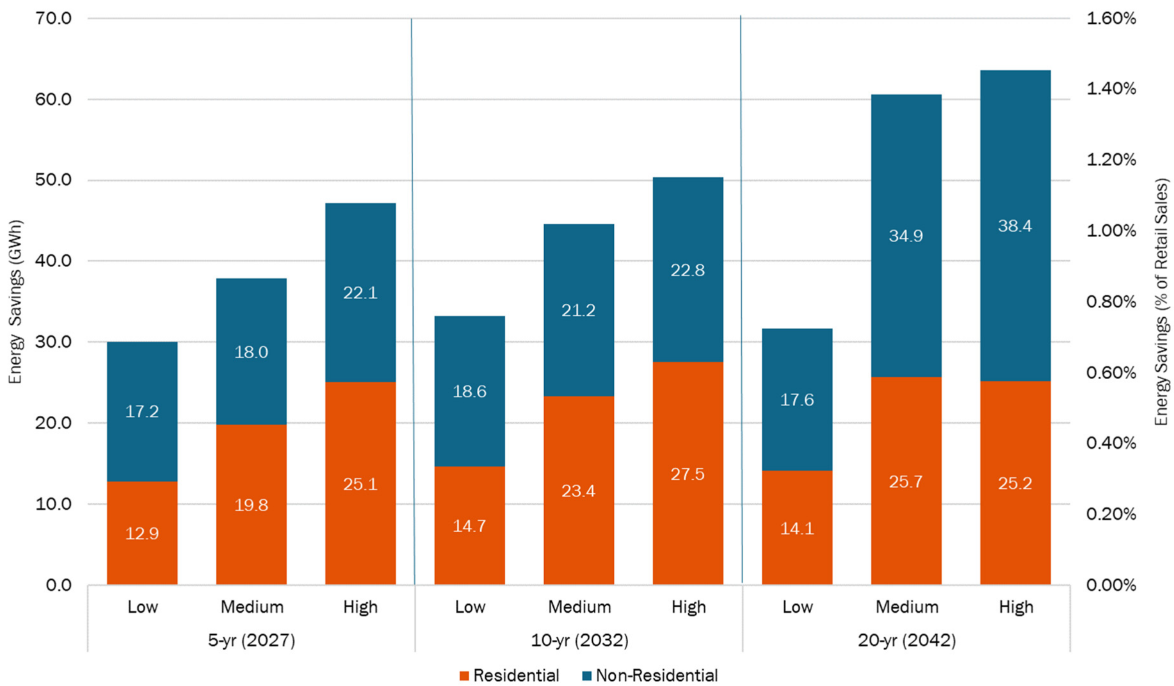
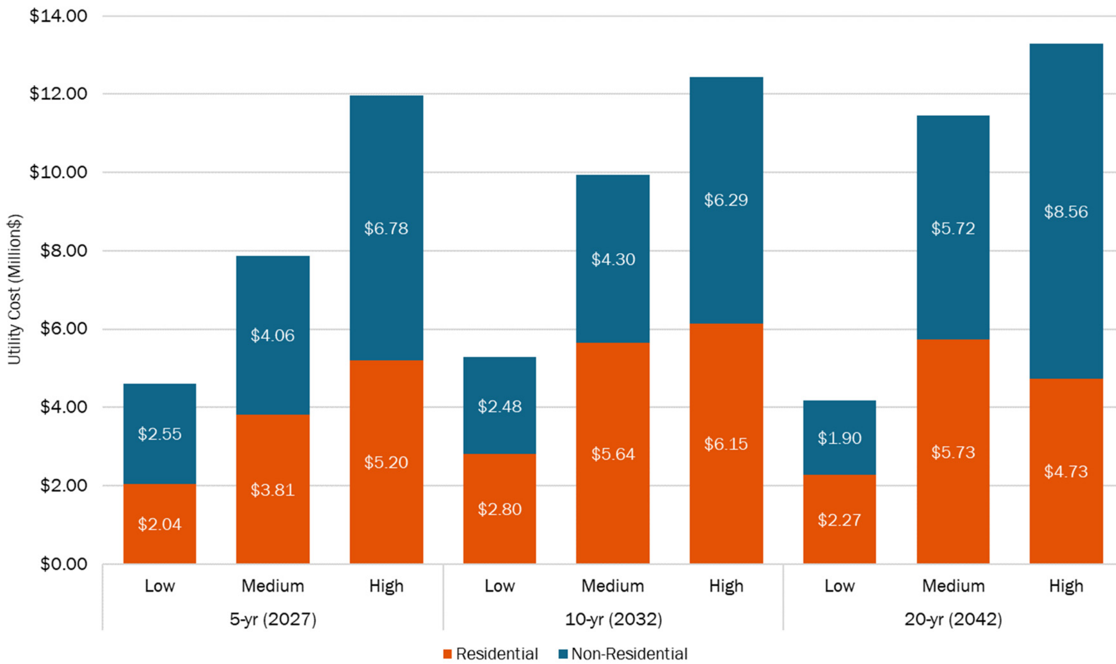


Figure 11. EE Annual Incremental Utility Costs (5-yr, 10-yr, 20-yr)



DEMAND RESPONSE MARKET POTENTIAL STUDY

The objective of the DR Market Potential Study ("DR MPS") is much the same as the EE MPS but is focused on developing estimates of technical, economic, and achievable potential for Santee Cooper's residential and commercial customers temporarily curtailing or shifting portions of their demand to off-peak times to reduce peak demand on the Santee Cooper system. The DR MPS is dated March 2023 and filed with this IRP as Attachment 4.

For the peak demand forecast, RI established a baseline forecast of what loads or operational requirements would be absent due to existing dispatchable DR. RI used Santee Cooper's peak forecast and hourly load forecast, adjusting as necessary to determine what the forecast would be in the absence of existing dispatchable DR.

For the DR assessment, the end-uses targeted for residential and small and medium commercial customers were limited to those with controllable load. For instance, for residential customers, AC/heating loads, as well as pool pumps and electric water heaters for certain achievable potential scenarios, were studied. For small and medium commercial customers, the analysis was limited to AC/heating loads during peak times.

For large commercial customers, all load during peak hours that the customer may be willing to reduce for a limited time if offered a large enough incentive during temporary system peak demand conditions was considered. The estimated load reduction from this set of customers was based on empirical information from other jurisdictions and available secondary information from RI's data sources.

The available measure list for DR-enabling technologies designed to deliver grid support services includes the following:

- Direct load control (HVAC, water heating, pool pumps)
- Voluntary curtailment incentive program
- Interruptible/curtailable rates

To estimate load impacts and costs for the installation and operation of DR measures, RI leveraged empirical information from other jurisdictions based on RI's experience and available secondary information.

Similar to the EE MPS, RI analyzed three achievable potential scenarios for DR, which include the following inputs and assumptions:

- **Business-as-Usual (Low Case)** – Aligned with Santee Cooper's current DR program, including eligibility requirements and incentive levels. Projected peak demand reductions are based on Santee Cooper's existing DR goals.
- **DR MPS Base Case (Medium Case)** – Based on the MPS analysis, which expands DR to include load control for additional equipment and a voluntary curtailment measure for commercial customers.
- **DR MPS Enhanced Case (High Case)** – Same DR programs as Medium Case but with increased incentives.

Figure 12 below shows the three scenarios that Santee Cooper considered for its direct-served retail load. The Business-as-Usual scenario reflects existing goals, while the Base and Enhanced scenarios are based on achievable potential estimates derived from the DR MPS.

Figure 12. Total Controllable Winter Peak Demand

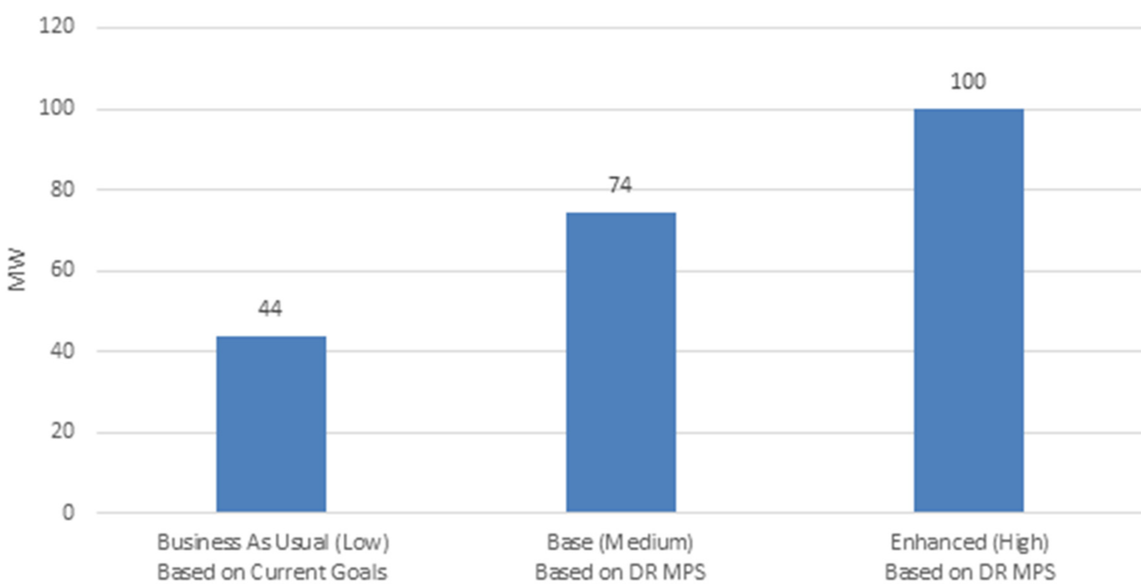


Figure 13 shows the weighted average levelized capital cost in dollars per kW-year for each scenario, based on the assumptions in the MPS and the assumed implementation over the Study Period.

Figure 13. Weighted Average Levelized Demand Response Capital Cost ($/kW-year)

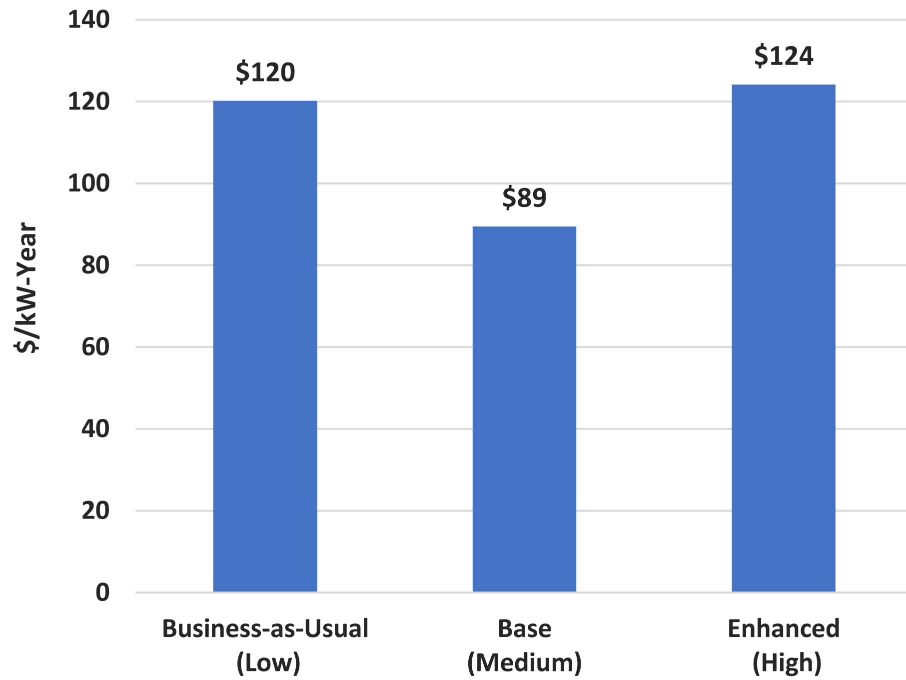
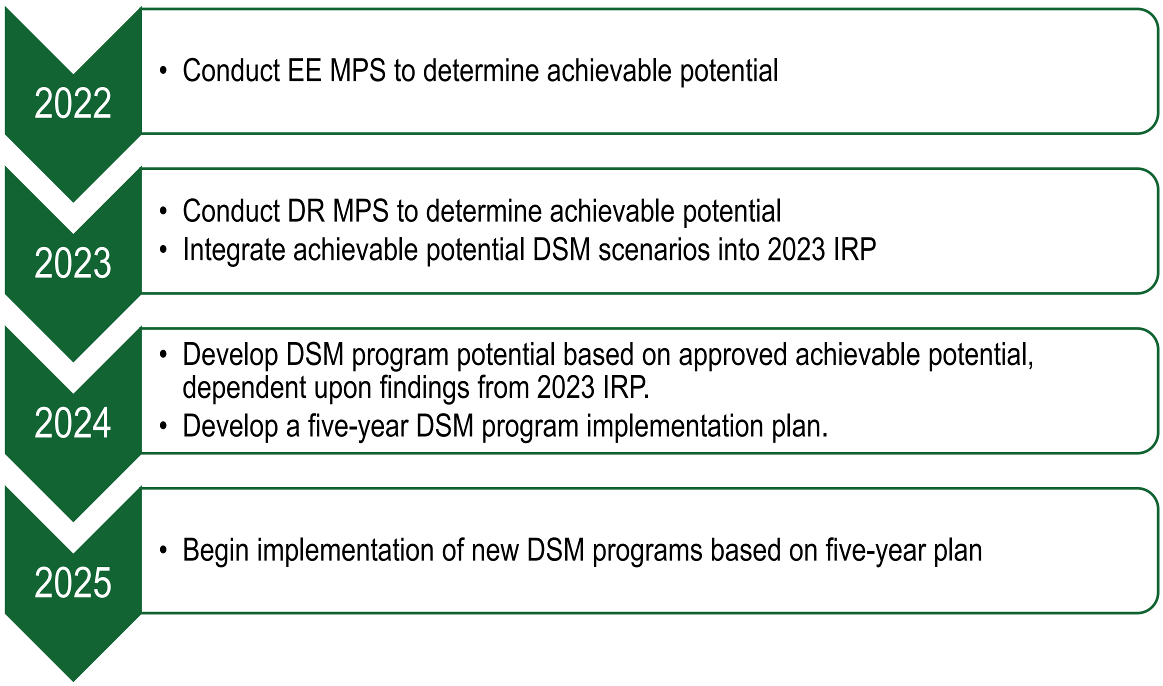


Figure 14 outlines the timeline over which Santee Cooper plans to transition from achievable potential to program potential. As shown in the last row in Figure 14, Santee Cooper will use the results of the EE and DR potential studies to develop program potential and a DSM program portfolio. The end-use measures and technologies will be bundled into program offerings where new updated marketing plans and program delivery strategies will be developed with the goal of maximizing customer participation. Creation of these programs will be developed with consideration from the EE and DR market potential studies, as well as input from program managers, internal DSM planners, and consultants. The final market potential study reports were prepared by RI and completed in 2023. The results of these studies are suitable for long-range system planning purposes and are incorporated into the power supply simulations that underpin the 2023 IRP.

Figure 14. Demand-side Management Timeline



During the period from 2023-2024, Santee Cooper will continue to offer programs based on current DSM goals.

CENTRAL PROGRAMS

Central works with its member-cooperatives to develop, implement, and administer DSM programs independently of Santee Cooper, though with significant coordination with respect to key assumptions and sharing of insights regarding program administration. Central's DSM programs are categorized and described in Central's 2020 IRP as follows.

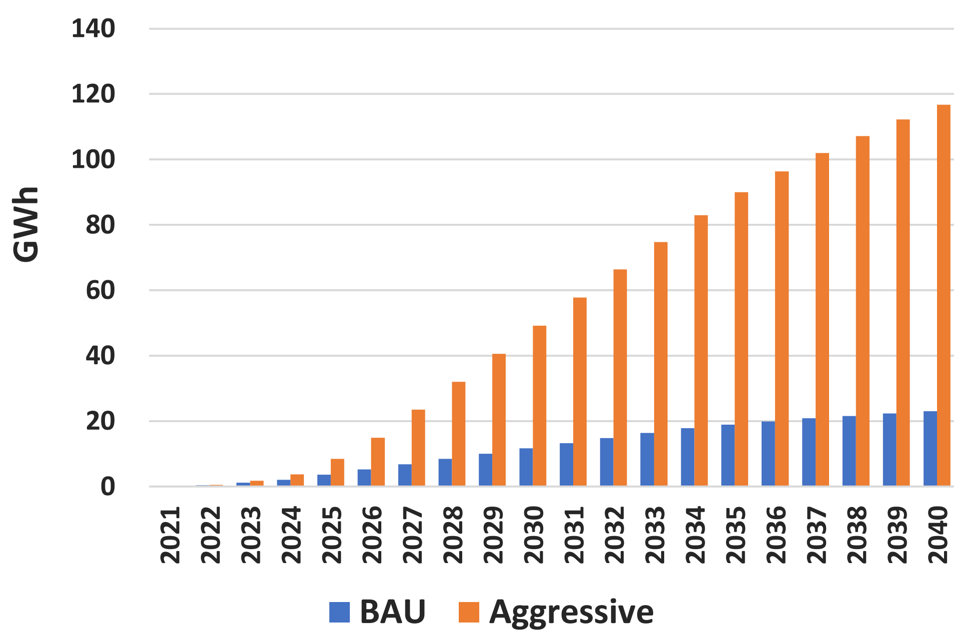
1) ***Energy Efficiency (EE)*** *– Support of efficient equipment or technology with the objective of reducing overall energy consumption.*
2) ***Demand Response (DR)*** *– Programs or tariffs designed to reduce consumption of electricity when the grid is most constrained, or the economic benefits are the greatest. Typically, the objective of DR programs is to shift load rather than reduce the total amount of consumption.*
3) ***Beneficial Electrification (BE)*** *– Programs or initiatives that encourage member-owners to transition energy-intensive equipment or processes from fossil fuel to electricity. As the electric grid becomes cleaner, BE measures have the potential to reduce total emissions. If the added load occurs primarily during off-peak periods, BE measures can improve system utilization and place downward pressure on rates.*
4) ***Renewable Energy (RE)*** *– Technologies such as behind-the-meter solar photovoltaic arrays reduce the amount of energy that must be supplied by the utility.*

As part of its 2020 IRP, Central conducted an economic evaluation of a variety of DSM measures in a similar fashion to Santee Cooper's EE MPS, as described more fully in Central's 2020 IRP report. Through its evaluations, Central developed the following two scenarios regarding future DSM impacts.

- **Business-as-usual**: Reflecting a continuation of historically typical level of funding for DSM measures[47]
- **Aggressive**: Reflecting a substantial increase in DSM expenditures to a level approximately "4.7 times that of the Business-as-usual scenario by 2027"

The resulting projections of DSM impacts for these two scenarios are provided in Central's 2020 IRP report. Central provided projections of DSM impacts for these two scenarios associated with the portion of Central load served by Santee Cooper. Central also indicated that its load forecast reflected in Santee Cooper's 2022 Load Forecast was consistent with the Business-as-usual scenario. Figure 15 below provides the projected cumulative impacts of new DSM/EE activity for the two scenarios associated with the portion of Central energy requirements served by Santee Cooper.

Figure 15. Central Projected Cumulative New DSM/EE Impacts



For purposes of the 2023 IRP, Santee Cooper adapted these projections to develop three DSM/EE scenarios, as follows.

- **Low Case** – Reflecting no new DSM activity beginning 2023

---

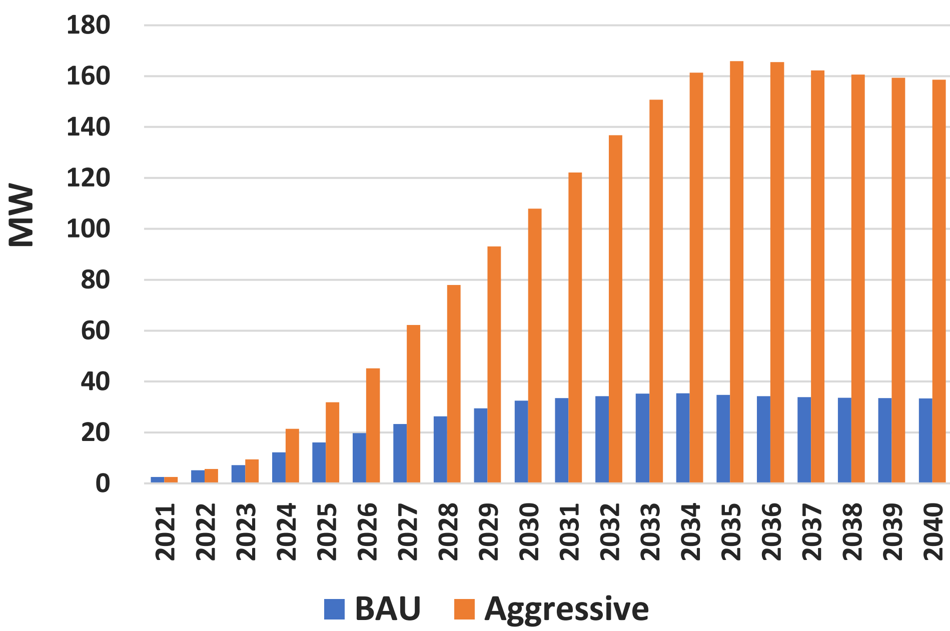
[47] However, as stated in Central's 2020 IRP, the projections reflect an "initial increase in [DSM] resources [other than renewable energy due to an]…increase in funding [for these resources] as the budget is reallocated away from renewables."

- **Medium Case** – Reflecting new DSM activity consistent with Central's Business-as-usual scenario above beginning 2023
- **High Case** – Reflecting new DSM activity consistent with Central's Aggressive scenario above beginning 2023

As discussed in the section titled Electric Load Forecast Overview, Santee Cooper adjusted Central's load forecast upward by the projected cumulative impacts of new DSM/EE activity. This adjustment resulted in a set of gross projections from which alternative scenarios regarding DSM/EE impacts could then be subtracted to test the cost effectiveness of these alternative scenarios relative to supply-side resources. For this purpose, Santee Cooper adapted DSM/EE cost assumptions from its EE MPS to represent approximate incremental costs across the two scenarios for Central.

Similar to the process above for DSM/EE, Santee Cooper obtained Central's projections of the capability of new DSM/DR resources from its Business-as-usual and Aggressive scenarios, which reflected winter peak capability associated with the portion of Central's load served by Santee Cooper shown in Figure 16 below.

Figure 16. Central Projected New DSM/DR Resource Winter Peak Capability



Similar to the approach for DSM/EE resources, projected impacts of DSM/DR resources in the Business-as-usual scenario were added back to Central load forecast to arrive at gross of new DSM/DR load determinants for use in the 2023 IRP. Medium, High, and Low Cases were adapted from Central's scenarios using the approach described above for DSM/EE resources. Additionally, incremental costs taken from Santee Cooper's DR MPS were adapted to represent the cost of Central's DR resources to the Combined System.

santee cooper®

TRANSMISSION PLANNING

SYSTEM-LEVEL PLANNING

Santee Cooper high voltage transmission line

Santee Cooper continually conducts assessments of the transmission system to allow for the safe, reliable, and efficient transfer of power across the Combined System and to delivery point substations throughout the 10-year planning horizon. As the Transmission Planner and Planning Coordinator for the Combined System, Santee Cooper is registered with NERC as both a Transmission Operator and Transmission Owner and adheres to NERC Reliability Standards associated with transmission planning when assessing the capabilities of the system under normal and contingency conditions. Santee Cooper triggers corrective action plans to meet performance requirements when necessary. For steady-state and dynamic system performance, the modeling and contingency conditions tested are outlined in NERC Reliability Standard TPL-001. Corrective action plans necessary to meet performance requirements may include the construction of new facilities or the implementation of operating procedures. Factors such as the likelihood and impact of an exceedance, cost and impact of a corrective action, and expected timeframe of any observed exceedance are considered in determining the most effective mitigation.

Routine transmission planning processes include the assessment of impacts associated with forecasted demand, generation additions and retirements, large load additions or losses, and changes on adjacent systems planned to occur within the 10-year planning horizon. Sensitivity cases are also analyzed to understand risks associated with changes to the base plan and inform strategic decisions related to future transmission facility needs.

REGIONAL-LEVEL PLANNING

Santee Cooper is an active participant in regional transmission planning study processes and is engaged in coordinated reliability assessments focused on the SERC Reliability Corporation ("SERC") region of the Eastern Interconnection. These assessments are coordinated through participation in reliability study activities through SERC, a Regional Entity that performs reliability functions under a delegation agreement with NERC. Studies performed through SERC provide an indication of the overall reliability of the region and provide insight into Santee Cooper's role in the reliable operation of the regional system.

Santee Cooper is also a participant in the South Carolina Regional Transmission Planning ("SCRTP") process. The SCRTP process was established by DESC and Santee Cooper to meet the transmission planning requirements of FERC Order No. 890, 890-A and 890-B, orders designed to "prevent undue discrimination and preference in transmission service." The SCRTP process was expanded to meet the transmission planning requirements of FERC Order No. 1000, 1000-A, and 1000-B, orders that reform the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers. It provides an open and transparent forum for DESC and Santee Cooper, as transmission providers, to engage with stakeholders regarding transmission plans in the SCRTP region. Through this forum, transmission plans and updates to regional planning processes are shared with stakeholders. Coordinated transmission studies are also conducted and results are shared with stakeholders.

INTERCONNECTION-LEVEL PLANNING

Santee Cooper is an active participant in Eastern Interconnection Planning Collaborative ("EIPC") activities, which provides a forum for interconnection-wide coordination of system planning activities for the Eastern Interconnection. EIPC also serves as a resource for policy makers and regulators by providing relevant, complete, and technically sound information related to the impact of proposed policies and/or regulations to the efficient and reliable operation of the Eastern Interconnection.

TRANSMISSION PROJECTS

Santee Cooper invested $117 million in capital additions and improvements to its transmission system in 2022. Any projects which 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 underway or otherwise expected to be completed within the next five years.

These projects are discussed in Appendix C.

MAJOR MODELING ASSUMPTIONS

This section details major modeling assumptions that underpin the 2023 IRP. These assumptions were developed based on industry best practices and incorporate stakeholder input and feedback received throughout the stakeholder process conducted for the 2023 IRP. The IRP process has also been guided by a review of South Carolina precedent from DEC, DEP, and DESC IRP proceedings. To better address IRP requirements and respond to stakeholder expectations, Santee Cooper has adopted EnCompass™, developed and marketed by Anchor Power Solutions, for production cost modeling and resource optimization analyses that underpin the 2023 IRP.

FINANCING AND ECONOMIC ASSUMPTIONS

The IRP reflects assumptions regarding future general cost escalation and Santee Cooper cost of debt depicted in Table 12 below. The net present value cost results shown herein reflect a discount rate set equal to Santee Cooper's assumed cost of debt.

Table 12. Financial Assumptions

General Inflation	2.30%
Santee Cooper Cost of Debt	5.25%
Weighted Cost of Short-term Debt	4.25%
Present Value Discount Rate	5.25%

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. 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"), based on a survey of market conditions during mid- to late-2022, long-term treasury rates, and average rates over the period 2016-early 2020.

SYSTEM ENERGY AND PEAK DEMAND

Forecasts of monthly energy requirements and peak demand for the Santee Cooper system through 2042 were developed as discussed in the section titled Electric Load Forecast Overview and as detailed in Santee Cooper's load forecast report titled Santee Cooper 2022 Load Forecast and filed with this IRP as Attachment 3. These values were taken on a gross of planned and potential new DSM/EE and DSM/DR basis, as further described in the section titled Demand-side Management Overview. Projections beyond 2041 reflect a simple linear extrapolation.

Table 13 provides the projected annual energy requirements and winter peak demand for the Combined System, including losses, for the medium, high, and low cases over the first 20 years of the Study Period.

Table 13. Combined System Energy and Winter Peak Demand with Losses

	Energy Requirements (GWh)			Winter Peak Demand (MW)		
Year	**Medium**	**High**	**Low**	**Medium**	**High**	**Low**
2023	28,095	31,699	24,571	5,492	6,011	5,016
2024	28,405	32,164	24,782	5,550	6,105	5,049
2025	28,326	32,212	24,453	5,559	6,147	5,010
2026	28,406	32,430	24,431	5,582	6,203	5,009
2027	28,487	32,649	24,403	5,611	6,266	5,012
2028	28,719	33,021	24,519	5,662	6,352	5,038
2029	28,615	33,054	24,299	5,591	6,316	4,942
2030	28,764	33,358	24,335	5,631	6,393	4,957
2031	28,860	33,617	24,314	5,672	6,472	4,972
2032	29,071	34,006	24,409	5,712	6,551	4,987
2033	29,191	34,316	24,420	5,744	6,625	4,996
2034	29,361	34,704	24,473	5,780	6,704	5,007
2035	29,537	35,114	24,522	5,816	6,781	5,017
2036	29,767	35,578	24,627	5,858	6,868	5,034
2037	29,914	35,961	24,647	5,893	6,949	5,044
2038	30,111	36,414	24,723	5,933	7,040	5,060
2039	30,315	36,874	24,802	5,976	7,134	5,078
2040	30,555	37,395	24,915	6,019	7,236	5,098
2041	30,749	37,841	24,972	6,059	7,338	5,118
2042	30,963	38,319	25,065	6,101	7,431	5,136

Future annual assumed DSM/EE impacts for Santee Cooper's Distribution system, across medium, high, and low scenarios, were taken from results of the EE MPS, discussed 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. Future DSM/EE impacts for Central were obtained from Central across a range of potential DSM scenarios, generally consistent with Central's 2020 IRP, adjusted to be consistent with the portion of Central's load served by Santee Cooper. Projections beyond 2041 generally reflect a simple linear extrapolation.

Table 14 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, for the medium, high, and low DSM cases over the first 20 years of the Study Period.

Table 14. Combined System Demand-side Management/EE Impacts with Losses

	Energy Requirements (GWh)			Winter Peak Demand (MW)		
Year	**Medium**	**High**	**Low**	**Medium**	**High**	**Low**
2023	23	31	14	4	5	2
2024	41	54	25	6	8	4
2025	63	86	41	9	12	6
2026	89	123	61	13	17	9
2027	118	164	85	17	22	12
2028	147	205	109	21	28	15
2029	176	245	135	25	34	19
2030	205	284	160	29	39	22
2031	232	320	183	33	44	26
2032	260	356	203	37	50	29
2033	286	388	220	41	54	31
2034	311	418	235	45	58	33
2035	334	444	247	48	61	35
2036	358	469	257	51	64	36
2037	380	491	265	54	67	38
2038	400	511	271	57	69	38
2039	422	532	277	60	71	39
2040	445	553	281	63	74	40
2041	467	575	285	67	76	40
2042	489	595	291	70	79	41

To support a full range of sensitivities in the 2023 IRP, the various load forecast scenarios were combined with selected DSM/EE scenarios to provide for an evaluation of the cost effectiveness of varying levels of DSM/EE impacts relative to supply-side resources.

System load profiles were based on 2019 data,[48] consistent with solar profiles discussed further below.

FUEL FORECASTS

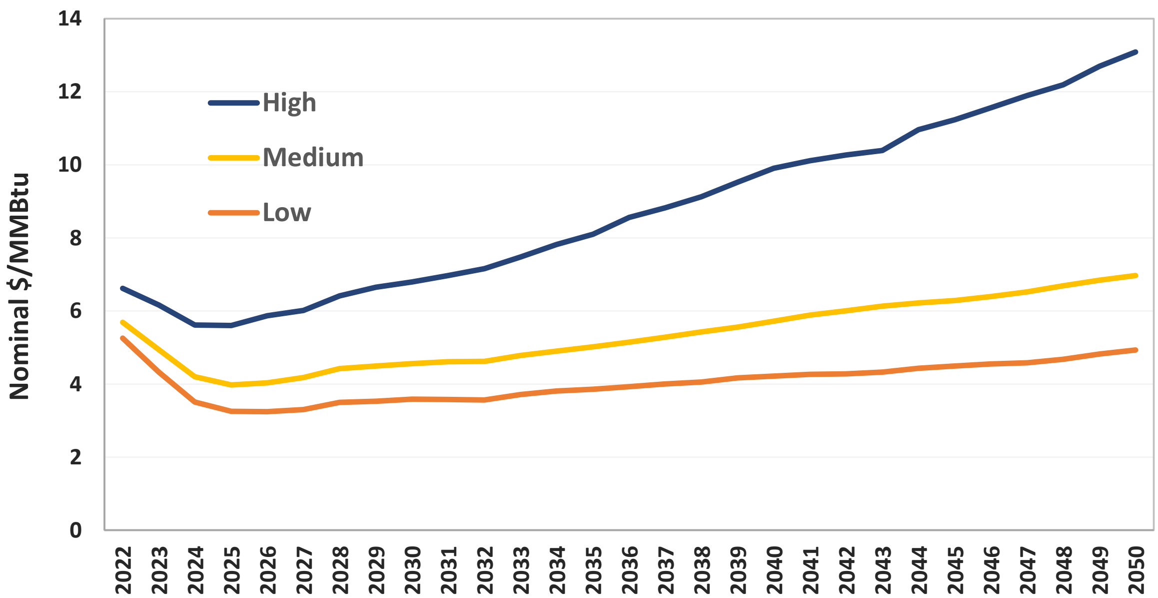
Forecasted fossil fuel prices throughout the Study Period generally reflect an average of forecasts taken from the Energy Information Administration's 2022 Annual Energy Outlook ("AEO") Reference Case and obtained from S&P Global's 2022Q3 Forecast. To study a reasonable range of uncertainty regarding 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,

[48] 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.

while the Low Oil and Gas Supply Case reflects less accessible resources and higher extraction costs.

Forecasts of natural gas prices are shown in Figure 17 below.

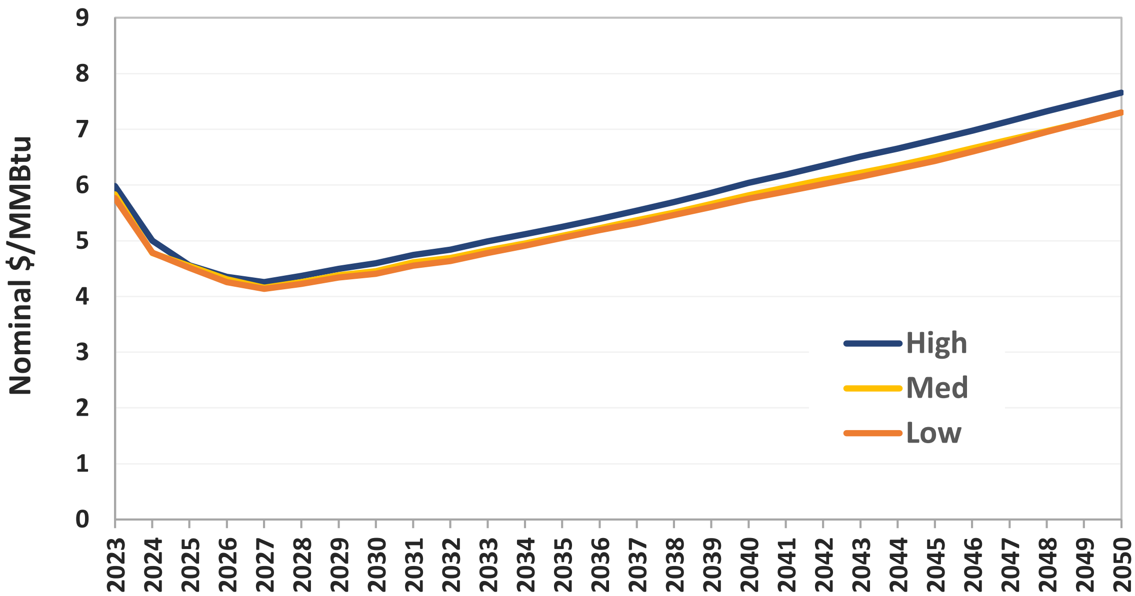
Figure 17. Natural Gas Price Forecasts



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 forecasts for delivery costs, including upstream pipeline transportation costs, basis differentials, and pipeline fuel use. For prospective new natural gas generation, Santee Cooper has assumed prices for new delivered natural gas supply based on information that has been provided by natural gas system operators in South Carolina for representative sites on Santee Cooper's system.

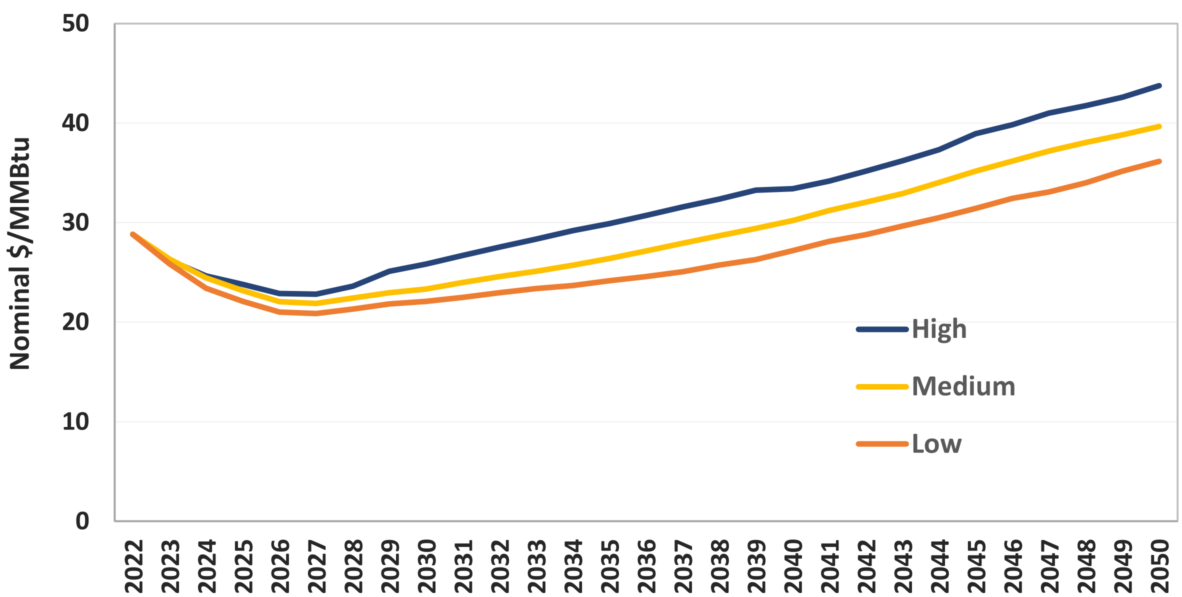
Forecasted coal prices are based on the average of basin price forecasts from the 2022 AEO and S&P Global, as above, for Central Appalachian, Northern Appalachian, and Illinois basins and rail delivery costs to South Carolina based on Santee Cooper estimates and are shown in Figure 18 below. As the High 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 in the 2022 AEO.

Figure 18. Coal Price Forecasts



Forecasted fuel oil prices, shown in Figure 19 below, were based on an average of forecasts from the 2022 AEO and S&P Global 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 19. Distillate Fuel Oil Price Forecasts

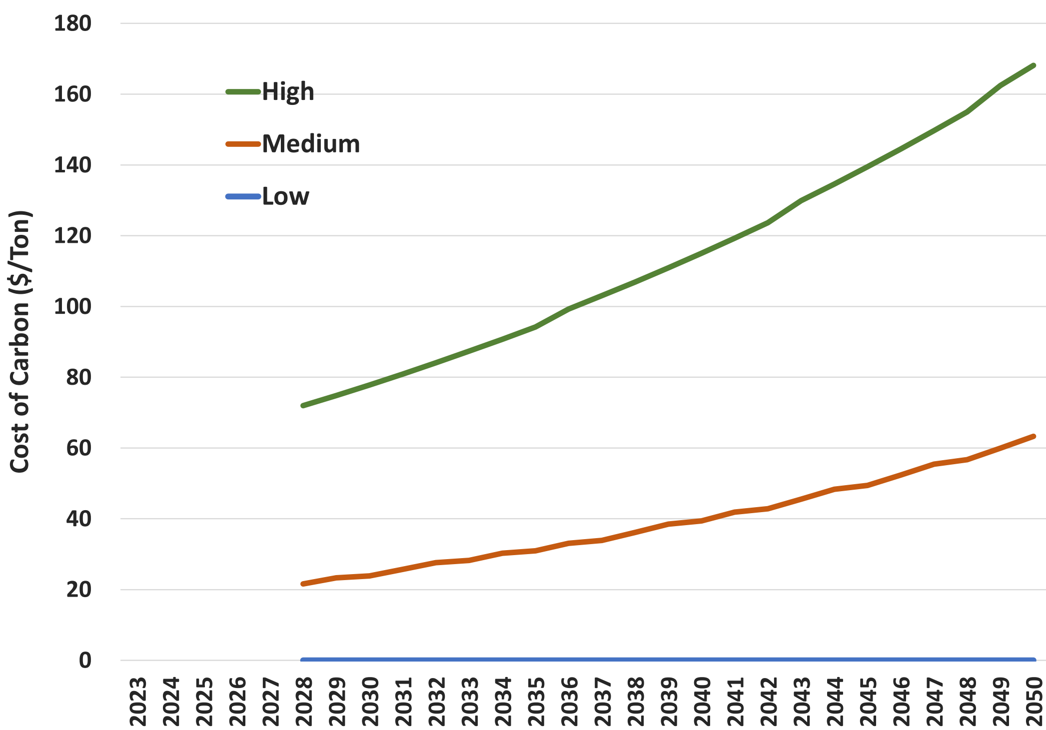


CARBON EMISSIONS PRICING

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 20 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% per year
- **High Case** – Reflecting a CO_2 emissions price starting in 2028 at $72/ton and escalating at 3.9% per year

Figure 20. CO_2 Emissions Price Forecasts



The Medium and High Cases draw on estimates of the social cost of CO_2 ("SCC") developed by the Interagency Working Group on Social Cost of Greenhouse Gases in February 2021.[49] For this purpose, Santee Cooper relied on estimates reflecting discount rates of 5% and 3% for the Medium and High Cases, respectively, and assumed that regulation would start in 2028, providing for a reasonable period for regulatory, legislative, and legal processes to be completed before any implementation.

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

[49] Available at https://costofcarbon.org/resources/entry/2021-IWG-tsd.

with general inflation. Cost estimates for market gypsum purchases to supplement production from coal unit operations are based on recent averages adjusted for inflation over the study horizon.

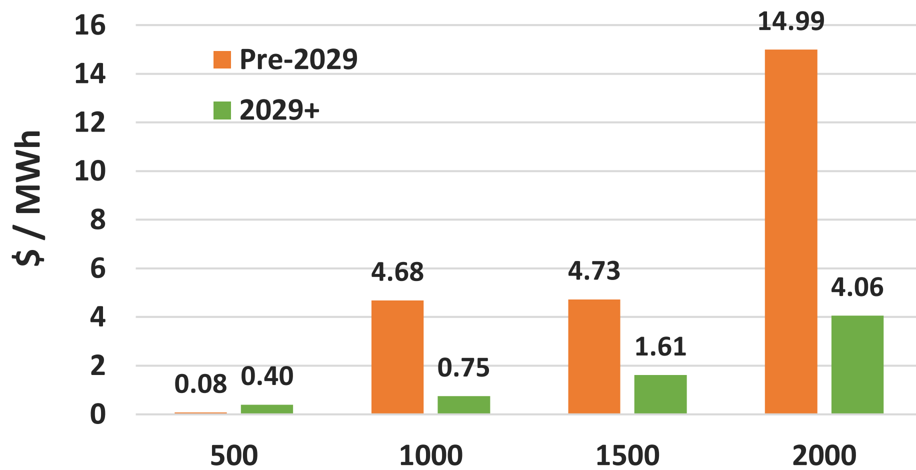
Fixed operation and maintenance costs and capital costs for existing resources are not included in the portfolio costs, except for costs associated with coal-fired resources that are avoided in portfolios in which such resources are assumed to be retired or are incurred for portfolios in which such resources 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.

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., storage hydro) 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.

To understand the integration, reliability, and operational challenges and opportunities for integrating such carbon-free resources into the Combined System, Santee Cooper retained Astrapé Consulting to conduct a Solar Integration Study, which is detailed in Astrapé's report titled Solar Integration Study and included with this IRP filing as Attachment 2. The study evaluated the impacts on system operations and reliability of adding increasing levels of utility-scale solar resources in both 2026, with Winyah still in operation, and 2029, with Winyah retired and replaced with a mix of NGCC and combustion turbine resources. Study results reflect incremental integration costs for the two representative years and resource mix scenarios shown in Figure 21 below. The values in the figure represent an estimate of the impact on system variable costs of intermittency in solar output by the varying amount of solar added to the system.

Figure 21. Estimated Solar Integration Costs



It is important to note that Santee Cooper utilized integration costs as a $/MWh adder for the modeled cost of solar and wind resources only when developing optimal portfolios. This is done because the EnCompass optimization simulations reflect a simplified dispatch of typical week daily profiles by month that does not consider unit commitment. This simplification was applied when evaluating and establishing optimal portfolios to allow the EnCompass model to reach solutions that might not have been possible with simulations reflecting unit commitment given computer runtime and memory limitations. By including integration costs, Santee Cooper can be assured that system costs normally associated with operating resources in response to renewable resource integration were captured in its portfolio optimization simulations. When preparing projections of production costs for previously optimized portfolios, on the other hand, Santee Cooper utilized a more robust all-hours (8760 hours per year) and full resource commitment for simulations and, therefore, does not use integration costs for production cost simulation and reporting.

Based on the results of the Astrapé study, Santee Cooper utilized the following assumptions for the cost of integration when performing portfolio optimization in all years. Costs of integration for quantities above 2,000 megawatts reflect a linear extrapolation. For purposes of the IRP, Santee Cooper has assumed the cost of integration is the same for solar and wind resources.

Table 15. Assumed Solar and Wind Integration Cost

Installed Nameplate Capacity (MW)	Incremental Cost of Integration ($/MWh)
0 - 500	$0.40
500 - 1000	$0.75
1000 - 1500	$1.61
1500 - 2000	$4.06
2000+	$6.51

RESOURCE OPTION ASSUMPTIONS

A wide range of resource technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs, including fossil-fueled, renewable, battery, and nuclear resources. The resource technologies considered for the 2023 IRP were guided by the planning activities of peer utilities, industry research regarding the state of development of various technologies, consultation with Santee Cooper advisers, and input and feedback received during the stakeholder process. These resources and associated assumptions regarding capital and operating costs and characteristics are discussed in the subsections below.

In addition, the 2023 IRP incorporates sensitivity cases reflecting a wide range of levels of DSM activity and associated costs, based on the conclusions of Santee Cooper's EE MPS and DR MPS. While those studies reflected evaluations of the cost-effectiveness of DSM measures based on assumptions that were broadly consistent with the 2023 IRP, the evaluation of sensitivities associated with higher and lower levels of DSM discussed herein result in an objective evaluation of the economics of demand-side measures relative to supply-side options.

FOSSIL-FUELED AND NUCLEAR ASSETS

Fossil-fueled and nuclear resources are assumed to be owned and financed by Santee Cooper. As noted in the section of this report titled Short-term Action Plan, Santee Cooper plans to determine how best to implement the large NGCC resource the IRP demonstrates would be an economical and valuable resource for the Combined System. This may include joint ownership or other options for acquiring entitlements to the NGCC capacity. As a not-for-profit State-owned entity, Santee Cooper does not seek investment opportunities but rather deploys capital considering impacts on customer cost and risks.

Base year capital costs, operating costs, and operating characteristics for CC, CT, reciprocating internal combustion engine ("RICE"), 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. Capital cost escalation was generally based on National Renewable Energy Laboratory's ("NREL") 2022 Annual Technology Baseline ("ATB"), 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 2023 IRP are shown in Table 16 below. All costs are shown in 2022 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 exclude land and transmission and natural gas pipeline interconnection. Fixed O&M costs exclude property taxes (or payments in lieu of taxes) and insurance.

Table 16. 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	792	4.86	2.68	6,116	2029
Combined Cycle (1x1; H-class)	630	1,103	7.31	2.68	6,136	2029
Combined Cycle (1x1; F-class)	357	1,702	11.05	3.11	6,668	2029
Combustion Turbine (H-class)	402	699	4.80	11.42	9,160	2029
Combustion Turbine (F-class)	230	744	7.70	8.53	10,021	2029
Aeroderivative Turbine (LMS100)	102	1,309	17.90	7.63	8,957	2029
Internal Combustion Engine	220	1,291	9.30	11.14	8,335	2029
Small Modular Nuclear Reactors	683	5,986	95.50	11.65	10,900	2040

Capital costs are assumed to decline in real dollars by approximately 0.6% per year, based on projections taken from NREL's 2022 ATB for these assets. Hence, in nominal dollars, given the underlying general inflation assumption utilized in the 2023 IRP, capital costs are assumed to increase at approximately 1.7% per year. Fixed and variable O&M are assumed to escalate at the rate of general inflation, or 2.3% per year.

Given development and permitting timeframes, as well as the desire to evaluate these major resource alternatives on a consistent basis upon the assumed retirement of Winyah, the 2023 IRP assumes these types of assets cannot be added to the Santee Cooper system until January 2029. Given the current state of development of small modular reactor technology, implementation of SMRs was assumed to be commercially viable beginning January 2040.

In addition to allowing for certain renewable and energy storage resource to be added prior to 2029, as discussed below, to meet planning reserves during that period, the IRP assumes the availability of short-term, off-system capacity and energy purchases based on pricing projections obtained from The Energy Authority. These resources are modeled as tolling agreements (i.e., indexed to natural gas at a given heat rate) from the Southern Company system that can be selected by EnCompass on a year-to-year basis through 2029.

RENEWABLE AND ENERGY STORAGE RESOURCES

Utility-scale solar, wind (both onshore and offshore), and BESS resources have been reflected in EnCompass as 20-year PPA options based on estimates of the levelized cost of energy ("LCOE"), or in the case of BESS resources, levelized cost of capacity ("LCOC"), from these resources over their useful lives. Santee Cooper assumes, for purposes of this IRP, that renewable and BESS resources will be implemented through PPAs rather than self-built resources to take greater advantage of tax credits available under the IRA and to reduce Santee Cooper's financing requirements and certain risks related to development and operation of these assets. However, as discussed in the Short-term Action Plan section herein, Santee Cooper intends to consider whether approaches other than PPAs for providing a portion of these resources needed for the Combined System would reduce costs and risks to customers.

Capital and operating cost assumptions for solar, wind, and BESS resources have been taken from the NREL 2022 ATB. Solar and BESS costs have been adjusted based on NREL's 2022Q1 Solar and Storage Cost Benchmark, which reflected approximately 15% higher costs for these resources relative to the values reflected in the 2022 ATB.[50] 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 2022 dollars) assumed for the 2023 IRP are provided in Table 17 below.

Table 17. Renewable Resource Option Parameters

Technology	Capital Cost ($/kW)	Fixed O&M ($/kW-yr.)	Operating Life (Years)	First Year Available
Solar (PV)	1,402	22.24	30	2026
BESS (4-Hour)	1,757	43.92	30	2026
BESS (8-Hour)	3,203	80.07	30	2026
On-shore Wind	2,080	53.70	30	2029
Off-shore Wind	3,952	118.73	30	2040

New[51] solar, onshore wind, and BESS resources are assumed to be available beginning January 2026. New Solar resources are assumed procured through an approved CPRE program, for which Santee Cooper is currently seeking approval from the PSC.[52] Due to the development and permitting timeframe of off-shore wind resources, such resources are assumed to be available beginning 2040.

Financing costs are assumed based on NREL's ATB, reflecting the cost structure of a taxable developer, but adjusted based on the trend in interest rates since the timeframe of development

[50] 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.

[51] "New" refers to solar resources in addition to solar resources already under contract resulting from Santee Cooper's 2020 RFP (totalling 350 MW, on a nameplate basis).

[52] See *Application of the South Carolina Public Service Authority for Approval of Competitive Procurement Program Pursuant to S.C. Code Ann. Section 58-31-227*, Docket No. 2022-351-E.

of ATB 2022 assumptions, or approximately 2020. Interest rate adjustments were determined based on differences between average U.S. Treasury rates during 2020 and such rates over the Study Period, which are assumed to be similar to long-term historical averages.

Table 18 below provides the debt interest rates and after-tax return on equity values assumed to underpin renewable and BESS PPA pricing for the 2023 IRP.

Table 18. Renewable Resource Debt Interest and After-tax Return on Equity Rates

Technology	Interest Rates
Debt Interest Rate	6.6%
Return on Equity:	
Solar	10.35%
Batteries	10.35%
Onshore Wind	11.60%
Offshore Wind	12.60%

Projected costs for renewable resources have been modeled assuming either investment or production tax credits ("ITC" and "PTC," respectively) available because of the IRA. Assumed PPA prices reflect the lesser of the projected costs under either credit regime and assume that 100% of facility costs will be eligible for the ITC.[53] Solar and wind resources are assumed to take advantage of the full tax credit rates—ITC at 30% and PTC at $27.50/MWh (2022 dollars; indexed to inflation), while battery resources are assumed to take advantage of the energy communities bonus credit for the first 400 MW of such resources, yielding an ITC of 40%, with additional battery resources at the 30% ITC rate. 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 2023 IRP assumes the tax credits are available throughout the Study Period ending 2052.

Figure 22 provides resulting projections of the LCOE for solar, onshore wind, and offshore wind resources. [54] Differences in escalation are driven primarily by differing projections of capital costs reflected in NREL's 2022 ATB, offshore wind reflecting greater increases in capital cost than the other resource types shown below.

[53] Industry estimates typically reflect that 85-90% of facility costs will be eligible.
[54] The levelized cost shown would apply over the life of a resource placed into service in the year indicated.

Figure 22. Levelized Cost of Energy of Renewable Resources by COD Year

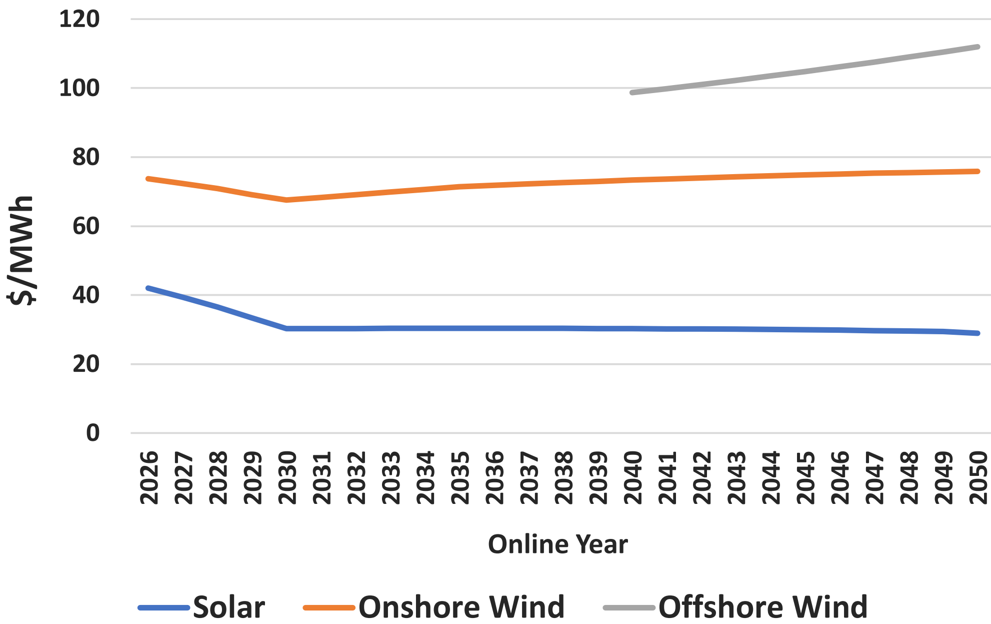
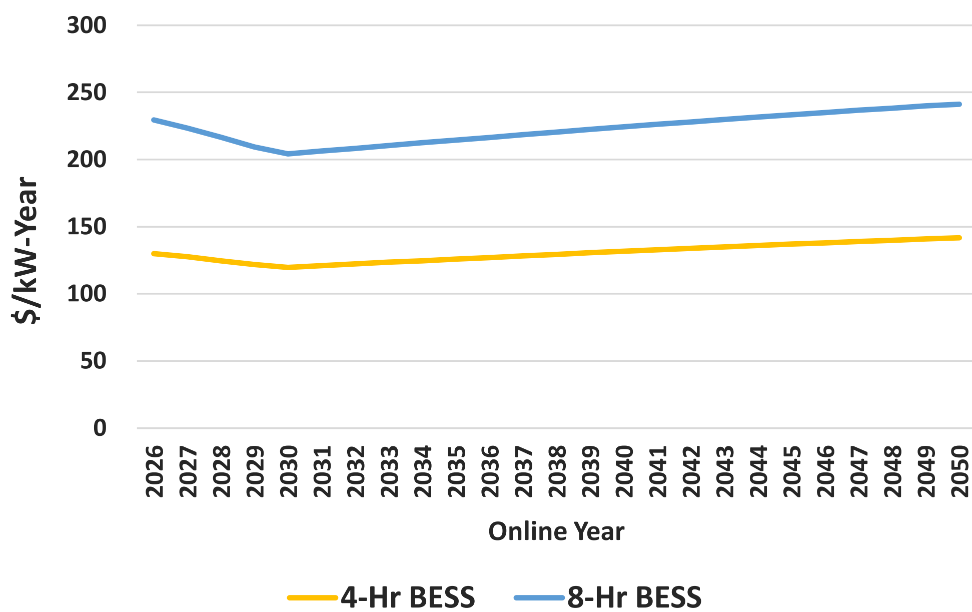


Figure 23[55] provides resulting projections of the LCOC for BESS resources, reflecting 4- and 8-hour durations.

Figure 23. Levelized Cost of Capacity of Battery Resources by COD Year



[55] 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.

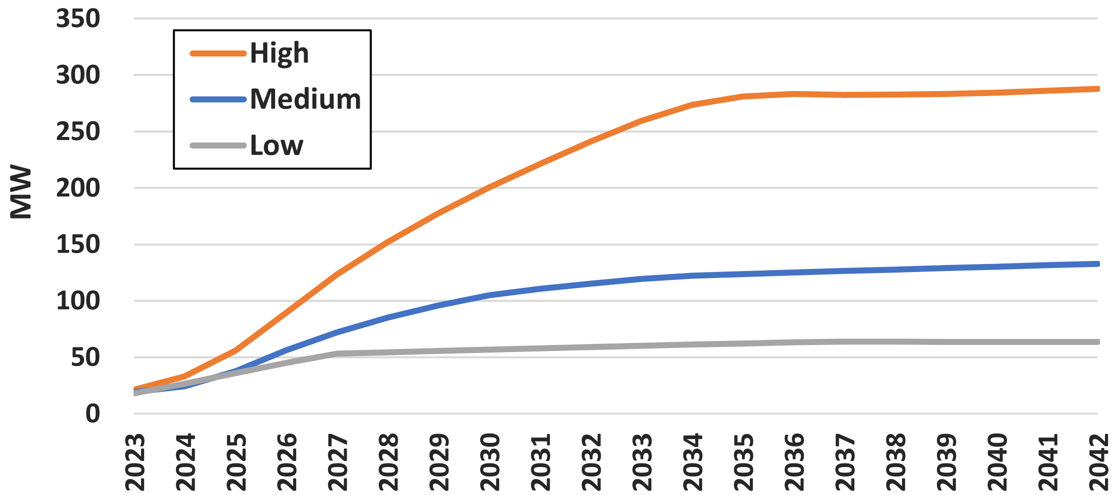
DEMAND-SIDE RESOURCES

Demand-side resources are evaluated in the 2023 IRP through variations in the extent of such resources and their costs, thereby capturing the net influence on capital and operating costs of these resources relative to supply-side resources. The sensitivities regarding the extent of demand-side resources are drawn from the market potential studies discussed in the section titled Demand-side Management Overview. For DSM/EE resources, these variations take the form of differing reductions to Santee Cooper's load forecast, as discussed in the subsection above titled System Energy and Peak Demand. Costs for demand-side resources are derived from the EE MPS and DR MPS and assumed to be similar for Central's resources.

For DSM/DR resources, these variations reflect differing amounts of DR being available both to offset supply-side capacity resources and to meet load during high load periods, when other resources are unavailable. Future assumed DR capability for Santee Cooper's Distribution system for medium and high cases was developed from results of the DR MPS, while the low case reflects projections related to a Santee Cooper program already under development, all as discussed in the section titled Demand-side Management Overview. Monthly impacts were derived from annual and seasonal impacts based on the underlying shape of the relevant segment of Santee Cooper's load. Future DR program impacts for Central were obtained from Central across a range of potential DR scenarios, generally consistent with Central's 2020 IRP, adjusted to be consistent with the portion of Central's load served by Santee Cooper. Monthly impacts were derived from annual and seasonal impacts based on the underlying shape of Central's load. Projections beyond 2041 generally reflect a simple linear extrapolation. These assumed program implementations and impacts were combined with Santee Cooper's existing conservation voltage reduction capability, assumed to be approximately 17 MW.

Figure 24 depicts the resulting DR program capability at the time of the winter peak for the medium, high, and low cases for the Combined System.

Figure 24. Combined System DR Capability During Winter Peak



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 this IRP, 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 net present value revenue requirements for each of the resource portfolio strategies, discussed in the next section. These range from approximately $0.4 billion in the Economically Optimized and No New Fossil portfolios to $1.9 billion in the Future Coal Retirement and Net Zero CO_2 by 2050 portfolios in 2022 dollars, with descriptions of these portfolios below in the section titled Potential Resource Portfolios .

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 IRP, the operating reserves modeled in EnCompass include regulating reserves, contingency reserves spinning (spinning reserves), and contingency reserves supplemental (non-spinning reserves). The CRSG reserve requirement, described in the subsection titled Operating Reserve Requirements, is modeled as 219 MW, half as spinning and half as non-spinning reserves. Table 19 below provides the operating reserves modeled for the IRP analysis and collectively referred to as the Base Ancillary Services Requirements.

Table 19. Base Ancillary Services Requirements

Reserve Component	Requirement (MW)
Total Contingency Reserves	219
Minimum Spinning Reserves	109.5

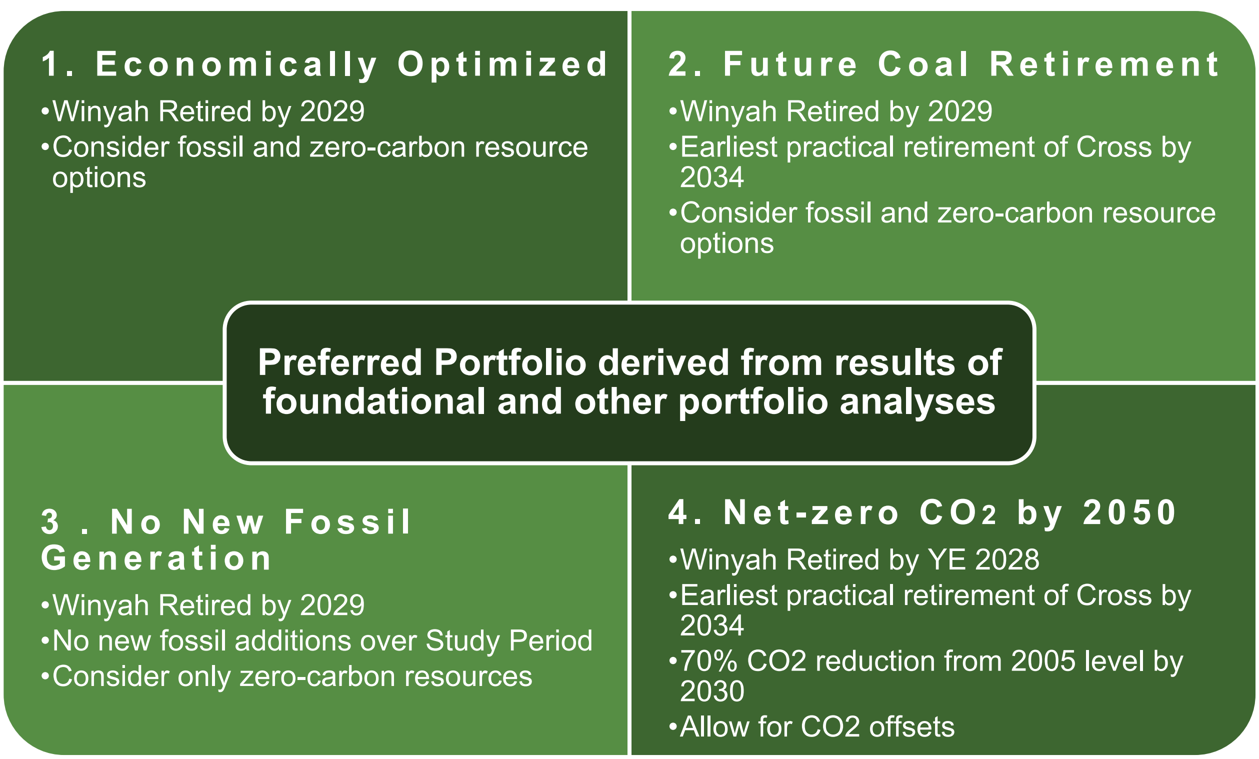
RESOURCE PLAN EVALUATION

For purposes of the 2023 IRP, Santee Cooper considered four major foundational portfolio alternatives and several sensitivity and side case analyses to gain an understanding of the relative impacts on costs and emissions of alternative resource options and plans. These alternatives reflect key differences regarding retirement of existing coal resources and constraints on new resources available to meet the system's needs. Each of these portfolio alternatives were evaluated under a wide range of assumptions regarding fuel costs, costs of CO_2 regulation, load growth, and levels of DSM activity and associated costs. Based on those analyses, Santee Cooper formulated its Preferred Portfolio.

POTENTIAL RESOURCE PORTFOLIOS

Figure 25 lays out the foundational portfolio alternatives Santee Cooper has developed and evaluated within this IRP. These potential strategies have been developed with input from Santee Cooper's stakeholders through the stakeholder engagement process detailed in the section titled Stakeholder Process for 2023 IRP. Each of the portfolio strategies reflects the retirement of the entire Winyah Generating Station and aggressive investment in non-carbon-emitting resources, with variations in strategies around resource option constraints, coal retirement extent and timing, and the imposition of specific, aggressive carbon reduction targets, as described further below.

Figure 25. Foundational Resource Portfolios



Portfolio 1, the **Economically Optimized Portfolio**, identifies the most cost-effective portfolio assuming Cross continues to operate over the Study Period through 2052 and without considering potential policy interventions related to CO_2 emissions.

Portfolio 2, the **Future Coal Retirement Portfolio**, considers the cost impacts and other implications of the retirement of Cross as early as practical, by 2034, in addition to the retirement of Winyah, which is common to all foundational portfolios. Portfolio 2 also does not consider policy interventions related to CO_2 emissions.

Portfolio 3, the **No New Fossil Generation Portfolio** was developed to understand the implications of a build plan considering the addition of only renewables and BESS resources, after the retirement of Winyah by 2029. Cross is assumed to continue to operate in Portfolio 3.

Portfolio 4, the **Net Zero CO_2 by 2050 Portfolio**, as required by Act 90, reflects the retirement of all coal resources and the imposition of CO_2 emissions targets over the Study Period designed to achieve net zero CO_2 emissions by 2050, with allowance for the use of offsets. CO_2 emissions targets were set to achieve an interim goal of reducing emissions to 70% of 2005 levels by 2030 and achieving a 90% reduction from the 2005 level by 2050, leaving the remaining 10% to be met using offsets. This approach is intended to recognize the progressively higher cost of achieving carbon reductions and the likelihood that offsets will represent a more economic means of doing so, on a net basis. The optimization analysis reflects simultaneous objectives of achieving emissions targets and minimizing total production costs.

OVERVIEW OF METHODOLOGY

SOFTWARE

For its 2023 IRP, Santee Cooper has utilized the EnCompass power systems dispatch and optimization simulation software system from Anchor Power Solutions. EnCompass provides a flexible tool for simulation of generating resource operations and optimization of long-term resource decisions. The software offers flexibility in the following ways.

- **Resource Expansion Optimization** – EnCompass simulates optimization of resource expansion decisions through a mixed integer linear programming algorithm.
- **Chronological Detail** – Like most power system simulation software, EnCompass can be configured to run full chronological detail or various time and calendar simplifications (e.g., typical week rather than full calendar, on- and off-peak average loads rather than 24 hours, etc.).
- **Dispatch Commitment** – Like most power system simulation software, EnCompass can be configured to commit resources and adhere to minimum up and down times, ramp rates, and the like or simplify the dispatch in various ways to reduce simulation run times.

EnCompass has become one of a handful of industry standard software tools for developing IRPs and was selected by Santee Cooper in recognition of its capabilities.

OPTIMIZATION ANALYSIS

Each of the potential portfolios was simulated over the Study Period, with resource additions determined through optimization, as necessary to meet load and reserve obligations. The optimization simulation utilized typical week load patterns by month rather than a full chronological representation and does not incorporate resource commitment simulations. However, spinning and non-spinning operating reserve requirements were modeled. These simplifications were necessary to allow the model to solve without inordinately long run times or failure due to computer memory limitations. Integration costs were added to solar and wind pricing, based on the integration study discussed in the preceding section.

For purposes of the resource optimization simulation, a Reference Case was developed reflecting assumptions for key variables described in Table 20 below.

Table 20. Reference Case Definition

Key Uncertainty	Reference Case Assumption	Assumption Basis
Fuel Prices	Medium Case	Average of AEO Reference Case and S&P Global Forecasts
CO_2 Emissions Regulation	Low Case	No CO_2 emissions regulation (i.e., CO_2 emissions cost at $0/ton)
Load Forecast	Medium Case	Most likely forecast, 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.

RISK ANALYSIS APPROACH

In addition to the Reference Case assumptions mentioned above, optimized portfolios for each Potential Resource Plan were simulated over the Study Period for several sensitivity cases to assess the sensitivity of power costs to wide range of potential future conditions 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 2022 Load Forecast
- **Demand-side Resources** – High and Low Case, drawn from more and less aggressive cases of DSM activity, impacts, and associated costs

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.

Resource strategies optimized under the Reference Case assumptions were simulated with the variations in fuel prices and CO_2 emissions costs outlined in the table above. For purposes of the load forecast and DSM sensitivities, however, given the variations in future load levels inherent in these cases, an additional optimization was run for each load forecast and DSM 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 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 initial resource decisions.

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

PORTFOLIO METRICS

The evaluation of potential resource plans included development and review of the following metrics, guided by Act 90 and Commission direction in previous IRP proceedings, as well as Santee Cooper resource planning principles.

- **NPV Cost** – Total cumulative NPV and average levelized 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.

Importantly, 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

PORTFOLIO OPTIMIZATION RESULTS

Each of the resource Portfolios were simulated and optimized using EnCompass over the study horizon, yielding variations in resource additions and resource plans specific to each Portfolio. As each resulting plan reflects the same future Combined System load, the resulting NPV power costs, CO_2 emissions, and other magnitude metrics of each Portfolio can be compared directly to others. Nameplate capacity added under each portfolio is also described.

The following subsections summarize the resulting optimized build plans under each Portfolio. Detailed build plans for each Portfolio are shown in Appendix D.

ECONOMICALLY OPTIMIZED PORTFOLIO

The Economically Optimized Portfolio offers a wide range of resource options to EnCompass to meet system requirements and results in resource additions totaling 5,056 MW of nameplate capacity by 2040 and 7,256 MW over the study horizon.

Portfolio optimization simulation identified a new 2x1 NGCC as the primary, base-load resource to be added following Winyah's retirement. Solar resources of 2,200 MW are added in 2029 and, beginning 2035, for nearly every year in increments between 50 and 300 MW throughout the Study Period. The Economically Optimized Portfolio also includes the addition of a new industrial frame CT in 2029. This CT is configured as a dual-fuel unit to assure firm fuel supply. In addition, during the period prior to 2029, EnCompass selects up to approximately 400 MW of short-term (i.e., single-year duration) purchases to help meet planning reserve margins, which is NOT shown in Table 21 below.

FUTURE COAL RETIREMENT PORTFOLIO

The Future Coal Retirement Portfolio reflects the retirement of both Winyah by 2029 and Cross by 2034, the earliest dates for retirement assumed practical. The Future Coal Retirement Portfolio results in resource additions totaling 7,510 MW of nameplate capacity by 2040 and 9,660 MW over the study horizon.

Portfolio optimization simulation identified new 2x1 NGCCs in 2029 and 2034 as replacement base-load resources for Winyah and Cross. Significant solar resources are added beginning in 2029 and for nearly each year beginning 2032 throughout the Study Period. The resulting build also reflects the addition of four industrial frame CTs in 2034. BESS resources are added periodically beginning 2029, and a small amount of onshore wind is added beginning 2032.

NO NEW FOSSIL GENERATION PORTFOLIO

The simulation of the No New Fossil Generation Portfolio reflects only zero carbon emitting resource options being offered to the EnCompass optimization. The No New Fossil Generation Portfolio results in resource additions totaling 8,850 MW of nameplate capacity by 2040 and 11,700 MW over the Study Period.

This simulation reflects that the Combined System requires a combination of large amounts of solar, wind, and BESS resources to replace a significant base-load resource like Winyah. Such builds are significantly concentrated in 2029, coincident with the assumed retirement of Winyah, reflecting 3,550 MW, 1,000 MW, and 1,550 MW nameplate capacity additions for solar, wind, and BESS, respectively in that year.

NET ZERO CO_2 BY 2050 PORTFOLIO

The Net Zero CO_2 by 2050 Portfolio reflects the retirement of both Winyah by 2029 and Cross by 2034 and the imposition of CO_2 reduction goals intended to aggressively reduce CO_2 emissions from the Combined System toward zero by 2050, allowing for the use of carbon offsets by 2050, as appropriate. The Net Zero CO_2 by 2050 Portfolio results in resource additions totaling over 10,156 MW of nameplate capacity by 2040 and nearly 15,000 MW over the study horizon. Similar to the Future Coal Retirement Portfolio above, the portfolio optimization simulation identified a new

2x1 NGCC in 2029 as the replacement base-load resource for Winyah but adds large amounts of nameplate capacity of solar and wind, supported by significant BESS resources to both replace Cross and fulfill the CO_2 requirements imposed on this simulation. In fact, more than 2,000 MW each of solar and onshore wind are added *before* the retirement of Cross by 2034. The resulting build also reflects the addition of four industrial frame CTs in 2034 when Cross is retired. BESS resources are added periodically beginning 2029, and significant onshore wind is added over 2030 to 2050.

OPTIMIZED PORTFOLIO BUILD SUMMARY

Table 21 summarizes the build plan that results from the optimization of each of the foundational Portfolios through 2040.

Table 21. Summary of Optimized Portfolios

Resource Changes	Optimized Portfolios – Additions (Retirements) - MW			
	Economically Optimized	Future Coal Retirement	No New Fossil Generation	Net Zero CO_2 by 2050
Coal Retirement • By 2029: Winyah • By 2034: Cross	(1,150)	(1,150) (2,330)	(1,150)	(1,150) (2,330)
New Solar[56] • 2029: • 2030-2040	2,200 750	2,250 750	3,550 1,350	2,250 1,100
New NGCCs • 2029 • 2034	1,360 0	1,360 1,360	None by policy	1,360 0
New Frame CTs • 2029: • 2030-2040	447 0	0 1,341	None by policy	0 1,597
New BESS • 2029: • 2030-2040	0 250	100 300	1,550 900	100 1,100
New Wind • 2029: • 2030-2040	0 50	0 50	1,000 500	0 2,650

Setting aside the "No New Fossil" policy-based portfolio, Table 21 shows the portfolios share following common resource additions.

[56] The amounts of New Solar capability shown are in addition to the solar PPA procured by Santee Cooper and Central in 2021.

1. Addition of over 2,000 MW of New Solar capacity in 2029 and then substantial additional amounts of New Solar capacity in the 2030s.
2. Addition of a large NGCC[57] resource (1,360 MW) upon retirement of Winyah, even in the Net Zero CO_2 by 2050 Portfolio.
3. Addition of CT (and/or BESS)[58] capacity by 2029 and thereafter.
4. Addition of wind resources only in the No New Fossil and Net Zero CO_2 by 2050 portfolios.

The Future Coal Retirement Portfolio includes a second 1,360 MW NGCC and additional CTs to replace retired Cross capacity.

The No New Fossil Generation Portfolio relies on large amounts of renewable resources and BESS capacity additions upon retirement of Winyah to serve system loads. More specifically, the No New Fossil Generation Portfolio includes a total of 6,100 MW of renewable capacity additions in 2029 in contrast to the approximately 4,000 MW of New Solar, NGCC and CT additions in the Economically Optimized Portfolio.

RESOURCE PORTFOLIO COMPARISON UNDER THE REFERENCE CASE

Table 22 summarizes the resulting net present value ("NPV") power costs, resource additions and coal retirements, carbon emissions, and generation mix under the Reference Case assumptions over the Study Period. NPV power costs below, and elsewhere in this section, are reported over the Study Period in 2023 dollars. Under the Reference Case assumptions, the Economically Optimized Portfolio results in the lowest NPV power costs. The Net Zero CO_2 by 2050 and No New Fossil portfolios result in the greatest amount of new nameplate capacity added to the system, both adding approximately double the amount of capacity as the Economically Optimized portfolio on a nameplate basis. This is driven from the fact that solar and wind resources do not contribute as much toward reserves as dispatchable generation and have both limited capacity factors and production patterns that are dominated by certain hours of the day, requiring more BESS resources to meet system load during all hours.

[57] The large NGCC would have two gas turbine electric generators (essentially CTs), and heat recovery steam generator, and a steam turbine generator with a total capacity of 1,360 MW in the winter season.

[58] Analyses indicate that projected costs of new CTs are marginally more cost-effective than costs of BESS over the Study Period. Compared to BESS, CTs have certain benefits in terms of operating flexibility and reliability. Although BESS can only "produce" energy to the extent stored, BESS may have certain advantages over CTs in terms of shorter implementation schedules, Santee Cooper has concluded that further consideration should be given to balancing addition of CTs and BESS instead of concluding that predominately CTs should be added as indicated by the optimization model.

Table 22.
Summary of Resource Portfolio Results Under the Reference Case

	Economically Optimized	Coal Retirement	No New Fossil	Net Zero CO2
NPV Power Cost ($B)	$23.5	$25.3	$25.3	$26.7
Cumulative Capacity Added (MW):				
NGCC	1,360	2,719	0	1,360
Peaking	447	1,341	0	1,597
Solar	4,000	4,200	6,750	4,950
Onshore Wind	850	550	1,500	5,000
Offshore Wind	0	0	0	0
BESS	600	850	3,450	2,000
Small Modular Nuclear	0	0	0	0
Total	7,256	9,660	11,700	14,906
Cumulative Coal Retired (MW)	1,150	3,480	1,150	3,480
CO2 Emissions Profile (2023-2052)				
Average Annual Emissions (MT)	408	320	371	240
Average Emissions Rate (Lbs/MWh)	920	728	839	552
Generation Mix over 2029-2052 (%)				
Coal	23%	5%	27%	2%
Natural Gas	39%	56%	12%	33%
Nuclear	9%	9%	8%	8%
Hydro	3%	3%	3%	3%
Solar	24%	25%	37%	26%
Onshore Wind	2%	1%	12%	26%
Offshore Wind	0%	0%	0%	0%
Other	1%	1%	1%	1%

PORTFOLIO METRICS

To evaluate the potential Portfolios, Santee Cooper simulated each optimized 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, future regulatory policies regarding CO_2 emissions regulation, load levels, and DSM program impacts. To allow for total costs and emissions to be comparable, results are separately provided for sensitivities reflecting Base Load Forecast load levels and for sensitivities related to variations in the load forecast and DSM levels. These sensitivity analyses and the resulting evaluation metrics provide useful information regarding the important elements and likely parameters of the Preferred Portfolio.

NPV POWER COSTS

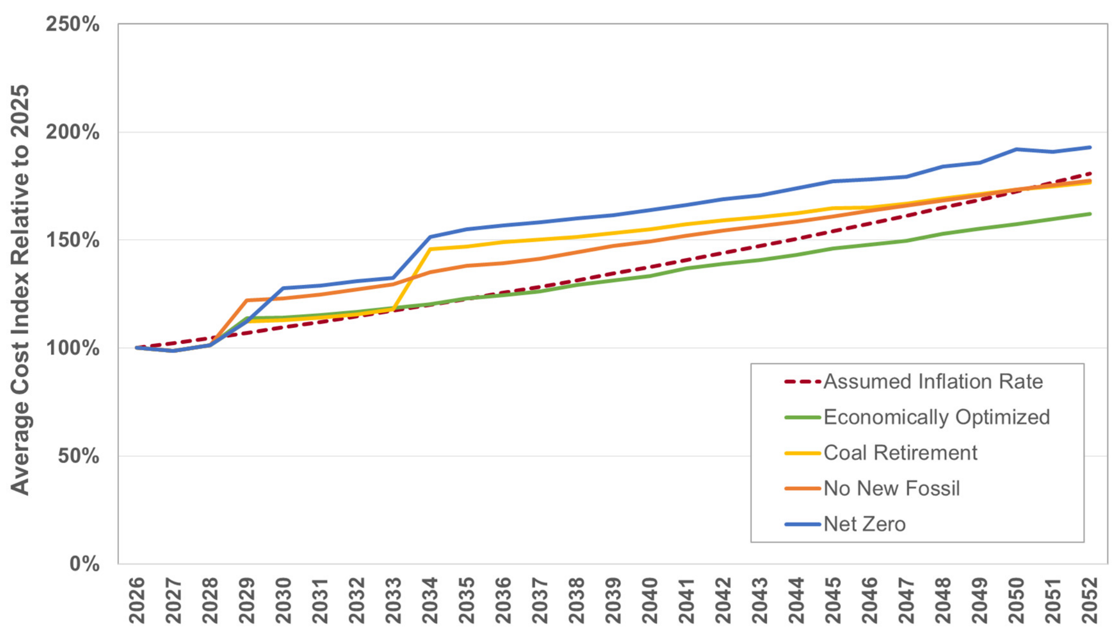
The NPV Power Cost metric measures the costs to customers of each of the resource portfolios based on NPV modeled power costs in 2023 dollars of each Portfolio over the Study Period. Table 23 compares the NPV power cost for the portfolios under the Reference Case Assumptions, with color-coding from light green, light gold, and then to a light rose color indicating lowest to highest values.

Table 23.
Comparison of NPV Power Costs for the Reference Case ($B)

Portfolio	NPV Power Costs
Economically Optimized	$23.5
Coal Retirement	$25.3
No New Fossil	$25.3
Net Zero	$26.7
Difference to Economically Optimized	
Coal Retirement	$1.8
No New Fossil	$1.8
Net Zero	$3.2

The Reference Case results show that the Economically Optimized Portfolio results in the lowest NPV power cost. The Coal Retirement and No New Fossil portfolios reflect somewhat higher costs, and the Net Zero CO_2 by 2050 Portfolio, considerably higher cost. Figure 26[59] below shows annual average projected portfolio costs per kWh indexed to 2026.

Figure 26 - Average Portfolio Costs Indexed to 2026 (Reference Case)



[59] Reflects only portfolio costs included in Table 23. Please see section titled Rate Impacts of Portfolios for projected total rate trends for each portfolio.

Table 24.
Comparison of NPV Power Costs for the Fuel Cost Sensitivities

Portfolio	NPV Power Costs ($B)			Diff. to Reference ($B)	
	Reference	Low Fuel Price	High Fuel Price	Low Fuel Price	High Fuel Price
Economically Optimized	$23.5	$22.1	$26.6	($1.5)	$3.1
Coal Retirement	$25.3	$23.5	$30.0	($1.8)	$4.7
No New Fossil	$25.3	$24.6	$26.6	($0.7)	$1.3
Net Zero	$26.7	$25.5	$29.8	($1.2)	$3.1
Difference to Economically Optimized					
Coal Retirement	$1.8	$1.4	$3.4		
No New Fossil	$1.8	$2.5	($0.0)		
Net Zero	$3.2	$3.4	$3.2		

Across the fuel cost sensitivities, the Economically Optimized Portfolio retains its position as the low-cost portfolio. However, the results demonstrate some differences in the sensitivity of the portfolios to variations in fuel prices, particularly recognizing that the primary fuel cost variation is in natural gas prices. The Coal Retirement Portfolio shows the most significant variation in NPV power costs as it relies more heavily on NGCC generation to replace the baseload coal facilities retired in that portfolio. The No New Fossil Portfolio reflects the least sensitivity given no additions of NGCC capacity during the Study Period.

Table 25.
Comparison of NPV Power Costs for the CO_2 Cost Sensitivities

Portfolio	NPV Power Costs ($B)			Diff. to Reference ($B)	
	Reference	Med CO2 Price	High CO2 Price	Med CO2 Price	High CO2 Price
Economically Optimized	$23.5	$28.2	$36.6	$4.7	$13.1
Coal Retirement	$25.3	$28.8	$35.6	$3.5	$10.3
No New Fossil	$25.3	$29.5	$37.2	$4.2	$11.9
Net Zero	$26.7	$28.9	$33.3	$2.2	$6.6
Difference to Economically Optimized					
Coal Retirement	$1.8	$0.6	($1.0)		
No New Fossil	$1.8	$1.2	$0.5		
Net Zero	$3.2	$0.7	($3.3)		

NPV power costs for the CO_2 cost sensitivities reflect that the Economically Optimized Portfolio retains its position as the low-cost position except in the High CO_2 price case. The Coal Retirement and Net Zero CO_2 by 2050 portfolios are less sensitive to CO_2 price variations given the retirement of Cross early in the Study Period. Similarly, the No New Fossil Portfolio is somewhat less impacted by the CO_2 sensitivities, as a result of greater implementation of renewable resources.

The overall results above reflect that the Economically Optimized Portfolio results in the lowest NPV power cost across nearly every sensitivity case. The Coal Retirement, No New Fossil, and Net Zero CO_2 by 2050 portfolios reflect higher costs across the sensitivities other than the High CO_2 Price case. Under the High CO_2 Price case, the Economically Optimized Portfolio results in NPV power costs that are just under 5% higher than the lowest cost case, the Coal Retirement Portfolio.

A summary of NPV power costs by Portfolio over both the full Study Period and over a 20-year period, 2029-2048, the period spanning the bulk of cost impacts of major resource decisions, are provided in Appendix E.

MINI-MAX REGRET

Mini-Max Regret is the potential to incur higher power costs by pursuing any resource portfolio relative to any other plan as evaluated across the modeled sensitivities. It is calculated by measuring the difference in NPV power cost between each portfolio and the lowest cost portfolio for each sensitivity. That difference can be referred to as the regret potential associated with that portfolio. The maximum regret is the maximum of that difference for any plan across all sensitivities. The idea behind the metric is to find the portfolio that minimizes this maximum regret.

Table 26 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 Economically Optimized Portfolio. The maximum regret across the other Portfolios is somewhat higher, with the No New Fossil Portfolio reflecting a maximum regret considerably larger than the maximum regret across the other portfolios.

Table 26. NPV Power Costs Across Sensitivities and Maximum Regret ($B)

Portfolio	Reference Case	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
Economically Optimized	$23.5	$22.1	$26.6	$28.2	$36.6
Coal Retirement	$25.3	$23.5	$30.0	$28.8	$35.6
No New Fossil	$25.3	$24.6	$26.6	$29.5	$37.2
Net Zero	$26.7	$25.5	$29.8	$28.9	$33.3

Max Regret by Portfolio	2023 $B
Economically Optimized	$3.3
Coal Retirement	$3.4
No New Fossil	$3.8
Net Zero	$3.4

FUEL COST RESILIENCY

Fuel costs are incorporated into the comparison of power costs presented above. However, fuel cost variability is useful as an additional evaluation metric to assess the risk inherent in each portfolio because of differences in the mix of installed generation and, in particular, the extent of natural gas-fueled resources.[60]

Table 27 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 No New Fossil Portfolio results in the lowest range of uncertainty, followed by the Net Zero by 2050 Portfolio. The Economically Optimized Portfolio follows closely behind the Net Zero Portfolio. Importantly, while the portfolios with greater reliance on renewables have lower fuel cost uncertainty, the cost of renewable facilities is also significantly uncertain, which is not captured in this metric.

Table 27. Fuel Price Sensitivity Results

Portfolio	NPV Fuel Costs ($B)			Differences Across Sensitivities ($B)		
	Medium Fuel Price	Low Fuel Price	High Fuel Price	Low v. Medium	High v. Medium	Uncertainty Range
Economically Optimized	$14.6	$13.0	$17.9	-$1.6	$3.3	$4.8
Coal Retirement	$13.5	$11.6	$18.2	-$1.9	$4.7	$6.6
No New Fossil	$12.4	$11.6	$13.8	-$0.8	$1.4	$2.2
Net Zero	$10.7	$9.5	$13.9	-$1.2	$3.1	$4.4

CO_2 EMISSIONS

Santee Cooper is committed to reducing the carbon footprint of its generating fleet. Table 28 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 indicate that the Net Zero CO_2 by 2050 Portfolio produces the lowest CO_2 emissions, considerably lower than the Economically Optimized Portfolio on both a mass and rate basis. Under the Medium and High CO_2 price sensitivities, the spread of emissions across the portfolios progressively closes somewhat.

[60] As discussed above, the variation in coal prices reflected in the fuel price scenarios likely understates the uncertainty in coal prices by a significant margin. However, such variation did not appear to be significantly correlated with natural gas prices, based on the results of the 2022 AEO Oil and Gas Supply Cases.

Table 28.
Comparison of CO_2 Emissions Across Fixed Load Sensitivities

Portfolio	Reference Cases	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
Cumulative Emissions (MT)					
Economically Optimized	408	393	482	387	366
Coal Retirement	320	318	336	318	313
No New Fossil	371	355	415	355	338
Net Zero	240	238	247	239	236
Average Emissions (lbs/MWh)					
Economically Optimized	920	888	1,083	875	827
Coal Retirement	728	723	766	723	711
No New Fossil	839	805	936	804	767
Net Zero	552	548	568	550	543

Table 29 compares CO_2 emissions in thousands of tons for the resource portfolios for the year 2050. As above, the Net Zero CO_2 by 2050 Portfolio produces the lowest CO_2 emissions, achieving results very close to the optimization target of a 90% reduction, leaving only an additional 11% reduction to be addressed through implementation of emissions mitigation technologies or by carbon offsets. However, all cases reflect a significant reduction in CO_2 emissions by 2050. For the Economically Optimized Portfolio, the High Fuel price sensitivity case reflects considerably higher cost for natural gas, which results in much greater operation of the coal units, and hence, greater emissions over the Study Period.

Table 29.
CO_2 Emissions in 2050 Across Fixed Load Sensitivities (Tons; Ths)

Portfolio	Reference Cases	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
Economically Optimized	11,129	10,342	14,315	10,065	9,447
Coal Retirement	6,885	6,886	6,880	6,878	6,880
No New Fossil	9,307	8,552	11,244	8,492	8,139
Net Zero	2,443	2,441	2,442	2,443	2,442
Percent Reduction from 2005:					
Economically Optimized	-52%	-55%	-38%	-56%	-59%
Coal Retirement	-70%	-70%	-70%	-70%	-70%
No New Fossil	-59%	-63%	-51%	-63%	-65%
Net Zero	-89%	-89%	-89%	-89%	-89%

GENERATION DIVERSITY

The Portfolios reflect a considerably different mix of installed generating capacity and energy sources over the Study Period. 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. The fact that portfolios that are heavily reliant upon renewables reflect much larger required capacity additions on a nameplate basis may contribute to these risks.

A useful measure of diversity for this purpose is the coefficient of dispersion. The coefficient of dispersion represents the standard deviation of a series of values divided by the average of the values. Hence, a lower coefficient of dispersion corresponds to a more uniform, equally distributed set of values.

Table 30 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.[61] The Economically Optimized Portfolio reflects the lowest coefficient of dispersion, reflecting a lower reliance on any one fuel or resource type than the other portfolios.

Table 30.
Diversity of Generation Resources Across Portfolios at Study End Year

Portfolio	Coefficient of Dispersion		
	Capacity	Energy	Average
Economically Optimized	1.17	1.10	1.14
Coal Retirement	1.55	1.59	1.57
No New Fossil	1.29	1.20	1.25
Net Zero	1.25	1.28	1.26

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 31 provides the proportion of carbon-free generation across the portfolios over the Study Period. The Net Zero CO_2 by 2050 Portfolio, not surprisingly, derives the highest proportion of system energy from carbon-free resources, with the No New Fossil Portfolio following closely behind. The Economically Optimized and Future Coal Retirement portfolios result in similar proportions of clean energy of just over 30% of system generation. The proportion of clean energy does not vary considerably across the fixed load sensitivities.

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

Table 31.
Carbon-free Generation Proportion Across Portfolios over Study Period

Portfolio	Reference Case	Low Fuel Price	High Fuel Price	Med CO2 Price	High CO2 Price
Economically Optimized	32.8%	33.0%	32.5%	33.1%	33.2%
Coal Retirement	33.5%	33.5%	33.5%	33.6%	33.6%
No New Fossil	51.8%	52.1%	51.4%	52.2%	52.3%
Net Zero	54.0%	54.0%	54.0%	54.0%	54.0%

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 32 provides the total fixed cost obligations across the portfolios on an NPV basis over the Study Period and reflects that the Economically Optimized Portfolio incurs the lowest burden of fixed costs of the portfolio options.

Table 32.
Fixed Cost Obligations by Portfolio Over the Study Period

Portfolio	NPV ($B 2023)
Economically Optimized	$6.2
Coal Retirement	$9.0
No New Fossil	$10.3
Net Zero	$13.1

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.

SUMMARY OF EVALUATION METRICS

Table 33 summarizes the evaluation metrics by ranking the portfolios relative to the others for each of the major metrics. As discussed above, the Economically Optimized Portfolio reflects the lowest NPV power costs and minimizes the maximum regret, based on the sensitivities evaluated. It also reflects the most diverse sources of generation. As should be expected, the Net Zero CO_2 by 2050 Portfolio scores best on the metrics related to CO_2 emissions and clean energy. The fuel cost resiliency metric is impacted by both the extent of natural gas generation versus non-CO_2-emitting resources and the extent of coal resources.

Table 33. Ranking of Potential Portfolios for Evaluation Metrics

Portfolio	NPV Power Cost	Mini-max Regret	Fuel Cost Resiliency	CO2 Emissions	Generation Diversity	Clean Energy	Fixed Cost Obligation
Economically Optimized	1	1	3	4	1	4	1
Coal Retirement	3	3	4	2	4	3	2
No New Fossil	2	4	1	3	2	2	3
Net Zero	4	2	2	1	3	1	4

The following are key observations from the portfolio evaluation results detailed above.

- The Economically Optimized Portfolio has the lowest NPV power costs under the Reference Case and reflects the lowest risk based on the Mini-max Regret metric.
- The Economically Optimized Portfolio also has the lowest NPV power costs under each of the sensitivity cases, other than the High CO_2 Cost sensitivity case.[62]
- Retiring the Cross Generation Station (in addition to Winyah) is currently projected to result in significantly higher costs than the Economically Optimized Portfolio, which would result in less affordable prices for customers, except under the High CO2 Price sensitivity case.
- A Net Zero CO_2 Portfolio is currently projected to result in significantly higher costs, which would result in less affordable prices for customers, under the Reference Case Assumptions and the sensitivity cases. The Net Zero CO_2 Portfolio performs better than the other portfolios under the High CO_2 Price sensitivity case.
- The No New Fossil Portfolio has the least reliance on natural gas-fueled resources and accordingly, the lowest exposure to fuel price variations. However, it is also among the highest cost portfolios under the Reference Case.
- The Economically Optimized Portfolio reflects the greatest diversity of fuel types.
- The No New Fossil and Net Zero portfolios have the highest percentage of energy from non-emitting resources.
- Government policy that would impose on utilities additional costs related to CO_2 emissions would materially increase projected future Combined System costs and therefore charges to customers under all four foundational portfolios. Should the level of costs imposed reach the levels assumed in the High CO_2 Price case, the differences in the costs of the four portfolios would be significantly smaller than under the Reference Case assumptions, which assumes no CO_2 charges would be imposed.

A key result of the analyses of the four “foundational” optimized portfolios described above is that the Economically Optimized, Coal Retirement, and even Net Zero CO_2 by 2050 portfolios include similar resources that are needed beginning in the late 2020s and upon retirement of Winyah—namely large amounts of solar power additions, an NGCC upon retirement of Winyah, and BESS and CTs to meet other peak load requirements. The need for these types of resources is not materially dependent on the differences in long-term priorities analyzed in those three portfolios.

[62] Under the High Fuel Price sensitivity, the Economically Optimized and No New Fossil have essentially identical NPV power costs.

RELIABILITY

An important characteristic of any resource plan is the ability to serve load and meet critical real-time operating requirements necessary to maintain a reliable electric system. Resource simulations performed for the IRP using the EnCompass simulation model ensure that all evaluated resource portfolios meet reliability standards for the target reserve margin and satisfy shared regional contingency reserves for spinning and quick-start operating reserves. The portfolios prepared through the IRP analyses are designed to provide capabilities necessary to serve electric system loads, both capacity and energy, and to meet planning reserve margins and regional reliability criteria.

To provide input on reliability consideration for the IRP Report, Santee Copper has prepared the following Table 34 and Table 35. Table 34 summarizes reliability attributes that must be supplied by resources within each portfolio to maintain a reliably operating electric system. These attributes include capabilities such as frequency response that is needed within a period of a few seconds, to longer-term considerations for unrestricted resource operation that will allow Santee Cooper to reliably manage emergency conditions and operate through potential multi-day, long-duration weather events.

Table 34. Reliability Attributes Necessary for Electric System Operation

Reliability Attribute	Description
Primary Frequency Response (hertz to seconds)	System inertia and excitation response.
Regulation Service (seconds to minutes)	Follow BA variability of load and intermittent resources.
Spinning Reserves (minutes)	Online reserves for loss of a large resource within a region.
Quick-start Reserves (15-30 minutes)	Typically met by generating units able to start and be interconnected to grid within 10-15 minutes.
Black Start (system restart after emergency event)	Need for resources that can be started without grid support, provide support to start other resources, provide real and reactive power, provide frequency and voltage support, and can be included in a transmission operator's system restoration plans.
Non-limited Dispatchability	Resources with flexible operating characteristics that can be committed and dispatched without limits to operating duration (i.e., continuous operation from multiple hours through multiple days, as needed).

Table 35 summarizes the reliability attributes that can be supplied by the new generating resource options that were considered for portfolio development within the IRP analyses.

The Economically Optimized Portfolio (as well as the Preferred Portfolio discussed in the next section) reflects substantial dispatchable resources (i.e., Cross, a new large NGCC, Rainey, existing hydro resources, BESS, and CT resources) to manage the levels of intermittent solar and wind resources included in that portfolio. Accordingly, Santee Cooper expects that portfolio will position Santee Cooper to continue to maintain expected high standards of reliability.

Table 35. Reliability Attributes Supplied by New Resource Options

Reliability Attribute	New Resource Options							
	Frame CC	Frame CT	RICE / Areo	Solar	Wind	BESS	SMR	Coal (Retire)
Primary Frequency Response	Medium	Low	Low	Low	Low	Low	Medium	High
Regulation Up	Yes	Yes	Yes	No	No	Yes (if charged)	Yes	Yes
Regulation Down	Yes	Yes	Yes	Yes (if curtailable)	Yes (if curtailable)	Yes (if discharged)	Yes	Yes
Spinning Reserves	Yes	Yes	Yes	No	No	Yes	Yes	Yes
Quick-start Reserves	Possible	Possible	Yes	No	No	Yes	No	No
Black Start	No	Possible (w/ BESS)	Yes	Weather dependent	Weather dependent	Possible (but energy limited)	No	No
Non-limited Dispatchability	Yes	Yes	Yes	No (intermittent)	No (intermittent)	No (energy limited)	Yes	Yes

Solar and wind resources provide zero-carbon energy but are intermittent resources and therefore cannot provide most capabilities needed for reliable system operation and cannot be relied upon to provide energy during emergencies or long duration events. BESS resources may be able to provide a broad range of capabilities needed for reliable system operation. However, BESS resources are energy limited. Accordingly, BESS may not fully provide system needs during extended weather events. While the IRP analysis has been performed in a manner that satisfies primary planning and operating reserve reliability criteria, Santee Cooper recognizes that certain real-time operating requirements are beyond the scope of simulations typically prepared for IRP studies. Santee Cooper plans to perform these additional analysis and investigations, as stated in its Short-term Action Plan, to better inform future consideration of portfolios that rely heavily on such resources.

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 determine (i) whether the identification of the most-cost effective portfolio is particularly sensitive to load levels and (ii) the impact on average NPV power cost of such load variations. Variations in average NPV power costs can be impacted by the volume of sales over which Santee Cooper fixed costs would be spread. The variation in average NPV power costs indicate the sensitivity of rate levels to load levels for the portfolio.

The analysis of costs under the high and low load forecasts assumed decisions to retire Winyah and develop a large NGCC upon Winyah's retirement would not be impacted by changes in the load forecast. While Santee Cooper may have flexibility under some circumstances to modify those decisions somewhat in response to a change in load growth outlook, the assumption was made to determine the impacts of different load levels without reflecting such cost mitigating actions regarding those decisions.

Table 36 summarizes the resource build plan resulting from the partial optimization of the Economically Optimized Portfolio across the load growth sensitivity cases. Under the Low Load case, significantly less solar is implemented, and the CT 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, and BESS resources are implemented.

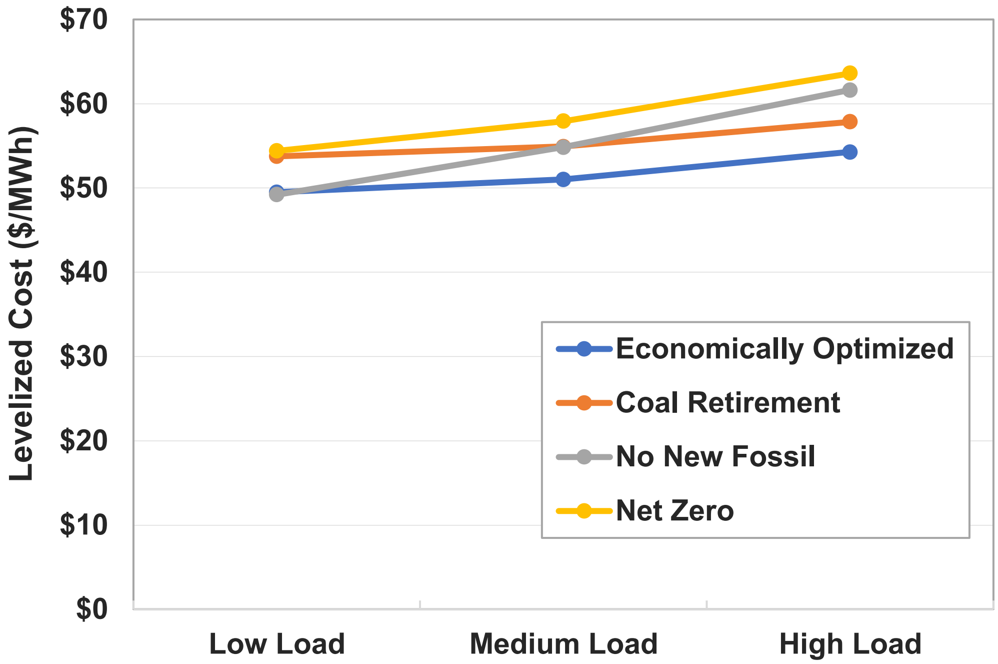
Table 36. Economically Optimized Portfolio Across Load Sensitivities

Resource Changes	Load Sensitivity – Additions (Retirements) - MW		
	Low Load Forecast	Base Load Forecast	High Load Forecast
Coal Retirement • Winyah – by 2029 • Cross	(1,150) Also Would Consider Mothballing or Retiring One or More Cross Units	(1,150) Cross Continues	(1,150) Cross Continues
New Solar[63] • In 2029 • 2030-2040	1,700 300	2,200 750	2,800 650
New NGCCs • 2029 • 2034	1,360 0	1,360 0	1,360 1,360
New Frame CTs • 2029 • 2030-2040	0 0	447 0	894 703
New BESS • 2029 • 2030-2040	0 0	0 250	50 50
New Wind • 2029 • 2030-2040	0 0	0 50	0 0

Figure 27 depicts the average levelized power cost of each of the four foundational portfolios for the three load forecast scenarios, Low Load through High Load.

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

Figure 27. Sensitivity of NPV Power Costs to Load Growth Variations



Key conclusions that can be drawn from Figure 27 include the following.

1. The Economically Optimized Portfolio average cost is relatively flat across the range of load forecasts tested. This indicates a relatively low level of load forecast-related risk.
2. The Coal Retirement Portfolio shows a similar level of load forecast risk to the Economically Optimized Portfolio—the levelized power cost is relatively flat under that portfolio, as well.
3. The average levelized power cost under the Coal Retirement Portfolio remains above the Economically Optimized Portfolio across the range of future load forecasts, indicating that the conclusion that continuing to operate Cross remains cost-effective, arrived at through the evaluation under the Medium Load case, is not particularly sensitive to load forecast levels.
4. Average levelized cost under the No New Fossil Portfolio is much more sensitive to load forecast than costs under the Economically Optimized and Coal Retirement portfolios. Interestingly, under the Low Load forecast, the average power cost for the Economically Optimized and No New Fossil portfolios are very close. However, the No New Fossil Portfolio becomes increasingly more costly as the load forecast moves higher—moving toward approximately 20% higher in cost under the High Load Forecast.
5. Costs of the Net Zero CO_2 by 2050 Portfolio are materially higher than the other three cases shown on Figure 27, and more sensitive to load variations than the Economically Optimized and Coal Retirement portfolios.

These results confirm that the Economically Optimized Portfolio has the flexibility to be adjusted in response to variations in future load levels with limited variation in resulting average power costs, resulting in low load forecast-related risk to customers. The Economically Optimized Portfolio remains the more cost-effective of the four foundational portfolios under a wide range of future load levels.

EVALUATION OF VARIATIONS IN DEMAND-SIDE RESOURCES

The NPV power cost comparisons above reflect Central and Santee Cooper's medium case DSM program implementation, based on information provided by Central generally consistent with Central's 2020 IRP and based on Santee Cooper's EE and DR Market Potential Studies, as discussed in the Demand-side Management Overview section. To understand the economics of variations in demand-side resources, a sensitivity analysis that assumes variations in Central and Santee Cooper's DSM programs has been prepared.

For this sensitivity, the Economically Optimized Portfolio was re-optimized under both Low DSM and High DSM cases, with all other assumptions consistent with the Reference Case. Variations in assumed DSM implementation resulted in differences in the optimized resource build, as additional demand-side resources can substitute, to some degree, for supply-side resources or allow the timing to be delayed in the High DSM case and reduced DSM can result in supply-side resources being brought forward or increased in magnitude in the Low DSM case. Under the Low DSM case, aside from minor differences in the timing of solar implementation, somewhat more BESS is implemented. In the High DSM case, the CT resource is delayed from 2029 to 2030 and significantly less solar and BESS resources are implemented, though some additional wind is selected.

Table 37 summarizes the resource build plan resulting from the optimization of the Economically Optimized Portfolio across the DSM sensitivity cases. Under the Low DSM case, aside from minor difference in the timing of solar implementation, somewhat more BESS and wind is implemented. In the High DSM case, the CT resource is delayed from 2029 to 2030 and significantly less solar, wind, and BESS resources are implemented.

[Left Intentionally Blank]

Table 37. Economically Optimized Portfolio Across DSM Sensitivities

Resource Changes	DSM Sensitivity – Additions (Retirements) - MW		
	Low DSM Case	Reference Case (Medium DSM)	High DSM Case
Coal Retirement • Winyah – by 2029	(1,150)	(1,150)	(1,150)
New Solar[64] • In 2029 • 2030-2040	2,100 850	2,200 750	2,200 600
New NGCCs • 2029 • 2034	1,360 0	1,360 0	1,360 0
New Frame CTs • 2029 • 2030-2040	447 0	447 0	0 447
New BESS • 2029 • 2030-2040	0 350	0 250	0 50
New Wind • 2029 • 2030-2040	0 50	0 50	0 100

Table 38 compares the NPV power costs resulting from power cost simulation for the Low DSM and High DSM cases to those under the Reference Case. As shown, the Reference and Low DSM Cases result in very close to the same NPV total portfolio costs. In other words, the supply-side and DSM program cost differences between the two cases are negligible. Accordingly, comparing the Low to Reference Case DSM Cases would suggest targeting the Medium DSM implementation rather than the Low DSM Case, because, while resulting power costs are projected to be similar, it would result in lower emissions.

However, projected costs under the High DSM Case are higher than under the Reference DSM Case indicating that the cost to obtain additional DSM impacts and DR capability beyond the Medium DSM implementation may be greater than the avoided cost of supply-side resources.

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

Table 38. NPV Power Costs Across Demand-side Management Sensitivities

Portfolio / Sensitivity	NPV Power Costs
Low DSM	$23.5
Reference Case (Medium DSM)	$23.5
High DSM	$23.7
Diff to Reference Case	
Low DSM	$0.0
High DSM	$0.2

As shown by the results summarized in Table 39, similar guidance is provided by considering the value of the High DSM Case under the High Load Forecast. These results also reflect that the High DSM Case results in higher portfolio costs.

Table 39. NPV Power Costs for DSM Sensitivities with High Load

Portfolio / Sensitivity	NPV Power Costs
High Load / Medium DSM	$29.8
High Load / High DSM	$29.9
Diff to High Load / Medium DSM	$0.1

Based on these DSM Sensitivity Case results, Santee Cooper has used the medium DSM assumptions in the other analyses included in this IRP. As noted in the section titled Short-term Action Plan, Santee Cooper plans to proceed with further implementation of attractive DSM programs and perform additional studies to further evaluate demand-side options. Central also plans to continue DSM studies and implementation activities. These additional efforts will provide valuable information for use in future IRPs.

RATE IMPACTS OF PORTFOLIOS

The primary focus of the analyses presented in this IRP is to compare projected portfolio costs for each of the foundational portfolios and the Preferred Portfolio. In this context, 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.

To approximate Santee Cooper's average rate level, Santee Cooper's total cost-of-service[65] has been projected by adding to the portfolio costs discussed above and elsewhere in this IRP 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 28 below provides the resulting trend in projected rates indexed to 2026 for Santee Cooper's customers for each of the foundational portfolios studied, based on the Reference Case Assumptions.[66]

Figure 28. Projected Rate Index for Foundational Portfolios (Reference Case)

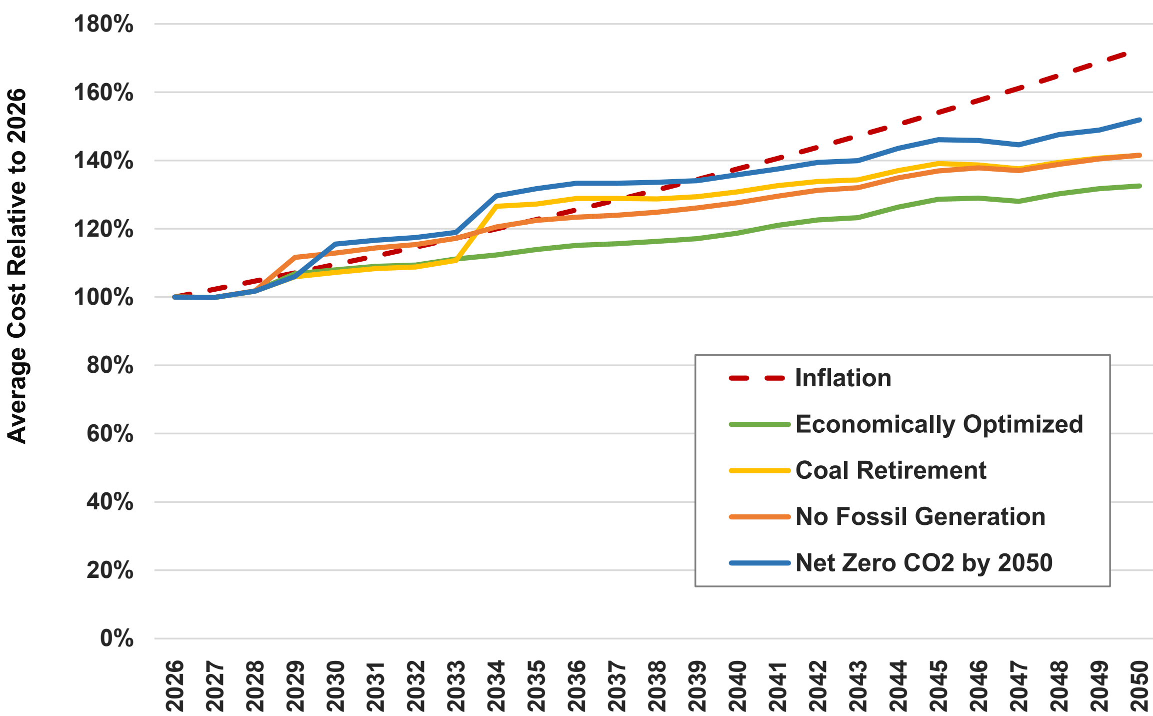


Figure 28 indicates significant increases in rates under the Coal Retirement, No New Fossil, and Net Zero CO_2 by 2050 portfolios at the time either Winyah or Cross is retired and replaced with new resources. Any step changes in annual revenue requirements would typically be smoothed

[65] The cost-of-service analysis prepared for this purpose is appropriate for assessing the difference in rate impacts of the portfolios analyzed in this IRP. 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.

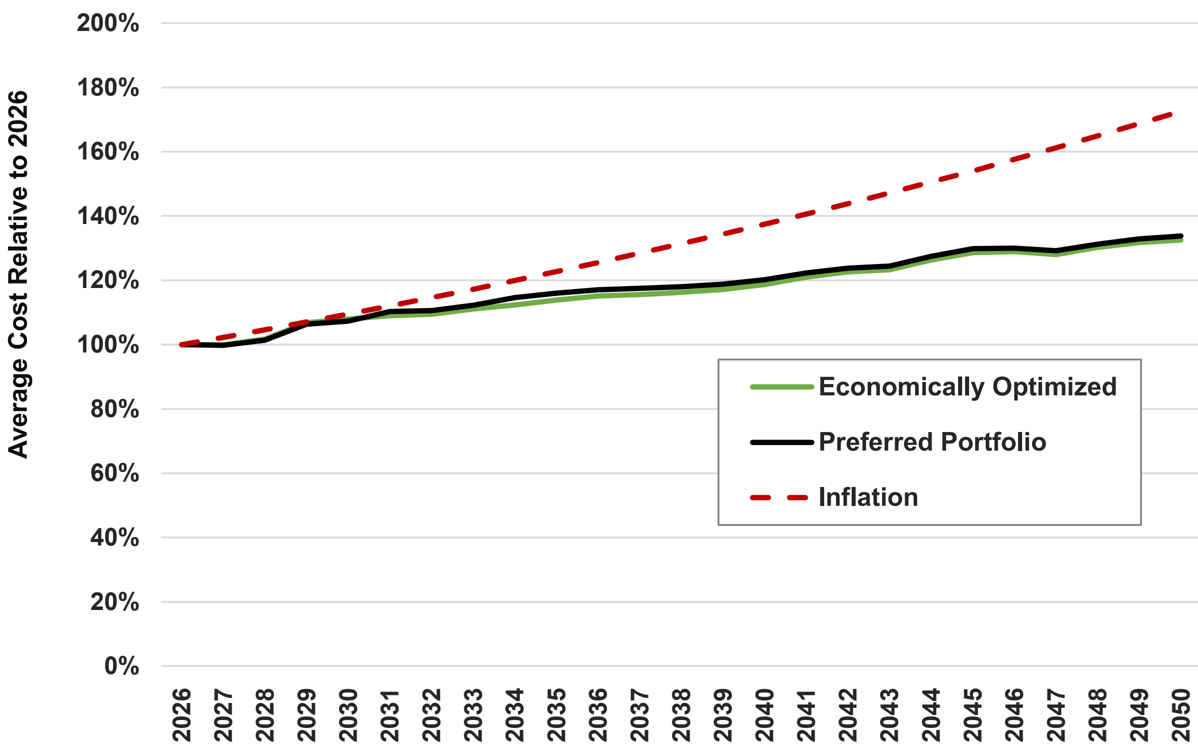
[66] Similar information for fuel and CO_2 price sensitivity cases is provided in Appendix G.

or mitigated over several years, after taking into consideration other changes to revenue requirements (not related to resource plans), but the impact of the cost increase would be significant.

Please note that the values shown in Figure 28 for the Net Zero CO_2 Portfolio are based on portfolio costs incurred to achieve approximately 90% reduction in CO_2 emissions by 2050, not a 100% reduction. Net Zero CO_2 would then be achieved by employing additional technologies (e.g., carbon capture), using alternative zero-carbon fuels (such as hydrogen), or achieving other offsets (e.g., purchasing renewable energy credits or investing in CO_2 mitigation projects). The additional cost level to be incurred to achieve that remaining 10% reduction in CO_2 emissions is currently extremely uncertain, and therefore is not reflected in the current analyses, but is expected to result in significant increases in rates beyond the levels shown toward the 2050 timeframe for the Net Zero CO_2 Portfolio.

As shown in Figure 29 below, projected rate impacts of the Preferred Portfolio and Economically Optimized Portfolio are very close to the same and trend well below the rate of inflation over the long term.

Figure 29. Projected Rate Index for the Preferred Portfolio



As shown in Table 40, the rate trends over the period 2026 through 2040 would be well below inflation for the Economically Optimized and Preferred Portfolios, but much nearer the assumed inflation rate for the other portfolios.

Table 40. Projected Average Rate Trends

	CAGR 2026-40
Economically Optimized	**1.2%**
Coal Retirement	**1.9%**
No Fossil Generation	**1.8%**
Net Zero CO2 by 2050	**2.2%**
Preferred Portfolio	**1.3%**
Inflation	**2.3%**

CAPITAL COST SENSITIVITY

To test the sensitivity of the conclusion that NGCCs and CTs represent important, cost-effective generation capacity additions, Santee Cooper has prepared sensitivity analyses assuming capital costs of those resource types would be approximately 50% higher than assumed under the Reference Case. These sensitivity cases do not assume higher costs of renewable, BESS, or other resource types considered in this IRP even though most of the circumstances that would result in higher fossil-fueled resource capital costs would also adversely impact costs of those other resources. Santee Cooper has taken this conservative approach to “stress test” the consideration of NGCC and CT resources.

Assuming capital costs of fossil-fueled resources that are 50% higher than in the Reference Case, projected costs of the Economically Optimized Portfolio would be higher by approximately $500 million, as shown in Table 41. However, the optimization model still chooses a 2x1 NGCC as the most economical resource to replace Winyah under the Economically Optimized Portfolio.

In addition, because NGCC and CT resources are also selected as viable replacement resources when Winyah and Cross retire under the Coal Retirement and Net Zero portfolios, the costs under those portfolios would also be higher, and the relationships between cost of the four foundational portfolios shown elsewhere in this IRP would not be very different (or cost differences would not be eclipsed by the incremental change in capital cost under the No New Fossil Portfolio).

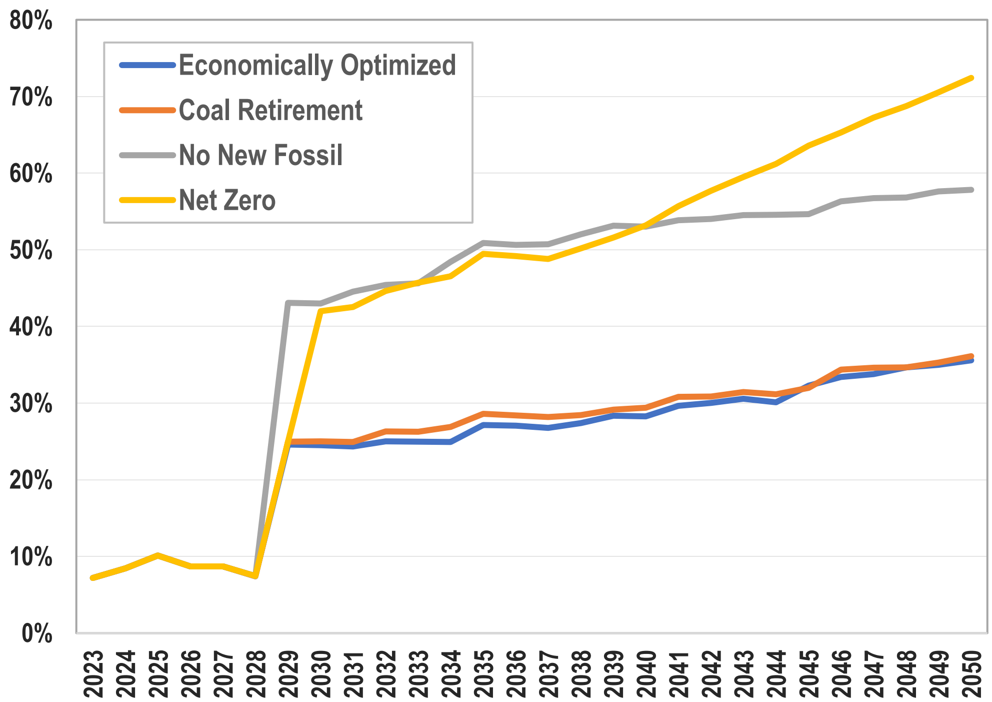
Table 41. Fossil-fueled Generation Capital Cost Sensitivity ($B)

Portfolio	NPV Power Costs
Economically Optimized - Reference	$23.5
Economically Opt - High Capital Cost	$24.1
Diff to Reference Case	$0.5

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 30 depicts the trend in this proportion over the Study Period. As should be expected, the No New Fossil and Net Zero portfolios reflect far higher concentration of renewable resources, with the Net Zero Portfolio increasing in the proportion of renewable generation well above all other portfolios beyond 2040.

Figure 30. Percentage of System Energy Served from Renewables



Renewable generation amounts by year are provided in Appendix F.

OTHER LONG TERM POWER SUPPLY ALTERNATIVES

Santee Cooper is a participant on the technical advisory board to the South Carolina Legislature Electricity Market Reform Measures Study Committee. The committee commissioned the Brattle Group to perform a market reform study. The study reviewed several areas of electric market reform: wholesale market reforms, resource planning and competitive investment reform, and retail market reform.

Of the three areas the wholesale market reforms reviewed several potential alternate power supply options. The power supply options consisted of retaining the status quo, developing a Carolinas-wide Joint Dispatch Agreement, implementation of a Southeast Energy Imbalance Market, creating a Southeast Regional Transmission Organization (RTO), and integrating with PJM Interconnection (PJM) RTO. The study report was released on April 27, 2023, and is available on the South Carolina State House website.[67] Santee Cooper is reviewing the report and monitoring the Electricity Market Reform Measures Study Committee for any actions or recommendations in response to the study for additional long-term power supply alternatives.

[67] Assessment of Potential Market Reforms for South Carolina's Electricity Sector Study Report

santee cooper®

PREFERRED PORTFOLIO

The results of the resource plan analyses presented in the previous section and other considerations lead to the key concepts presented in the table below as foundational to Santee Cooper's Preferred Portfolio.

Topic	Conclusions
Portfolio Direction	▪ Economically Optimized Portfolio provides cost and risk advantages over the other portfolios studied. ▪ Resource additions that need to be planned for in the near term are similar under the Economically Optimized, Future Coal Retirement, and Net Zero CO_2 portfolios.
Viability of a New Large NGCC	▪ Analyses support an NGCC as an attractive new resource upon retirement of Winyah and demonstrate that adding an NGCC is an important component of future portfolio development. ▪ An NGCC could be important for integrating solar resources in a cost effective and reliable manner.
Timing of Winyah Retirement	▪ Continuing to operate Winyah through 2030 provides the following benefits. – Added near term flexibility and reliability to effectively manage higher load cases – Opportunities to collaborate with DESC to achieve greater economies of scale
Solar Additions	▪ Solar additions reflected in the Economically Optimized Portfolio of over 2,000 MW in 2029 would be better implemented over a several year phase-in period, through a future competitive procurement RFP. ▪ The Preferred Portfolio assumes 300 MW per year from 2026 through 2030, then as optimized by the model.
BESS Additions	▪ BESS resources may be a viable alternative to CTs installed in the late 2020s and early 2030s (depending on positive outcome of competitive procurement) – May provide flexibility and shorter implementation schedule – Provides for early experience with storage technologies – May provide for advantages in procurement through IRA, under Energy Communities bonus provision

Based on the analyses in the preceding section and the major considerations discussed above, Santee Cooper's Preferred Portfolio builds from, and adheres closely to, the Economically Optimized Portfolio, but reflects the following modifications.

- Delayed retirement of Winyah to allow for greater time to develop a major baseload replacement resource and for flexibility related to the potential option for a joint build with DESC
- Gradual, phased-in implementation of solar resources beginning in 2026, reaching similar levels of solar additions by 2031
- Significant BESS resources by 2029 to help meet Santee Cooper's PRM and develop operational experience with such resources

Given the modifications above, the Preferred Portfolio was then optimized using EnCompass to determine the most cost-effective build plan for remaining resource needs. Table 42 below summarizes the resulting resource additions under the Preferred Portfolio versus those in the Economically Optimized Portfolio through 2040. More detailed information regarding the resulting build plan for the Preferred Portfolio is provided in Appendix D.

Table 42. Comparison of Economically Optimized and Preferred Portfolios

Resource Changes	Portfolios – Additions (Retirements) - MW	
	Economically Optimized	Preferred Portfolio
Coal Retirement • Winyah • Cross	by 2029 (1,150) Continues to Operate	by 2031 (1,150) Continues to Operate
New Solar[68] • 2029 • 2030-2040	All in 2029: 2,200 750	2026-2029: 1,200 1,850
New Large NGCCs to Replace Winyah	In 2029: 1,360	In 2031: 1,360
New Frame CTs • 2029: • 2030-2040	447 0	0 447
New BESS • 2029: • 2030-2040	0 250	350 50
New Wind • 2029: • 2030-2040	0 50	0 0

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

.

Overall, the Preferred Portfolio features significant additions of carbon-free resources, such as solar and wind, while also reducing the carbon intensity of remaining fossil generation by reducing dependence on coal and increasing utilization of more efficient, lower-carbon natural gas resources.

Projected costs for the Preferred Portfolio are marginally higher than costs for the Economically Optimized Portfolio under Reference Case assumptions as discussed under Impacts on the Preferred Portfolio below.

However, the Preferred Portfolio can be expected to have lower risks as follows:

1. Procurement of solar power would be phased in from 2026 through 2029 instead of a large addition in 2029 to reduce implementation and price risk and to allow for Santee Cooper to become more familiar with managing impacts of large amounts of solar resources on system operation.
2. The need for a post-Winyah retirement large NGCC would be delayed from 2029 to 2031, providing more time for evaluating implementation options, obtaining approvals, and project development.
3. Substituting BESS for a portion of the CTs indicated by the Economically Optimized Portfolio would reduce permitting risks and involve shorter implementation schedules, making implementation of the portfolio more flexible and adaptable, but will require further consideration of the limited duration of energy that can be provided to the system by BESS in comparison to CTs.
4. Continuing to operate Winyah beyond 2028 would better position the Combined System to serve higher loads expected to result from ongoing economic development efforts, that may result from accelerated electrification, and that would be accompanied by extension of certain sales contracts to Off-system Sales customers that have not been reflected in the Medium Case load forecast.
5. Continuing to operate Winyah through 2030 also presents Santee Cooper with greater optionality to consider a joint NGCC project with DESC, as discussed in the DESC Joint Project Opportunity section, and/or other resource alternatives.

CENTRAL RESOURCE DECISIONS

During Santee Cooper's IRP preparation process, Central announced decisions to enter into three power purchase agreements ("Central PPAs"). Central PPAs have been proposed by Central to meet a portion of Central's obligations under the Coordination Agreement to provide NSRs to supply a portion of the capabilities of the 2029 NGCC PSR identified in 2021. At that time, following joint planning with Central, Santee Cooper identified the NGCC as needed by the Combined System subject to approval of Santee Cooper's IRP by the Commission. Central has indicated that it has already executed two of the contracts and is awaiting counterparty approval for the third. Central has also indicated that the greatest outstanding risk to the PPAs is obtaining transmission to deliver the resources to the Santee Cooper Balancing Authority.

Central's PPAs would supply a substantial portion of the NSR capacity Central is obligated to provide under the Coordination Agreement. However, the PPAs proposed by Central do not proportionately provide other capabilities expected to have been supplied by the PSR, such as load following and other system support capabilities.

Under each PPA, Central would purchase power from resources interconnected with other bulk transmission systems. The PPAs would be must-run or scheduled by Santee Cooper but not dispatched automatically by our energy control center. Central indicated it would provide firm electric transmission over adjacent systems to deliver the power to the Santee Cooper Balancing Authority.

A summary of information concerning the Central PPAs based on information provided by Central and publicly available about source resources is below in Table 43. Central advises it cannot release certain information regarding the Central PPAs to Santee Cooper due to obligations under non-disclosure agreements. Therefore, Santee Cooper has not been provided access to Central PPAs and has incomplete information concerning cost and emissions profiles of the resources.

Table 43. Information Provided by Central and from Other Sources Regarding PPAs

	Base Load PPA	NGCC PPA	Peaking PPA
Approximate Capacity Entitlement	150 MW	230 MW	292 MW
Term to Assume for IRP	2029 through 2058	2029 through 2058	2029 through 2058
Availability	Unit Contingent, with some replacement energy	Unit Contingent	Unit Contingent, Multi-CT Plant
Fuel Type	Not natural gas or coal	Natural Gas (No backup fuel)	Natural Gas (No backup fuel)
Transmission Path to Santee Cooper from:	Duke System	FPL and SoCo System	SoCo System
Resource Type	Not specified	NGCC	CTs
Resource	Not specified	2003 vintage 274 MW 1x1 GE Frame 7F.04 NGCC Cogen Facility	A portion of a 2002 vintage 692 MW plant with 8-GE Frame 7E.03 Gas Turbines
Dispatchability	Must-run, little to no scheduling flexibility	Day-ahead scheduling with notice required for limited intra-day scheduling	Day-ahead scheduling with notice required for limited intra-day scheduling

	Base Load PPA	NGCC PPA	Peaking PPA
Pricing	None specified.	No fixed cost information. Info provided to use as basis for variable cost estimate.	No fixed cost information. Info provided to use as basis for variable cost estimate.
Basis for Estimating 3rd Party Transmission Charges	Duke's transmission rates apply.	SoCo's transmission rates apply.	SoCo's transmission rates apply.
Cost Dependency on Natural Gas Prices or CO_2 Prices	Not specified, (Central's price could be indexed to either or both natural gas and/or CO_2 prices.)	Estimate based on heat rate and fuel source info provided	Estimate based on heat rate and fuel source info provided

To analyze potential adjustments to the Preferred Portfolio assuming all three PPAs are finalized and implemented, Santee Cooper has prepared estimates of the cost of the power to be supplied to the Combined System under the three PPAs. The projections have been prepared based on the information supplied by Central and other available information deemed to be reasonable for this limited purpose.

The capacity pricing assumptions used were deemed to be toward the low-end range of expected prices. Also, the projections do not include an allowance for cost of Combined System transmission system upgrades that may be required to import the power supplied under the three Central PPAs into the Combined System. From a portfolio cost analysis standpoint, transmission upgrade costs to be borne by Combined System customers should be included without regard to whether those costs would ultimately be borne by Central or Santee Cooper's customers. Reliable estimates of the cost of resulting transmission system upgrades are not currently available to Santee Cooper.

Based on these optimistic estimates, incorporating the three Central PPAs into the Preferred Portfolio causes the projected cost of the Preferred Portfolio to be higher approaching $400 million on a cumulative present worth basis over the Study Period through 2052.

Table 44 and Table 45 below summarize assumptions used in projecting costs of Central PPAs.

Table 44. Assumptions Pertaining to Central PPAs

Cost Category (2029$)		Base Load PPA		NGCC PPA		Peaking PPA	
		Rate	Esc	Rate	Esc	Rate	Esc
Fixed O&M	$/kW-yr	92	2.3%	None Provided (Incl. in capacity charge)		None Provided (Incl. in capacity charge)	
NG Transportation	$/kW-yr $/MMBtu	n/a	n/a	22	0%	0.47	0%
3rd Party PTP	$/kW-yr	21	4%	71	4%	71	4%
Total Fixed	$/kW-yr	113		94		71	
Variable O&M	$/MWh	2.93	2.3%	2.87	2.3%	2.00	2.5%

Table 45. Assumed Central PPA Capacity Charges

	Base Load PPA			NGCC PPA			Peaking PPA		
	2023 $/kW-mo	2029 $/kW-mo	Esc	2023 $/kW-mo	2029 $/kW-mo	Esc	2023 $/kW-mo	2029 $/kW-mo	Esc
Capacity Charge	15.00	15.00	0%	6.00	6.37	1.0%	4.00	4.25	1.0%

DESC JOINT PROJECT OPPORTUNITY

DESC has stated in its most recent IRP that its preferred portfolio includes a joint project with Santee Cooper involving a 2x1 NGCC. Subsequently, DESC has indicated interest in studying two NGCC project configurations that, based on the assumptions used in this IRP, would range in winter capacity from 1,360 MW to 2,034 MW. Santee Cooper and DESC have begun working together to consider a joint NGCC project.

Santee Cooper anticipates that a joint project with DESC could result in cost benefits and reduce project risk. Key considerations are expected to be impacts of the joint project approach on the amount of NGCC capacity that would be provided to the Combined System, costs and risks of firm natural gas transportation arrangements and required electric transmission modifications, and operational considerations relative to other alternatives, including developing an NGCC project dedicated to the Combined System.

Assuming a 50% share of the joint project, analyses presented in this IRP assume the joint project could provide approximately 680 MW to 1,017 MW of NGCC capacity to the Combined System. Santee Cooper plans to further explore joint development of its NGCC resource with DESC.

Examples of potential advantages to doing so could involve:

- Greater economies of scale,
- Reduced implementation risks,
- Obtaining firm natural gas supply on more favorable terms,

- Optimizing transmission impacts holistically, and
- Appropriately considering economic development impacts in South Carolina.

IMPACTS ON THE PREFERRED PORTFOLIO

Santee Cooper has made initial assessments of potential adjustments to the resource build plan reflected in the Preferred Portfolio needed to accommodate Central's PPAs and the joint NGCC project opportunity with DESC as summarized below in Table 46 through 2040. As in the Preferred Portfolio, Santee Cooper assumed that 1,200 MW of solar resources are gradually implemented over 2026-2029 (300 MW per year) and that Winyah is retired by 2031 and replaced by NSRs brought online by Central and Santee Cooper, as discussed above. Remaining resource needs are optimized by EnCompass.

Table 46 provides the resulting build plan for the Preferred Portfolio, adjusted based on the Central PPAs and a DESC Joint Project, as compared to the Economically Optimized and Preferred Portfolios.

[Left Intentionally Blank]

Table 46. Preferred versus Adjusted Preferred Portfolios

Resource Changes	Portfolios – Additions (Retirements) - MW		
	Economically Optimized	**Preferred Portfolio**	**Preferred Portfolio** Adjusted for DESC Joint Project[69] and Central PPAs
Coal Retirement • Winyah • Cross	2029 (1,150) Cross Continues	2031 (1,150) Cross Continues	2031 (1,150) Cross Continues
New Solar[70] • 2029: • 2030-2040	All in 2029: 2,200 750	2026-2029: 1,200 1,850	2026-2029: 1,200 1,800
New NGCC upon Winyah Retirement	In 2029: 1,360	In 2031: 1,360	In 2031: 1,020
New Frame CTs • 2029: • 2030-2040	447 0	0 447	0 0
Central's PPAs • by 2029	0	0	672
New BESS • 2029: • 2030-2040	0 250	350 50	0 450
New Wind • 2029: • 2030-2040	0 50	0 0	0 0

As shown in Table 46, the Preferred Portfolio can readily be modified to address the Central PPAs and/or the opportunity to jointly develop an NGCC project with DESC.

Table 47 shows the impact on costs of the Preferred Portfolio with and without impacts of the Central PPAs and a smaller NGCC project size as may be expected to occur through a joint project with DESC.

[69] Assumed to involve 50% of a NGCC Project consisting of a 2x1 NGCC and a 1x1 NGCC (i.e., 2x1 is two gas turbine generators, plus one steam generator and 1x1 is one steam turbine and only one gas turbine with the single steam generator and steam turbine). A 3x1 configuration may also be considered.
[70] The amounts of New Solar capability shown are in addition to the solar PPAs procured by Santee Cooper and Central in 2021.

Table 47. Impacts on Preferred Portfolio of Central PPAs and DESC Joint Build

NPV Portfolio Costs -- $ Billion	Reference Case	Higher Cost than Economically Optimized Portfolio	Higher Cost than Preferred Portfolio Without Adjustment
Economically Optimized	$23.5		
Preferred Portfolio			
Without Adjustment	$23.6	$0.1	
With Adjustment	$24.0	$0.5	$0.4

OTHER POTENTIAL RESOURCES

Santee Cooper is considering short-term power supply alternatives to meet the potential higher loads that are expected to result from ongoing economic development activities. Those resources have been modeled in the IRP analyses as short-term capacity purchases from 2024 through 2028. One of the resources, an NGCC plant with a capacity of approximately 100 MW, identified through that short-term planning process, may be acquired by Santee Cooper. Central and Santee Cooper have agreed that the resource be acquired and treated as a Shared Resource under the Coordination Agreement, and, on May 10, 2023, Central's board voted to approve this as a Shared Resource. The next step is for Santee Cooper to seek other approvals necessary for the acquisition, including from the Commission. Should that acquisition occur, Santee Cooper would evaluate its impact on the Preferred Portfolio, which is expected to be minimal.

SHORT-TERM ACTION PLAN

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

NEAR-TERM CAPACITY NEEDS

Santee Cooper would continue to work with Central and engage with market participants to identify options and transmission arrangements that would allow purchases to meet capacity needs over the next several years.

NGCC IMPLEMENTATION

Santee Cooper would proceed with further actions and investigations to determine how best to implement the large NGCC resource the IRP demonstrates would be an economical and valuable resource for the Combined System.

Santee Cooper would engage further with DESC regarding the potential for jointly developing a project.

Santee Cooper would also engage with Central regarding the project, Central's expressed interest in participating in the project, and its treatment under the Coordination Agreement.

Santee Cooper would proceed with steps to:

- Confirm critical cost information (such as processes to confirm costs of project development, transmission system upgrades, and RFPs regarding firm natural gas transportation to the project),
- Seek further approvals and permits, and
- Take other appropriate actions toward implementing the NGCC, working with Central and/or DESC to the extent appropriate.

EVALUATIONS TO SUPPORT FUTURE IRP UPDATES AND FILINGS

The following studies and investigation are expected to prove valuable for future resource planning processes.

CROSS RETIREMENT OPTIONS

This IRP indicates that scenarios under which it would become economic to retire Cross are most likely to involve governmental policy changes aimed at reducing CO_2 emissions. Under those scenarios, Santee Cooper would likely be constrained to establish a reliable system using primarily renewable and BESS resources.

Accordingly, Santee Cooper intends to perform additional evaluations of future portfolios that assume Cross is retired and only zero carbon resources are added to the system.

Initial studies indicate that retirement of Cross may require major upgrades to the Combined System transmission network, including potentially developing 500 kV transmission corridors.

Another approach to be considered is to what extent system needs can be met from extensive, strategically sited renewable resources and BESS and thereby the need for major transmission upgrades due to retirement of Cross may be lessened or avoidable. The evaluations performed will be structured to better inform future IRPs regarding these issues.

Other utilities have identified reliability issues that could arise during extended periods of adverse weather as portfolios become more dependent on intermittent renewable resources. In addition, sub-hourly impacts of renewable intermittency may impact reliability. Accordingly, Santee Cooper intends to perform analysis to identify issues of that nature that could impact the Combined System and the most economic solutions to those issues.

RETIREMENT OF OLDER COMBUSTION TURBINES

Santee Cooper has assumed for purposes of this IRP that its Hilton Head (approximately 100 MW) and Myrtle Beach (approximately 56 MW) CT plants would continue to operate through 2033. Santee Cooper plans to further evaluate the options for operating or retiring those resources.

PLANNING RESERVE MARGIN

This IRP reflects reserve margin, solar integration cost, and effective load carrying capacity studies conducted in 2022. The results of those studies are dependent on the resources assumed available to meet Combined System load and therefore will be updated considering the portfolio plans and options identified in this IRP.

DEMAND-SIDE MANAGEMENT IMPLEMENTATION

Santee Cooper plans to proceed with further implementation of attractive DSM programs and perform additional studies to further evaluate demand-side options. Santee Cooper understands that Central also intends to perform additional DSM studies soon.

BESS RESOURCES

Santee Cooper plans to proceed with a BESS pilot project to enhance corporate familiarity with that technology. The learnings from this pilot will inform our future planning and ensure we are ready to operate this type of resource at a larger scale in the future.

WIND RESOURCES

The current IRP indicates that onshore wind may be an economical component of certain portfolios. Accordingly, Santee Cooper plans to undertake additional investigations of cost and appropriate locations for future wind projects, as well as impacts on system operations of wind resources.

STAKEHOLDER ENGAGEMENT

Santee Cooper plans to continue to appropriately engage stakeholders as Santee Cooper proceeds with the above-described evaluations.

SOLAR IMPLEMENTATION

This IRP, and prior planning studies, have indicated it would be cost effective to add substantial solar resources through the remainder of the 2020s and into the 2030s.

Santee Cooper has submitted its *Application of the South Carolina Public Service Authority for Approval of Competitive Procurement Program Pursuant to S.C. Code Ann. § 58-31-227* Docket 2022-351-E. Upon approval of Santee Cooper's "CPRE" process, Santee Cooper anticipates working with Central to procure additional solar resources for the Combined System targeting addition of new solar capacity in 2026 or as soon thereafter as may prove reasonable. Santee Cooper plans to phase-in large additions of solar resources targeted in its Preferred Portfolio through multiple procurements.

Santee Cooper plans to gather additional information on locations within the Combined System footprint that may have the characteristics necessary to maximize benefits of certain provisions of the IRA. Santee Cooper also may examine approaches other than PPAs for providing a portion of the solar capacity needed for the Combined System to determine if other approaches may be more beneficial to Combined System customers.

REGULATORY DEVELOPMENTS

The current Federal administration has placed a high priority on reducing carbon emissions from the production of electricity from coal and natural gas fueled resources. Regulatory developments in this area can impact future IRPs and resource planning more generally.

Accordingly, Santee Cooper plans to continue monitoring regulatory processes and identifying and evaluating potential impacts of new regulations on Santee Cooper's resource plans.

santee cooper

APPENDIX A: ABBREVIATIONS

ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AMEA	Alabama Municipal Electric Authority
ANSI	American National Standard Institute
ATB	Annual Technology Baseline
BAA	Balancing Authority Area
BAT	Best available technology
BESS	Battery energy storage system
CAA	Clean Air Act
CAGR	Compound average growth rate
CC	Combined cycle generator
CO_2	Carbon dioxide
CPP	Clean Power Plan
CRSG	Carolinas Reserve Sharing Group
CT	Combustion turbine generator
CVR	Conservation voltage reduction
CWA	Clean Water Act
DEC	Duke Energy Carolinas, LLC
DEP	Duke Energy Progress, LLC
DESC	Dominion Energy South Carolina
DG	Distributed generation
DHEC	Department of Health and Environmental Control
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)
EIDB	Eastern Interconnection Data Base
EGU	Electric generating unit
ELCC	Effective load carrying capability
ELG	Effluent limitation guidelines
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EUE	Expected unserved energy
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GADS	Generating Availability Data System
GDP	Gross domestic product
GHG	Greenhouse gas
GWh	Gigawatt-hour (i.e., 1,000 MWh)
HVAC	Heating, ventilation, and air conditioning
IRA	Inflation Reduction Act
IRP	Integrated resource plan
ITC	Investment tax credit
IWG	Interagency Working Group
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
MO	Maintenance outage
MOU	Memorandum of understanding
MPS	Market potential study
MSSC	Most severe single contingency
MW	Megawatt
MWh	Megawatt-hour

NERC	North American Electric Reliability Corporation
NGCC	Natural gas-fired combined cycle
NGCT	Natural gas-fired combustion turbine
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSR	Non-Shared Resource
NSRDB	National Solar Radiation Database
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance
ORDC	Operating reserve demand curve
PCT	Production tax credit
PMPA	Piedmont Municipal Power Agency
PO	Planned maintenance outage
PPA	Power purchase agreement
PRM	Planning reserve margin
PSC	Public Service Commission
PSR	Proposed Shared Resource
PURPA	Public Utility Regulatory Policies Act (of 1978)
PVRR	Present value revenue requirement
QF	Qualifying Facility
RICE	Reciprocating internal combustion engine
RFP	Request for proposal
RNG	Renewable natural gas
RTO	Regional transmission organization
SAE	Statistically-adjusted end-use
SAIDI	System average interruption duration index
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
SME	Subject matter expert
SMR	Small modular reactor
TEA	The Energy Authority
TRC	Total resource cost (test)
TTF	Time to fail
TTR	Time to repair
UCT	Utility cost test

APPENDIX B: EE/DSM DETAIL

CURRENT DSM PROGRAMS AVAILABLE TO RESIDENTIAL AND COMMERCIAL CUSTOMERS

Santee Cooper offers a portfolio of customer-focused programs called “EmpowerSC” which include three umbrellas of DSM programs:

- EmpowerHOME for residential energy efficiency
- EmpowerBUSINESS for commercial energy efficiency
- EmpowerSmartRewards for residential demand response

The Empower umbrella of DSM programs was developed in 2019 based on Santee Cooper’s strategic EE and DR goals at the time. Santee Cooper’s Energy Efficiency programs are based on non-dispatchable end-uses that provide rebates for customers to install higher efficiency end-use products and measures. The rebates in Santee Cooper’s current EE programs are designed to be about 30% of the incremental cost for the higher efficiency end-use product or measure.

Figure B-1 below shows DSM programs available as of December 31, 2022:

Figure B-1: Current Santee Cooper DSM Programs

Residential EE Programs	Commercial EE Programs	Residential Demand Response Programs
Smart Energy Existing Homes	Commercial Prescriptive	SmartRewards
Smart Energy New Homes	Small Business Energy Saver	

Residential EE Programs	Commercial EE Programs	Residential Demand Response Programs
Home Energy House Calls		
Smart Energy Loans		

SMART ENERGY EXISTING HOMES

The Smart Energy Existing Homes program is designed to help residential customers improve the efficiency of their existing homes. Rebates promoted through this program aim to reduce Santee Cooper customers' incremental cost to upgrade to high-efficiency equipment over standard-efficiency options. Santee Cooper offers rebates for the following measures in the Smart Energy Existing Homes program: HVAC measures, whole home duct replacement, smart thermostats, heat pump water heaters, heat pump pool heaters, pool pump motors, ENERGY STAR Refrigerators, and ENERGY STAR Clothes Washers.

SMART ENERGY NEW HOMES

The Smart Energy New Homes program is designed to increase the efficiency of residential new construction. Historically, home builders have been given two pathways to achieve certification as energy efficient. The first is a performance pathway that offers rebates based on the Home Energy Rating System ("HERS") score of the home. The rebate amount is based on the HERS score and whether the home type is single- or multi-family. Additionally, there are bonuses available for meeting ENERGY STAR requirements. There was also an equipment pathway that offered rebates for individual measures including HVAC measures, smart thermostats, heat pump water heaters, heat pump pool heaters, pool pump motors, ENERGY STAR Refrigerators, and ENERGY STAR Clothes Washers. The equipment pathway was discontinued in 2023 due to low utilization.

HOME ENERGY HOUSE CALL

Santee Cooper offers its residential customers Home Energy House Calls. As part of a Home Energy House Call, a Santee Cooper Energy Advisor will conduct an evaluation of the home to identify program measures for which the customer may be eligible through Santee Cooper's EE programs. Energy Advisors may provide a list of energy efficiency recommendations to the customer and discuss any financial assistance available from Santee Cooper to help offset the cost of the improvements.

SMART ENERGY LOANS

Santee Cooper offers loans to approved residential customers to help with the upfront expense of installing high efficiency equipment and measures. Loans are available for the following qualifying equipment and measure: high efficiency electric heat pumps, duct replacements and heat pump water heaters.

COMMERCIAL PRESCRIPTIVE

The Commercial Prescriptive program is designed to help commercial customers improve the efficiency of their businesses. Rebates are available for new construction, major renovations, and retrofit applications. Santee Cooper offers rebates for the following measures in the Commercial Prescriptive Program: lighting measures, HVAC measures, smart thermostats, refrigeration and kitchen equipment, domestic hot water equipment, and pumps/motors.

SMALL BUSINESS ENERGY SAVER

The Small Business Energy Saver program is a direct-install energy efficiency program designed to help small businesses improve the efficiency of the property in which they are doing business. In this program, a Santee Cooper contractor performs a free energy assessment for a small business. After the assessment is complete, the contractor gives the customer an upfront price for the direct installation of EE measures with rebates already included. If the customer agrees to the terms, the contractor procures the materials and equipment and has it installed for the customer. Santee Cooper currently offers rebates for interior lighting, exterior lighting, and refrigeration through this program.

SMARTREWARDS

The SmartRewards program is a residential DR program that offers customers bill credits for allowing Santee Cooper to activate a switch on a customer’s all-electric HVAC and/or electric water heater during periods of high demand. Customers who sign up for this program receive a one-time enrollment credit, as well as an annual credit for every year they participate in the program. Customers interested in signing up for the program are given the option of having a switch installed on their all-electric HVAC, electric water heater, or both. The amount of the customer’s bill credit is based on which option they enroll in.

santee cooper®

APPENDIX C: 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.

Yemassee Station Improvements

This project is expected to mitigate thermal loading on the Yemassee (Santee Cooper) – Yemassee (DESC) 230 kV tie line under various operating conditions by increasing the ratings on lines terminated to the station. Such conditions exist for generator or transmission outages on Santee Cooper and neighboring systems. Increasing the rating on these lines is necessary to maintain transmission reliability and increase operational flexibility.

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.

PLANNED PROJECTS

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 right of way. This line provides an additional path into the load center in the Myrtle Beach area and alleviates thermal loading under contingency conditions.

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.

Wassamassaw – Carnes (via Cane Bay) 115 kV Line

This project provides thermal loading relief to the Carnes 230-115 kV transformers under contingency conditions as well as support future load growth in the area. Construction of this 115 kV line utilizes the existing right-of-way for the Wassamassaw-Carnes Crossroads 230 kV line where possible from the Wassamassaw 230-115 kV Substation to the Cane Bay 115 kV tap for approximately 6.5 miles.

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.

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.

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

These 230 kV circuits together 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 the rapid load growth in this area and to maintain transmission reliability. These 230 kV lines will be constructed utilizing as two double circuits with one configured as 230/230 kV double circuits with the Cross – Wassamassaw 230 kV #2 Line, and the other configured as 230/115 kV double circuits with the Wassamassaw – Jefferies 115 kV Line using existing right of way.

Varnville 230-115 kV Substation

Planning studies indicate the need to construct a new Varnville 230-115 kV Substation to facilitate additional 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, transformation, and long-term plans to convert the 69 kV delivery points in the area to 115 kV service. The need for this project will continue to be evaluated based on 230 kV and 115 kV network expansion plans in the area.

APPENDIX D: OPTIMIZED RESOURCE PORTFOLIO BUILDS

Table D-1: Economically Optimized Portfolio Additions and Retirements (MW)

Year	NGCC	Peaking	Solar	Onshore Wind	BESS	SMR	Total	Retirements
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	1,360	447	2,200	0	0	0	4,006	(1,150)
2030	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0
2032	0	0	100	0	50	0	150	0
2033	0	0	0	0	0	0	0	0
2034	0	0	0	0	50	0	50	(165)
2035	0	0	300	50	0	0	350	0
2036	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0
2038	0	0	100	0	50	0	150	0
2039	0	0	150	0	50	0	200	0
2040	0	0	100	0	50	0	150	0
2041	0	0	100	100	0	0	200	0
2042	0	0	100	0	50	0	150	0
2043	0	0	100	0	50	0	150	0
2044	0	0	50	0	50	0	100	0
2045	0	0	50	300	50	0	400	0
2046	0	0	250	0	0	0	250	0
2047	0	0	100	0	0	0	100	0
2048	0	0	150	0	150	0	300	0
2049	0	0	100	0	0	0	100	0
2050	0	0	0	100	0	0	100	0
2051	0	0	50	100	0	0	150	0
2052	0	0	0	200	0	0	200	0
Total	**1,360**	**447**	**4,000**	**850**	**600**	**0**	**7,256**	**(1,315)**

Table D-2: Future Coal Retirement Portfolio Additions and Retirements (MW)

Year	NGCC	Peaking	Solar	Onshore Wind	BESS	SMR	Total	Retirements
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	1,360	0	2,250	0	100	0	3,710	(1,150)
2030	0	0	0	0	50	0	50	0
2031	0	0	0	0	50	0	50	0
2032	0	0	150	50	0	0	200	0
2033	0	0	0	0	50	0	50	0
2034	1,360	1,341	50	0	50	0	2,800	(2,495)
2035	0	0	250	0	0	0	250	0
2036	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0
2038	0	0	50	0	0	0	50	0
2039	0	0	100	0	50	0	150	0
2040	0	0	150	0	50	0	200	0
2041	0	0	150	50	50	0	250	0
2042	0	0	50	0	0	0	50	0
2043	0	0	100	0	50	0	150	0
2044	0	0	100	0	50	0	150	0
2045	0	0	0	200	50	0	250	0
2046	0	0	400	0	0	0	400	0
2047	0	0	50	0	50	0	100	0
2048	0	0	50	0	50	0	100	0
2049	0	0	50	50	50	0	150	0
2050	0	0	100	50	50	0	200	0
2051	0	0	50	150	0	0	200	0
2052	0	0	100	0	50	0	150	0
Total	**2,719**	**1,341**	**4,200**	**550**	**850**	**0**	**9,660**	**(3,645)**

Table D-3: No New Fossil Generation Portfolio Additions and Retirements (MW)

Year	NGCC	Peaking	Solar	Onshore Wind	BESS	SMR	Total	Retirements
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	0	0	3,550	1,000	1,550	0	6,100	(1,150)
2030	0	0	0	0	50	0	50	0
2031	0	0	100	150	0	0	250	0
2032	0	0	150	0	50	0	200	0
2033	0	0	50	0	50	0	100	0
2034	0	0	350	50	350	0	750	(165)
2035	0	0	50	300	0	0	350	0
2036	0	0	0	0	0	0	0	0
2037	0	0	50	0	100	0	150	0
2038	0	0	250	0	100	0	350	0
2039	0	0	200	0	150	0	350	0
2040	0	0	150	0	50	0	200	0
2041	0	0	200	0	50	0	250	0
2042	0	0	100	0	100	0	200	0
2043	0	0	100	0	100	0	200	0
2044	0	0	150	0	50	0	200	0
2045	0	0	100	0	100	0	200	0
2046	0	0	500	0	100	0	600	0
2047	0	0	50	0	100	0	150	0
2048	0	0	100	0	50	0	150	0
2049	0	0	200	0	100	0	300	0
2050	0	0	50	0	100	0	150	0
2051	0	0	200	0	100	0	300	0
2052	0	0	100	0	50	0	150	0
Total	**0**	**0**	**6,750**	**1,500**	**3,450**	**0**	**11,700**	**(1,315)**

Table D-4: Net Zero CO_2 by 2050 Portfolio Additions and Retirements (MW)

Year	NGCC	Peaking	Solar	Onshore Wind	BESS	SMR	Total	Retirements
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	1,360	0	2,250	0	100	0	3,710	(1,150)
2030	0	0	350	1,700	0	0	2,050	0
2031	0	0	50	50	0	0	100	0
2032	0	0	50	200	50	0	300	0
2033	0	0	100	100	0	0	200	0
2034	0	1,597	0	0	700	0	2,297	(2,495)
2035	0	0	0	350	150	0	500	0
2036	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0
2038	0	0	150	50	150	0	350	0
2039	0	0	250	0	0	0	250	0
2040	0	0	150	200	50	0	400	0
2041	0	0	100	250	50	0	400	0
2042	0	0	300	100	100	0	500	0
2043	0	0	0	250	50	0	300	0
2044	0	0	150	250	50	0	450	0
2045	0	0	0	350	150	0	500	0
2046	0	0	550	0	0	0	550	0
2047	0	0	250	150	0	0	400	0
2048	0	0	0	300	150	0	450	0
2049	0	0	0	300	0	0	300	0
2050	0	0	0	400	200	0	600	0
2051	0	0	0	0	0	0	0	0
2052	0	0	250	0	50	0	300	0
Total	**1,360**	**1,597**	**4,950**	**5,000**	**2,000**	**0**	**14,906**	**(3,645)**

Table D-5: Preferred Portfolio Capacity Additions and Retirements (MW)

Year	NGCC	Peaking	Solar	Onshore Wind	BESS	SMR	Total	Retirements
2026	0	0	300	0	0	0	300	0
2027	0	0	300	0	0	0	300	0
2028	0	0	300	0	0	0	300	0
2029	0	0	300	0	350	0	650	0
2030	0	0	300	0	50	0	350	0
2031	1,360	0	900	0	0	0	2,260	(1,150)
2032	0	0	150	0	0	0	150	0
2033	0	0	0	0	0	0	0	0
2034	0	447	100	0	0	0	547	(165)
2035	0	0	200	0	0	0	200	0
2036	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0
2038	0	0	100	0	0	0	100	0
2039	0	0	50	0	0	0	50	0
2040	0	0	50	0	0	0	50	0
2041	0	0	150	0	0	0	150	0
2042	0	0	50	0	0	0	50	0
2043	0	0	100	0	0	0	100	0
2044	0	0	0	100	0	0	100	0
2045	0	0	0	350	0	0	350	0
2046	0	0	250	0	0	0	250	0
2047	0	0	150	0	50	0	200	0
2048	0	0	50	0	50	0	100	0
2049	0	0	50	150	0	0	200	0
2050	0	0	0	150	0	0	150	0
2051	0	0	50	200	0	0	250	0
2052	0	0	0	150	0	0	150	0
Total	**1,360**	**447**	**3,900**	**1,100**	**500**	**0**	**7,306**	**(1,315)**

APPENDIX E: NET PRESENT VALUE POWER COST SUMMARY

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

Portfolio	Sensitivity Case	Study Period (2023-52)	20 Years (2029-48)
Economically Optimized	Reference	$23.5	$14.9
Coal Retirement	Reference	$25.3	$16.5
No New Fossil	Reference	$25.3	$16.4
Net Zero	Reference	$26.7	$17.7
Preferred Portfolio	Reference	$23.6	$15.0
Economically Optimized	Low Fuel	$22.1	$13.8
Coal Retirement	Low Fuel	$23.5	$15.1
No New Fossil	Low Fuel	$24.6	$16.0
Net Zero	Low Fuel	$25.5	$16.7
Preferred Portfolio	Low Fuel	$22.2	$14.0
Economically Optimized	High Fuel	$26.6	$17.2
Coal Retirement	High Fuel	$30.0	$20.1
No New Fossil	High Fuel	$26.6	$17.2
Net Zero	High Fuel	$29.8	$20.1
Preferred Portfolio	High Fuel	$26.5	$17.2
Economically Optimized	Med CO2	$28.2	$18.6
Coal Retirement	Med CO2	$28.8	$19.2
No New Fossil	Med CO2	$29.5	$19.7
Net Zero	Med CO2	$28.9	$19.4
Preferred Portfolio	Med CO2	$28.5	$18.9
Economically Optimized	High CO2	$36.6	$25.3
Coal Retirement	High CO2	$35.6	$24.5
No New Fossil	High CO2	$37.2	$25.8
Net Zero	High CO2	$33.3	$22.7
Preferred Portfolio	High CO2	$37.3	$26.1
Economically Opt - High Load	High Load	$29.8	$18.9
Coal Retirement - High Load	High Load	$31.8	$20.6
No New Fossil - High Load	High Load	$33.8	$22.4
Net Zero - High Load	High Load	$34.9	$23.2
Preferred - High Load	High Load	$30.9	$20.0
Economically Opt - Low Load	Low Load	$19.0	$12.1
Coal Retirement - Low Load	Low Load	$20.6	$13.5
No New Fossil - Low Load	Low Load	$18.9	$11.9
Net Zero - Low Load	Low Load	$21.1	$13.8
Preferred - Low Load	Low Load	$19.1	$12.1
Economically Opt - High Capital Cost	High Cap Cost	$24.1	$15.4
Economically Opt - Low DSM	Low DSM	$23.5	$14.9
Economically Opt - High DSM	High DSM	$23.7	$15.0
Economically Opt - High DSM / High Load	High Load / High DSM	$29.9	$18.9

APPENDIX F: RENEWABLE GENERATION FORECAST

Table F-1: Renewable Generation by Portfolio (GWh)[71]

Year	Economically Optimized	Coal Retirement	No New Fossil Generation	Net Zero CO_2 by 2050	Preferred
2023	2,001	2,001	2,001	2,001	2,001
2024	2,394	2,394	2,394	2,394	2,394
2025	2,861	2,861	2,861	2,861	2,861
2026	2,461	2,461	2,461	2,461	3,146
2027	2,459	2,459	2,459	2,459	3,827
2028	2,128	2,128	2,116	2,128	4,175
2029	7,137	6,764	11,974	6,858	4,727
2030	7,144	6,776	12,214	11,578	5,413
2031	7,112	6,842	12,486	11,669	7,446
2032	7,142	7,047	12,969	12,341	7,663
2033	7,144	7,054	13,131	12,654	7,917
2034	7,142	7,159	14,078	12,988	8,036
2035	7,645	7,480	14,742	13,574	8,395
2036	7,693	7,485	14,782	13,588	8,418
2037	7,651	7,458	14,900	13,999	8,373
2038	7,777	7,475	15,225	14,847	8,397
2039	8,007	7,698	15,700	15,610	8,604
2040	8,107	7,743	15,828	16,129	8,611
2041	8,487	8,281	16,265	16,955	8,952
2042	8,670	8,361	16,465	17,717	9,091
2043	8,827	8,893	16,829	18,379	9,205
2044	9,086	8,847	16,959	19,061	9,283
2045	9,633	8,994	17,401	19,826	10,257
2046	10,074	9,742	18,044	20,622	10,694
2047	10,247	9,968	18,313	21,383	11,082
2048	10,483	10,052	18,570	22,102	11,340
2049	10,824	10,566	18,770	22,763	11,588
2050	11,067	10,599	19,063	23,595	12,010
2051	11,184	11,129	19,410	23,895	12,308
2052	11,358	11,331	19,710	24,161	12,592

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

APPENDIX G: RATE IMPACTS ACROSS SENSITIVITIES

Figure G-1: Projected Rate Index for Foundational Portfolios Under Low Fuel Prices

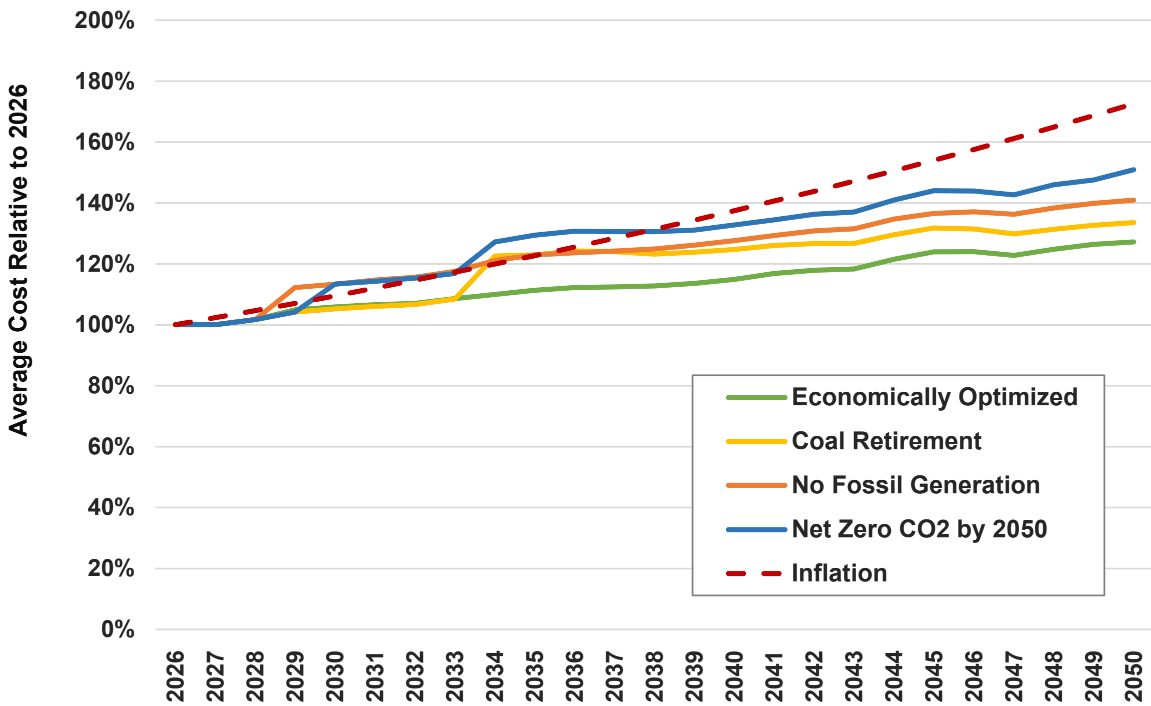


Figure G-2: Projected Rate Index for Foundational Portfolios Under High Fuel Prices

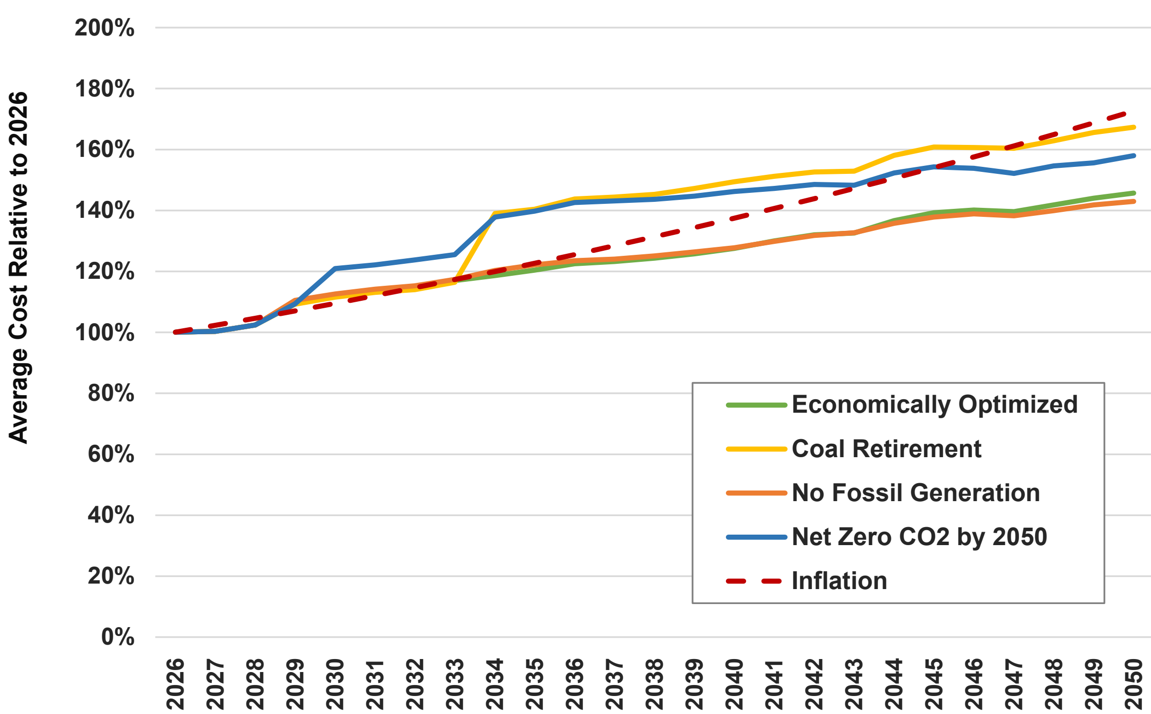


Figure G-3: Projected Rate Index for Foundational Portfolios Under Medium CO_2 Prices

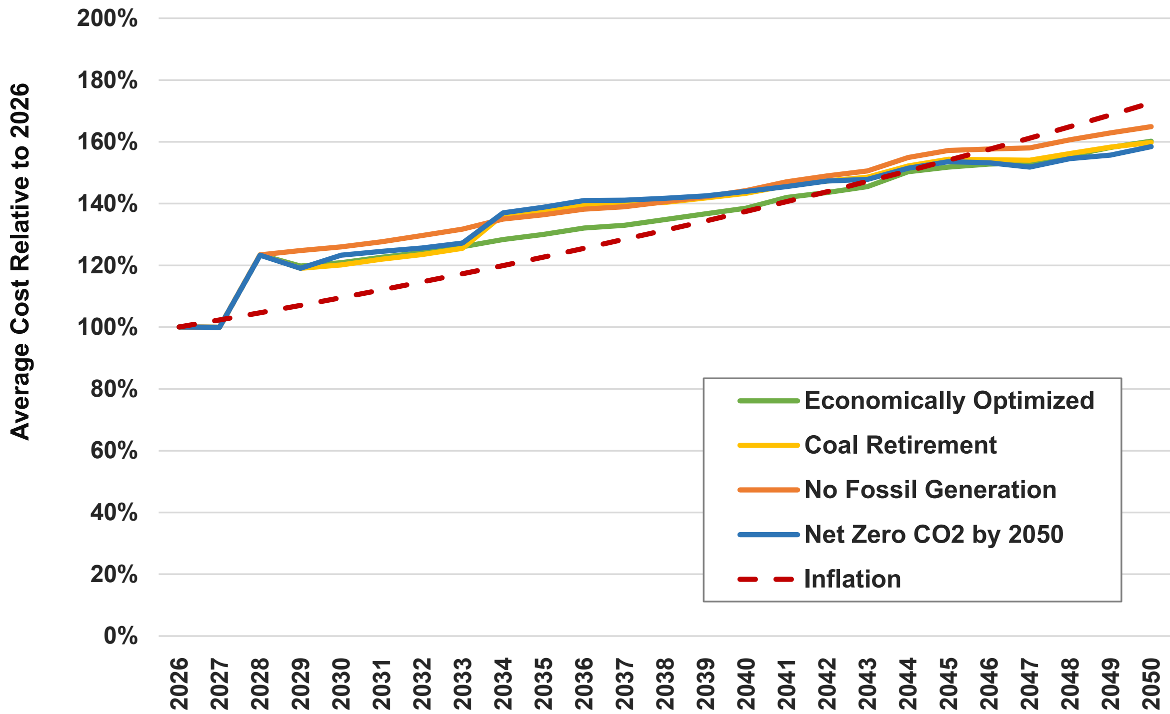
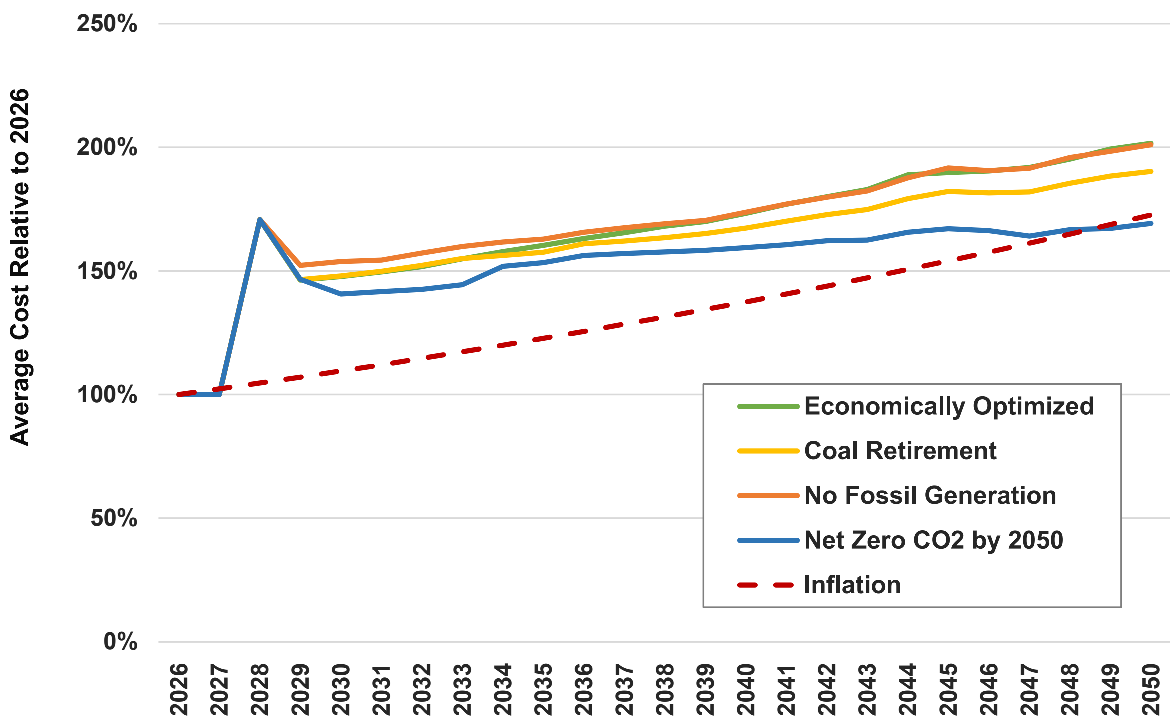


Figure G-4: Projected Rate Index for Foundational Portfolios Under High CO_2 Prices



APPENDIX H: CROSS RETIREMENT SENSITIVITIES

The foundational portfolios examined in this 2023 IRP include a Future Coal Retirement Portfolio, which reflects the retirement of the entire Cross Generating Station by 2034. The portfolio optimization model used to analyze the portfolios indicates the most cost-effective resources to replace Cross would include a second 2x1 NGCC (second to the NGCC included in the Economically Optimized Portfolio, among most others, to replace Winyah) and additional CTs and BESS resources, adding significantly to the use of natural gas-fired generation for the Combined System.

The resulting comparison of NPV power costs reflects that, under most sensitivities, this Coal Retirement Portfolio yields higher projected costs over the Study Period than the Economically Optimized Portfolio in which Cross is assumed to continue to operate.[72] Under the High CO_2 Price sensitivity case, Cross retirement appears to become attractive, subject to further consideration of reliability of the system. Accordingly, the decision to continue to operate, or retire, Cross is clearly sensitive to governmental policy that may in the future be implemented to compel further reductions in CO_2 emissions by utilities. Costly CO_2-limiting government policy or prohibition of use of coal to generate electricity could compel Cross retirement.

Stakeholders have posed the question as to whether the decision to retire Cross is sensitive to the assumption as to timing of that retirement. Santee Cooper has considered this timing question. In considering the potential timing of Cross retirement, an important consideration is the age of Cross relative to other coal units that are being retired. For instance, Cross Units 1 and 2 were placed into service between 1983 and 1995, and Cross Units 3 and 4, between 2007 and 2008, while Winyah was placed into service between 1975 and 1981.

As shown below, adjusting the timing of Cross retirement either to an earlier or later date, is not projected to change portfolio costs sufficiently to make the cost of the Future Coal Retirement Portfolio more attractive than the Economically Optimized Portfolio that assumes continued Cross operation over the remainder of the Study Period.

More specifically, Santee Cooper has prepared sensitivities in which the Future Coal Retirement Portfolio reflects Cross retirement in 2029, 2034, or 2039. In each case, the optimum portfolio is identified drawing from the most cost-effective mix of available resource types, whether fossil-fueled or renewable resources. Portfolio costs are computed, net of the Cross-related costs of O&M and capital improvements assumed avoided due to retirement.

This analysis shows that projected cost of the Future Coal Retirement Portfolio varies with the timing assumed for retirement of Cross but does not approach becoming lower than costs projected under the Economically Optimized Portfolio, which assumes continued Cross operation over the entire Study Period through 2052. Moreover, the investment that could be avoided by

[72] Another foundational portfolio, the Net Zero CO2 by 2050 Portfolio, also assumes retirement of Cross, but additionally assumes a Net Zero policy that causes the replacement resources to be renewable (solar and wind), BESS, and CT resources. Projected costs under this portfolio also are higher than under the Economically Optimized Portfolio, except under the High CO_2 Price sensitivity case.

retiring Cross would have to be over $1 billion higher in 2023 NPV$ than allowed for in this analysis to push NPV cost of the Economically Optimized Portfolio up to the level of the Future Coal Retirement Portfolio, assuming Cross would be retired in 2039.

Figure H-1: Cross Retirement Timing Sensitivity Analyses

Portfolio	Reference Case ($B)
Economically Optimized - Cross Not Retired	$23.5
Future Coal Retirement Portfolio	
Cross Retire 2029	$25.9
Cross Retire 2034	$25.3
Cross Retire 2039	$24.7

santee cooper

APPENDIX I: GENERATION FLEET PERFORMANCE DATA

Table I-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	580
	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
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[4]	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						5305	5086

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) Current operating license expires 2042 plans to seek license extention to 2062.

Table I-2: Annual Forced Outage Rate

Annual Forced Outage Rate						
Generating Station	**Unit**	**2018**	**2019**	**2020**	**2021**	**2022**
Cross Pineville, SC	1	2.04%	0.54%	1.51%	1.31%	3.15%
	2	15.67%	25.48%	0.00%	5.37%	35.50%
	3	4.94%	6.26%	1.30%	8.52%	1.67%
	4	10.65%	6.68%	1.00%	1.84%	4.41%
Winyah Georgetown, SC	1	14.50%	0.46%	4.93%	5.08%	2.75%
	2	5.15%	4.59%	3.26%	4.92%	3.72%
	3	17.71%	5.83%	0.91%	0.69%	1.81%
	4	0.77%	1.82%	6.99%	0.00%	8.99%
Rainey Iva, SC	1A	0.50%	0.37%	0.00%	0.41%	0.19%
	1B	0.21%	0.41%	0.21%	0.16%	0.11%
	1S	0.10%	0.40%	0.00%	0.06%	0.01%
	2A	0.84%	2.40%	0.01%	0.11%	0.01%
	2B	0.23%	0.08%	0.22%	0.14%	0.02%
	3	0.00%	0.46%	0.27%	0.59%	0.00%
	4	4.15%	0.23%	22.54%	5.91%	0.00%
	5	0.03%	0.00%	0.67%	1.71%	0.93%
Myrtle Beach	1	98.22%	40.33%	0.00%	99.76%	90.90%
	2	92.40%	100.00%	66.31%	70.21%	47.19%
	3	97.96%	0.00%	52.12%	98.87%	12.32%
	4	100.00%	100.00%	100.00%	100.00%	100.00%
	5	50.65%	99.95%	99.12%	0.00%	93.19%
Hilton Head	1	79.69%	0.00%	0.00%	0.00%	99.05%
	2	99.91%	0.00%	0.00%	0.00%	0.00%
	3	1.10%	19.08%	97.07%	26.37%	79.62%
V.C. Summer Nuclear Unit 1 Jenkinsville, SC	1	0.00%	4.08%	0.73%	8.36%	0.00%
Jefferies Lake Moultrie	1	0.00%	0.00%	0.00%	4.35%	46.24%
	2	0.00%	0.01%	0.10%	0.17%	0.12%
	3	0.11%	0.73%	0.00%	24.77%	0.45%
	4	0.11%	0.27%	0.01%	0.15%	3.24%
	6	100.00%	6.55%	0.00%	0.00%	0.00%
Spillway Lake Marion	-	5.94%	57.90%	12.75%	8.36%	1.87%

Table I-3: Annual Availability Factor

Annual Availability Factor						
Generating Station	**Unit**	**2018**	**2019**	**2020**	**2021**	**2022**
Cross Pineville, SC	1	93.9%	89.7%	97.8%	91.5%	67.4%
	2	6.7%	72.1%	96.3%	89.3%	66.4%
	3	72.0%	93.0%	96.9%	61.3%	95.9%
	4	87.1%	82.1%	97.1%	75.8%	92.6%
Winyah Georgetown, SC	1	93.4%	88.4%	89.7%	91.4%	90.0%
	2	94.4%	94.8%	69.2%	71.7%	93.1%
	3	89.5%	97.9%	92.5%	75.3%	95.1%
	4	91.2%	86.1%	97.3%	43.2%	86.4%
Rainey Iva, SC	1A	84.4%	93.6%	92.2%	88.4%	94.5%
	1B	85.0%	92.4%	88.3%	88.5%	94.6%
	1S	85.2%	93.4%	92.3%	89.2%	95.1%
	2A	85.1%	96.5%	96.5%	95.1%	97.7%
	2B	95.0%	83.3%	96.3%	95.7%	98.8%
	3	97.4%	97.3%	98.0%	96.2%	98.3%
	4	97.1%	97.2%	94.2%	97.1%	96.8%
	5	97.4%	98.5%	96.0%	92.9%	99.1%
Myrtle Beach	1	78.9%	94.3%	100.0%	96.7%	94.9%
	2	94.7%	92.8%	99.9%	99.9%	99.3%
	3	89.0%	99.8%	99.9%	75.9%	99.8%
	4	0.0%	0.0%	0.0%	0.0%	0.0%
	5	99.5%	79.8%	94.2%	100.0%	81.4%
Hilton Head	1	99.9%	100.0%	100.0%	100.0%	41.5%
	2	89.0%	0.0%	0.0%	100.0%	99.9%
	3	99.9%	96.9%	92.1%	95.5%	93.5%
V.C. Summer Nuclear Unit 1 Jenkinsville, SC	1	89.1%	95.9%	91.1%	82.5%	99.4%
Jefferies Lake Moultrie	1	96.8%	99.9%	95.8%	99.1%	79.6%
	2	99.9%	95.3%	96.0%	99.6%	100.0%
	3	98.6%	98.5%	99.9%	86.5%	98.8%
	4	99.9%	97.9%	99.8%	99.2%	96.8%
	6	97.8%	99.6%	100.0%	99.7%	99.1%
Spillway Lake Marion	-	94.3%	55.5%	89.9%	85.4%	94.5%

Table I-4: Annual Capacity Factor

Annual Capacity Factor						
Generating Station	**Unit**	**2018**	**2019**	**2020**	**2021**	**2022**
Cross Pineville, SC	1	54.8%	41.9%	20.1%	39.0%	17.5%
	2	2.1%	2.9%	-0.6%	9.5%	0.5%
	3	55.8%	61.2%	40.5%	41.8%	67.7%
	4	70.2%	54.4%	62.2%	54.4%	62.3%
Winyah Georgetown, SC	1	20.6%	8.5%	36.3%	55.5%	36.9%
	2	18.7%	12.4%	30.8%	36.9%	30.6%
	3	11.9%	5.1%	16.7%	31.1%	22.9%
	4	12.5%	4.6%	8.2%	1.5%	3.6%
Rainey Iva, SC	1A	78.2%	87.1%	87.0%	79.0%	86.8%
	1B	80.1%	86.3%	82.4%	79.5%	87.0%
	1S	86.9%	94.8%	92.4%	87.8%	95.0%
	2A	47.4%	58.0%	57.3%	45.4%	53.8%
	2B	53.3%	52.3%	55.3%	48.2%	54.5%
	3	6.6%	6.9%	5.0%	7.4%	13.4%
	4	6.8%	7.6%	4.3%	7.0%	13.3%
	5	6.8%	7.7%	3.7%	6.4%	13.0%
Myrtle Beach	1	0.1%	0.0%	0.0%	0.0%	0.1%
	2	0.2%	0.0%	0.0%	0.0%	0.3%
	3	0.0%	0.0%	0.0%	0.0%	0.5%
	4	0.0%	0.0%	0.0%	0.0%	0.0%
	5	0.2%	0.0%	0.0%	0.0%	0.2%
Hilton Head	1	0.0%	0.0%	0.0%	0.0%	0.3%
	2	0.0%	0.0%	0.0%	0.0%	0.4%
	3	0.2%	0.1%	0.0%	0.1%	0.5%
V.C. Summer Nuclear Unit 1 Jenkinsville, SC	1	87.1%	97.5%	91.1%	82.7%	101.5%
Jefferies Lake Moultrie	1	0.2%	6.2%	6.1%	5.6%	4.7%
	2	35.8%	34.6%	35.1%	34.4%	34.5%
	3	1.6%	5.4%	5.2%	5.5%	5.6%
	4	35.1%	35.2%	37.1%	34.4%	33.1%
	6	0.0%	0.0%	0.0%	0.0%	0.0%
Spillway Lake Marion	-	56.1%	20.4%	29.6%	50.3%	58.5%

APPENDIX J: CROSS REFERENCE FOR COMPLIANCE WITH ACT 90

The details of the IRP requirements under Act 90 are shown in the following table along with a reference to each page number of Santee Cooper's IRP demonstrating compliance:

Act No. 90 § 58-37-40	Requirement	2023 IRP Page Number
(A)(3)	[Santee Cooper] shall develop a public process allowing for input from all stakeholders prior to submitting the [IRP]. The [IRP] must be developed in consultation with the electric cooperatives and municipally owned electric utilities purchasing power and energy from [Santee Cooper] and consider any feedback provided by retail customers and shall include the effect of demand-side management activities of the electric cooperatives and municipally owned electric utilities that directly purchase power and energy from [Santee Cooper] or sell power and energy generated by [Santee Cooper].	Stakeholder Process for 2023 IRP (P. 53); Demand-side Management Overview (P. 77); (Attachment 5)
(A)(3)	The [IRP] must be posted on the commission's website and on [Santee Cooper's] website.	Link to website (www.santeecooper.com/IRP)
(A)(4)(a)	[Santee Cooper's IRP] shall include an analysis of long-term power supply alternatives and enumerate the cost of various resource portfolios over various study periods including a twenty-year study period and, by comparison on a net present value basis, identify the most cost-effective and least ratepayer-risk resource portfolio to meet [Santee Cooper's] total capacity and energy requirements while maintaining safe and reliable electric service.	Resource Plan Evaluation (P. 105); Preferred Portfolio (P. 133)
(A)(4)(c)	[Santee Cooper's IRP]…must be developed in consultation with the electric cooperatives, including Central Electric Power Cooperative, and municipally owned electric utilities purchasing power and energy from [Santee Cooper], and consider any feedback provided by retail customers and shall include the effect of demand-side management activities of the electric cooperatives, including Central Electric Power Cooperative, and municipally owned electric utilities that directly purchase power and energy from [Santee Cooper] or sell power and energy generated by [Santee Cooper].	Stakeholder Process for 2023 IRP (P. 53); Demand-side Management Overview (P. 77); (Attachment 5)

(A)(4)(c)	[Santee Cooper's IRP] shall include and evaluate at least one resource portfolio, which will reflect the closure of the Winyah Generating Station by 2028, designed to provide safe and reliable electric service while meeting a net zero carbon emission goal by the year 2050.	Planned Retirements (P. 71); Resource Plan Evaluation (P. 105)
(B)(1)(a)	A long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Electric Load Forecast Overview (P. 56); System Energy and Peak Demand (P. 89)
(B)(1)(b)	The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Major Modeling Assumptions (P. 89); Portfolio Optimization Results (P. 109)
(B)(1)(c)	Projected energy purchased or produced by the utility from a renewable energy resource;	Renewable Energy Forecast (P. 131); Appendix F
(B)(1)(d)	A summary of the electrical transmission investments planned by the utility;	Transmission Projects (P. 88); (Appendix C)
(B)(1)(e)	Several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet [Santee Cooper's] service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Resource Plan Evaluation (P. 105); Evaluation of Variations in Demand-side Resources (P. 126)
(B)(1)(f)	Data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Current Resource Overview (P. 62); Planned Retirements (P. 71); (Appendix I; Table I-1)
(B)(1)(g)	Plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;	Results and Conclusions (P. 14);

		Resource Option Assumptions (P. 97); Rate Impacts of Portfolios (P. 128); Preferred Portfolio (P. 133)
(B)(1)(h)	An analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and	Portfolio Metrics (P. 113); (Appendix E)
(B)(1)(i)	A forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Supply and Demand Balance (P. 75); Demand-side Management Overview (P. 77)
(B)(2)	An [IRP] may include distribution resource plans or integrated system operation plans.	N/A