Chapter 2: Methodology & Key Assumptions

Highlights

- The 2025 Carolinas Resource Plan is the result of a robust analysis and modeling process designed to identify the most reasonable, least-cost resource portfolio for the Carolinas. This process ensures system reliability is maintained or improved as the Companies modernize their generation fleet and prepare to serve growing demand.
- The Companies' planning objectives prioritize the development of a diverse, executable, reliable, and increasingly clean resource portfolio. Balancing these objectives provides value to customers and mitigates risks associated with technology, fuel, and execution.
- The inputs and assumptions used to develop the 2025 Carolinas Resource Plan represent a snapshot in time. They include economic development projections and load forecasts, existing and anticipated Grid Edge and customer program offerings, current resource technology inputs, and assumptions around future technologies. As the Companies check and adjust their Plan across future planning cycles, these inputs and assumptions are subject to change.
- The Companies conducted three sequential Initial Evaluations, each building on the results of the previous: a Fuel Security Evaluation, a Representative Nuclear Technology Selection, and an updated Coal Retirement Analysis.

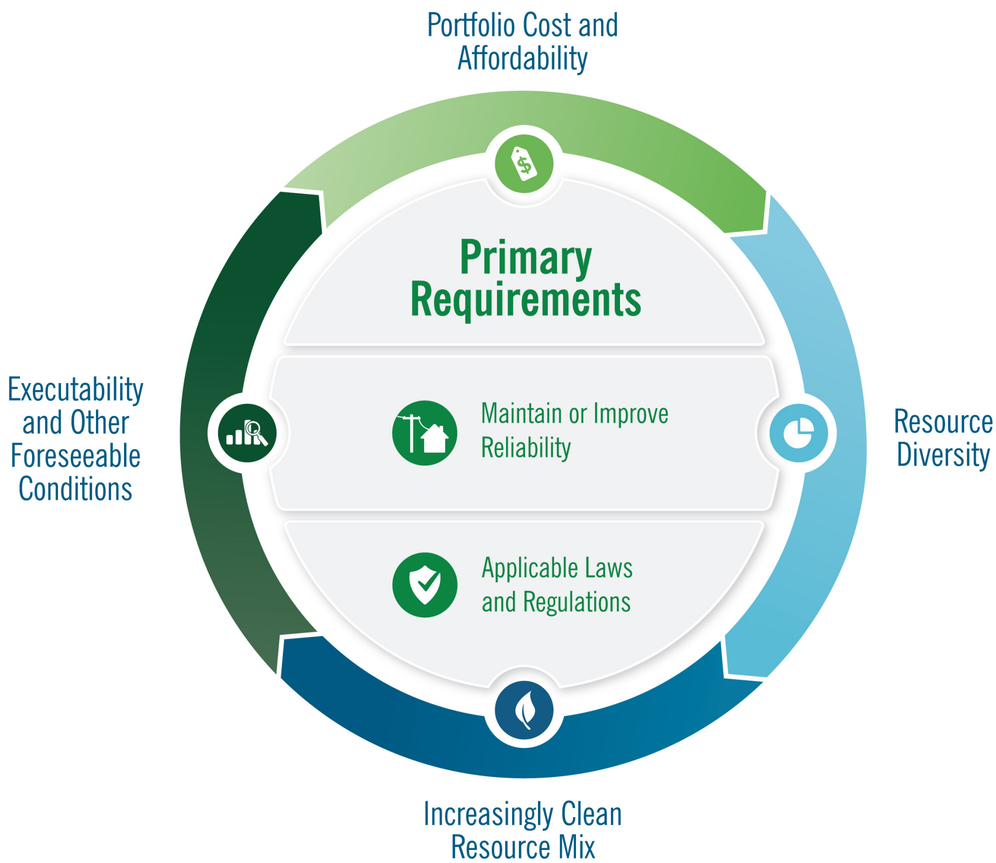
As described in Chapter 1 (Powering the Carolinas), Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP” and, together with DEC, “Duke Energy” or the “Companies”) are continuing to plan for growing demand and the orderly retirement of aging generation facilities. To continue to maintain system reliability and meet the needs of existing and future customers, the Companies need to deploy a balanced and diverse portfolio of supply-side resources and demand-side programs over the planning horizon. This Chapter provides an overview of the planning objectives, analytical processes, and modeling tools used to develop the 2025 Carolinas Resource Plan (the “Plan” or “Resource Plan”), as well as a summary of key inputs and assumptions informing the Plan. The analytical processes and key modeling assumptions for the Plan are described in greater detail in Appendix C (Quantitative Analysis) and across other Appendices to the Plan.

The inputs, assumptions, and modeling framework utilized to develop the Plan represent a snapshot in time – 2025 – and are subject to change in future planning updates as the Companies continue to check and adjust in response to the changing policy, market, and industry conditions highlighted in Chapter 1. The analytical process uses reasonable inputs and assumptions for long-term planning that are informed by the best data available at the time the Plan is developed, recognizing that actual project-specific costs, configurations, operating characteristics, and transmission requirements will be refined during Plan execution. Supply-side resources and demand-side solutions included in planning analytics reflect a representative sample of the wide range of potential generating unit and program capacities, configurations, or specific technology designs that may be deployed. Accordingly, the execution of the Plan is discussed further in Chapter 4 (Execution Plan).

Resource Planning Objectives

The Companies' long-term resource planning addresses the interdependencies and risks associated with executing a reliable, cost-effective, and increasingly clean generation fleet. Resource decisions are evaluated against the Companies' planning objectives, which are shown below in Figure 2-1, to ensure the Plan provides adequate energy and capacity resources to meet current and anticipated future demand with a reasonable reserve margin while keeping customer bills as low as possible. The Companies must also continue orderly retirements of their aging generation infrastructure while planning for the execution of replacement resources that provide reliable, efficient, and flexible service to meet the needs of customers. The Resource Plan must consider applicable planning requirements, environmental regulations, and other relevant laws and regulations, while ensuring reliability is maintained or improved for customers. The Companies' planning objectives focus on modernizing the generation fleet while managing associated risks. This means applying reasonable least-cost planning principles, promoting resource diversity to reduce fuel and technology risks, managing rate impacts to customers, adapting to changes in policy, weighing benefits and risks associated with the ongoing use of aging resources, and maximizing the value of existing resources.

Figure 2-1: Resource Planning Objectives



Maintaining or Improving Reliability

Customers expect Duke Energy to meet their electricity needs at all times of the day and across all seasons of the year, including during periods of extreme weather conditions. Maintaining resource adequacy to ensure the continued reliable operation of the system is the primary obligation of the Companies, along with meeting specific reliability requirements in system planning and operations established by the North American Electric Reliability Corporation ("NERC"). In planning to meet the current and future capacity and energy needs of the system, the Companies carefully consider ways to bolster system reliability across normal and extreme weather conditions, including winter storm events.

Building and maintaining an adequate planning reserve margin ("PRM") is a critical component to ensuring the system has sufficient resources to meet the needs of customers. The PRM functions as a safety net by ensuring there is enough generating capacity available to serve demand at all times, including during unexpected events such as unanticipated generating unit outages or periods of high customer demand that stress the grid. The Companies' most recent resource adequacy study, which was completed in 2023, determined a PRM of 22% was necessary to maintain resource adequacy and reliability of the Companies' systems. Both the North Carolina Utilities Commission ("NCUC") and the Public Service Commission of South Carolina ("PSCSC") found the 2023 Resource Adequacy Study, as well as the Companies' approach to adding capacity to meet the updated 22% PRM by 2031, to be reasonable.[1]

In addition to planning for an appropriate PRM, the Companies' modeling process includes a Reliability Verification step that validates the Companies' Plan meets system needs by taking into consideration a given portfolio's ability to meet peak demand under a range of conditions and across varying winter demand patterns like those experienced during major winter events (e.g., Winter Storm Elliott in 2022 or the polar vortex conditions experienced in January 2024). Appendix L (Reliability & Operational Resilience) provides further information on the Companies' efforts to maintain reliability as they prepare to serve growing demand and modernize the generation fleet.

As discussed in Appendix D (Load Forecast), the economic development success across North Carolina and South Carolina continues to drive rapid growth in energy needs that the Companies must serve in a timely manner. This period of significant load growth is occurring while the Companies continue an orderly retirement of their aging coal fleet. Sufficient generating capacity must be available when load growth is anticipated to materialize to maintain reliable operations of the electric system and ensure the Carolinas remain open for business.

Finally, a reliable system requires real-time flexibility to serve dynamic customer demand, which increasingly varies by year, season, day, and minute. As generating unit characteristics and load behaviors change, the system must adapt accordingly. Thus, flexibility is an increasingly important factor in the Plan to ensure continued system reliability.

Complying with Applicable Laws & Regulations

A primary objective of long-term resource planning is translating applicable federal, state, and local laws and regulations into planning inputs. Similarly, the Companies consider the impacts of international trade policies (i.e., tariffs), executive orders, federal agency guidance, and other relevant policy-related requirements. Because the Companies' dual-state electricity systems serve both North Carolina and South Carolina, the Plan must adhere to the laws and regulations of both states. This includes new requirements under the Power Bill Reduction Act, Session Law 2025-78 ("Senate Bill 266") in North Carolina and the Energy Security Act ("Act 41") in South Carolina. Additionally, the Plan considers applicable regulations set by the U.S. Environmental Protection Agency ("EPA"), Federal Energy Regulatory Commission ("FERC"), NERC, SERC Reliability Corporation, and the U.S. Nuclear Regulatory Commission ("NRC").

A cross-reference table of requirements for this Plan is provided in Appendix M (Cross-Reference & Glossary).

[1] NCUC Order Accepting Stipulation, Granting Partial Waiver of Commission Rule R8-60A(d)(4), and Providing Further Direction for Future Planning at 49-51, Docket No. E-100, Sub 190 (Nov. 1, 2024) ("2023 CPIRP Order"); PSCSC Order Approving 2023 Integrated Resource Plan, Order No. 2024-767 at 105, Docket Nos. 2023-8-E, 2023-10-E (Nov. 25, 2024)

Accounting for Plan Execution & Foreseeable Conditions in the Planning Environment

Effective and prudent planning requires consideration of practical execution and operational limitations. Otherwise, the resulting long-term plan may be inexecutable and fail to maintain system reliability. As discussed in Chapter 1, the Companies are navigating changing policy, market, and industry conditions. These dynamics, including growing energy demand and recent state and federal policy changes, are influencing the planning environment. Other key considerations that must be incorporated into the Companies' planning process include project lead times and costs, supply chain and workforce constraints, delays related to permitting and siting, and infrastructure dependencies such as transmission and fuel supply needs. These factors – assessed in light of the Companies' extensive experience operating the electric system in the Carolinas – must be balanced alongside other planning objectives to inform the executability of the Plan.

Considering Portfolio Cost & Customer Impacts

Like reliability, balancing costs to customers is critical to support continued economic growth in the Carolinas. The long-term planning process must follow reasonable, least-cost planning principles, including but not limited to:

- Accounting for land, capital, fuel, and operations and maintenance costs that vary by resource type
- Appropriately balancing risks and uncertainties regarding future fixed and variable costs
- Incorporating applicable federal energy tax credits and incentives
- Considering both cumulative long-term costs expressed in present value terms and forecasted customer bill impacts at future snapshots in time

Aggregate resource cost impacts must be balanced with legal and regulatory compliance requirements, reliability standards for keeping the lights on at all times during all seasons, and pace of execution. For example, retiring existing coal-fired generation too quickly may create reliability issues if equally reliable replacement resources are not operational prior to retirement. Conversely, retiring aging coal generation too slowly could increase risks related to coal supply, price volatility, and plant operations, as further discussed in Appendix F (Coal).

Resource Diversity to Mitigate Fuel & Technology Risks, Enhance Reliability

Currently, the Companies, and their customers, benefit from a diverse portfolio of generating resources. The Companies' fleet of nuclear, coal, natural gas, hydroelectric, and solar generating units has operated as a hedge against operational and fuel cost risks associated with any singular resource type. In addition, resource diversity has allowed the Companies to take advantage of complementary operating characteristics of different types of generating technologies to optimize the system across ranging economic, system reliability, and environmental conditions. The long-term planning process must continue to focus on delivering a diverse portfolio of resources to ensure these same benefits are realized in the future. Ultimately, a balanced and diverse resource mix prudently manages technology- and fuel-related risks and provides for the operational flexibility that will be increasingly important moving forward.

Planning for an Increasingly Clean Resource Mix

The Companies are committed to planning for and building increasingly clean generating resources to reliably serve growing demand in the Carolinas. The Companies' long-term planning continues to target achieving carbon neutrality by 2050. This supports the objective of ensuring diversity of the resource mix and mitigating fuel rate volatility through inclusion of additional nuclear and renewable resources in the Plan. Delivering an increasingly clean resource mix also supports the economic growth occurring across the Carolinas, as it aligns with the clean energy goals of many existing customers looking to expand their operations and is often an important siting criterion for businesses looking to locate in the Carolinas.

Analytical Process Overview

The analytical process used to develop the 2025 Carolinas Resource Plan is composed of several important steps, which are highlighted in Figure 2-2 below. These steps are summarized below and described in greater detailed in Appendix C.

Figure 2-2: 2025 Carolinas Resource Plan Analytical Process Flow Chart

Development of Modeling Assumptions

- DEC & DEP System Configuration
- Reliability Requirements
- Load Forecasts
- Demand-Side Solutions
- Supply-Side Resource Availability & Costs
- Fuel Price
- Applicable Laws & Regulations

Initial Evaluations

- Fuel Security Evaluation
- Representative Nuclear Technology Selection
- Coal Retirement Analysis

Development of Resource Portfolios

- Capacity Expansion Model – Preliminary identification of resource additions using simplified system simulation to optimize resource portfolios to meet system capacity, energy, and other requirements

Detailed Portfolio Results and Verification

- Production Cost Modeling – Detailed hourly system simulation to assess system and unit performance of a specified resource portfolio over time
- Reliability Verification – Stochastic analysis, simulating hourly system dispatch to ensure adequate resources to maintain system reliability across weather, outage, and load uncertainties

Performance Analysis

Calculate Present Value of Revenue Requirements and Customer Bill Impacts

Assess portfolio performance:

- Portfolio Cost & Projected Customer Impacts
- Capacity & Energy Mix
- Portfolio Reliability
- Execution Considerations
- CO_2 Emissions and Reduction Trajectory

Execution Planning

- Identification of recommended Near-Term Action Plan resources and execution activities considering range of modeling results and execution risks

Modeling Software & Development of Modeling Assumptions

This section outlines key inputs to the Resource Plan modeling process. These inputs include, but are not limited to, updates to the Companies' load forecasts, including impacts of utility energy efficiency ("UEE") program savings, new rate offerings, voltage control programs, plans for economic development, and other demand-side customer programs, along with existing and new supply-side technology modeling input data. Key reliability requirements used in the portfolio development and analysis process include PRM, effective load carrying capability ("ELCC") values for renewables and energy storage resources, and operational reserve requirements. As previously noted, the inputs, assumptions, and modeling framework utilized to develop the Plan represent a snapshot in time as of 2025 and are subject to change in future resource plan updates.

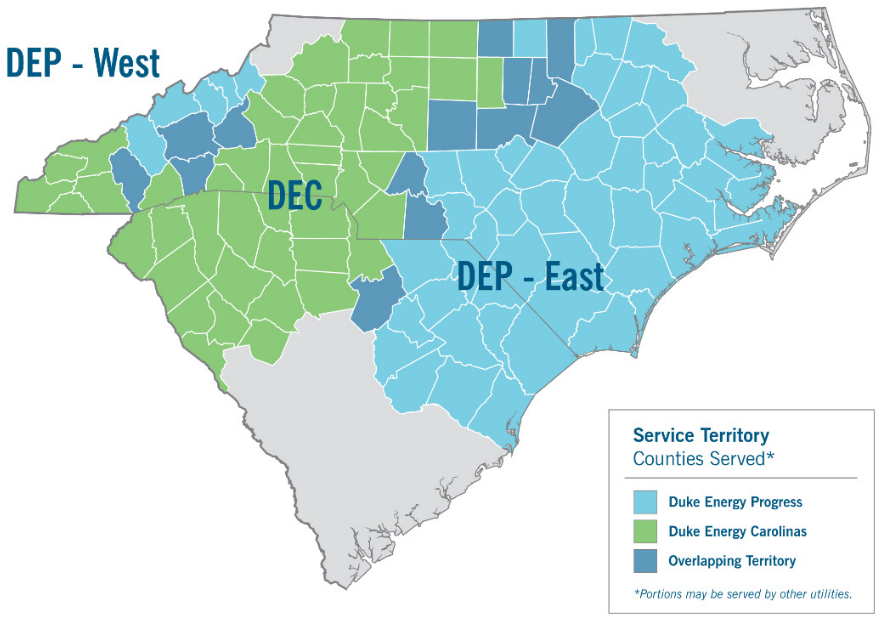
Modeling Software

The Companies utilized version 7.3.4 of EnCompass as the primary modeling tool for the development and analysis of portfolios in the Plan. The capacity expansion model and the production cost model are separate modules within EnCompass. In addition, the Companies utilized more granular reliability modeling tools as part of the overall modeling process to ensure the lowest reasonable cost for customers while maintaining system reliability as the mix of resources on the system changes over time. Modeling tools are discussed in greater detail in Appendix C.

DEC & DEP System Configuration

In the 2025 capacity expansion and production cost modeling of the Plan, DEC and DEP are modeled as two separate utilities and legal entities, operating across three areas (DEP-West, DEC, and DEP-East, as depicted below in Figure 2-3). Each is modeled with its own load, resources, and transmission limits between them. DEC and DEP utilize joint dispatch, when possible, which allows the utilities to optimize the dispatch of the system on an intraday basis to provide cost savings to customers.

Figure 2-3: DEC & DEP Service Territories



Consistent with prior resource plan modeling, the planning analytics assume the implementation of a "Consolidated System Operations" ("CSO") model where the NERC Balancing Authority ("BA"), Transmission Service Provider, and Transmission Operator functions are consolidated for DEC and DEP. This consolidated approach allows for the economic dispatch of the combined system and further allows for optimization in meeting operating services requirements, such as balancing and regulating reserves. In the current operations of the DEC and DEP systems, each utility must meet its own operating requirements with its own units to meet the system operational needs of its BA area. The CSO model allows the collective operating requirements to be aggregated at the combined system level, which improves efficiency by allowing the requirement to be met by resources from the combined system. The two utilities do, however, retain responsibility for independently committing resources for meeting forecasted demand and maintaining long-term capacity planning requirements in the modeling.

As discussed in Chapter 4, the Companies are planning for CSO as part of the pending business combination of DEC and DEP. In future planning cycles, the Companies will base the system configuration of DEC and DEP on the outcome of the pending business combination proceedings. As discussed in Appendix C, the Companies modeled sensitivities assuming a fully combined utility (single utility, or "1U") and a scenario where the business combination is not approved ("2U"), resulting in DEC and DEP independently planning, executing, and operating in absence of the combined system benefits.

Reliability Requirements

The modeling process necessarily begins and ends with ensuring reliability. As previously noted, key reliability inputs in Resource Plan modeling include PRM, ELCC values, and operational reserve requirements. These inputs, described below, are foundational resource planning components that ensure the Companies continue to maintain or improve the reliability of the system.

Planning Reserve Margin

To support the development of the 2023 Carolinas Resource Plan, the Companies retained PowerGEM (formerly Astrapé Consulting)[2] to conduct a new resource adequacy study. The study included updates to all inputs including impacts on cold weather load response and unit outage performance experienced during Winter Storm Elliott in December 2022. Based on the results of this study, the Companies increased the minimum winter PRM from 17% to 22% in developing portfolios for the 2023 Carolinas Resource Plan. The NCUC and PSCSC both found the 22% PRM, as well as the Companies' plans for meeting it by 2031, to be reasonable for planning purposes, and the NCUC directed the Companies to prepare a new resource adequacy study in 2027 for use in the 2027 update to the Resource Plan.[3] Thus, the Companies continued to utilize the 22% PRM as a base assumption for this Plan. As described in more detail in Appendix C and in the 2023 Resource Adequacy Study report, included as Attachment I, the PRM is based on achieving the widely accepted industry threshold of one event-day in 10-year Loss of Load Expectation ("LOLE"). Also, as described later in this Chapter and in Appendix C, the Resource Plan analytical process includes a Reliability Verification step to ensure that the LOLE threshold is maintained for each portfolio and, if required, adds additional capacity to keep the portfolio at the threshold.

Effective Load Carrying Capability

The ELCC values for various energy sources were determined through comprehensive studies conducted by PowerGEM using the Strategic Energy & Risk Valuation Model ("SERVM").[4] Specifically, the ELCC values for solar and energy storage were derived from a study completed in 2025, while the wind ELCC values were based on an earlier study conducted in 2023.

Operational Reserve Requirements

The Companies include operational reserve requirements in the expansion plan modeling process to capture the variance in load and renewables due to forecast error, intra-hour volatility, and system ramping needs. The operational reserve model was developed by Duke Energy, based at a high level on a planning and reliability tool developed by the Electric Power Research Institute ("EPRI"),[5] and is

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[2] Astrapé Consulting, an energy software and consulting firm with expertise in resource adequacy and integrated resource planning, is the firm that conducted several Resource Adequacy and Effective Load Carrying Capability Studies for the Companies in recent years. In 2024, PowerGEM acquired Astrapé Consulting.

[3] 2023 CPIRP Order at 49, 174-175

[4] SERVM is a state-of-the-art reliability and hourly production cost simulation tool managed by PowerGEM.

[5] EPRI's Dynamic Assessment and Determination of Operating Reserve ("DynADOR") tool is a stand-alone application used to determine operating reserve requirements. See EPRI, Program 173: Bulk Integration of Renewables and Distributed Energy Resources, Dynamic Reserve Determination Tool, available at https://www.epri.com/research/programs/067417/results/3002020168. The Companies developed their methodology based on the DynADOR tool with some modifications, including to generate reserves for a multiyear planning horizon.

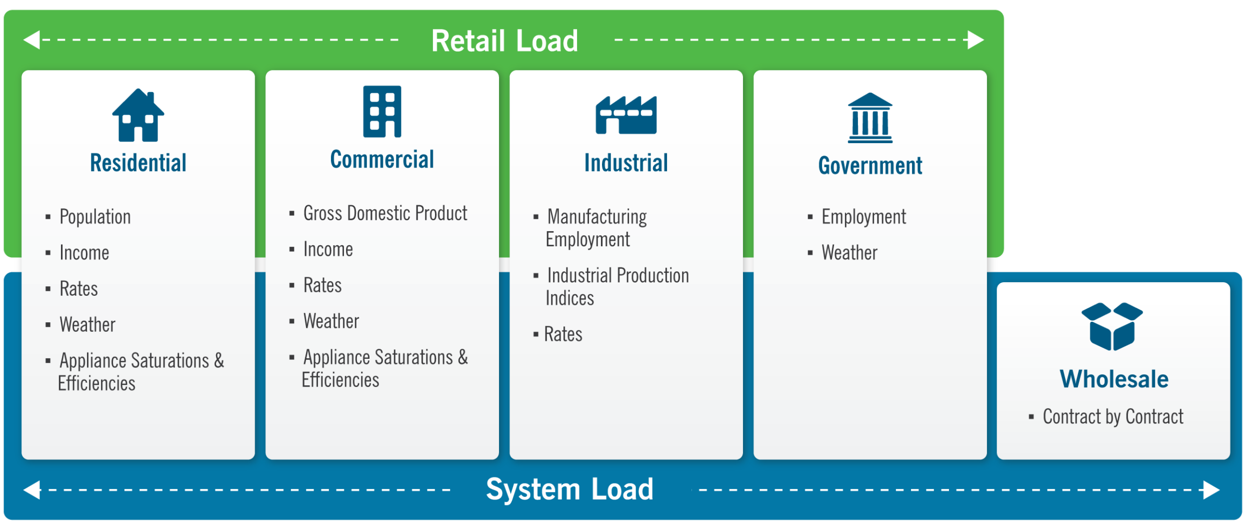
used to calculate hourly operational reserves required to ensure that the Companies will have sufficient flexible resources available to mitigate the risk of load and renewable output uncertainty.

Operational reserve requirements are heavily influenced by the level of intermittent resources on the system and are used in both the capacity expansion process for the development of portfolios and in the production cost modeling for the detailed operations of the system. The reserve requirements, which are influenced by the selected levels of solar and wind capacity in each portfolio, are also included during the Reliability Verification step.

Electric Load Forecast

The Companies' peak demand and energy load forecast, which includes significant demand-side factors impacting the forecast, is a critical component of the planning process. This section provides an overview of the demand-side assumptions impacting the load forecast. More details can be found in Appendix D and Appendix E (Grid Edge & Customer Programs). The 2025 Spring Load Forecast used to develop the Resource Plan continues to project steady growth driven by economic development success. A summary of key drivers of the load forecast by customer segment is shown in Figure 2-4 below.

Figure 2-4: Primary Load Forecast Drivers by Customer Class



Load Forecast Scenarios

The Resource Plan utilizes an hourly electric load forecast projection through 2050, which includes the annual energy and seasonal peak demands of the customer base within the DEC and DEP service areas. The econometric process used to create the load forecast leverages historical data to create models that attribute sales changes to economic and weather variables. These models then forecast future sales and peak energy demand by applying projected values of these variables, with the most effective approach being to group similar customers who respond to comparable economic factors. The forecast is adjusted to account for key load modifiers, such as independent forecasts for the state of the economy, electric vehicle ("EV") adoption, and behind-the-meter ("BTM") solar generation.

As further discussed in Appendix D, the economic development environment in the Carolinas continues to be dynamic and unprecedented in terms of the number and size of new businesses seeking to locate in the Companies' service territories in North Carolina and South Carolina. Since June 2024, the planned large load additions to the DEC and DEP systems that are in an advanced stage of development ("Advanced Development Projects") have increased by approximately 50%, or more than 2,000 MW on a full load projection basis. To capture the impact of this significant and sustained economic development activity, the Companies evaluated four load forecast scenarios in this Plan. Continuation of the strong economic growth experienced by the Carolinas during recent years is part of the baseline forecast projection and aligns with the economic forecast the Companies receive from Moody's.

The four load forecast scenarios – Low, Moderate Development, Advancing Development, and High – enable the Companies to evaluate resource needs under different potential futures in the Carolinas. To develop each scenario, the Companies formulated detailed assumptions for key factors such as economic growth, EV adoption, BTM solar adoption, and economic development. The four load forecast scenarios are introduced below and discussed further in Appendix D.

Load Forecast Scenario Assumptions

In the Low Load Forecast, Moody's "90/10" economic forecast is utilized, which reflects a forecast that has a 90% probability that the actual economic outcome will exceed forecasts and a 10% probability that the actual economic outcome will fall short. The Low Load Forecast includes the low case for EV adoption and the high case for BTM solar adoption. For economic development, the Low Load Forecast includes only projects with Electric Service Agreements ("ESAs") with no discount.

In the Moderate Development Load Forecast, the Companies utilized the economic forecast in the "50/50" case from Moody's, which reflects a forecast that has a 50% probability that the actual economic outcome will exceed forecasts and a 50% probability that the actual economic outcome will fall short. The Moderate Development Load Forecast includes the most likely case for adoption of EVs and the most likely case for adoption of BTM solar generation. For economic development, the Moderate Development Load Forecast includes projects with ESAs at 100%, letter agreements ("LAs") at a 25% discount, and Late-Stage projects at a 30% discount.

In the Advancing Development Load Forecast, the economic forecast, adoption of electric vehicles, and behind-the-meter solar are the same as in the Moderate Development Load Forecast. As further addressed in Appendix D, recognizing the dynamic and unprecedented nature of economic development activity in the Carolinas, the Advancing Development Load Forecast starts with the same economic development assumptions as the Moderate Development Load Forecast (it includes projects with ESAs at 100%, LAs at a 25% discount, and Late-Stage Pipeline projects at 30% discount), then adds a portion of the Mid-Stage Pipeline projects to more fully represent the anticipated 2,000-MW impact of the extensive pipeline of economic development opportunities, whose success is beginning to appear in the periodic reports regarding this portfolio of sites being produced in between forecast refresh cycles. The Advancing Development Load Forecast reflects the Carolinas' evolving economic development pipeline opportunities beyond committed Advanced Development Projects and allows the Companies to plan for the resources needed to support economic development and industry retention in the Carolinas.

In the High Load Forecast, the “10/90” economic forecast from Moody's is utilized, which reflects a forecast that has a 10% probability that the actual economic outcome will exceed forecasts and a 90% probability that the actual economic outcome will fall short. The High Load Forecast includes the high case for adoption of EVs and the low case for adoption of BTM solar generation. For economic development, the High Load Forecast includes projects with ESAs, LAs, and Advanced Development Projects in the Late-Stage Pipeline at full load, while Mid-Stage projects are included at a 50% discount.

Table 2-1 summarizes the key assumptions for the four load forecasts used in the Resource Plan.

Table 2-1: Key Assumptions for Load Forecast Scenarios

	Economics	Electric Vehicles	Behind-the-Meter Solar	Economic Development
Low	90/10	Low Adoption	High Adoption	ESA – no discount
Moderate Development	50/50	Base Adoption	Base Adoption	ESA – no discount LA – 25% discount Late-Stage Pipeline – 30% discount
Advancing Development	50/50	Base Adoption	Base Adoption	Moderate Development plus 2,000 MW by 2040 to allow for continued economic development
High	10/90	High Adoption	Low Adoption	ESA – no discount LA – no discount Late-Stage Pipeline – no discount Mid-Stage Pipeline – 50% discount

Note: See Appendix D for additional information on load forecast scenario assumptions.

Base Planning Load Forecast

In developing the Resource Plan, the Companies utilized the Advancing Development Load Forecast as the base planning assumption. Table 2-2 below provides forecasted annual system peak and energy over the Base Planning Period. Additional detail is provided in Appendix D.

Table 2-2: Advancing Development Load Forecast

	Winter Peak (MW)			Energy (MWh)		
Year	**DEC**	**DEP**	**Total**	**DEC**	**DEP**	**Total**
2026	18,866	14,312	33,178	99,973	65,027	165,000
2027	18,636	14,596	33,233	103,476	69,062	172,538
2028	19,403	14,854	34,257	110,959	71,011	181,970
2029	20,113	15,119	35,232	117,633	73,822	191,455

2030	20,747	15,322	36,069	123,670	76,322	199,992
2031	21,139	15,449	36,589	126,695	77,487	204,181
2032	21,560	15,605	37,165	130,048	78,540	208,588
2033	22,123	15,770	37,892	135,711	79,545	215,256
2034	22,542	15,857	38,399	139,794	80,611	220,405
2035	23,115	15,979	39,094	143,751	81,835	225,586
2036	23,391	16,179	39,570	146,058	83,228	229,286
2037	23,893	16,447	40,340	148,319	84,621	232,940
2038	24,156	16,616	40,771	150,571	86,049	236,619
2039	24,520	16,876	41,396	152,746	87,403	240,148
2040	24,775	16,978	41,753	155,256	88,634	243,890

Demand-Side Management

Demand-side management ("DSM") contains three components: (1) customer-sited demand response ("DR"), including programs like Power Manager and EnergyWise Home; (2) circuits-focused peak shaving, including Integrated Volt-VAR Control's ("IVVC") peak shaving mode; and (3) peak shifting via critical peak pricing ("CPP"), hourly pricing, and peak time rebate ("PTR") rate programs. All share similarities in that DEC and DEP system operators initiate DSM events to reduce system load during winter and summer peaks. DR and IVVC peak shaving are similar in that they are counted as capacity, while CPP and PTR programs send price signals to participating customers to avoid usage during peak times, therefore reducing aggregate peak demand on the system. The forecasted DSM contributions are summarized in Table 2-3 below and explained in further detail in Appendix C. More information on the Companies' suite of DSM programs can be found in Appendix E.

Table 2-3: Forecasted Demand-Side Management Contributions, Winter (MW)

Mechanical & Manual Demand Response		
Year	**DEC**	**DEP**
2026	625	315
2030	753	453
2035	866	560
2040	970	639
Critical Peak Pricing Demand Response		
Year	**DEC**	**DEP**
2026	4	4
2030	51	46
2035	115	106
2040	151	140
IVVC Peak Shaving Capacity		
Year	**DEC**	**DEP**
2026	177	148
2030	199	152
2035	210	161
2040	222	171

DR capacity is modeled as a controllable peaking resource, similar to traditional generation, and contributes equally to meeting planning reserve margins. Effective utilization of DR programs has the potential to decrease the runtime of older, more expensive generation and help avoid or defer the need for new supply-side peaking resources. In the Resource Plan, the Companies modeled a sensitivity associated with the DSM Capacity available from customers in PowerPair^{SM}, a three-year pilot program available in North Carolina that launched in May 2024 to provide incentives for customers who want to combine the savings of solar power with the reliability and security of backup battery storage. The storage component of PowerPair is reflected in the Mechanical and Manual Demand Response programs in Table 2-3, and additional information on the modeling and results of the PowerPair sensitivity is provided in Appendix C.

Supply-Side Resources

Growing customer demand and the retirement of aging generation resources require the planning, development, and execution of a new portfolio of demand-side programs and supply-side resource options over the planning horizon to meet customer adequacy and reliability needs, while also maintaining the lowest reasonable cost for customers. Supply-side options considered in developing the Resource Plan include reliable and increasingly clean generating resources like nuclear, natural gas, energy storage, solar, and wind. The Companies considered a diverse range of baseload, peaking/intermediate, variable energy, and energy storage technologies in developing the Plan.

Appendix G (Screening of Supply-Side Resources) describes the technical and economic screening of resources that was conducted prior to performing the detailed Resource Plan modeling and analysis. This section provides an overview of the input assumptions associated with the selectable supply-side resources made available in the EnCompass capacity expansion modeling phase.

Table 2-4 below summarizes the key base availability assumptions for resources included in the capacity expansion modeling. Further details regarding model input assumptions for selectable resources are provided in this section with additional information also provided in the related Appendices.

Table 2-4: Key Availability Assumptions for Supply-Side Resources

Resource	Assumptions
Nuclear	
	Large Light-Water Reactor ("LLWR") • One unit (1,117 MW, AP1000®) available for model selection per year beginning in 2037 • Maximum of two units in the first three years selected and a total cumulative limit of 10 units **Small Modular Reactor ("SMR")** • First two SMRs (300 MW each) available beginning 2037 • Maximum of three units in the first two years selected **Non-Light-Water Reactor ("Non-LWR")** • This technology will not be available for selection until the 2040s
Natural Gas[6]	
	Combined Cycle ("CC") • One unit (1,365 MW) available for selection in 2030, then two units (2,730 MW) per year beginning in 2031 • Cumulative limit of six CCs[7] **Combustion Turbines ("CTs")** • Up to two Advanced Class CTs (856 MW total) in the year 2030 and 2,140 MW per year beginning in 2031 with no cumulative limit • Up to one F-class CT (255 MW) available in the years 2030 and 2031

[6] Fuel security options for new and existing natural gas generating resources are detailed in Appendix I (Natural Gas and Low-Carbon Fuels).

[7] Includes Person CC1 approved for construction by the NCUC in Order Granting Certificate of Public Convenience and Necessity, Docket Nos. E-2, Sub 1318 & EC-67, Sub 55 (Dec. 6, 2024)

Energy Storage

Battery

- 4-hour and 8-hour lithium-ion battery
- Up to 500 MW available for model selection in 2028, 1,000 MW per year beginning in 2029; no cumulative limit

Long-Duration Energy Storage (“LDES”)

- 10-hour technology-neutral resource
- 100 MW available for model selection in 2033, 200 MW in 2034, and then 400 MW per year beginning in 2035
- Cumulative limit of 1,000 MW

Pumped Storage Hydro

- 1,760-MW Bad Creek II long-duration pumped storage hydro evaluated for inclusion in 2040

Solar

- Up to 825 MW available for model selection in 2030 and 2031 and 1,200 MW/year from 2032 through the end of the planning period; no cumulative limit
- Bifacial panels, single-axis tracking

Wind

Onshore Wind

- Approximately 19% capacity factor (DEC)
- Approximately 27% capacity factor (DEP)
- Up to 300 MW per year beginning in 2034
- Up to 1,050 MW total available for selection (450 MW on DEC system and 600 MW on DEP system) throughout the planning period

Offshore Wind

- Approximately 38% capacity factor
- First 1,200-MW block available for selection beginning 2037
- Up to 2,400 MW total available for selection through 2043 and 3,600 MW through 2050

Fuel

The Companies' generating units that utilize natural gas rely on interstate firm transportation ("FT") or dual-fuel capability with coal or diesel to ensure fuel security. In developing the Resource Plan, the Companies' modeling added intrastate enhanced liquefied natural gas ("ELNG") storage as an additional fuel supply option for CCs 4-6. The additional option of ELNG increases reliability, assists with intermittency, and may serve as an economic alternative to interstate enhanced FT ("EFT") from the Gulf Coast. The Companies' modeling also considered hydrogen blending and conversion for new and existing units.

Table 2-5 below summarizes the key base assumptions for fuel resources included in the capacity expansion modeling. Appendix I (Natural Gas & Low-Carbon Fuels) further describes the evaluation of fuel resources conducted prior to performing the detailed Resource Plan modeling and analysis.

Table 2-5: Key Fuel Security Assumptions

Gas
Interstate Firm Transportation • FT and natural gas supply from Appalachia, via Transco Southeast Supply Enhancement and Mountain Valley Pipeline Southgate for the first three CCs • Beginning with CC4, additional Enhanced Firm Transportation ("EFT") natural gas supply delivered from the Gulf Coast • Cumulative limit of three additional CCs with EFT supply **Enhanced Liquefied Natural Gas Storage ("ELNG")** • Beginning with CC4, ELNG fuel security • Cumulative limit of three additional CCs with ELNG fuel security **Additional Considerations** • Beginning with CC4, the model will select either EFT or ELNG, as discussed in the Fuel Security Evaluation later in this Chapter
Hydrogen
• Clean hydrogen blended into natural gas supply to all existing gas units (CC, CT, and natural gas co-fired coal units) starting in 2040 • Clean hydrogen market assumed available by 2050 • All new CTs selected after 2044 are assumed capable of operating on up to 100% hydrogen • All new CTs and CCs added to the portfolios either operate on gas (would incur carbon offset costs) or operate on hydrogen in 2050 and beyond

Federal Energy Tax Credit Assumptions

The Resource Plan includes assumptions around federal energy tax credits,[8] including tax credits that were recently amended by the H.R. 1 Reconciliation Bill. These federal energy tax credits primarily represent production tax credits ("PTC") and investment tax credits ("ITC"). As further discussed in Appendix C, the H.R. 1 Reconciliation Bill accelerated the phaseout of federal energy tax credits for solar and wind while retaining (and in some instances enhancing) availability for other technologies, including storage and nuclear. PTCs are a 10-year, inflation-adjusted U.S. federal income tax credit for each kilowatt-hour ("kWh") of electricity generated.[9] ITCs are a U.S. federal income tax credit based on a percentage of the capital investment and can be taken immediately upon facility completion. Bonus tax credits are also available if projects are sited in designated energy communities or meet stringent domestic content guidelines.

For modeling purposes, wind energy resources are no longer eligible for federal energy tax credits if they cannot be in-service for commercial operation ("CO") before tax credit eligibility ends. New nuclear projects beyond the first available LLWR benefit from a 10% energy community bonus, including SMRs. Forecasted solar and some model-selected solar in 2030 and 2031 continue to receive the solar PTC, as long as construction begins by July 4, 2026. Lithium-ion storage systems qualify for the full storage ITC through 2037, with an additional 10% bonus available for meeting domestic content criteria and another 10% bonus for projects located in designated energy communities. Pumped storage hydro projects are eligible for a 30% ITC and have been grandfathered under Internal Revenue Code Section 48 start of construction guidelines. Additionally, nuclear and storage are now subject to a phaseout, which is reflected in Table 2-6 below. The table also details the base modeling assumptions of the tax credits for specific supply-side resources.

Table 2-6: Federal Energy Tax Credit Assumptions

	Start Construction By	First CO[1] Date in Modeling	Last Available CO Date for 100% Credit	Phase Down Schedule by CO Date
SMR	12/31/2033	2037	2043	100% (2043), 75% (2044), 50% (2045); 0% (2046+)
LLWR	12/31/2033	2037	2045	100% (2045), 75% (2046), 50% (2047); 0% (2048+)
Storage	12/31/2033[2]	2028	2037	100% (2037), 75% (2038), 50% (2039); 0% (2040+)
Solar	7/4/2026[2]	2030	2031[3]	N/A
Onshore Wind	7/4/2026[2]	2033	2032	N/A
Offshore Wind	7/4/2026[2]	2037	2036	N/A

Note 1: Commercial Operation ("CO")

[8] Federal energy tax credits established via the Inflation Reduction Act of 2022 and, in some instances, amended by the H.R. 1 Reconciliation Bill

[9] Public Law No: 119-21, H.R.1 – Reconciliation Bill 119th Congress (2025-2026)

Note 2: Projects beginning construction after 12/31/2025 are subject to Foreign Entity of Concern ("FEOC") restrictions.
Note 3: Assuming grandfathering of safe harbor rules.

In addition to federal energy tax credits that can be leveraged to build new generation, hydrogen and carbon capture and sequestration ("CCS") are also eligible to receive tax incentives. The hydrogen commodity prices used in the Plan include a clean hydrogen federal tax credit given the modeling assumes all hydrogen is produced by a carbon-neutral source. In the sensitivity analysis evaluating CCS, the modeling assumes that CCS will receive tax credits for the first 12 years of service.

Initial Evaluations

Before the development of resource portfolios, the Companies conducted three sequential evaluations, with each evaluation building upon the results of the previous one. These evaluations included a Fuel Security Evaluation for incremental CC generation, a Representative Nuclear Technology Selection, and an updated Coal Retirement Analysis.

Fuel Security Evaluation

The Companies first performed a Fuel Security Evaluation within the EnCompass capacity expansion model to evaluate potential fuel security options for incremental CC generation. For modeling purposes in prior resource planning, the Companies assumed that a generic brownfield pipeline expansion from the Gulf Coast would provide fuel to incremental CC units. That modeling assumption remained; however, given the Companies' executed agreements for interstate capacity with Transco for its Southeast Supply Enhancement expansion and Mountain Valley Pipeline, LLC for their Southgate project (as further described in Appendix I), the Companies also modeled an ELNG storage alternative for the three selectable incremental CCs. After inputting estimated costs associated with each fuel option, the Companies compared the present value revenue requirements and determined that ELNG is the most economic fuel security assumption. Based on this assessment, ELNG is used as a base assumption in the Plan. Appendix C provides further detail on the Fuel Security Evaluation.

Representative Nuclear Technology Selection

In the 2023 Resource Plan, the Companies modeled SMR and non-LWR technologies as available resources. In its approval of the 2023 Plan, the NCUC directed the Companies to model LLWRs, such as an AP1000®, as selectable resources in the 2025 Resource Plan.[10] As further discussed in Appendix J (Nuclear), the Companies continue to actively monitor nuclear industry developments to assess the reasonable planning assumptions for both LLWR technology as well as SMRs and non-LWR technologies. To comply with the NCUC's directive, and to assess the most reasonable nuclear technology to include in the base case modeling assumptions, the Companies conducted a comprehensive Representative Nuclear Technology Selection within the capacity expansion model to establish a representative, generic nuclear technology for planning purposes. This assessment consisted of evaluating multiple scenarios where the model was able to select between LLWR and SMR. Importantly, the analysis does not inherently indicate the superiority of one technology over the other. Consistent with other technologies included in the IRP, the purpose is to instead provide the

[10] 2023 CPIRP Order at 179 (Ordering Paragraph No. 38)

model a single nuclear technology for selection throughout the remaining steps of the modeling framework, thereby avoiding competition between two technologies with similar attributes during the resource selection phase.

Through this evaluation, LLWR technology was selected as the generic nuclear technology for modeling purposes. The multi-step approach ensured a thorough evaluation of nuclear technology options, balancing cost considerations with technological attributes to inform the Companies' long-term resource planning strategies. This preliminary technology evaluation process is explained in more detail in Appendix C.

Coal Retirement Analysis

Similar to the 2023 Resource Plan proceeding, the Companies performed a Coal Retirement Analysis endogenously, utilizing capacity expansion and allowing the model to optimize retirement dates with the in-service dates of potential replacement resources. The analysis compares the projected costs for maintaining coal unit operations to the costs of replacing the capacity and energy of coal generation with new resources that can maintain or improve system reliability.

While the analysis captures potential economic benefits of maintaining coal operations at specific sites, the model is not capable of fully assessing incremental system reliability risk related to keeping these units in service. These risks, as further described in Appendix F, include persisting challenges to the coal supply chain and potential unknown costs associated with maintaining reliable operations of these aging facilities. Thus, the Companies prudently assessed targeted opportunities to extend operations of certain coal units beyond the retirement schedule approved in the 2023 Resource Plan. This approach seeks to maintain resource adequacy while enabling a disciplined and strategic transition to new generation sources. Ultimately, planning retirement dates were established based on several factors, including the ability to execute replacement resources before the coal unit retirement; relative costs; relative risks; the feasibility of implementing necessary transmission upgrades to ensure or improve reliability; and other qualitative considerations.

Coal Retirement Analysis was conducted for both the Advancing Development Load Forecast and the Moderate Development Load Forecast. This approach allowed the Companies to adapt their coal retirement strategy to different potential future scenarios of continued economic development. Additional details on the Coal Retirement Analysis can be found in Appendix F and Appendix C.

Development and Simulation of Resource Portfolios

Following the development of the base planning assumptions, including those established through the Initial Evaluations, the Companies develop portfolios using the EnCompass capacity expansion model. Each portfolio is then simulated through production cost modeling to evaluate its performance against the planning objectives and inform the recommended near-term actions. These steps are described further below and in Appendix C.

Development of Resource Portfolios

Capacity Expansion Modeling

As discussed in the Modeling Software section of this Chapter, the Companies utilize the EnCompass capacity expansion model to optimize the mix of resources used to reliably meet customer energy and peak demand needs over the planning horizon. This model is widely used across the industry and has served as the Companies' capacity expansion model in all recent resource plans. The model develops a portfolio of resources that will minimize overall system costs – including capital costs for new resources and ongoing operation, maintenance, and fuel costs. Additionally, the capacity expansion model examines numerous permutations of possible resource portfolio options that adhere to given system reliability and carbon emissions reduction targets. Given the vast number of resource options examined during this phase of analysis, the capacity expansion model uses a simplified, average representation of hourly system demand to screen for the optimal resource portfolio for a given set of input assumptions. Once a portfolio is developed for that set of assumptions, it is then modeled in a detailed hourly production cost step, which is discussed below and in Appendix C.

Modeling Framework

The Companies' modeling framework begins with the development of a Preliminary Base Portfolio. The Preliminary Base Portfolio is developed within the capacity expansion model noted above, utilizing the Companies' base case assumptions for all planning parameters. This portfolio provides a baseline starting point to compare portfolios developed under different planning assumptions. The Preliminary Base Portfolio is then tested and refined through extensive sensitivity analysis – consisting of over 30 Sensitivity Analysis Portfolios that further evaluate risks, uncertainties, and potential trade-offs across planning objectives. The Sensitivity Analysis Portfolios explore various planning parameters including potential differences in assumptions around load, demand-side management, fuel price, resource cost, resource availability, and the impact of combined utility planning. The results from the Sensitivity Analysis Portfolios are evaluated for changes in resource selection to best meet the changes in planning assumptions and how those resource portfolios ultimately impact reliability, cost, system operations, and risk exposure to executability, commodity prices, technologies, and against an increasingly diversified and clean resource mix. The use of the modeling framework is described in more detail in Chapter 3 (Portfolios).

Detailed Portfolio Results & Verification

Detailed Hourly Production Cost Modeling

The Preliminary Base and Sensitivity Analysis Portfolios developed using the capacity expansion model are then evaluated via detailed system simulations in the production cost model. This model uses chronological, hourly granularity over the planning horizon to simulate the commitment and dispatch of resources to meet weather normal hourly load requirements of the system in a least-cost manner. This level of detail enables assessment of the system operations under hourly load and operating requirements and the impacts of hourly and daily variations in generation and storage profiles (or other detailed operating characteristics of the portfolio). Completion of this step allows for additional analysis of each portfolio's cost, reliability, diversity and risk adjustment generation mix, and execution considerations.

Ensuring Portfolio Reliability – Reliability Verification

Finally, a check on system operation and reliability is performed on the Preliminary Base Portfolio and select Sensitivity Analysis Portfolios to assess resource and energy adequacy to serve customer load across all hours, during periods of extreme weather, as unplanned resource outages occur, and if there is an economic load forecast error. Initial reserve margin and effective load carrying capability ("ELCC") values are dependent on many factors, including: the system peak demand and load shape over the course of multiple hours, days, and weeks; the existing resource mix; and the expected adoption level of different renewable and energy storage resource technologies.

Resource portfolios developed through capacity expansion modeling can result in a resource mix with reliability characteristics that differ from those identified in the ELCC studies. Since it is not practical to determine ELCC values for infinite combinations of resources, nor are such inputs easily integrated into resource planning models, the Companies conducted the additional reliability modeling step referred to as Reliability Verification. This step was performed within the Strategic Energy and Risk Valuation Model ("SERVM"), which is the reliability model used to calculate loss of load expectations ("LOLE") for the Companies' Resource Adequacy and ELCC studies. This verification step ensures that reliability is maintained with the specific resources identified in the capacity expansion model for the selected portfolios in 2035 and 2040. If additional firm capacity is needed to maintain system reliability, the Companies add dispatchable resources during this step. The results of Reliability Verification further inform the Companies' reliability requirements and execution strategies, supporting the selection of required near-term actions. Additional detail on the LOLE verification process is provided in Appendix C.

Proceeding to Performance Analysis and Execution Planning

With the Preliminary Base and Sensitivity Analysis Portfolios developed and detailed operations modeling completed, the Companies can assess each portfolio for trends in cost, reliability, risk, and execution factors. These insights support the identification of a recommended NTAP that reflects the most reasonable, least-cost set of resources and actions to pursue in the near term.