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Supplemental Planning Analysis

Introduction

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") submit this supplemental modeling and additional portfolio analysis ("Supplemental Planning Analysis") in support of their 2023 Carolinas Resource Plan (the "Plan" or "Resource Plan") to provide the North Carolina Utilities Commission ("NCUC") and Public Service Commission of South Carolina ("PSCSC", and together with the NCUC, "the Commissions") with additional context, portfolio analysis and planning information to further inform the Commissions' ongoing review of the Resource Plan based upon recent significant developments since the Plan was filed.[1] The initial Plan filing highlighted the rapidly changing energy landscape, including how significant new load growth in the Carolinas informed the need for decisive and urgent actions to serve customers' capacity and energy needs, as shown in the Companies' recommended near-term actions. This Supplemental Planning Analysis is necessitated by recent further significant increases in the Companies' 2023 fall load forecasts ("Updated 2023 Fall Load Forecast") due to the Carolinas' substantial economic development successes through 2023, as described in the Supplemental Direct Testimony of Glen A. Snider ("Supplemental Testimony") filed on behalf of the Companies with the PSCSC and NCUC on November 30, 2023.[2]

This Supplemental Planning Analysis builds on (but does not replace) the expansive modeling and portfolio analysis[3] presented in the Plan with supplemental modeling and additional portfolio analysis that integrates load increases from the Updated 2023 Fall Load Forecast primarily driven by real, tangible and beneficial economic development activity occurring in 2023 across the Carolinas.

[1] The Carolinas Resource Plan was filed with the PSCSC as the Companies' SC IRP in Docket Nos. 2023-8-E and 2023-10-E on August 15, 2023, and with the NCUC as the 2023–2024 Carbon Plan and Integrated Resource Plan ("CPIRP") on August 17, 2024, in Docket No. E-100, Sub 190.

[2] Supplemental Direct Testimony of Glen A. Snider on Behalf of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, PSCSC Docket Nos. 2023-8-E, 2023-10-E (filed Nov. 30, 2023); Supplemental Direct Testimony of Glen A. Snider on Behalf of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, NCUC Docket No. E-100, Sub 190 (filed Nov. 30, 2023).

[3] See Chapter 2 (Methodology and Key Assumptions) of the Carolinas Resource Plan that includes three Pathways with related Core Portfolios, 13 Portfolio Variants, and 10 Sensitivity Analysis Portfolios.

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Reliable, affordable and increasingly clean energy is a foundational element of the current and future economic success of the Carolinas, and the Supplemental Planning Analysis supports the need to pursue additional near-term actions to serve the new businesses, industries and residents that are investing in and relocating to the Carolinas.

The Companies applied the same planning objectives, modeling approach and analytical methodologies in this Supplemental Planning Analysis as those described and applied in Chapter 2 (Methodology and Key Assumptions) and Appendix C (Quantitative Analysis) to the Plan. However, given the dynamic nature of the energy industry and the broader economic environment in which the Resource Plan was developed, this Supplemental Planning Analysis also integrates additional updated information regarding natural gas fuel supply, resource availability and financial assumptions, including resource costs, to better inform the Commissions' review and decision-making regarding the Plan.

This Supplemental Planning Analysis filing is comprised of the following components:

- **Section 1: Summary**: Summarizes background, scope and results of Supplemental Planning Analysis;
- **Section 2: Methodology and Key Assumptions Updates**: Provides details of limited updated inputs integrated into the Supplemental Planning Analysis and describes the scope of additional modeling;
- **Section 3: Portfolio Additions and Analysis Results**: Summarizes supplemental modeling and portfolio analysis outputs for Energy Transition Pathway 3 Portfolio P3 Fall Base, including comparisons to Portfolio P3 Base, with respect to the Plan's long-term planning objectives;
- **Section 4: Execution Plan Updates**: Proposes incremental resources and actions, above those identified in the August filing, required to reliably meet increased needs as determined by this Supplemental Planning Analysis;
- **Technical Appendix**: Provides additional technical details including modeling inputs, outputs and additional portfolio results prepared in support of this Supplemental Planning Analysis; and
- **South Carolina Chapter and North Carolina Chapter Supplements**: Provides state-specific context and updates to the Companies' recommended Portfolio P3 Fall Base and requests for relief based on this Supplemental Planning Analysis.

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Section 1: Summary

Background

Historic Load Growth Through Robust Economic Development in the Carolinas

The Carolinas Resource Plan, developed in early 2023 and filed with both Commissions in August 2023, highlighted that the Carolinas were experiencing significant new load growth stemming from favorable economic development across both states. This significant growth in projected electricity demand — levels of which have not been experienced in decades — has continued in the Carolinas as is reflected in the Updated 2023 Fall Load Forecast and is consistent with and confirmed by trends broadly experienced across the nation[4] and the Southeast region.[5]

South Carolina's and North Carolina's continued efforts to attract jobs and grow the states' economies through 2023 have produced truly unprecedented economic development growth. As described in the initial Plan, interest over the past year from new large-load customers exploring siting new facilities in the Companies' service territory in concert and partnership with local and state economic development entities has occurred at a scale and pace that is well beyond the Companies' historical experience. Over the past several months, numerous prospective customers that have been exploring locating or expanding their operations in the Companies' service territory have made new announcements and material commitments to take electric service from the Companies, such that the Companies must now include their load demand in the Companies' updated load forecast. These large new economic development customers include manufacturers, the electric transportation industry, data centers and advanced cloud computing and blockchain operations, with many of these projects being very high load factor customers with 24x7x365 operations that will require substantial generation and constant energy delivery to ensure reliable service.

Table SPA 1-1 below illustrates the extraordinary economic development activity in South Carolina and North Carolina through 2023, with total mature projects of 20 MW or above and their related megawatt-hours ("MWh") of increased demand through 2033 tripling since the Plan was developed using the 2023 Spring Load Forecast.[6]

[4] The NERC 2023 Long Term Reliability Assessment report found "Electricity peak demand and net energy growth rates in North America are increasing more rapidly than at any point in the past three decades" with forecasted growth "higher than any point in the past decade", at 33, report available at https://www.nerc.com/.

[5] The Companies' November 30, 2023, Supplemental Testimony of Glen A. Snider filed with both Commissions cited at page 4 recent significant load growth forecasted by Dominion Energy Virginia and Georgia Power Company.

[6] See Appendix D (Electric Load Forecast) Table D-11 of the Carolinas Resource Plan for summary of the total adjustments made as a result of 8 economic development projects included in Plan's load forecast. See Table SPA 2- 2 in Section 2 for summary of the total adjustments as a result of the 35 economic development projects included in the Updated 2023 Fall Load Forecast used in this Supplemental Planning Analysis.

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Table SPA 1-1: Impacts of Large Site Development Integrated into DEC and DEP Load Forecasting

Load Forecast	2023 Spring	Updated 2023 Fall
Incremental Economic Development Projects	8	35
Cumulative MWh Impact in 2033	8,755,771	24,741,067
MW Impact to Winter Peak in 2033	1,351	3,044

As shown below in Figure SPA 1-1, compared with the 2023 Spring Load Forecast used to develop the initial Plan, the combined peak load growth for DEC and DEP identified in the Updated 2023 Fall Load Forecast has increased by approximately 2,100 MW in 2033 — and includes a projected peak demand increase in 2033 of over 4,000 MW to the 2022 resource planning load forecast baselines.

The Supplemental Planning Analysis also recognizes the potential for the Carolinas' economic development successes to continue in 2024 and beyond. The Companies' engagement with potential new customers has not stopped and there is continued interest in project sites in the Carolinas, including several recent inquiries at future potential sites for large loads that may exceed 500 MW. This potential for further economic development commitments above and beyond the Updated 2023 Fall Load Forecast is represented by the Continued Economic Development Load Forecast,[7] and the Supplemental Planning Analysis includes an additional high load Sensitivity Analysis Portfolio developed using this Continued Economic Development Load Forecast. This sensitivity shows the impact on resource needs in the Carolinas if this positive trajectory of new economic development success continues into 2024. Additional details on the Updated 2023 Fall Load Forecast and the Continued Economic Development Load Forecast analysis are presented in Section 2 of the Supplemental Planning Analysis.

[7] See Section 2 for details on a higher Continued Economic Development Load Forecast used in a High Load Sensitivity Analysis completed as part of the scope of this analysis.

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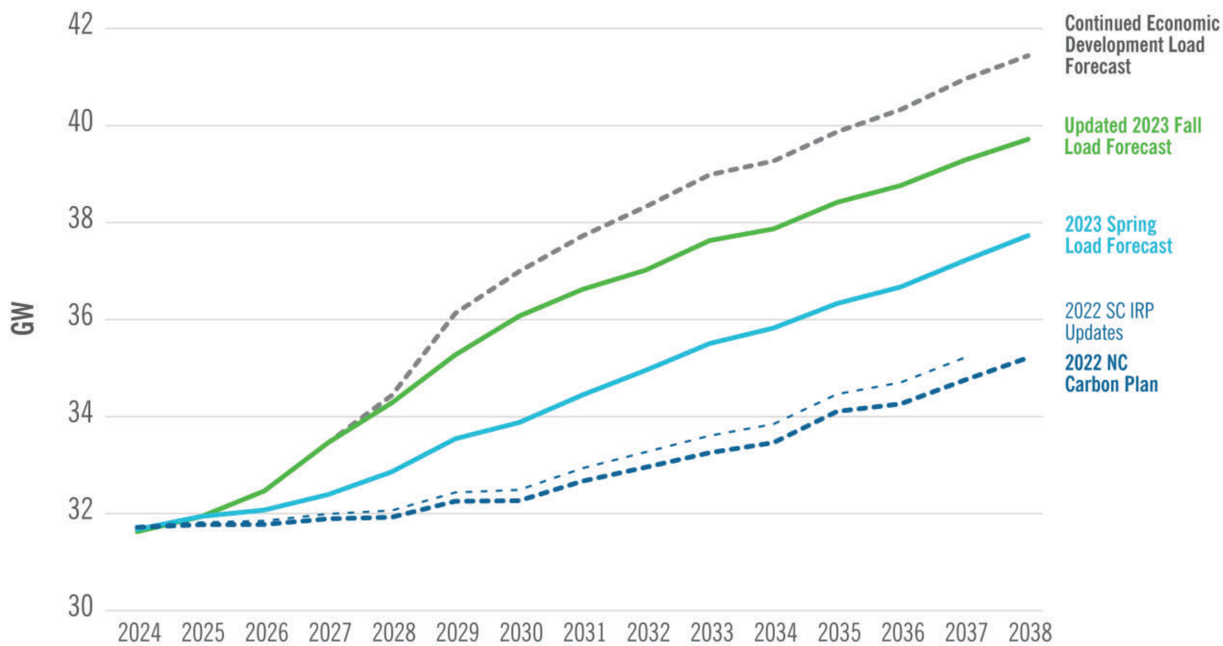
Figure SPA 1-1: Load Forecast Evolution, 2021 to 2023 Carolinas Combined DEC and DEP Non-Coincident Winter Peak at the Generator



Other Recent Changes in Energy Landscape Integrated into Supplemental Planning Analysis

Because the magnitude of the load forecast changes necessitated supplemental modeling, it was also prudent and reasonable to utilize such an opportunity to further integrate limited material updates to key modeling inputs and planning assumptions. Simply stated, given the need to perform supplemental modeling, it is reasonable for this modeling to incorporate material developments and reflect the most updated information available at the time the Commissions review the Plan. For instance, advances in the development of Mountain Valley Pipeline ("MVP") since the August 2023 filing have provided the Companies more certainty to treat MVP as part of base assumptions in this Supplemental Planning Analysis rather than treating MVP as an alternate fuel supply scenario as was done in the initial Plan.[8] Similarly, continued dynamic inflation, interest rate and supply chain factors have influenced resource costs even in the time period since costs were baselined for the Plan earlier in 2023. Therefore, the Companies have integrated specific financial assumptions and generic technology cost updates into this Supplemental Planning Analysis. Considering these dynamic energy landscape changes, the Companies also further refined resource availability assumptions to better reflect plan executability

[8] See Appendix K (Natural Gas, Low Carbon Fuels and Hydrogen) of the Carolinas Resource Plan for further background of MVP. On July 27, 2023, the Supreme Court of the U.S. granted MVP's Emergency Application to vacate the Fourth Circuit's stay, and MVP was free to resume construction on the pipeline, which they have since done.

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and updates in near-term projected capacity resources. Section 2 provides additional details on the load forecast, gas supply, financial and resource cost and resource availability input updates integrated into the Supplemental Planning Analysis. Other than the changes discussed in Section 2, the Companies' Supplemental Planning Analysis builds on and utilizes the same methodological approach as detailed in the initial Plan.

Scope

This Supplemental Planning Analysis complements the existing Plan portfolio analysis scope and is intended to further inform the Commissions' consideration of the Companies' proposed Near-Term Action Plan ("NTAP"), as well as the intermediate- and long-term least cost pathways to serve customers during the energy transition with a diverse fleet that reduces risks to customers, meets customer needs, maintains reliability and affordability, is the most practicable of the portfolios identified and evaluated by the Companies, complies with state and federal laws and provides resource adequacy and capacity. This Supplemental Planning Analysis continues focus on Energy Transition Pathway 3 ("Pathway 3") as the most reasonable, least cost, and least risk planning pathway informing the Companies' Execution Plan and NTAP. Accordingly, the Companies developed a new Core Portfolio under Pathway 3 ("P3 Fall Base") to augment the existing P3 Base Core Portfolio, incorporating the updated load forecast and limited other updates addressed in Section 2. The initial Plan's relative comparisons of all Energy Transition Pathways including Portfolio Variants and Portfolio Sensitivity Analyses[9] remain relevant, particularly in the face of meeting significantly increased load growth driven by economic development and other critical planning objectives.

For this Supplemental Planning Analysis, the Companies also ran additional Portfolio Sensitivity Analyses against P3 Fall Base to assess (1) the Continued Economic Development Load Forecast, (2) availability of higher levels of large customer interruptible loads, and (3) even higher capital costs for combined cycle ("CC") and combustion turbine ("CT") resources.[10] Notwithstanding that the Companies continue to recommend Pathway 3 as the most reasonable, least cost and least risk pathway under the current Plan, the Companies also modeled supplemental portfolios under Pathway 1 and Pathway 2, as well as the South Carolina Supplemental Informational No Carbon Constraints Portfolio incorporating updated supplemental modeling inputs and assumptions with results available in the Technical Appendix.[11]

[9] Chapter 2 (Methodology and Key Assumptions) of the Carolinas Resource Plan describes the three Energy Transition Pathways and related Portfolio Variants and Sensitivities. Chapter 3 (Portfolios) of the Carolinas Resource Plan describes the relative outcomes of initial analysis across these Pathways.

[10] See Section 2 section for additional details on the scope of the portfolio and sensitivity analyses and the Technical Appendix for details on additional portfolio sensitivity analysis results.

[11] Evaluation of an updated Pathway 1 portfolio fulfills the requirement that the Companies file a portfolio that meets the 70% carbon emissions reduction target by 2030 as part of its planned supplemental modeling per the NCUC's Order Scheduling Public Hearings, Establishing Interventions and Testimony Due Dates, Requiring Public Notice, and Providing Direction Regarding Duke's Supplemental Modeling, Docket No. E-100, Sub 190 (Jan. 17, 2024).

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Summary of P3 Fall Base Results

Additional Supply-Side Resources are Needed to Meet Significant Load Growth Due to Robust Economic Development

The Supplemental Planning Analysis demonstrates that through 2035, approximately 6.8 gigawatts ("GW") of new and diverse resource additions are required beyond the resources identified in Portfolio P3 Base in the Companies' initial Plan in order to reliably meet the over 23 terawatt-hours ("TWh") of increased energy demand reflected in the Updated 2023 Fall Load Forecast. Figure SPA 1-2 below shows the incremental resource additions identified in the P3 Fall Base supplemental modeling by 2035 and then 2038, the end of the 15-year IRP Base Planning Period.[12] Section 3 of this Supplemental Planning Analysis provides further details on the P3 Fall Base portfolio analysis and results. This increased need accelerates the pace, scope, and scale of resource additions from the already aggressive P3 Base presented in the initial Plan to support load growth and the 24x7x365, high load factor nature of economic development projects locating in the Carolinas, while also retaining an optimal coal retirement schedule through 2035, as modeled in P3 Base and confirmed in this Supplemental Planning Analysis.[13]

Based on the results of the Supplemental Planning Analysis and the entirety of the Plan, the Companies reaffirm their focus on planning for Energy Transition Pathway 3 while continuing to pursue full coal retirements by 2035. The Companies now recommend P3 Fall Base as the most reasonable, least cost, and least risk portfolio for planning purposes and to inform execution plan activities at this snapshot in time to serve customers while providing resource adequacy and capacity ensuring an orderly energy transition.

[12] As explained in Chapter 2 (Methodology and Key Assumptions) of the Carolinas Resource Plan, the 15-year IRP Base Planning Period meets North Carolina and South Carolina long-term planning requirements.

[13] Additional details on the Supplemental Coal Retirement Analysis are included in Section 2 and the Technical Appendix.

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Figure SPA 1-2: Supplemental Portfolio Analysis Results - Incremental Resource Additions by 2035 and 2038

By January 1 2035	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-6.2 GW	11.9 GW	4.3 GW	2.1 GW	4.1 GW	2.1 GW	1.7 GW	0.6 GW	0 GW
P3 Fall Base			12.6 GW	5.1 GW		6.8 GW		1.8 GW		2.4 GW
Difference		*0 GW*	*0.7 GW*	*0.8 GW*	*0 GW*	*2.7 GW*	*0 GW*	*0.2 GW*	*0 GW*	*2.4 GW*

By January 1 2038	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-8.4 GW	14.6 GW	6.0 GW	3.0 GW	4.1 GW	2.3 GW	1.7 GW	2.4 GW	0 GW
P3 Fall Base			17.5 GW	6.3 GW	2.1 GW	6.8 GW		1.8 GW	2.1 GW	2.4 GW
Difference		*0 GW*	*2.9 GW*	*0.3 GW*	*-0.9 GW*	*2.7 GW*	*0 GW*	*0.2 GW*	*-0.3 GW*	*2.4 GW*

Supplemental Planning Analysis Further Informing the Pace, Scope and Scale of Execution Plan and Near-Term Actions

The additional system resources identified under the P3 Fall Base portfolio are necessary to reliably meet the robust, additional load growth and economic development needs of the Carolinas identified in the Updated Fall 2023 Load Forecast and form the basis for necessary Execution Plan and NTAP updates. Importantly, as discussed in Section 4, all original Execution Plan activities and resource additions presented in the Resource Plan, as filed in August 2023, continue to be needed. The additional resource needs driven by the Updated 2023 Fall Load Forecast and identified in Figure SPA-1 include additional solar, batteries, combustion turbine and combined cycle resource additions by 2035, as well as adding 2,400 MW of offshore wind into the Plan.

A summary of proposed NTAP adjustments based on the P3 Fall Base portfolio is presented in Table SPA 1-2 below.[14]

[14] See Table SPA 4-1 of Section 4 for detailed updates to the Carolinas Resource Plan Chapter 4 (Execution Plan) Table 4-2: Supply-Side Near-Term Actions Plan 2023 to 2026 with NTAP adjustments and additions proposed through this Supplemental Planning Analysis based on the P3 Fall Base portfolio.

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Table SPA 1-2: Summary of Supply-Side Near-Term Action Plan Incorporating Supplemental Planning Analysis Adjustments

Resources	August NTAP MW by Target In-Service Year[1]	Supplemental Planning Analysis MW Adjustments	Total NTAP MW by Target In-Service Year	Resource Notes
Solar	6,000 by 2031	460 by 2031	6,460 by 2031	- Continue RZEP 1.0 advance RZEP 2.0 projects - 2024 Procurement: 1,585 MW - 2025–2026 Procurement: target 2,700 MW to 3,460 MW
Battery Storage	2,700 by 2031	175 MW of Stand-alone Storage now planned for Storage paired with Solar	2,700 by 2031	- Increase in battery need by 2035, outside of NTAP window - Adjusted ratio of stand-alone storage and storage paired with solar based on updated solar NTAP
Onshore Wind	1,200 by 2033	-	1,200 by 2033	- Onshore wind new to Carolinas at scale - No additional MW added in near-term
CT	1,700 by 2032	425 by 2031	2,125 by 2031	- Additional CT driven by increased load and maintaining system reliability
CC	4,080 by 2031	2,720 by 2033	6,800 by 2033	- Additional CCs (2) driven by increased load and maintaining system reliability - At least one of the CCs is expected to be located in South Carolina in planning assumptions
Pumped Storage Hydro	1,700 by 2034	134 by 2034	1,834 by 2034	- Recent equipment bids refined the total planned capacity for new Bad Creek II powerhouse adding 134 MW
Advanced Nuclear	600 by 2035	-	600 by 2035	- Earliest availability remains 2035, reduced pace of additions for subsequent sites better representing overlapping execution activities
Offshore Wind	-	2,400 by 2035	2,400 by 2035	- Updated near-term actions informed by P3 Fall Base including conducting and Acquisition Request for Information ("ARFI") in 2025 with current Carolinas Wind Energy Area (off NC coast) lessees - Continue limited development of onshore transmission to support offshore wind

Note 1: Beginning-of-year (BOY) in-service.

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As detailed in Chapter 4 (Execution Plan) of the initial Plan, and now supplemented by the updated Execution Plan activities identified in Section 4 of this Supplemental Planning Analysis, successful execution of the proposed near-term actions between now and 2026 and continued action to support the recommended portfolio will require prudent and intentional planning and timely regulatory approvals to meet growing customer needs, enable retirement of aging coal generation in an orderly manner while ensuring that reliability is maintained or improved for the Carolinas. Importantly, the Execution Plan includes activities designed to proceed with procurement and construction of substantial new resources and, in the case of long lead-time resources, includes activities designed to prudently advance development and gather information in advance of future decision points. Further, as evaluated in the P3 Fall Base High Load sensitivity analysis, if economic development continues a trajectory similar to 2023, even more system resources would be necessary to reliably meet customer needs.[15]

Customer Financial Impacts

The accelerated pace of resource additions in recommended portfolio P3 Fall Base translates to increases in the forecasted system residential bill impact differences, as shown below in Figure SPA 1-3, recognizing that the projected cost impacts will change over time with evolving market conditions and regulatory policies. As described in the initial Plan, the Companies will continue to utilize all available tools to minimize costs, including leveraging available tax incentives and loan program opportunities, conducting competitive procurements for materials and services, pursuing the merger between DEC and DEP to further optimize system scale and efficiencies for customers and advancing grid edge and customer programs that focus on energy efficiency and demand-side optimization to reduce demand.

The Companies note that with any long lead-time resource that results in a large, multi-year construction project, the authorization to recover the Companies' financing costs during the construction period will be an essential prerequisite to construction so as to ensure strong credit ratings and a fundamental capability to access capital markets, facilitating the lowest possible financing costs for customers. In addition, recovery of financing costs during construction lowers the overall cost that customers pay over the life of the investment. When financing costs are recovered during the construction period, non-financing project costs are still included in customer rates only after the related project is in operation and providing service to customers, unless otherwise determined by the Commissions.

[15] See Technical Appendix for results of P3 Fall Base High Load Sensitivity Analysis.

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Figure SPA 1-3: Bill Impact Snapshots for Portfolios P3 Fall Base and P3 Base, 2033 and 2038

Note: The Carolinas Combined impacts above is the total combined bill impact of DEC and DEP as separate utilities, not as a merged utility. Additionally, the above customer rate impacts assume that for large, multi-year construction projects, the Company is able to recover its financing costs during the construction period, which will accelerate rate impacts into earlier years but lowers the overall cost that customers pay over the life of the investment from what would otherwise be. When financing costs are recovered during the construction period, non-financing project costs are still included in customer rates only after the related project is in operation and providing service to customers, unless otherwise determined by the Commissions.

As recognized in the initial Carolinas Resource Plan, the Companies reiterate that successful implementation of the Carolinas' energy transition must also be enabled by timely and constructive regulatory actions across a myriad of workstreams and timely cost recovery. In this critical execution phase of the energy transition, decisive actions must be taken to advance solutions and to mitigate risks of inaction as the Companies plan for an orderly exit from coal over the next several years while preparing for a future of higher energy demand requiring increasingly clean resources.

The Carolinas Resource Plan, now informed by this Supplemental Planning Analysis, is reasonable for planning purposes and is designed to inform and manage the risks, opportunities and challenges of the current changing energy landscape as the Companies advance an orderly energy transition. The Plan sets a course of reasonable and prudent actions supporting resource improvements, additions and retirements, while always maintaining reliability and affordability for customers. The Companies' proposed NTAP and Execution Plan are appropriate for approval by the NCUC and the PSCSC, and the overall Plan provides a reasonable and balanced approach for resource planning purposes that is in the best interest of customers and meets the legal requirements and policy goals of both North Carolina and South Carolina, while ensuring the foundation for a continued strong economic environment.

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Section 2: Methodology and Key Assumptions Updates

As described in Section 1 to this Supplemental Planning Analysis, the Carolinas' recent economic development success, as well as other material planning factors, such as fuel supply and the inflationary financial impacts of the current state of the economy in this changing energy landscape, prompted the need for additional modeling and supplemental analysis in support of the Carolinas Resource Plan filed with both Commissions in August 2023. This section supplements Chapter 2 (Methodology and Key Assumptions) of the initial Resource Plan and outlines the major input changes and modeling scope of this Supplemental Planning Analysis. Other than the inputs identified in this Section and the Technical Appendix to this Supplemental Planning Analysis, the Companies applied the same modeling approach and analytical methodologies to meet long-term planning objectives as described and applied in Chapter 2 (Methodology and Key Assumptions) and Appendix C (Quantitative Analysis) to the Plan for purposes of this Supplemental Planning Analysis. This Supplemental Planning Analysis evaluates the impacts of the changes identified in this section or in the Technical Appendix. All other inputs and assumptions remain as described in the initial Plan filing, although some inputs have been updated to include the months of 2023 for which historical data became available.

Updated Modeling Inputs Used for Supplemental Planning Analysis

In preparing this Supplemental Planning Analysis, certain key inputs have seen impactful changes since the original Plan filing was made several months ago. This section provides an overview of the modeling inputs and associated changes impacting the analysis. Table SPA 2-1 below provides an overview of the most impactful inputs and the changes associated with each updated planning assumption. The Supplemental Planning Analysis Technical Appendix includes other limited information updates, technical updates, and adjustments that have also been incorporated into this supplemental modeling exercise.

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Table SPA 2-1: Overview of Supplemental Planning Analysis Assumptions

Input Variable	Supplemental Planning Analysis Assumption	Impact to Variable (Compared to Initial Plan)
Electric Load Forecast	• Updated with Fall '23 Load Forecast • Significantly increased economic development activity	• 5% increase in winter peak forecast (2038) • 12% increase in energy forecast (2038)
Financial Assumptions & Resource Costs	• Cost of capital • Resource capital costs • Resource cost escalation • Transmission costs • Operations and maintenance (variable & fixed) costs	• Increased cost of debt and updated DEP ROE (higher cost of capital) • Increased resource capital costs • Reduced technology learning escalation • Reduced transmission costs • Various updated O&M costs
Natural Gas Supply	• MVP gas supply volumes • Updated generic firm transportation rates • Included full interstate firm transportation costs for more than 6 CTs	• New, indicative commodity and transportation pricing structures and volumes • Capped exposure to delivered interstate gas for new CTs at 6 and assigned fuel security costs for incremental CTs 7+
Resource Availability	• Up to 6 CCs (1 CC sited in SC) • Up to 1,800 MW of solar/yr. (beg. in 2032) • Standalone battery annual availability (DEC/DEP combined): 200 MW (2027); 500 MW (2028-2029); 1,000 MW (2030 and beyond) • First 800 MW of offshore wind available BOY 2033 • Long-term advanced nuclear availability adjusted	• Increased CC limit (from 3) based on potential for incremental fuel supply • Increased solar limit (from 1,575 MW/yr.) • Applied progressive annual standalone battery limits to better reflect executability considerations • First 800 MW of offshore wind delayed one year from BOY 2032 to BOY 2033 • Increased time between advanced nuclear sites reducing cumulative availability

Electric Load Forecast

Updated 2023 Fall Load Forecast

Chapter 2 (Methodology and Key Assumptions), Appendix C (Quantitative Analysis) and Appendix D (Electric Load Forecast) to the initial Plan provided significant detail on the process the Companies use to develop the electric load forecast. This section highlights the most significant changes to the load forecast and reasons for and drivers of those changes. The Updated 2023 Fall Load Forecast was provided to all parties in December 2023 and the Companies have already responded to a significant amount of discovery regarding the forecast.

While the Companies generally followed the same methodological approach to developing the Updated 2023 Fall Load Forecast as was used to prepare the 2023 Spring Load Forecast used in

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preparing the initial Plan, the Updated 2023 Fall Load Forecast incorporated limited changes into this fall update, several of which deserve particular discussion because of their impact on the results of the supplemental analytics. It is useful to examine the changes in two groups: those that happen during the development of model inputs and those that are classified as "post-modeling" inputs. The factors listed below affected both work streams:

- Economic- and weather-related inputs, as well as sales history.
- Post-estimation inputs, including electric vehicle/behind-the-meter solar projections, discussed in more detail below, and utility energy efficiency ("UEE") programs. Apart from an adjustment to allocation between residential and non-residential customers, as well as a "year forward" roll — which is meant to account for the impact of new energy impacts achieved by the programs at the termination of the historical data — the UEE programs were little changed.
- Post-estimation inputs, including economic development projections, which had a significant material impact on the results.

Adjustments for Economic and Weather Inputs

While the data and procedures align with those described on pp. 4-5 of Appendix D (Electric Load Forecast), the Updated 2023 Fall Load Forecast incorporates the following updates:

- Additional time having passed since the calculations that supported the Resource Plan submitted in August of 2023 has allowed the Companies to capture updated economic and weather-related inputs. The most salient of these — weather — was milder than expected during the first half of 2023, with these new observations being included in the model estimation. The Companies roll the years for calculation of normal weather forward only at the end of the calendar year; therefore "normal weather" conditions are identical in both forecast versions.
- With respect to economic factors, the Moody's Analytics projections have been updated to those available in July 2023.
- End-use equipment and appliance indices have been updated to the 2023 update of Itron's end-use data, consistent with the U.S. Energy Information Administration's ("EIA's") 2023 Annual Energy Outlook.

Adjustments for Economic Development Activity

As described in Section 1, as well as in the November 30, 2023, Supplemental Testimony of Companies' witness Glen Snider, material commitments from new large site development occurring in 2023 are a primary driver of this Supplemental Planning Analysis. Importantly, the Supplemental Planning Analysis applies the same procedures described in Appendix D (Electric Load Forecast) to the initial Plan to identify and incorporate the impacts of these material new economic development

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project commitments into the electric load forecast.[16] As noted in the initial Plan, the Companies had previously integrated large site development activity into the 2023 Spring Load Forecast in response to an accelerating level of economic development activity across the Carolinas in late 2022 through early January 2023. The methodology used to capture large site development activity relied on two major strategies: a focus on projects with letter agreements or in the very late stages of development[17] and adjusting those projects to avoid overlap with other economic growth predicted by macroeconomic drivers in the load forecast estimation equations. The Companies' load forecasting process recognizes that site selection processes are often very competitive for both potential customers and the regions they are considering and, therefore, endeavor to include only the most mature and committed projects into the base load forecast. This same methodology was again applied with available data through early October 2023 for input into the development of the Updated 2023 Fall Load Forecast used for this Supplemental Planning Analysis.

In developing the 2023 Spring Load Forecast utilized in the initial Plan, the Companies identified eight economic development projects that justified inclusion. In preparing the Updated 2023 Fall Load Forecast, an additional group of 27 projects in both North Carolina and South Carolina have now made material new economic development project commitments sufficient to justify inclusion applying the same large economic development site adjustment process used in establishing the 2023 Spring Load Forecast described above. In addition to consideration of the progress of the projects toward construction and electric service, the Companies calculate the extent to which the economic data already explains changes in load, discounting the energy amounts used for planning with the customer when applied to the total load forecast.

While specific customer contract detail is confidential, many of the sites included would fall into several categories of commercial and industrial customers: among "commercial classified" customers, data centers (including advanced cloud computing and blockchain operations) predominately, generally with very high load factors anticipated. Among "manufacturing classified" customers, many support the emerging EV sector via battery production or vehicle manufacturing, as well as reemerging industries, including steel production and semiconductors.

Table SPA 2-2 below lists the adjustments applied to the annual forecast based on these "Large Site Adjustments" within both service territories. The source of the additional energy (when compared with the August 2023 Plan filing) is the greater number of projects meeting the requirements for inclusion. The growing portfolio of large economic development projects reflects vigorous efforts from the economic development team to solidify and expand the commitments with these customers, who are seeking the Carolinas as a welcoming location for their businesses. This table represents a reasonable projection of how the energy from these projects affect the Updated 2023 Fall Load Forecast. The

[16] Carolinas Resource Plan, Appendix D (Electric Load Forecast) at 13-15.

[17] G. Snider Supp. Direct Testimony at 5 (describing material commitments as: (1) executed an agreement indicating an intention to obtain service from the Companies or are in an advanced stage of engagement with the Companies for the same, and (2) demonstrated other indicia of material development activities with respect to the location in question (e.g., obtaining site control, initiation of rezoning activities, etc.).

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continued economic development forecast and "high load" portfolio sensitivity analysis is discussed later in this section.

Table SPA 2-2: Adjustments in the Base 2023 Fall Load Forecast for Large Site Developments

Year	Base Case Energy (MWh)		Base Case Winter Peak (MW)	
	DEC	DEP	DEC	DEP
2024	776,443	423,559	-	-
2025	2,089,610	957,915	265	114
2026	3,317,631	2,383,577	425	286
2027	7,051,824	4,180,469	892	500
2028	8,861,914	5,834,729	1,115	684
2029	10,540,844	7,170,805	1,318	854
2030	13,527,566	7,897,315	1,742	943
2031	15,389,504	7,893,023	1,993	936
2032	15,389,504	8,030,993	2,015	965
2033	16,710,074	8,030,993	2,103	941
2034	16,710,074	8,030,993	2,175	967
2035	16,710,074	8,030,993	2,089	957
2036	16,710,074	8,030,993	2,152	959
2037	16,710,074	8,030,993	2,188	965
2038	16,710,074	8,030,993	2,114	960

Adjustments for Rooftop Solar

The updated rooftop solar or behind-the-meter ("BTM") forecast uses the same methodology previously outlined in Appendix D (Electric Load Forecast) to the initial Plan. Overall, the net change is a lower forecast when compared to the original Spring 2023 BTM projection.

The BTM forecasts are predicated on two main variables — payback and adoptions — and developing a relationship between these variables that can be projected forward. Paybacks were impacted by higher projected system costs as well as the implementation of the new net metering tariffs in North Carolina, while customer adoptions were lower and showed declining trends, with economic headwinds such as higher borrowing costs and inflationary pressures contributing to the lower adoption rates.

As noted, the forecast-to-forecast changes in paybacks and adoption trends resulted in lower BTM projections. The impact over 2024–2038 is a reduction of about 16% across the Carolinas jurisdictions.

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Table SPA 2-3 below presents BTM forecast results for both 2024 and 2038. Please note that the data is presented as cumulative totals beginning January 1, 2024.

Table SPA 2-3: BTM Forecast Results for 2024 and 2038 (MWh)

System	Year	Customers		Energy (MWh)	
		Residential	Non-Residential	Residential	Non-Residential
DEC	2024	6,752	159	36,124	7,385
	2038	98,795	2,382	948,326	193,846
DEP	2024	4,761	110	26,534	3,276
	2038	70,656	1,612	696,541	85,301

Adjustments for Electric Vehicles

The Fall 2023 Electric Vehicle ("EV") Forecast uses the same methodology previously outlined in Appendix D (Electric Load Forecast) to the initial Resource Plan and includes refreshed variable updates from the Spring 2023 EV Forecast. The refreshed variables and registration data are through mid-2023, previously through end of year 2022.

The updated Fall 2023 EV forecast includes implementation of Time-of-Use ("TOU") rates in North Carolina. Forecasted adoption of EV owners using TOU rates was implemented using the Guidehouse Vehicle Analytics and Simulation Tool ("VAST"), which bases the charge profile characteristics from Guidehouse's collected database of public (such as NREL's Electric Vehicle Infrastructure — Projection ("EVI-Pro") tool) and private load profiles across charging use cases, from residential to different types of commercial and industrial customers. VAST models EV owners' responsiveness to pricing signals in TOU rates to shift the load over the course of the day to minimize electricity bills to the extent possible.

Overall, the net change from the refreshed EV forecast resulted in less than a 5% increase in net new energy consumption through the 2038-time horizon. Tables SPA 2-4 and SPA 2-5 below show the number of EVs that are projected to be in operation at the end of 2024 and forecasted to be in operation in 2038, the associated percent it represents of the entire vehicle fleet and the net new energy associated with those vehicles for DEC and DEP, respectively.

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Table SPA 2-4: Projected EVs in Operation through 2038 (MWh) – DEC

Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2024	70,373	1.26%	49,374
2038	2,512,065	38.13%	8,313,054

Table SPA 2-5: Projected EVs in Operation through 2038 (MWh) – DEP

Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2024	49,606	1.47%	33,815
2038	1,576,381	39.43%	5,086,859

Updated 2023 Fall Load Forecast

Tables SPA 2-6 through SPA 2-9 below provide an overview of the Updated 2023 Fall Load Forecast over the Base Planning Period utilized in the Supplemental Planning Analysis. The tables provide the components of the net load forecast and the compound annual growth rates ("CAGR") for these components for the DEC and DEP annual energy and peak winter load requirements.

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Table SPA 2-6: Updated 2023 Fall Base DEC Winter Peaks – Impacts of Program (MW)

Year	Gross Retail Peak	UEE/RS/ CPP[1]	Electric Vehicles	Net Retail Peak	Line Loss + Co Use	Retail Peak at Gen	Wholesale	System Peak at Gen
2024	14,603	(24)	1	14,579	932	15,511	2,154	17,664
2025	14,775	(139)	4	14,640	953	15,593	2,224	17,817
2026	15,174	(248)	9	14,935	974	15,909	2,249	18,158
2027	15,864	(336)	21	15,550	995	16,545	2,320	18,865
2028	16,394	(445)	37	15,986	987	16,973	2,481	19,454
2029	16,897	(595)	59	16,361	1,039	17,400	2,617	20,016
2030	17,494	(707)	89	16,876	1,077	17,953	2,726	20,679
2031	17,967	(821)	127	17,274	1,103	18,377	2,743	21,120
2032	18,243	(929)	175	17,489	1,119	18,609	2,766	21,375
2033	18,713	(1,029)	232	17,915	1,089	19,005	2,790	21,795
2034	18,913	(1,101)	292	18,104	1,091	19,194	2,755	21,949
2035	19,124	(1,155)	356	18,325	1,141	19,466	2,831	22,298
2036	19,338	(1,194)	425	18,570	1,162	19,732	2,842	22,574
2037	19,581	(1,223)	498	18,856	1,186	20,042	2,865	22,907
2038	19,793	(1,238)	572	19,127	1,183	20,310	2,898	23,208
CAGR	**2.2%**	**32.4%**	**63.2%**	**2.0%**	**1.7%**	**1.9%**	**2.1%**	**2.0%**

Note 1: “UEE” is Utility Energy Efficiency, “RS” is Rooftop Solar, and “CPP” is Critical Peak Pricing.

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Table SPA 2-7: Updated 2023 Fall Base DEP Winter Peaks – Impacts of Program (MW)

Year	Gross Retail Peak	UEE/RS/ CPP	Electric Vehicles	Net Retail Peak	Line Loss + Co Use	Retail Peak at Gen	Wholesale	System Peak at Gen
2024	9,631	(25)	0	9,607	435	10,041	3,923	13,965
2025	9,753	(53)	2	9,703	441	10,143	3,979	14,122
2026	9,922	(83)	5	9,843	452	10,295	4,013	14,309
2027	10,163	(117)	9	10,055	460	10,515	4,082	14,597
2028	10,371	(160)	16	10,226	476	10,703	4,126	14,829
2029	10,761	(201)	25	10,586	492	11,078	4,180	15,258
2030	10,872	(244)	38	10,666	500	11,166	4,226	15,392
2031	10,971	(288)	55	10,737	499	11,236	4,267	15,504
2032	11,099	(332)	75	10,842	502	11,345	4,301	15,645
2033	11,261	(373)	99	10,987	509	11,497	4,335	15,832
2034	11,318	(409)	124	11,032	516	11,549	4,370	15,919
2035	11,482	(438)	151	11,195	519	11,714	4,406	16,120
2036	11,505	(463)	180	11,222	524	11,746	4,443	16,189
2037	11,647	(487)	211	11,371	522	11,893	4,481	16,374
2038	11,727	(505)	242	11,464	523	11,987	4,520	16,507
CAGR	**1.4%**	**24.0%**	**63.0%**	**1.3%**	**1.3%**	**1.3%**	**1.0%**	**1.2%**

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Table SPA 2-8: Updated 2023 Fall Base DEC Forecast Energy Sales (GWH), Gross to Net

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	CPP/ PTR[1]	Net Retail Sales at Meter	Line Loss + Co Use	Gross Retail at Gen	Wholesale	System Obligation at Gen
2024	81,547	(288)	(44)	49	(49)	(2)	81,214	5,300	86,513	9,765	96,279
2025	83,571	(814)	(128)	141	(234)	(3)	82,535	5,385	87,919	9,839	97,758
2026	85,796	(1,342)	(217)	300	(318)	(4)	84,214	5,492	89,706	10,122	99,828
2027	90,433	(1,868)	(308)	537	(337)	(6)	88,452	5,765	94,217	11,360	105,576
2028	93,622	(2,388)	(397)	868	(353)	(8)	91,345	5,951	97,295	12,414	109,709
2029	96,706	(2,916)	(487)	1,307	(356)	(10)	94,245	6,137	100,381	13,462	113,844
2030	100,862	(3,446)	(582)	1,861	(359)	(12)	98,323	6,399	104,722	13,963	118,685
2031	103,877	(3,969)	(680)	2,524	(362)	(14)	101,375	6,595	107,969	14,045	122,014
2032	105,004	(4,469)	(782)	3,283	(366)	(17)	102,652	6,677	109,329	14,145	123,474
2033	107,318	(4,931)	(877)	4,095	(369)	(19)	105,217	6,842	112,059	14,197	126,256
2034	108,272	(5,252)	(964)	4,933	(373)	(21)	106,596	6,930	113,527	14,277	127,803
2035	109,345	(5,451)	(1,026)	5,794	(379)	(22)	108,260	7,037	115,298	14,358	129,655
2036	110,398	(5,602)	(1,065)	6,653	(384)	(24)	109,975	7,148	117,123	14,466	131,589
2037	111,352	(5,695)	(1,102)	7,494	(390)	(25)	111,635	7,254	118,889	14,525	133,414
2038	112,341	(5,726)	(1,142)	8,313	(396)	(26)	113,364	7,365	120,729	14,611	135,340
CAGR	**2.3%**	**21.4%**	**23.3%**	**36.6%**	**14.9%**	**19.6%**	**2.4%**	**2.4%**	**2.4%**	**2.9%**	**2.4%**

Note 1: “PTR” is Peak Time Rebate.

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Table SPA 2-9: Updated 2023 Fall Base DEP Forecast Energy Sales (GWH), Gross to Net

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	CPP/ PTR	Net Retail Sales at Meter	Line Loss + Co Use	Gross Retail at Gen	Wholesale	System Obligation at Gen
2024	44,647	(151)	(30)	34	-	(1)	44,499	2,205	46,704	18,315	65,018
2025	45,890	(425)	(86)	93	(39)	(2)	45,431	2,249	47,680	19,137	66,817
2026	47,964	(700)	(143)	198	(398)	(3)	46,918	2,319	49,237	19,614	68,851
2027	50,000	(983)	(202)	354	(402)	(5)	48,763	2,408	51,171	19,822	70,992
2028	51,960	(1,273)	(262)	569	(406)	(6)	50,581	2,494	53,075	20,028	73,103
2029	53,974	(1,555)	(324)	848	(409)	(8)	52,526	2,587	55,112	20,195	75,308
2030	55,288	(1,825)	(387)	1196	(413)	(10)	53,848	2,649	56,497	20,384	76,882
2031	55,747	(2,086)	(453)	1607	(417)	(12)	54,386	2,675	57,061	20,591	77,652
2032	56,380	(2,330)	(521)	2071	(420)	(14)	55,167	2,712	57,878	20,834	78,712
2033	56,835	(2,550)	(584)	2565	(424)	(15)	55,826	2,744	58,569	20,951	79,520
2034	57,202	(2,693)	(644)	3070	(428)	(17)	56,491	2,775	59,266	21,070	80,336
2035	57,646	(2,780)	(688)	3585	(432)	(18)	57,313	2,814	60,127	21,193	81,320
2036	58,137	(2,861)	(720)	4098	(438)	(19)	58,196	2,856	61,052	21,318	82,371
2037	58,516	(2,928)	(750)	4599	(444)	(20)	58,974	2,893	61,867	21,448	83,315
2038	58,910	(2,971)	(782)	5087	(451)	(21)	59,772	2,931	62,703	21,582	84,285
CAGR	2.0%	21.3%	233%	35.8%	18.7%	19.8%	2.1%	2.0%	2.1%	1.2%	1.9%

2023 Fall High Load Forecast Sensitivity – Continued Economic Development

In addition to updating the Base 2023 Fall Load Forecast, the Companies also prepared a higher Continued Economic Development Load Forecast ("2023 Fall High Load Forecast") to support modeling system resource needs recognizing the potential for significant economic development-driven increases to the load forecast to continue by incorporating known potential "mega projects" sites that have not yet made material commitments sufficient to be included in the Updated 2023 Base Fall Load Forecast but have the potential to make such commitments. The total impact of this expanded group of "mega sites" on the high load forecast is provided below in Table SPA 2-10 (which is meant to be compared to table SPA 2-2). For the purposes of developing Continued Economic Development high load forecast, no other inputs were modified.

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Table SPA 2-10: Large Site Developments (MW) Adjustments in Continued Economic Development 2023 Fall High Load Forecast

Year	High Case Energy (MWh)		High Case Winter Peak (MW)	
	DEC	DEP	DEC	DEP
2024	776,443	423,559	-	-
2025	2,089,610	957,915	265	114
2026	3,317,631	2,383,577	425	286
2027	7,051,824	4,180,469	892	500
2028	10,024,436	6,609,744	1,169	781
2029	14,767,010	9,988,248	1,815	1,209
2030	18,207,277	11,017,122	2,267	1,336
2031	20,939,425	11,592,970	2,625	1,403
2032	21,841,354	12,332,226	2,784	1,507
2033	23,445,748	12,521,442	2,897	1,507
2034	23,611,312	12,631,818	2,995	1,547
2035	23,824,180	12,773,730	2,941	1,554
2036	24,297,220	13,089,090	3,076	1,596
2037	24,770,260	13,404,450	3,184	1,642
2038	25,006,780	13,562,130	3,146	1,653

Resource Costs

Technology costs continue to change as demand and inflation continue to drive prices up, adding to the cost increases from well-recognized supply chain issues over the last several years. Resource costs were reviewed against information available from various procurement efforts, updated tools from Guidehouse on renewable and storage costs, and additional industry information available since costs were finalized earlier in 2023. All current assumed resource cost estimates are subject to further refinement as new information and data is gathered. A description of changes to each technology cost is provided below:

- **Combustion Turbine/Combined Cycle**: Benchmarking activities of generic resource cost estimates against execution in the current period of high inflation and continuing uncertainty around equipment, materials and labor costs signaled increased costs for these resources, which have been integrated into the supplemental assumptions. Additionally, the generic combined cycle is now assumed to include dual fuel optionality.
- **Solar**: Costs were benchmarked to recent proposal costs submitted into the 2023 Solar Request for Proposal ("RFP"). Costs have been adjusted to ensure that the modelled generic solar cost curve is being aligned with market data from the procurement.

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- **Onshore wind**: Costs have been updated with the latest tool information from Guidehouse released in October 2023.
- **Li-Ion Storage**: Costs have been updated with the latest tool information from Guidehouse finalized in November 2023.
- **Solar + Li-Ion Storage**: Costs have been updated with the latest tool information from Guidehouse finalized in November 2023. As part of the update, there were greater savings observed on some of the solar paired with storage components compared to previous tool updates.
- **Pumped Storage Hydro**: Costs for this resource have been updated to reflect information received from third-party constructor estimates and major equipment RFP bids.
- **Offshore wind**: Capital development and operating costs were not updated from the assumptions in the initial Plan and as such the supplemental analysis continues to use the 2023 data provided by the offshore wind developers and verified by DNV.[18]
- **Small Modular Reactor Nuclear**: Costs have been updated to show a present-day cost which is based on a First of a Kind ("FOAK") installation due to the current maturity of the technology. A cost curve reflective of the expected future reductions as the costs move from FOAK to Nth of a Kind ("NOAK") is also included in the price forecast. Costs have been aligned to a publicly available report from the Idaho National Lab including the FOAK premium.[19]

In addition to the changes described above, the Companies' benchmarking activities dictated supplemental assumption changes to more accurately reflect the translation of the 2023 overnight cost to an all-in cost of each technology by adjusting the application of general inflation, technology-specific inflation rates, and financing costs. This resulted in the capture of more inflation and financing costs over the generic project development timeline while reducing the learnings for technologies built in the future.

Natural Gas Supply

Natural gas supply is one of the areas where significant changes in the energy landscape since the initial Plan filing have justified updating planning assumptions for purposes of preparing this Supplemental Planning Analysis. Most notably, MVP has made significant construction and permitting progress toward its ultimate completion since the summer of 2023. Equitrans, the lead developer for MVP, has most recently stated that it targets completion of the pipeline in the first quarter of 2024.[20] Recognizing these recent developments, the increased confidence in the ultimate delivery of gas

[18] As discussed in Carolinas Resource Plan Appendix I (Renewables and Energy Storage), the offshore wind market is a nascent industry in the United States. Given the recent trends in offshore wind projects along the Atlantic coast, costs will be reevaluated in future resource plans or related Commission-directed activities to adjust for evolving industry trends.

[19] Abdalla Abou-Jaoude et al., *Literature Review of Advanced Reactor Cost Estimates Nuclear Science & Technology Directorate*, (Oct. 2023), https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_66425.pdf.

[20] Equitrans Midstream, Investor Presentation October 2023:
https://s22.q4cdn.com/743133753/files/doc_presentations/2023/Oct/31/investor-presentation-q3-2023-final-1-1.pdf

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supply via MVP allows the Companies to assume the availability of incremental volumes of gas supply is reasonable.

The updated fuel supply assumption essentially combines both the initial Plan's Base Fuel Supply Assumption from the Gulf Coast and the Alternate Fuel Supply Sensitivity from Appalachia into a singular scenario. Each of these original fuel supply assumption scenarios were assumed to support the gas supply requirements of up to three incremental combined cycles. Thus, by combining the procurement scenarios in the Supplemental Planning Analysis, the Companies' updated fuel supply assumption supports the fuel supply volume requirements of up to six additional CCs.

This updated fuel supply assumption incorporates an assumed MVP completion and incremental infrastructure in the future to expand gas deliverability into the Carolinas from MVP as well as additional brownfield pipeline expansion(s) from the Gulf Coast, if required. Thus, the modeled commodity component assumes an integrated portfolio of volumes and pricing levels of Appalachian, Transco Zone 4 and Transco Zone 5 indexed natural gas. The modeled generic costs have been updated appropriately with updated market cost information. See Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) for more details about natural gas firm transportation.

Resource Availability

In light of additional execution considerations and other planning or external factors since the initial Resource Plan, the Companies have taken the opportunity with the Supplemental Planning Analysis to develop supplemental resource availability assumptions to reflect how these considerations impact annual and cumulative resource availability. The assumption changes for each of the technologies are discussed in the following sections.

Solar

The initial Resource Plan modeling assumed the maximum solar megawatt ("MW") availability to be selected by the model was 1,350 MW/year starting in 2028 and increasing to 1,575 MW/year starting in 2031.[21] The Plan also recognized that increasing solar availability to 1,575 MW/year for purposes of real-world plan execution would necessitate continued success in proactively achieving transmission additions through the Red Zone Expansion Project ("RZEP") 2.0 projects.[22] In 2023, the Companies continued to face challenges around adding solar with regard to developer contract terminations and interconnection constraints. Notwithstanding the foregoing challenges, the Companies have updated longer-term supplemental input assumptions regarding solar availability. The Supplemental Planning Analysis assumed the same solar resource limits as the initial Plan through 2031 but increased solar availability to 1,800 MW per year across DEC and DEP starting in 2032 and beyond. This increased resource availability recognizes the potential for larger projects to increase annual solar capacity availability. Since transmission outages to interconnect facilities is a limiting factor, larger projects should bring more capacity online per outage. Should the Companies'

[21] Carolinas Resource Plan, Chapter 2 (Methodology and Key Assumptions) at 31, 33.

[22] Carolinas Resource Plan, Chapter 4 (Execution Plan) at Table 4-2.

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upcoming solar procurements fail to yield larger projects to enable the increased solar capacity assumptions, the Companies will continue to check and adjust this assumption in future planning cycles.

Stand-alone Energy Storage

To support the supplemental resource planning model runs, the Companies reconsidered the most appropriate limit on quantities of this resource type which could be integrated with reasonable confidence while balancing operating considerations and the cost of incremental battery MW. Considering many factors, selection of additional stand-alone battery storage resources (beyond those already forecast for availability) was limited to 1) 200 MW for 2027, 2) 500 MW per year for 2028-29, and 3) 1,000 MW for 2030 and beyond. This supplemental assumption reflects a reduction in selectable stand-alone battery energy storage resources availability from 2,200 MW per utility per year in the initial Plan.[23] This supplemental assumption recognizes challenges with developing larger quantities of battery energy resources in the near-term and the benefits of a more sustainable year-over-year availability on a long-term basis. This supplemental annual availability limit on standalone battery energy storage does not affect the selectable batteries associated with solar paired with storage projects or put a cumulative cap on overall energy storage selectable by the model. Significant factors considered when setting the above annual limits included cumulative effect on interconnection construction volumes, impact to forecast global stationary battery storage equipment and construction services markets, potential for further storage technology development and price declines over the longer-term, and availability of locations on the transmission system requiring relatively low upgrades to facilitate new firm interconnection.

Combined Cycle

With the supplemental fuel supply assumptions described in the Natural Gas Supply section above, the Companies have developed a supplemental availability assumption for new CC units. The Supplemental Planning Analysis increases the limit on CC availability by three additional 1,360 MW CC units by 2033 to six CCs cumulatively across the combined Carolinas systems. Overall, this assumption increases the number of CCs available for selection; however, the Supplemental Planning Analysis continues to recognize that there is a practical limit on the total number of gas turbine sites that can be developed based on the availability of reasonably suitable sites with access to gas supply, transmission, land, cooling sources, as well as other factors such as zoning and environmental permitting. Finally, in recognition of the fact that the updated Execution Plan now identifies that the third new CC unit will be located in South Carolina, the Companies have excluded carbon dioxide (“CO_2”) emissions from that CC unit from the North Carolina CO_2 reduction calculation for carbon baseline and accounting purposes.[24]

[23] Carolinas Resource Plan, Chapter 2 (Methodology and Key Assumptions) at 35.

[24] See 2022 Carbon Plan Appendix A (Carbon Baseline and Accounting) for details.

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Advanced Nuclear

The advanced nuclear resource availability for the Supplemental Planning Analysis has been updated from the initial Plan to reflect optimal project learnings for a continuous construction schedule at the first site (Belews Creek) to realize execution efficiencies from deployment of the first unit to subsequent units, and thereafter for future sites. The supplemental resource availability assumption seeks to execute on the nuclear resources needed in the Resource Plan focusing on completion of the first two units at the first site to maximize construction and design learnings. This change further reduces the financial exposure of future units on the second site by performing the construction of the first two units at the first site over a three-year period before starting construction at the second site. The supplemental approach also incorporates a resource allocation plan that takes the projected southeast region labor resource availability into account, optimizing the construction sequence. Based on these factors, the supplemental resource availability for advanced nuclear reflects no more than two small modular reactors/advanced reactors ("SMR/AR") units online per year, after the first three units at the first site are completed. This supplemental availability assumption effectively reduces the cumulative number of nuclear units available to be selected by four units through 2040 and by seven units through 2050. This resource availability assumption, however, does not change the total of two nuclear SMR units available by the start of 2035, as assumed in the initial Resource Plan.

Offshore Wind

Offshore wind resource availability was updated for the Supplemental Planning Analysis. The first availability of the resource of 2032 in the initial Plan was shifted out one year to 2033 in the Supplemental Planning Analysis. This assumption reflects impacts of potential supply chain constraints with yet to be determined projects off the coast of North Carolina based on manufacturing schedule of long lead materials, informed by current offshore wind projects in the US, along with enabling interconnection and transmission system projects also challenged to complete within the aggressive timeline assumed in the initial Plan. The additional time also provides an added benefit of allowing for regulatory and policy decisions around integrating offshore wind in the portfolio to develop.

Table SPA 2-11 below summarizes the updated supply-side resource availability assumptions used to develop the Supplemental Planning Analysis as compared to the initial Plan assumptions.

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Table SPA 2-11: Combined DEC/DEP Annual Resource Availability Assumptions

Technology	Initial Plan Assumption		Supplemental Planning Analysis Assumption	
	Annual	Cumulative	Annual	Cumulative
Solar (including SPS)	2028-2030: 1,350 MW 2031+: 1,575 MW	N/a	2028-2030: 1,350 MW 2031: 1,575 MW 2032+: 1,800 MW	N/a
Stand-alone Battery	2027+: 4,400 MW	N/a	2027: 200 MW 2028-2029: 500 MW 2030+: 1,000 MW	N/a
CT	2029+: 4,250 MW	N/a	2029+: 4,250 MW	N/a
CC	2029: 1,360 MW 2030+: 2,720 MW	4,080 MW (3 CC Units)	2029: 1,360 MW 2030+: 2,720 MW	8,160 MW (6 CC Units)
Onshore Wind	2031: 300 MW 2032+: 450 MW	2,250 MW	2031: 300 MW 2032+: 450 MW	2,250 MW
Pumped Storage	2034: 1680 MW	1,680 MW	2034: 1834 MW	1,834 MW
Offshore Wind	2032+: 800 MW	2,400 MW through 2038	2033+: 800 MW	2,400 MW through 2038
Advanced Nuclear	2035: 2 Units	15 Units through 2040	2035: 2 Units	11 Units through 2040

Forecasted Resources

As described in Appendix C (Quantitative Analysis) to the Companies' initial Resource Plan filing, the Plan includes a limited number of forecasted resources. Additions to and subtractions from those resource forecasts for this Supplemental Planning Analysis are described below.

- **Solar** – The Supplemental Planning Analysis utilizes a solar forecast with approximately 200 fewer MW of solar capacity installed by 2030 as compared to the projections in the initial Plan. The primary reductions include less capacity from prior resource solicitations due to project cancellations as well as lower procured contracted capacity from the 2022 Solar RFP than targeted. These capacity reductions were offset in part by additional capacity sought in the current 2023 Solar RFP and planned 2024 Solar RFP and additional capacity from a more recent evaluation of the interconnection queue accounting for various additions and reductions that have occurred over time. Based on solar capacity reaching approximately 10,000 MW as comprised of existing connections, prior legislative mandates, and the 2023 and 2024 RFP targets from the NTAP, the 200 MW reduction in the solar forecast represents a reduction of about 2%.

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- **Battery Energy Storage** – Forecasted stand-alone battery storage resources were largely unchanged in the Supplemental Planning Analysis, with the notable exceptions of one additional project forecast to come online during calendar year 2026 and an adjustment to the size of a previously forecast project. First, in order to bring reliable dispatchable capacity on earlier, DEC now intends to utilize the generator replacement request interconnection process to integrate 167 MW of additional stand-alone battery storage capacity at its Allen Steam Station, a project known as "Allen-2." Second, DEP now intends to construct the Knightdale project as a full 100-MW/2-hour resource in 2025 instead of augmenting its rating over several years.

- **Additional Unit Uprates** – As explained in Appendix C (Quantitative Analysis) to the initial Plan, the Companies continue to evaluate projects at existing generating facilities that can provide incremental benefits to customers. A limited number of additional planned uprate projects have been included in this Supplemental Planning Analysis. These projects are listed in Table SPA T-2 in the Technical Appendix.

- **Demand Response** – The supplemental demand response program forecasted capability consists of an incremental 179 MW in DEC and 10 MW in DEP. Expected economic development load data in the Updated 2023 Fall Load Forecast was reviewed at the business and customer level, applying expected participation rates to what is experienced today at a business type level. The Companies factored whether the expected economic development load customers are already a customer in other non-Carolinas Duke Energy service territories, and if they participated in similar demand response programs in other jurisdictions, into the forecasted participation in existing programs as they come online.

Portfolios Modeled in Supplemental Planning Analysis

The Companies' developed four additional portfolios under Energy Transition Pathway 3, consistent with the methods, modeling approach, and analytical framework described in Chapter 2 (Methodology and Key Assumptions) and Appendix C (Quantitative Analysis) of the initial Resource Plan. Except where specified in this document and the accompanying Technical Appendix, the Companies used the same modeling inputs to develop these portfolios as described throughout the initial Plan filing.

In addition to Portfolio P3 Fall Base, the Companies developed three additional Sensitivity Analysis Portfolios to explore potential changes to resource selection and portfolio performance under future conditions in which rapid economic development continues (P3 Fall High Load), in which some of the peak demand from that continued economic development could be managed with new or existing customer programs (P3 Fall High Load Interruptible) and in which capital costs for new CC and CT units exceed the forecast used in this Supplemental Analysis (P3 Fall High CC/CT Cost). Finally, the Companies also developed portfolios under Energy Transition Pathway 1 and Energy Transition Pathway 2, along with the South Carolina Supplemental Informational No Carbon Constraints Portfolio, using the updated supplemental modeling inputs and assumptions described in this section. Table SPA 2-12 below lists these portfolios.

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Table SPA 2-12: Portfolio Matrix for Additional Portfolio Analysis

<table>
<tr><th>Portfolio</th><th>CO_2 Constraint</th><th>Resource Availability</th><th>Gas Supply</th><th>Supply-Side Resource Costs</th><th>Fuel Commodity Price</th><th>Load</th><th>EE</th><th>DSM</th></tr>
<tr><td colspan="9">Pathway 3</td></tr>
<tr><td>P3 Fall Base</td><td>70% reduction by 2035 Carbon-neutral by 2050</td><td>Fall Base</td><td>Appalachia + Gulf Coast</td><td>Fall Base</td><td>Base</td><td>Updated 2023 Fall Load Forecast</td><td>Base</td><td>Fall Base</td></tr>
<tr><td colspan="9">Pathway 3 Portfolio Sensitivity Analysis</td></tr>
<tr><td>P3 Fall High Load</td><td rowspan="2">70% reduction by 2037 Carbon-neutral by 2050</td><td rowspan="3">Fall Base</td><td rowspan="3">Appalachia + Gulf Coast</td><td rowspan="2">Fall Base</td><td rowspan="3">Base</td><td rowspan="2">Continued Economic Dev.</td><td rowspan="3">Base</td><td>Fall Base</td></tr>
<tr><td>P3 Fall High Load Interruptible</td><td>Additional Interruptible</td></tr>
<tr><td>P3 Fall High CC/CT Cost</td><td>70% reduction by 2035 Carbon-neutral by 2050</td><td>1.25x CC/CT Capital Cost</td><td>Updated 2023 Fall Load Forecast</td><td>Fall Base</td></tr>
<tr><td colspan="9">Supplemental Portfolio Analysis</td></tr>
<tr><td>P1 Fall Supplemental</td><td>70% reduction by 2030 Carbon-neutral by 2050</td><td>2035 Resources by 2030[1]</td><td rowspan="3">Appalachia + Gulf Coast</td><td rowspan="3">Fall Base</td><td rowspan="3">Base</td><td rowspan="3">Updated 2023 Fall Load Forecast</td><td rowspan="3">Base</td><td rowspan="3">Fall Base</td></tr>
<tr><td>P2 Fall Supplemental</td><td>70% reduction by 2033 Carbon-neutral by 2050</td><td>2035 Resources by 2033[1]</td></tr>
<tr><td>SP SC No CO_2 Constraint Fall Supplemental</td><td>No Constraint</td><td>Fall Base</td></tr>
</table>

Note 1: Excluding advanced nuclear and Bad Creek II

Additional Supporting Analyses

Reliability Verification

Given the obligation to maintain or improve the reliability of the existing grid and to ensure resource adequacy of the system, the Companies conducted Reliability Verification as described in Appendix C (Quantitative Analysis) to the initial Resource Plan to ensure Portfolios accomplish this requirement of the system. Reliability Verification was performed for Portfolio P3 Fall Base, as well as P1 Fall Supplemental, P2 Fall Supplemental and the South Carolina Supplemental Informational No Carbon Constraints portfolio. Results of these reliability verification runs are discussed in the Technical Appendix.

Bad Creek Powerhouse II Economic Verification

To continue to verify the economic inclusion of Bad Creek II in the Portfolio P3 Fall Base, the Companies conducted an updated economic verification where the portfolio was developed excluding Bad Creek II as described in Appendix C (Quantitative Analysis) to the Plan. The results of the economic verification are discussed in the Technical Appendix.

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Supplemental Coal Retirement Analysis

As part of the Supplemental Planning Analysis, the Companies conducted Supplemental Coal Retirement Analysis for Pathway 3 utilizing the Supplemental Planning Analysis' base planning assumptions. The Companies used the same process as described in Appendix F (Coal Retirement Analysis) of the initial Resource Plan to conduct the analysis with results discussed in the Supplemental Planning Analysis Technical Appendix.

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Section 3: Portfolio Additions and Analysis Results

This section provides the results of the Supplemental Planning Analysis focused on Energy Transition Pathway 3. These results and the four resource portfolios described in this section should be considered in the context of the 33 portfolios and extensive supporting analysis presented in the Companies' initial Resource Plan filing. In addition to the four portfolios discussed in this section, the Technical Appendix also provides supplemental updates to the Core Portfolios for Pathways 1 and 2, and an update to the supplemental informational "SC No Carbon Constraints" portfolio. Considered together, the portfolios presented in this supplemental analysis and the 33 portfolios in the initial Plan filing comprise 40 portfolios that provide the Commissions and stakeholders with a thorough evaluation of the potential effects that a variety of future conditions may have on optimal resource selection and portfolio performance with respect to the Companies' resource planning objectives for an orderly transition — maintain or improve reliability, compliance with laws and regulations, least cost planning and affordability, increasingly clean resource mix, resource diversity, accounting for executability and foreseeable conditions impacts, uncertainties and risks.[25]

The results of this additional analysis yield several important insights:

- Reliably meeting the energy needs of rapidly growing Carolinas' economies as projected in the Updated 2023 Fall Load Forecast will require significant new resource additions inclusive of but greater than the initially recommended Portfolio P3 and proposed Near-Term Action Plan included in the Companies' initial Plan.

- High load factor economic development projects of the types seeking to locate in the Carolinas necessitate the addition of reliable, around-the-clock generation supply to maintain system reliability.

- Reaching the Interim Target[26] by 2035 will require the addition of both advanced nuclear and offshore wind resources to the portfolio.

- If economic development continues in the Carolinas at a pace consistent with the Continued Economic Development load forecast, the Interim Target may not be reached until later in the 2030s.

Informed by this analysis, the Companies are updating their recommended portfolio for planning purposes to Portfolio P3 Fall Base as further addressed in the SC Chapter Supplement and NC Chapter Supplement being filed along with this Supplemental Planning Analysis.

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[25] *See* Carolinas Resource Plan Chapter 2 (Methodology and Key Assumptions) at 3.

[26] Interim Target, as defined in Carolinas Resource Plan Chapter 3 (Portfolios), is the Companies' North Carolina resource planning target and interim goal to achieve 70% carbon-dioxide ("CO_2") emissions reductions from 2005 levels on the long-term path to achieving carbon neutrality.

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Coal Unit Retirements Dates

The Companies continue to support an orderly exit from coal that mitigates long-term risk to customers of continued coal operations while maintaining reliability of the grid and ensuring resource adequacy through the energy transition. This approach further allows the Companies to plan for the changing economics of operating coal and preserve flexibility on retirements in the early 2030s to respond as load develops and new resources are needed to meet growing load and replace the 8.4 GW of retiring coal capacity.

For the Supplemental Planning Analysis, the Companies utilized the coal retirement dates from Pathway 3 consistent with the initial Plan with limited adjustments. First, the Companies adjusted the retirement dates of Allen 1 and Allen 5 from March 31, 2024 to December 31, 2024, and September 30, 2024, respectively, consistent with the current planned retirement dates for these resources. Furthermore, the Companies adjusted the retirement schedule for Roxboro Units 2 and 4. As addressed in the Execution Plan update, the Companies have accelerated the retirement of Roxboro Unit 4 to 2029 in order for Roxboro Unit 1 and Roxboro Unit 4’s transmission capability to be utilized as part of the generation replacement request for Person County Energy Complex CC 1. Accordingly, the retirement of Roxboro Unit 2 was delayed to 2034, consistent with the retirement date of Roxboro unit 4 in the initial filing, effectively switching the retirement dates of these units. A comparison of the retirement dates used for Pathway 3 in the initial filing and for the portfolios in the Supplemental Planning Analysis is shown in Table SPA 3-1, below.

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Table SPA 3-1: Coal Unit Retirements (effective by January 1 of year shown)

Unit	Utility	Winter Capacity (MW)	Effective Year (Jan 1)	
			P3 Base	P3 Fall Base
Allen 1[1]	DEC	167	2025	2025
Allen 5[1]	DEC	259	2025	2025
Belews Creek 1	DEC	1,110	2036	2036
Belews Creek 2	DEC	1,110	2036	2036
Cliffside 5	DEC	546	2031	2031
Cliffside 6[2]	DEC	849	2049	2049
Marshall 1	DEC	380	2029	2029
Marshall 2	DEC	380	2029	2029
Marshall 3	DEC	658	2032	2032
Marshall 4	DEC	660	2032	2032
Mayo 1	DEP	713	2031	2031
Roxboro 1	DEP	380	2029	2029
Roxboro 2[3]	DEP	673	2029	2034
Roxboro 3	DEP	698	2034	2034
Roxboro 4[3]	DEP	711	2034	2029

Note 1: Allen Units 1 & 5 to be retired by December 31, 2024.
Note 2: Cliffside 6 is assumed to continue operating on 100% on natural gas beyond 2035 and was not included in the coal retirement analysis for the Carolinas Resource Plan.
Note 3: Based on execution considerations, the Companies updated the retirement dates for Roxboro, switching Unit 2 with Unit 4, reflecting that Roxboro 1 and 4 will be retired and their transmission capacity will be used as a part of a Generator Replacement Request for Person County CC 1.

Importantly, to ensure system reliability, coal retirements must be considered together with load growth and equally reliable, replacement resources being placed into service. As a result, changes or delays to replacement generation in-service dates or accelerated materialization of load would affect the retirement dates shown in Table SPA 3-1 above.

The Companies conducted supplemental coal retirement analysis as further discussed in the Supplemental Planning Analysis Technical Appendix, which supports the continued use of Pathway 3 Optimal Unit Retirement Dates from the initial Plan.

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Supplemental Portfolio Analysis

The Companies developed Portfolio P3 Fall Base under Energy Transition Pathway 3, using the Updated 2023 Fall Load Forecast, resource cost forecasts, and gas supply and resource availability assumptions described in Section 2. All other inputs and assumptions used to develop Portfolio P3 Fall Base are consistent with those described in Chapter 2 (Methodology and Key Assumptions) and Appendix C (Quantitative Analysis) of the Companies' initial Plan filing. Portfolio P3 Fall Base targets reaching the Interim Target by 2035. Figure SPA 3-1 below provides a summary of P3 Fall Base.

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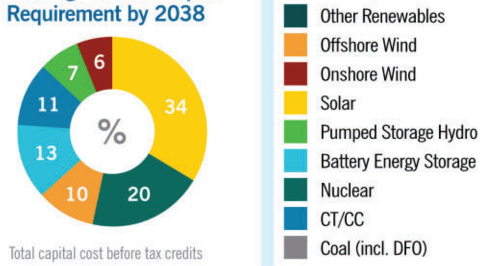
Figure SPA 3-1: P3 Fall Base Summary

P3 Fall Base Summary

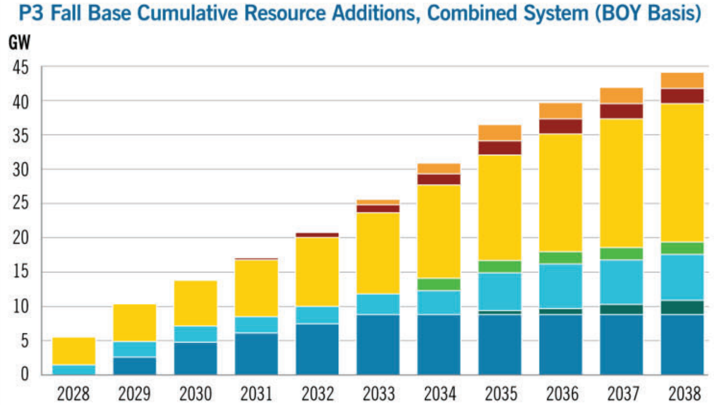
P3 Fall Base		2038	2050
PVRR ($B)	Combined System	$78	$149
	DEP PVRR	$30	$60
	DEC PVRR	$48	$89
		2033	**2038**
BILL IMPACT	Combined System CAGR	4.1%	3.6%
	DEP CAGR	4.0%	3.4%
	DEC CAGR	4.1%	3.7%
Year in which 70% target is met		**2035**	

Percentage of Total Capital Requirement by 2038

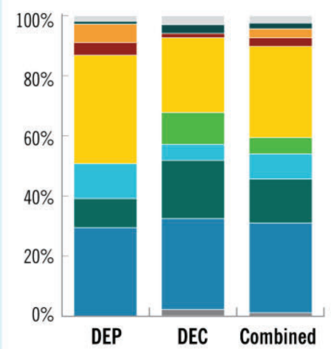


Total capital cost before tax credits

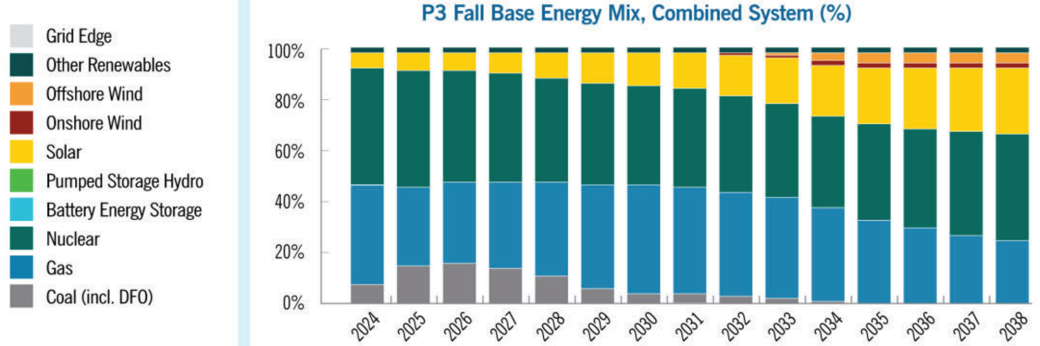
P3 Fall Base Cumulative Resource Additions, Combined System (BOY Basis)



P3 Fall Base Capacity Mix, BOY 2038 (%)



P3 Fall Base Energy Mix, Combined System (%)



P3 Fall Base Coal Retirements by Year (MW, effective by January 1 of year shown)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
DEP						1,091		713			1,371		
DEC		426*				760		546	1,318				2,220
TOTAL		**426***				**1,851**		**1,259**	**1,318**		**1,371**		**2,220**

*Allen Units 1 & 5 are planned to retire by December 31, 2024.

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Figure SPA 3-2 below illustrates model-selected resource additions for portfolio P3 Fall Base and P3 Base, as well as differences in resource selection between the two, through 2030, 2033, 2035, and 2038.

Figure SPA 3-2: Incremental Resource Additions by 2030, 2033, 2035 and 2038

By January 1 2030	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-2.2 GW	4.1 GW	0.7 GW	2.1 GW	1.4 GW	0 GW	0 GW	0 GW	0 GW
P3 Fall Base		-2.3 GW	3.8 GW	1.9 GW		2.7 GW				
Difference		-0.1 GW	-0.2 GW	1.2 GW	0 GW	1.4 GW	0 GW	0 GW	0 GW	0 GW

By January 1 2033	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-4.8 GW	8.8 GW	3.4 GW	2.1 GW	4.1 GW	1.2 GW	0 GW	0 GW	0 GW
P3 Fall Base		-4.9 GW	9.0 GW	2.6 GW		6.8 GW				0.8 GW
Difference		-0.1 GW	0.2 GW	-0.9 GW	0 GW	2.7 GW	0 GW	0 GW	0 GW	0.8 GW

By January 1 2035	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-6.2 GW	11.9 GW	4.3 GW	2.1 GW	4.1 GW	2.1 GW	1.7 GW	0.6 GW	0 GW
P3 Fall Base			12.6 GW	5.1 GW		6.8 GW		1.8 GW		2.4 GW
Difference		0 GW	0.7 GW	0.8 GW	0 GW	2.7 GW	0 GW	0.2 GW	0 GW	2.4 GW

By January 1 2038	Grid Edge	Coal Retirements	Solar	Battery	CT	CC	Onshore Wind	Pumped Storage Hydro	Advanced Nuclear	Offshore Wind
P3 Base	EE at least 1% of eligible retail sales IVVC growing to 96% DEC & 97% DEP circuits Winter DR & CPP	-8.4 GW	14.6 GW	6.0 GW	3.0 GW	4.1 GW	2.3 GW	1.7 GW	2.4 GW	0 GW
P3 Fall Base			17.5 GW	6.3 GW	2.1 GW	6.8 GW		1.8 GW	2.1 GW	2.4 GW
Difference		0 GW	2.9 GW	0.3 GW	-0.9 GW	2.7 GW	0 GW	0.2 GW	-0.3 GW	2.4 GW

Note 1: Columns may not sum due to rounding. Note 2: Solar includes solar paired with storage, excludes projects currently in advanced development. Note 3: IVVC = Integrated Volt/VAR Control. Note 4: CPP = Critical Peak Pricing. Note 5: Battery includes batteries paired with solar.

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As shown in Figure SPA 3-2 above, Portfolio P3 Fall Base requires the addition of considerably larger resource amounts relative to Portfolio P3 by 2035, following the addition of approximately 2 GW of high load factor demand in the Updated 2023 Fall Load Forecast and maintaining the timeline for reaching the Interim Target by 2035. In fact, the capacity expansion model selects nearly all available renewable and advanced nuclear resources available by 2035 to reach the Interim Target by that year in P3 Fall Base, leaving less than 2% of available solar capacity unselected. In total, resource additions for P3 Fall Base exceed those required for P3 Base by 6.8 GW by 2035 when the Interim Target is achieved and by 7.3 GW by the end of the Base Planning Period in 2038.

Figures SPA 3-3 and SPA 3-4 and tables SPA 3-2 and SPA 3-3 below provide the energy and capacity mixes for P3 Fall Base and P3 Base through 2050.

Figure SPA 3-3: Modeled Energy Mix, Combined Carolinas System

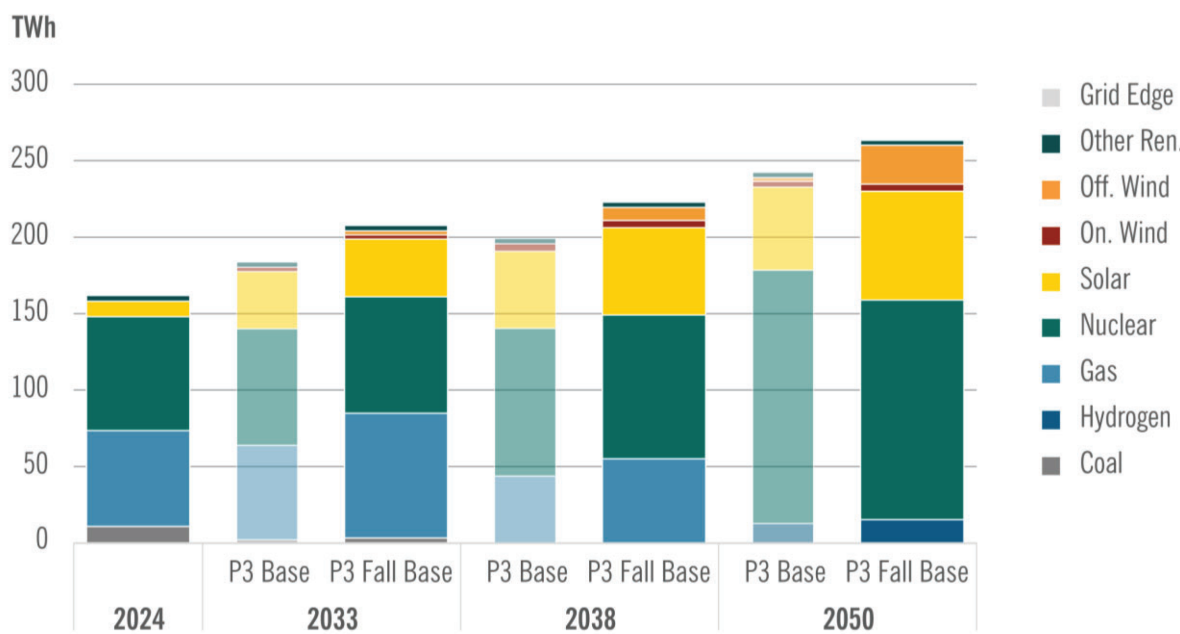

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Table SPA 3-2: Modeled Energy Mix, Combined Carolinas System

Resource Type	2024	2033		2038		2050	
		P3 Base	P3 Fall Base	P3 Base	P3 Fall Base	P3 Base	P3 Fall Base
Grid Edge	0%	0%	0%	0%	0%	0%	0%
Other Ren.	2%	2%	2%	2%	2%	1%	1%
Offshore Wind	0%	0%	1%	0%	4%	1%	10%
Onshore Wind	0%	2%	1%	2%	2%	1%	2%
Solar	6%	20%	18%	25%	26%	22%	27%
Nuclear	46%	41%	37%	48%	42%	68%	54%
Gas	39%	34%	39%	22%	25%	0%	0%
Hydrogen	0%	0%	0%	0%	0%	5%	6%
Coal	7%	1%	2%	0%	0%	0%	0%

Note 1: Columns may not sum to 100% due to rounding.

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Figure SPA 3-4: Nameplate Capacity Mix, Combined Carolinas System (beginning-of-year basis)

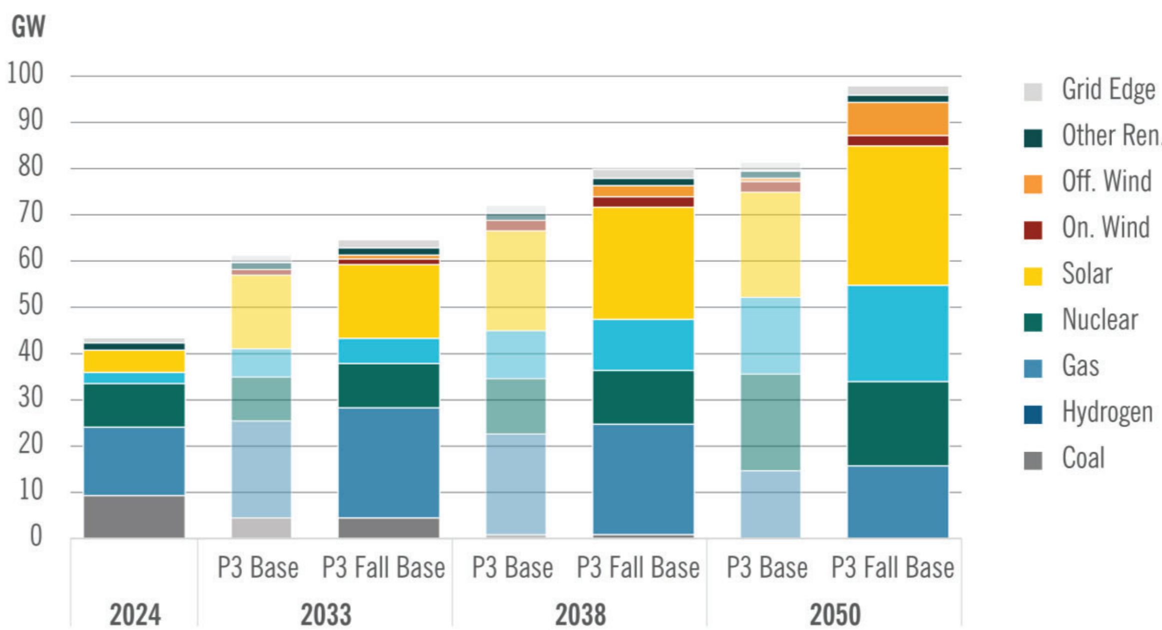

Table SPA 3-3: Nameplate Capacity Mix, Combined Carolinas System (percentages, beginning-of-year basis)

Resource Type	2024	2033		2038		2050	
		P3 Base	P3 Fall Base	P3 Base	P3 Fall Base	P3 Base	P3 Fall Base
Grid Edge	2%	3%	3%	2%	2%	2%	2%
Other Ren.	4%	2%	2%	2%	2%	2%	2%
Off. Wind	0%	0%	1%	0%	3%	1%	7%
On. Wind	0%	2%	2%	3%	3%	3%	2%
Solar	11%	26%	25%	30%	30%	28%	31%
Storage	6%	10%	8%	14%	14%	20%	21%
Nuclear	22%	16%	15%	17%	15%	26%	19%
CC / CT	34%	34%	37%	30%	30%	18%	16%
Coal (incl. DFO)	21%	7%	7%	1%	1%	0%	0%

Note 1: Columns may not sum to 100% due to rounding.
Note 2: Dual fuel optionality ("DFO")

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In addition to Portfolio P3 Fall Base, the Companies developed additional Sensitivity Analysis portfolios under Energy Transition Pathway 3 to explore the potential impacts of the following: further increases in capital costs for CC and CT resources (P3 Fall High CC/CT Cost), continued rapid economic development driving expected load higher than reflected in the Updated 2023 Fall Load Forecast (P3 Fall High Load), and continued rapid economic development with some subset that is interruptible (P3 Fall High Load Interruptible). These portfolios are listed in Table SPA 2-12. The following key insights can be drawn from these portfolios:

- The flexibility and dispatchability of hydrogen-capable CC and CT resources are critical to reliably serve the additional high load factor customer demand included in the Updated 2023 Fall Load Forecast. There is no difference in model selection of CCs between P3 Fall Base and P3 Fall High CC/CT Cost, and only one fewer CT is selected in the P3 Fall High CC/CT Cost sensitivity than in P3 Fall Base.

- Strong continued economic development above that considered in the Updated 2023 Fall Load Forecast would delay achievement of the Interim Target beyond 2035. Portfolio P3 Fall Base includes renewable and nuclear resource additions up to the maximum available by 2035 (except for 225 MW of solar). For the development of the P3 Fall High Load portfolio, the supplemental analysis demonstrates it is possible to achieve the Interim Target by 2037 with the projected resource availability limits.

- Achieving higher levels of demand response participation from new customers or otherwise allowing a portion of economic development load to be interruptible reduces the amount of supply-side resources the Companies need to add to serve system load during peak hours. However, these types of demand response initiatives do not materially change energy needs or CO_2 emissions trajectory.

Portfolio Performance

Similar to Table 3-7 in Chapter 3 (Portfolios) of the initial Plan filing, Table SPA 3-4 below illustrates cost, reliability, risk assessment, and pace of energy transition for Portfolio P3 Fall Base in comparison to Portfolio P3. The Companies then provide a more detailed comparative evaluation of these portfolios after the summary tables below.

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Table SPA 3-4: Portfolio Comparison P3 Fall Base to P3 Base

Carolinas Resource Plan Portfolios	P3 Base		P3 Fall Base		Difference	
DEC/DEP Combined System Resources [Nameplate MW] start of year (2033 | 2038)						
Total Contribution from Grid Edge & Customer Programs[1]	2,087	2,536	2,254	2,760	167	224
Incremental System Solar (excl. projects in dev.)	8,775	14,625	9,000	17,475	225	2,850
Incremental Onshore Wind	1,200	2,250	1,200	2,250	0	0
Incremental Offshore Wind	0	0	800	2,400	800	2,400
Incremental Advanced Nuclear Capacity	0	2,400	0	2,100	0	-300
Incremental Energy Storage[2]	3,694	7,954	3,053	8,627	-641	673
Incremental Gas (CC)[3]	4,080	4,080	6,800	6,800	2,720	2,720
Incremental Gas (CT)[3]	2,125	2,975	2,125	2,125	0	-850
Remaining Coal Capacity[4]	4,473	0	4,440	0	-33	0
Total Coal Retirements [MW] by End of 2035[4]	8,445		8,445		0	
Portfolio Cost						
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP/DEC Combined System) [$/month] 2033|2038[5]	$35	$55	$54	$80	$19	$26
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [$/month] 2033|2038[5]	$41	$48	$57	$81	$16	$33
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [$/month] 2033|2038[5]	$30	$59	$52	$80	$21	$21
Present Value Revenue Requirement (PVRR) (DEP/DEC Combined System) through 2038|2050 [$B]	$66	$119	$78	$149	$12	$30
PVRR (DEP) [$B] through 2038|2050	$26	$48	$30	$60	$4	$12
PVRR (DEC) [$B] through 2038|2050	$40	$71	$48	$89	$8	$18
Increasingly Clean Resource Mix (2033 | 2038)						
CO_2 Intensity (DEP/DEC Combined) [lbs/MWh]	313	182	363	196	50	14
Year in which 70% CO_2 Reduction is Achieved	2035		2035		None	
Reliability & Flexibility (2033 | 2038)						
95th Percentile Expected Net Load Ramp (MW/hr)	9,201	12,880	9,185	14,571	-16	1,691
Average CC Starts per Unit per Year	60	81	17	40	-43	-41
Energy Transition Risk Assessment (2033 | 2038)						
Cumulative Nameplate MW Additions of Resources with Limited Operational History in the Carolinas[6]	4,894	10,924	5,053	13,543	159	2,619
Cumulative Nameplate MW Additions, Combined Carolinas System[7]	22,887	37,297	25,764	44,563	2,877	7,266
Cumulative Nameplate MW Additions as % of Current Combined Carolinas System	53%	86%	60%	103%	7%	17%
Cumulative Capital Dollar Requirement, Combined Carolinas System [$B]	$44	$92	$61	$128	$17	$36
Overall Pathway Risk Related to Cost, Reliability, and Plan Execution					Risk Increased	

Note 1: Includes winter peak impact of load modifiers (utility-sponsored energy efficiency, behind-the-meter solar, critical peak pricing), integrated Volt/VAR control ("IVVC"), and demand response programs.
Note 2: Includes standalone, paired with solar, pumped storage hydro.
Note 3: New natural gas facilities will be capable of burning zero-carbon hydrogen in the future; hydrogen blending assumed to begin in 2035.
Note 4: Cliffside 6 continues to operate on 100% natural gas.
Note 5: Average retail rate impact across all customer classes applied to representative residential bill.
Note 6: Includes onshore wind, offshore wind, battery energy storage and advanced nuclear.
Note 7: Includes solar and battery projects currently in advanced development.

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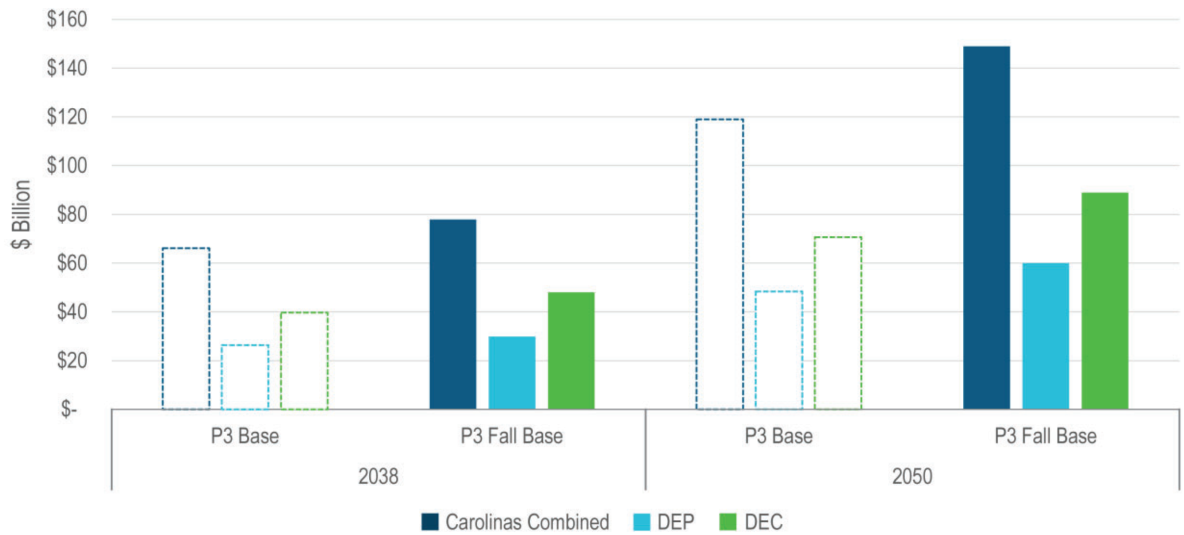
Portfolio Evaluation: Cost and Affordability

Figure SPA 3-5 shows the total cost of Portfolios P3 and P3 Fall Base through 2038 and 2050 expressed as the PVRR. The higher increase in PVRR from Portfolio P3 to Portfolio P3 Fall Base reflects both the additional resources required to meet rapidly growing customer needs and the increased cost of those resources as described in Section 2 of this document.

Figure SPA 3-5: PVRR for Portfolios P3 Fall Base and P3 Base, Calculated through 2038 and 2050



The accelerated pace of resource additions identified as needed to serve increased customer load in Portfolio P3 Fall Base is also reflected in the forecasted customer bill impacts, with projected increases by 2033 under Portfolio P3 Fall Base that are roughly comparable to the increases projected by 2038 under Portfolio P3. The associated compound annual growth rate through 2033 for Portfolio P3 Fall Base is approximately 4% per year. Bill impact snapshots for Portfolios P3 and P3 Fall Base through 2033 and 2038 are shown in Figure SPA 3-6 below.

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Figure SPA 3-6: Bill Impact Snapshots for Portfolios P3 Fall Base and P3 Base, 2033 and 2038

Note: The above customer rate impacts assume that for large, multi-year construction projects, the Company is able to recover its financing costs during the construction period, which will accelerate rate impacts into earlier years but lowers the overall cost that customers pay over the life of the investment from what would otherwise be. When financing costs are recovered during the construction period, non-financing project costs are still included in customer rates only after the related project is in operation and providing service to customers, unless otherwise determined by the Commissions.

Portfolio Evaluation: Increasingly Clean Resource Mix

Rapidly increasing customer energy needs over the next decade will necessitate increased generator output from both new and existing units. In the near term, while new resource additions are ramping up, there is a temporary corresponding increase in projected CO_2 emissions in the Carolinas before reaching the Interim Target in 2035 and ultimately reaching carbon neutrality by 2050. In addition to the decisive activities described in the Execution Plan, the Companies will continue to seek to identify ongoing opportunities to reduce emissions through all available cost-effective means, including pursuit of higher amounts of EE/DSM as well as the pursuit of additional efficiency enhancement projects within the existing generation fleet. Projected CO_2 emissions for North Carolina and the combined Carolinas system are shown in Table SPA 3-5 below.

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Table SPA 3-5: Projected Approximate CO_2 Emissions for Portfolio P3 Fall Base (million short tons)

	2005 Baseline	2035[1]	2038[1]
Combined Carolinas System (MM tons)		30	20
NC Only (MM tons)	75	25	20
NC % Reduction		70%	77%

Note 1: Estimated future emissions are based on a point-in-time forecast of weather normal load, projected fuel prices, system operations as well as projected resource retirements and additions. Emission estimates will change over time as these projected drivers are updated commensurate with changing market conditions and actual emissions will vary from estimates.

Summary of Portfolio Evaluation

Considering the rapid and significant increases in forecasted customer energy needs, and the associated increase in new resource additions, Energy Transition Pathway 3 remains the most reasonable and prudent approach for the Carolinas. Portfolio P3 Fall Base builds on Portfolio P3 to reliably and cost-effectively serve forecasted load while maintaining a measured pace of coal retirements and planning to achieve the Interim Target emission reductions by the year 2035. Looking ahead, Portfolio P3 Fall Base positions the Companies well to reliably support continued economic development in the region providing the resources needed to meet increased electricity demand required to support a growing economy and keeping the Companies squarely on the longer-term path toward achieving carbon neutrality by 2050. The Companies recommend Portfolio P3 Fall Base as the most reasonable, least cost, and least-risk portfolio for planning purposes and to inform execution plan activities.

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Section 4: Execution Plan Updates

As addressed in Chapter 4 (Execution Plan) of the initial Carolinas Resource Plan, successful Plan execution will require prudent and intentional actions and timely regulatory approvals to deliver the resource additions, retirements and system transformation needed to ensure that the Companies are able to continue to serve customers' growing energy needs and maintain or improve the reliability of the system. The next 10 to 15 years represent an even more critical execution phase in the Companies' orderly energy transition in light of the need to serve significantly more energy and capacity due to economic development successes across the Carolinas, which will involve the retirement of 8,400 MW of aging coal units in North Carolina (which serve all of the Companies' customers) and replacement with equally reliable resources.

Additional Supply-Side Actions

The pace, scope and scale of incremental supply-side resource additions now required to meet the increased capacity and energy needs identified in the Updated 2023 Fall Load Forecast necessitate additions to the Companies' NTAP and Execution Plan. These additions to the proposed NTAP detailed in Table SPA 4-1 below serve to reinforce the importance of pursuing all Execution Plan actions defined in the initial Plan to meet forecasted economic development and to be positioned for the potential for continued economic development commitments and even more load growth.

Table SPA 4-1: Updated Proposed Near-Term Actions and Development Activities Informed by Supplemental Analysis [27]

August NTAP Resource	August NTAP MW Amounts	Supplemental Incremental Resource MW Amounts	Total August NTAP + Supplemental Resource MW Amounts	Total August NTAP + Supplemental Proposed Near-Term Actions 2024–2026 and Development Activities
Solar	6,000 by 2031	460 by 2031	6,460 by 2031	- Continue RZEP 1.0 projects and advance RZEP 2.0 projects.[1] - 2024: Procurement targeting 1,585 MW of solar and solar paired with battery energy storage ("SPS") (approximate 2028 in-service date). - 2025–2026: Procurements targeting approximately 2,700 to 3,460 MW of solar and dependent on RZEP 2.0 (approximate 2029-2030 in-service date) and future RFP attrition of procured solar.
Battery Storage[2]	2,700 by 2031	175 MW of Standalone Storage now planned for Storage paired with Solar	2,700 by 2031	- 2024 to 2026: Develop and study additional 475 MW of stand-alone battery storage incremental to 2022 NC Plan. - 2024 to 2026: Target procurement of 965 MW of SPS (625 MW of SPS incremental to 2022 NC Plan).
Onshore Wind	1,200 by 2033	-	1,200 by 2033	- Select development partner(s), perform site feasibility studies and begin activities associated with siting and development for onshore wind projects.[3] - Submit interconnection requests into 2025-2026 DISIS interconnection clusters.
CT[4]	1,700 by 2032	425 by 2031	2,125 by 2031	- 2024: File Certificate of Public Convenience and Necessity ("CPCN") for 2 Marshall Advanced CTs at 900 MW (BOY 2029 in-service), submit air permits, begin transmission build-out engineering/modifications. - 2024: Evaluate siting options and submit interconnection Study requests for 850 MW CT 3 & 4 - (BOY 2030 in-service). - 2025: File CPCN and air permit for 850 MW (CT 3 and 4) (BOY 2030 in-service). - 2025: Evaluate siting options and submit interconnection request/GRR for 425 MW CT 5 (BOY 2031 in-service). - 2026: File CPCN and air permit for 425 MW (CT 5) (2031 BOY in-service).

[27] See Carolinas Resource Plan Chapter 4 (Execution Plan) Table 4-2: Supply-Side Near-Term Actions Plan 2023 to 2026 for additional detail on proposed near-term actions presented in the Initial Plan.

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August NTAP Resource	August NTAP MW Amounts	Supplemental Incremental Resource MW Amounts	Total August NTAP + Supplemental Resource MW Amounts	Total August NTAP + Supplemental Proposed Near-Term Actions 2024–2026 and Development Activities
CC[4]	4,080 by 2031	2,720 by 2033	6,800 by 2033	- 2024: File CPCNs for Person County Advanced CC1 and CC2 (each at 1,360 MW) (BOY 2029 & 2030 in-service, respectively); submit air permit, begin transmission build-out engineering/modifications. - 2024: Submit Interconnection Requests for 2 CCs (Person County Advanced CC2 and SC-located CC3; 1,360 MW each; BOY 2030 and 2031 in-service, respectively). - 2025: File SC Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN") for CC3 (2031 in-service), submit air permit. - 2025: Evaluate siting options and submit Interconnection Requests and/or GRR for 2 additional CCs (CC4 and CC5; 1,360 MW each; BOY 2032 and 2033 in-service, respectively). - 2025: File CPCN and submit air permit for CC4 (2032 in-service). - 2026: File CPCN and submit air permit for CC5 (2033 in-service). - 2026: Begin transmission build-out engineering/modifications for CC4 & CC5 (BOY 2032 and 2033 in-service, respectively).
Pumped Storage Hydro[5,6]	1,700 by 2034	134 by 2034	1,834 by 2034	- 2025: Subject to necessary regulatory guidance and support, target SC CECPCN. - 2025 and 2026: File NC Out of State CPCN, file final FERC licensing application, prepare for construction.
Advanced Nuclear[6]	600 by 2035	-	600 by 2035	- Site 1 – 2024 to 2026: Choose reactor technology, submit early site permit ("ESP"), develop construction permit/license application, contract with reactor vendor, and order long-lead equipment. - Site 2 – 2025 to 2026: Develop and submit ESP.
Offshore Wind[6]	-	2,400 by 2035	2,400 by 2035	- Conduct Acquisition Request for Information ("ARFI") with current Carolinas Wind Energy Area (off NC coast) lessees. - Conduct stakeholder engagement and outreach in connection with ARFI. - Report results of ARFI in next Carolinas Resource Plan filings. - Continue limited development of onshore transmission to support offshore wind.

Note 1: RZEP 2.0 subject to local transmission planning process. See Carolinas Resource Plan Appendix L (Transmission System Planning and Grid Transformation).
Note 2: Battery Storage amount includes stand-alone battery development and SPS amounts. Annual targets may be adjusted during development.
Note 3: To achieve in-service capacities for onshore wind, the Companies will target higher development quantities to account for assumed levels of project attrition.
Note 4: The exact amounts, models, configurations, and timing of CTs and CCs will depend on specific system needs and optimizing for execution.
Note 5: Bad Creek II Pumped Storage Hydro is projected to come into service by mid-2033; for planning purposes, the modeling reflects this resource coming into all portfolios at BOY 2034. Capacity was rounded up from 1,680 MW to 1,700 MW in initial Plan NTAP.
Note 6: The Companies note that with any long lead-time resource that results in a large, multi-year construction project, the recovery of the Companies' financing costs during the construction period is important to ensure strong credit ratings to facilitate the lowest possible financing costs for customers. In addition, recovery of financing costs during construction lowers the overall cost that customers pay over the life of the investment. When financing costs are recovered during the construction period, non-financing project costs are still included in customer rates only after the related project is in operation and providing service to customers, unless otherwise determined by the Commissions.

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Supplemental Updates to Detailed Execution Plan

Chapter 4 (Execution Plan) to the initial Resource Plan explained that a detailed Execution Plan is essential for a reliable and orderly energy transition. The Companies' initial Execution Plan provided a detailed road map outlining significant near-term and intermediate-term actions across all major Plan components, including actions in the 15-year Base Planning Period to advance longer lead-time resources and breakthrough technologies. In support of this Supplemental Planning Analysis, the Companies are updating certain components of the detailed Execution Plan to reflect the expanded resources needs identified in the NTAP. The detailed execution plan tables that follow are intended to supersede and replace the detailed Execution Plan activities tables for coal retirements, solar, nuclear, offshore wind, advanced nuclear and new natural gas assets.[28]

Retiring Existing Coal

Table 4-3 in Chapter 4 (Execution Plan) and Table F-6 in Appendix F (Coal Retirement Analysis) to the initial Plan present the Companies' planned coal unit retirement schedule between 2024 and 2035. As addressed in Section 3 and the Technical Appendix to this Supplemental Planning Analysis, the Companies reviewed the coal retirement analysis and determined no material changes to the optimal unit retirement dates are needed. An update to Intermediate-Term actions (2027–2032) based on P3 Fall Update is planning to retire Roxboro unit 4 in 2028–2029 along with Roxboro unit 1 instead of Roxboro unit 2. Roxboro units 2 and 3 retirements are targeted for 2034.

[28] This updated detailed Execution Plan is intended to supersede and replace Table 4-3 (Coal Retirements), Table 4-7 (Solar), Table 4-9 (Energy Storage), Table 4-11 (Offshore Wind), Table 4-12 (Advanced Nuclear), and Table 4-13 (Natural Gas Assets) in Chapter 4 (Execution Plan) of the Carolinas Resource Plan.

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Table SPA 4-2: Supplement to Execution Plan – Coal Retirements (Initial Plan Execution Plan Table 4-3)

Near-Term Actions (2024–2026)	
2024	• Retire Allen 1 & 5 units by December 31, 2024, assuming internal approvals gained and permission granted to take care, custody, and control of Lincoln 17 on December 1, 2024.[1]
Intermediate-Term Actions (2027–2032)	
2028–2029	• Retire Roxboro Units 1 & 4 and Marshall 1 & 2 after their respective in-flight hydrogen-enabled natural gas assets are placed in-service and commissioned at existing sites.
2031	• Approximate BOY time frame for Cliffside 5 retirement pending equally reliable replacement resources exist to allow retirements.
2031	• Approximate BOY time frame for Mayo retirement pending equally reliable replacement resources exist to allow retirements.
2032	• Approximate BOY time frame for Marshall 3 & 4 retirements pending equally reliable replacement resources exist to allow retirements.

Note 1: At the time of the initial filing, DEC was pursuing an amendment to the CPCN for Lincoln CT 17 to take care, custody, and control of the unit on January 1, 2024. Pursuant to the NCUC-approved Revenue Requirement Stipulation in Docket Nos. E-7, Sub 1134 and E-7, Sub 1276, DEC plans to take care, custody, and control of the unit no earlier than November 1, 2024.

Significantly Expanding Utility-Scale Solar

As described in the initial Plan, the addition of controllable solar capacity is a key component of the Companies' NTAP and continues to be critically important to Plan execution. The updated NTAP for solar and solar paired with battery energy storage ("SPS") reflects an increased overall procurement target for 2024–2026 RFPs of 6,460 MW solar and 965 MW of paired storage, as further detailed in table SPA 4-3 below. This increased solar procurement target (adding 460 MW across 2024-2026) is designed to address possible future attrition (recognizing ~24% average terminations of solar PPA projects over the past five years) by procuring some volumes in the NTAP above the model-selected solar. Adding that possible attrition volume to each procurement would increase the NTAP by an aggregate of 460 MW over the course of the 2024, 2025, and 2026 solar procurements, with approximately a third of that volume of solar and SPS targeted for procurement in the upcoming 2024 procurement cycle. The updated NTAP also adjusts the ratio of stand-alone and paired storage to move 175 MW of planned stand-alone storage from the initial NTAP to be paired storage targeted for procurement over the next three years along with the additional 460 MW of targeted controllable solar. The Companies will continue to monitor solar resource needs based on potential future project attrition in future procurements along with future development of customer-directed and must-take solar resource additions outside of the procurement process. The Companies will also continue to refine cost control measures as part of future RFPs and seek to optimize the timing of resource additions

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based on advancing future strategic transmission including Red Zone Expansion Plan 2.0 projects to ensure optimal targeted volumes of incremental controllable solar and SPS resources are achieved in future procurements.

Table SPA 4-3: Supplement to Execution Plan – Solar (Initial Plan Execution Plan Table 4-7)

Near-Term Actions (2023–2026)	
2023	• Issue and execute 2023 Solar RFP to procure next tranche of solar and SPS resources (1,435 MW targeted with volume adjustment mechanism up to 1,600 MW), which may require additional filings in SC.
2024	• Establish 2024 Solar RFP targeting 1,585 MW solar and 400 MW paired storage utilizing 2024 Resource Solicitation Cluster and targeting Q3 bid window opening. • Selection of and contracting with 2023 Solar RFP winners (Q2–Q3 2024). • Finalize and issue 2024 Solar RFP by Q3 2024.
2025–2026	• Issue additional dual state Solar Procurements, with targets based on NTAP for solar coming online in 2029–2030. Target quantities 2,700 MW to 3,460 MW solar with 565 MW paired storage across 2025-2026 RFPs.
Intermediate-Term Actions (2027–2032)	
2027–2030	• Issue subsequent solar procurement RFPs in alignment with then- approved resource plan.

Increasing System Flexibility and Maintaining Reliability with Energy Storage

Pumped Storage Hydro

In light of the increased load growth, the unique operational benefits of pumped hydro storage as described in the initial Plan to provide dispatchable capacity and to help manage fluctuations in higher levels of renewable generation and contribute to system reliability will be even more critical. Duke Energy is advancing the execution plan actions related to Bad Creek as outlined in the initial Plan.[29] The only adjustment to the NTAP is a refinement to projected capacity for the new Bad Creek II powerhouse increasing from 1,680 MW to 1,834 MW by 2034 based upon OEM equipment capability improvements from initial centerline equipment (major pump turbine and generator components) engineering included in recent bid information. As engineering progresses, additional refinements in total capacity may also occur.

[29] Carolinas Resource Plan Chapter 4 (Execution Plan), Table 4-8 (Pumped Storage Hydro) at 20.

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Battery Energy Storage

As described in the Solar section above, ratio adjustments to the ratio of stand-alone and paired storage are reflected in updated execution steps for energy storge in Table SPA 4-4 below.

Table SPA 4-4: Supplement to Execution Plan (Initial Plan Execution Plan Table 4-9)

Near-Term Actions (2023–2026)	
2023–2026	• Test and study non-lithium and long-duration technologies at the research and development scale. • Procure, construct and interconnect projects in advanced stages of development which are assumed in all modeled portfolios. • Continue development activities, including filing of interconnection requests and procurement of necessary long-lead equipment for stand-alone battery energy storage projects at strategic grid locations. • Finalize procurement strategy and initiate relevant procurement activities to support addition of 1,475 MW of stand-alone energy storage being placed in-service by beginning of 2031. • Finalize procurement strategy and initiate relevant procurement activities to support addition of 1,225 MW of battery energy storage that is paired with solar by beginning of 2031.
Intermediate-Term Actions (2027–2032)	
2027–2032	• Procure, construct and interconnect energy storage selected in Resource Plan. • Continue development activities, including filing of interconnection requests, for battery energy storage projects at strategic grid locations to allow for upward flexibility in future resource plans as well as preparation for projects to be connected beyond the 2032 intermediate-term time horizon.

Offshore Wind

As discussed in Chapter 3 (Portfolios) and Chapter 4 (Execution Plan) of the initial Plan filed in August 2023, offshore wind was not selected in the Core Portfolio P3 Base but was selected by the model in a number of Variant and Sensitivity portfolios and the Companies committed to monitoring potential future development of offshore wind for consideration in future Plans.[30] Under the Supplemental

[30] See Carolinas Resource Plan Chapter 3 (Portfolios) discussing portfolio resource selections and Appendix C (Quantitative Analysis) describing outcomes of Portfolio Variant and Sensitivity Analyses.

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Planning Analysis, offshore wind is selected in all P3 cases, including the Companies' recommended P3 Fall Base portfolio. Accordingly, the Execution Plan has been updated to reflect further activity to gather more information that would be used to inform the cost and scale of offshore wind resources located off the North Carolina coast in the next comprehensive Resource Plan.

Specifically, the Companies believe that additional information is needed to allow the Commissions to better assess offshore wind, particularly in light of the fact that the Companies do not currently hold a wind energy area ("WEA") lease. Thus, to facilitate more detailed consideration of offshore wind, the Companies propose to issue an Acquisition Request for Information ("ARFI") to provide a structure in which the WEA lessees can provide more detailed information regarding proposed acquisition structures (including proposed acquisition or development fees, structures to ensure financing and construction capability, payment structuring and risk sharing), along with updated pricing. While the WEA comparative analysis conducted in 2023 provided valuable pricing information to inform the Companies' modeling, it did not result in definitive feedback from the WEA lessees regarding key variables that will shape and define a future potential acquisition of an offshore wind generating facility, including the many varied ways in which such acquisition could be structured and designed. In addition, an ARFI would allow for updated pricing, since offshore wind prices were not updated in the Supplemental Planning Analysis, unlike most of the other resource options.

The Companies intend to engage interested stakeholders, including the WEA lessees, in providing input on the development of the ARFI. The results of the ARFI would then be presented to the Commissions once complete to facilitate the consideration of further action. In parallel, the Companies will continue limited early project development and engineering work on the related transmission while not taking definitive actions prematurely.

Given the expected timeline to execute the ARFI and obtain further necessary approvals, it will likely not be possible to achieve a 2033 in-service date for the first 800- MW block of offshore wind as currently modeled in Fall P3 Base. However, a 2034 in-service date may be achievable assuming proposed NTAP actions progress.

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Table SPA 4-5: Supplement to Execution Plan – Offshore Wind (Initial Plan Execution Plan Table 4-11)

Near-Term Actions (2023–2026)	
2023	• Submit findings of WEA comparative Analysis.
2024	• Request NCUC approval to pursue ARFI. • Continue limited development of onshore transmission to support offshore wind. • Monitor Offshore Wind projects along the United States East Coast (all years).
2025	• Engage stakeholders for feedback regarding structure, approach and timing of ARFI. • Issue ARFI. • Receive and evaluate responses from WEA lessees.
2026	• Provide information to Commissions and assess appropriate further actions.
Intermediate-Term Actions (2027–2032)	
2027–2032	• Further actions in the intermediate term will be guided by necessary regulatory approvals and support.

Table SPA 4-6: Supplement to Execution Plan – Offshore Wind

Activity Description	2024 ($M)	2025 ($M)	2026 ($M)	Total ($M)
Stakeholder Engagement and ARFI	0.2	0.9	0.3	**1.4**

Advanced Nuclear Strategy

Table SPA 4-7 below outlines the Companies' updated near-term actions to progress development of advanced nuclear resources in the Carolinas. The actions support the initial SMR in-service date for the first quarter of 2034 at site one (Belews Creek) and evolved deployment strategy to bring five additional SMR units online at that site in 12-month intervals. The first SMR at a second site has a scheduled in-service date of January 2037, followed by five additional units at that site that are also assumed to come online in 12-month intervals as determined to be needed in future resource plans.

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Table SPA 4-7: Execution Plan – Advanced Nuclear (Initial Plan Execution Plan Table 4-12)

Near-Term Actions (2023–2026)	
2023–2024	• Perform SMR technology assessment and due diligence review.
2023–2025	• Prepare an advanced nuclear ESP application for the Belews Creek site (SMR Site 1). • Choose an SMR technology for Belews Creek SMR site 1.
2025	• Submit ESP application for the Belews Creek site to the NRC.
2025–2026	• Develop ESP application for Site 2.
2025–2027	• Develop a construction permit application (“CPA”) or combined construction & operating license application (“COLA”) for SMR Site 1.
2026	• Submit ESP application for Site 2 to the NRC. • Enter contract with a reactor vendor of choice and order long-lead equipment for Site 1.
Intermediate-Term Actions (2027–2032)	
2027–2030	• Develop a CPA or COLA for SMR Site 2. • Develop Site 3 ESP application, if ESP path determined to be the necessary route.
2027	• Submit a CPA or COLA to the NRC for Site 1.
2029	• Submit a CPA or COLA to the NRC for Site 2.
2028–2030	• Submit a CPCN application for Site1 and a CPCN application for Site 2.
2027–2032	• Enter contract with reactor vendor and order long-lead equipment for Sites 2 and 3. • Begin CPA or COLA for Site 3. • Begin site preparations in accordance with the limited work authorization for Sites 1 and 2.
2030–2033	• Construction period for Site 1, Unit 1.
2031–2035	• Construction period for Site 1, Units 2 and 3.

Dispatchable Natural Gas

The Supplemental Planning Analysis identifies the Companies’ expanded need for new dispatchable natural gas-fueled resources to retire coal, reliably integrate renewables and maintain system reliability.

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To progress new natural gas resource additions at the Marshall Station and Person County Energy Complex as identified in the initial Plan, interconnection requests for incremental capacity have been submitted into the 2023 Definitive Interconnection System Impact Study (DISIS) and Generator Replacement Requests (GRR) were also submitted in 2023 for two Marshall CTs and Person County Advanced CC1. Also, the Companies filed pre-CPCN applications for Person County Advanced CC1 in September 2023 and Marshall CTs in November 2023. The Companies have now also identified Person County as the preferred site for the second Advanced CC2 identified in the initial Plan and have determined that CC3 will be sited at a location in South Carolina. The Companies plan to submit new interconnection requests for CC2 and CC3 into 2024 DISIS by June 2024.

To reliably serve the significant additional capacity and energy requirements identified as needed by the early 2030s in the updated supplemental P3 Fall Base modeling, the Companies are also planning to accelerate the addition of CTs 3 and 4 to achieve commercial operation by the beginning of 2030, the addition of CT5 by the beginning of 2031 and planning for a fourth and a fifth CC with targeted beginning of 2032 and 2033 in-service dates, respectively, as part of this updated execution plan for dispatchable natural gas generation.

Based on the supply chain constraints identified in today's marketplace, it is necessary that the Company enter purchase commitments for long-lead equipment such as, but not limited to, turbines, transformers, electrical switchgear, and circuit breakers prior to the anticipated CPCN Orders. These commitments are required to preserve the forecasted project in-service dates. Should CPCN Orders not be received as anticipated, and if these commitments cannot be applied toward future projects, Company will seek recovery of funds committed for these long-lead commitments.

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Table SPA 4-8: Supplement to Execution Plan – Natural Gas Assets (Initial Plan Execution Plan Table 4-13)

Near-Term Actions (2024–2026)	
2024	• Submit CPCNs and air permit applications for Marshall Advanced CTs and Person County Advanced CC1 & CC2. • Submit Person County Advanced CC2, SC-located CC3 and CTs 3 & 4 into 2024 DISIS. • Receive Marshall Advanced CTs and Person County Advanced CC1 CPCN orders to commence construction activities.
2025	• Receive Person County Advanced CC2 CPCN order to commence construction activities. • Receive interconnection agreements for Marshall Advanced CTs and Person County Advanced CC1. • Submit CPCNs and air permits for CC3 (SC-located BOY 2031), CC4 (BOY 2032) and CTs 3 & 4 (BOY 2030). • Submit Generator Replacement Request (GRR) and/or DISIS for CC4 and CT5.
2026	• Submit CPCN for CT5 (BOY 2031 in-service). • Receive interconnection agreements for Person County Advanced CC2, CC3 (SC-located) and CTs 3 & 4. • Submit CC5 into 2026 DISIS (BOY 2033 in-service). • Submit CPCN for CC5 (BOY 2033 in-service).
Intermediate-Term Actions (2027–2032)	
2027	• Receive interconnection agreements for CC4 (BOY 2032 in-service) and CT5 (BOY 2031 in-service), where applicable.
2028	• Submit interconnection requests (DISIS / GRR as applicable) for two CTs (BOY 2034 in-service). • Receive interconnection agreement for CC5 (2033 in-service). • Commission and place Marshall Advanced CTs 1 & 2 in-service (BOY 2029). • Commission and place Person County Advanced CC1 in-service (BOY 2029).
2030	• Commission and place CTs 3 & 4 (BOY 2030) and Person County Advanced CC2 in-service (BOY 2030).
2031–2032	• Commission and place CC3 (BOY 2031) and CT5 (BOY 2031) in-service. • Commission and place CC4 (BOY 2032) in-service.

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Transmission System Planning and Grid Transformation

Transmission system planning and grid transformation continue to be critical path components of successfully executing the Resource Plan, especially as the Supplemental Planning Analysis identifies the needs for additional supply-side resource additions to meet increasing customer energy needs in the planning horizon. The Companies are actively progressing transmission planning and projects identified in Table 4-15 in Chapter 4 (Execution Plan) of the initial Plan to enable orderly coal unit retirements and renewable enabling transmission. As mentioned in Appendix L (Transmission System Planning and Grid Transformation) to the initial Plan, the Carolinas Transmission Planning Collaborative (CTPC) is currently responding to a public policy request to study high renewables integration. The results of the public policy request study will be completed and published in a report by April 2024 and will provide further input into the RZEP 2.0 project needs as well as address long- term transmission project needs such as greenfield 230 kV and 500 kV transmission lines. RZEP 2.0 projects or alternative solutions beyond those described in Appendix L (Transmission System Planning and Grid Transformation) to the Resource Plan will be identified through the results of this study.

Furthermore, the CTPC local transmission planning process for addressing and identifying local transmission project needs has been revised to reflect multi-value benefits for local transmission expansion plan projects. FERC acceptance of these process revisions is expected in March 2024.

Other Execution Considerations

Optimizing for Execution

As explained in Chapter 4 (Execution Plan) of the initial Plan, in order to optimize for execution, there will continue to be refinements and modifications to quantities, timing, and scope of generic planning units and annual dates used for modeling purposes. For example, the total megawatt capacity for Bad Creek II has been adjusted slightly upwards with recent bid information and may be adjusted again as engineering plans progress. Similarly, specific technology procurement amounts may be adjusted to optimize efficiency or take advantage of supply chain or market opportunities, or generation unit configurations or project timing may be adjusted based on site or fuel supply interdependencies. The Companies need to maintain the ability to be adaptable and flexible in execution to respond to opportunities and manage risks on behalf of customers as they transition the system and support the growth in the Carolinas. This includes managing interdependencies across projects, such as fuel supply or transmission work that may be required to bring new assets into service and facilitate coal retirements. The Definitive Interconnection System Impact Study and the revised CTPC local transmission planning processes will be the main mechanisms for identifying high-benefit, long lead time transmission projects or alternative solutions that will need to be proactively pursued to meet resource and load integration timelines.

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Continued Commitment to Grid Edge and Customer Programs Integral to the Plan

The Companies will continue to identify and investigate opportunities to "shrink the challenge" of increasing load and costs through aggressively pursuing Grid Edge and other Customer Programs,[31] which include energy efficiency ("EE") and demand-side management ("DSM") measures, as well as certain rate designs, voltage control efforts, renewable energy programs, behind-the-meter generation and storage, and electric transportation programs. Over the past year, the Companies have worked diligently with stakeholders to advance the necessary regulatory filings for approval of new Grid Edge and Customer Programs and to implement the required enablers that will increase the potential impacts that they can achieve. For example, subsequent to the August 2023 Plan filing, in both South Carolina and North Carolina, DEC filed for approval of new modifications to a non-residential large customer DSM program, PowerShare Mandatory Plus,[32] in which large non-residential customers may commit to 100 hours of load curtailment per year. The Companies have also proposed a new low-income demand response program that has been approved in North Carolina and is pending approval in South Carolina.[33]

As discussed in the Companies' Grid Edge direct testimony, however, much of the new load that is coming onto the Companies' systems is likely able to opt-out of the Companies' EE programs, built with the highest energy-saving measures and standards already included, or both, leaving limited opportunity for expansion of the Companies' energy efficiency programs to these customers' load.

Checking and Adjusting in Response to Changing Energy Landscape

The need for this Supplemental Planning Analysis demonstrates how rapidly the energy landscape can change in the course of a proceeding and across many risk and signpost areas identified in Chapter 4 (Execution Plan) to the Resource Plan.[34] For example, the Companies studied the potential of continued robust economic development activity in this Supplemental Analysis through a P3 Fall Base High Load Sensitivity Analysis that could result in additional incremental changes to resource needs and the NTAP. The dynamic economic, political, technological, market, and supply chain environments can rapidly change, thus influencing modeling assumptions, Execution Plan and NTAP activities, or both. The Companies will continue to monitor, highlight, and propose adjustments for material changes that are reasonable, prudent and in the best interest of customers.

[31] As described in Carolinas Resource Plan, Appendix H (Grid Edge and Customer Programs).

[32] *See* Proposed Modifications to the PowerShare Nonresidential Load Curtailment Program, Docket No. E-7, Sub 1032 (Oct. 9, 2023); Letter Requesting Approval of Modification to PowerShare Nonresidential Load Curtailment Rider, Docket No. 2013-298-E.

[33] *See* Order Approving Programs, Docket Nos. E-2, Sub 927 & E-7, Sub 1032 (Nov. 28, 2023); Application of Duke Energy Carolinas, LLC for Approval of Residential Income-Qualified Power Manager Load Control Program RIQLC (SC), Docket No. 2013-298-E (Dec. 15, 2023); Application of Duke Energy Progress, LLC for Approval of Residential Income-Qualified Power Manager Load Control Program RIQLC (SC), Docket No. 2016-149-E (Dec. 15, 2023).

[34] Carolinas Resource Plan Chapter 4 (Execution Plan) Figure 4-5, pages 39 to 41