C

Quantitative Analysis

Highlights

- The modeling and quantitative analysis performed to develop the Core Portfolios, Portfolio Variants, and Sensitivity Analysis Portfolios is supported by a robust process to develop inputs and leverage sophisticated capacity expansion, production cost, and reliability models. This quantitative analysis supports the selection of Core Portfolio P3 Base as the Recommended Portfolio to guide a Near-Term Action Plan in executing the next reasonable steps in the transition of the system to support dramatic economic growth in the context of a changing energy landscape.
- This Appendix provides additional insights into the development of inputs and modeling setup as well as the development and verification of portfolios. This Appendix also describes the detailed portfolio performance analysis utilized to assess the opportunities, trade-offs, and risks between resource selection that impacts affordability, reliability, and emissions reductions.
- Advanced nuclear resources make a significant and material impact on emissions reductions, given a 2035 timeline for nuclear to contribute to achieving the Interim Target. Core Portfolio P3 Base combines advanced nuclear with a diverse mix of renewable, storage and hydrogen-capable natural gas resources, as well as supporting transmission infrastructure and Grid Edge programs.
- Offshore Wind, while not necessarily required to achieve the Interim Target, generally provides value across many Portfolio Variants and Sensitivity Analysis Portfolios, indicating the need to retain optionality in pursuing offshore wind.
- While each portfolio reflects significant benefits from solar, wind, storage, and demand-side resources, hydrogen-capable natural gas resources continue to be necessary for reducing emissions, enabling the retirement and de-risking of coal generation and the coal supply chain, while also providing critical operational flexibility needed to integrate and backstand weather-dependent renewables.

Introduction

This Appendix discusses the quantitative analysis performed by Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP” and, together with DEC, “Duke Energy” or the “Companies”) in developing the Carolinas Resource Plan (the “Plan” or “the Resource Plan”). The Resource Plan is a long-term planning analysis that includes a variety of input assumptions regarding the current system and future resources, capacity expansion and production cost modeling, reliability modeling and analysis of portfolio outputs such as present value of revenue requirements (“PVRR”), and average retail customer bill impacts. To assist the North Carolina Utilities Commission (“NCUC”) and the Public Service Commission of South Carolina (“PSCSC”, and together with NCUC, the “Commissions”) and interested parties in evaluating this Resource Plan, this Appendix provides a detailed overview of the Companies’ modeling inputs and assumptions, modeling approach and methodology, analytical evaluation, as well as observations and conclusions from the quantitative analysis performed in developing the Resource Plan.

Maintaining reliability while planning for the most reasonable, least cost path for customers to transition the Carolinas system and achieve targeted carbon dioxide (“CO_2”) emissions reductions on the path to carbon neutrality is a core focus of the Resource Plan analysis. As will be discussed in more detail for each topic below, the Resource Plan quantitative analysis involved extensive evaluation of input assumptions, modeling, and analysis of results. This included identifying base assumptions and sensitivities to these assumptions to further quantify risks and opportunities of how parameters affecting the resource portfolio could evolve, development and verification of portfolios, and portfolio and performance sensitivity analyses to evaluate the robustness of portfolios. Operational, logistical, and financial analysis of the modeling was used to derive observations and planning approaches for the recommended portfolio to inform execution.

Analytical Process - Overview

The Companies’ analytic process supports the resource planning objectives presented in Chapter 2 (Methodology and Key Assumptions). The overall modeling and analysis framework ensures primary requirements of maintaining or improving reliability and complying with all applicable laws and regulations. The Companies have developed resource portfolios that meet these requirements, quantifying performance of these portfolios and considering opportunities and risks associated with resource diversity, executability, and meeting customer needs for increasingly clean energy. These considerations inform the identification of the most reasonable, least cost portfolio. The analytical process consists of the following steps outlined in Figure C-1 below. Each of these steps will be discussed in more detail in later sections of this Appendix.

Figure C-1: Carolinas Resource Plan Analytical Process Flow Chart

Portfolio Verification

Modeling Software and Development of Modeling Assumptions

- Modeling Software
- DEC & DEP System Configuration
- Reliability Requirements
- Net Load Forecasts
- Demand-Side Resources
- Supply-Side Resources
- Fuel
- Tax Incentives

Portfolio Development

- Coal Retirement Analysis
- Capacity Expansion Modeling – screening model using simplified system simulation to identify resource changes to meet system capacity, energy, and emissions targets
  - Preliminary Identification of Resource Additions

Production Cost

- Production Cost Modeling – Hourly-detailed, chronological system simulation to quantify system and unit performance with specified resource portfolio over time
  - Initial Reliability Verification
  - Verification Bad Creek PH II

Reliability Verification

- Evaluate portfolios to ensure adequate resources to maintain system reliability
- Final Portfolios – Update production cost modeling with any additional capacity needed to address reliability

Performance Analysis

- Present Value of Revenue Requirements
- Performance Sensitivity Analysis
- Customer Bill Impact Analysis
- CO_2 Emissions Reductions

Execution Plan

As discussed later in this Appendix, and as presented in more detail in Chapter 2, Core Portfolios are developed using base planning assumptions for each Energy Transition Pathway. Portfolio Variants, additionally, were developed to evaluate the significance of specific supply-side resource availability (fuel supply and generation and storage resources) variables in resource selection and provide a thorough assessment of the risks and potential opportunities that could be realized in the future as events unfold. The Companies developed Portfolio Variants in Pathways 2 and Pathway 3 as these pathways allow for more opportunity to impact the selected resource plan in achieving the 70% CO_2 emissions reduction from 2005 levels ("Interim Target").[1] The Companies created additional Sensitivity Analysis Portfolios derived from Pathway 3's Core Portfolio, P3 Base, since P3 Base provides additional time for the Portfolio to adapt to these long-term planning changes. The Sensitivity Analysis Portfolios assess planning factors, other than those evaluated in Portfolio Variants (such as Resource Capital Costs, Load, and Demand-side resources), that were modified both up and down to see the impacts of a particular factor to the Resource Plan and portfolio costs. Finally, Supplemental Portfolios were developed for informational purposes to address specific regulatory needs or informational needs.

Each portfolio in the Plan was developed similarly, utilizing specific scenario inputs and assumptions, developed in the capacity expansion model (using the respective pathway's coal retirement schedule), evaluated in the production model, and analyzed for reliability, cost, and portfolio performance. However, certain portions of the analytical process, such as the detailed Portfolio Loss of Load Expectation ("LOLE") Verification and Customer Bill Impacts, were only performed on Core Portfolios, while supplemental portfolios are generally discussed for information purposes.

Modeling Software and Development of Modeling Assumptions

The Carolinas Resource Plan deploys a rigorous approach in developing input assumptions and utilizing sophisticated modeling software to assess the pace of implementation required for each resource type in order for the system to achieve the planning objectives as described in Chapter 2 and subsequently in this Appendix. The modeling assumptions presented in this Appendix represent the assumptions at the time of development of the Resource Plan. The actual costs, operational abilities, and deployment timelines will change over time depending on the pace of technology development, supply chain constraints and availability, and policy advancements as the country and global energy industry continue to transition to lower carbon generation resources.

Modeling Software

The Carolinas Resource Plan modeling utilizes two main types of models: a capacity expansion model and a production cost model. The Companies used the EnCompass modeling software version 7.05,

[1] The Companies' methodology for establishing the 2005 baseline, from which the Interim Target is measured, was established by the NCUC. See N.C. Gen Stat. § 62.110.9; Order Adopting Initial Carbon Plan and Providing Direction for Future Planning at 35, Docket No. E-100, Sub 179 (Dec. 30, 2022) ("[…] achieving the Interim Target will require that Duke limit carbon dioxide emissions from electric generation facilities located in the state and owned, operated by, or operated on its behalf to 22,759,556 short tons of carbon dioxide.").

licensed through Anchor Power Solutions, to perform both capacity expansion modeling and production cost modeling, which are contained within the EnCompass software as separate modules.

Capacity Expansion Modeling

Capacity expansion models are first and foremost screening models. These models assess a broad range of potential resource portfolio options to determine a mix of resources that minimize the cost of the system, while also adhering to planning parameters intended to simulate real world operations and availability of resources. To accomplish this complex modeling analysis in a manageable analytical time frame, the capacity expansion model relies on various deterministic input assumptions such as detailed load requirements, new and existing resource availabilities, generation profiles, fuel and operations costs, and various operating requirements. The capacity expansion model then develops representative blocks from these inputs to assess the performance of portfolios more quickly against a simplified representation of the system load requirement. Iterations of different mixes of resources over time are applied to these simplified system representations to determine a mix of resources that results in the lowest cost to the system while also meeting the energy and capacity requirements of the system. In short, capacity expansion models are input with details on the existing system, assumptions regarding future capacity and energy needs of the system, and assumptions on the resource options available to meet those needs. The model outputs a preliminary resource portfolio that represents a specific set of resources used to meet system energy and capacity needs over time.

Capacity expansion models are used to identify cost-effective system resources. However, due to the necessary computational simplifications these models make against a single set of deterministic inputs, additional modeling in a detailed production cost model is necessary to verify the resource selections with respect to cost, reliability, and environmental compliance as well as to conduct an overall assessment of the performance of the portfolio. More discussion regarding how DEC and DEP used the capacity expansion model in the development of the Resource Plan’s resource portfolios, sensitivity analyses, and the steps DEC and DEP undertook to verify the capacity expansion modeling results are contained in later sections of this Appendix.

Production Cost Modeling

Production cost models differ from capacity expansion models in that they do not solve for which resources to include in the portfolio; instead, the resources are specified to the model, and the model uses detailed, hourly granularity simulations of resource commitment and dispatch to meet system load requirements through economical operation the system. In contrast to capacity expansion models, production cost models maintain full chronology and load requirements in all hours simulating the hour-to-hour operation of the system. This level of detailed analysis appropriately captures a resource portfolio’s ability to reliably serve customer load and the costs and benefits to the system accounting for resources with specified generation profiles and those resources that operate from hour-to-hour, day-to-day, and even month-to-month or season-to-season. More discussion on how the production cost model is used in sensitivity analysis is provided later in this Appendix.

Modeling Advancements

The Companies leveraged the Encompass model in several ways, considering new ways to advance modeling and the analytical rigor of the Resource Plan. As discussed in Appendix F (Coal Retirement Analysis), the Companies utilized EnCompass's Capacity Expansion resource screening model to assess coal retirements endogenously within the model simultaneous with the selection of new resources. This allowed the model to economically evaluate the potential benefits of accelerating coal retirements, enabled by economic selection of replacement resources. This economic screening analysis fed into the final coal retirement schedules used for each Pathway.

To promote transparency in the modeling process, the Companies transitioned from using a proprietary cost levelization model used in previous planning cycles to leveraging the initial capital cost economic carry charge capabilities within the Encompass model. This change allows the model to internally calculate the annual costs of the resources used in the economic evaluation that is then used in the selection of resources. The resource selection process utilizes the DEC and DEP utility-specific financial inputs such as capitalization structure, debt and equity rates, and other factors, along with the technology-specific financial inputs including construction period, capital expenses, asset life, tax life, and other parameters. Utilizing the model to internally calculate these factors allows the detailed calculation of initial capital costs to be fully integrated throughout the modeling process and alleviates steps of transferring data and results to calculate the full portfolio cost.

Additionally, the Companies integrated dynamic storage dispatch of batteries paired with solar. This added detail allows the model to optimize the usage of the batteries paired with solar, so over time the usage of the battery could adapt to the most economic dispatch of storage. The Companies also have taken advantage of software advancements that now allow them to assess the value of solar paired with storage, where the storage can utilize the facility's interconnection to charge the battery directly from the grid, if optimal to do so for the system. The Companies also refined the model set ups in this planning cycle including updates to Capacity Expansion's typical day structure to improve the evaluation of resources, and segmentation, to test and benchmark longer segmentation optimization periods within the Capacity Expansion model to improve the simultaneous assessment of significant investments over the same time frames. Due to the significantly increased run time observed with longer optimization periods, the Companies used an optimization period of seven years that purposefully included the optimization of larger and long-lead time resources of offshore wind, CCs, and nuclear, in the same segment to optimize the selection of these resources at the same time.

As increasing capabilities are made available in the modeling process, the Companies must continue to be cognizant of the impacts to model run time. Additional capabilities of the model, including complex operations and resource selection modeling, cost information, and energy transition objectives, further increase the size of the problem the model is trying to solve. As mentioned above, the Companies deployed several modeling advancements in this planning cycle. Both now and in the future, the trade-offs between the sheer number of resource selections, operational options and requirements, and other modeling set up parameters must be balanced to allow for efficient while meaningful and differentiating analysis.

Planning Horizon

The Resource Plan consists of two planning horizons. First, special focus is given to the Base Planning Period, the 15-year period from 2024 through 2038. This ensures the long-term planning of the system through development of load forecasts and resources to maintain reasonable planning firm capacity reserve margins is achieved and can support translating modeling and planning results and analysis to execution to maintain or improve the reliability of the system.

The Resource Plan also conducts full capacity expansion and production cost modeling through 2050, the Carbon Neutrality Planning Horizon. This allows the Companies to ensure the portfolios developed remain on the least cost path towards achieving carbon neutrality targets. For the purposes of analyzing resource needs to achieve carbon neutrality beyond the Base Planning Period, the Companies use simplifying assumptions and analytical approaches recognizing the inherent uncertainty in long range planning beyond the 15-year base planning period. This recognition and use of placeholder resources or assumptions allows the Companies to perform the necessary analysis but provides for substantial time to make adjustments in future planning as the Companies identify and mitigate risks and monitor signposts for development of breakthrough technologies.

CO_2 Emissions Planning Consideration in Portfolio Development

To assess how the long-term resource planning objectives presented in Chapter 2 are met with the existing and future resources to fulfill the long-term energy and capacity needs of the systems, the Companies developed several resource portfolios along three Energy Transition Pathways. The development of multiple portfolios along different pathways allows for the evaluation of a range of demand-side, supply-side, storage and other technologies and services available to meet the Companies' service obligations while complying with all applicable state and federal laws and regulations and assessing future uncertainties and risks, including regarding CO_2 emissions policies and regulations.

To develop portfolios along these three Energy Transition Pathways the Companies utilized a system CO_2 mass cap within the capacity expansion model to seek the least cost set of resources to meet the CO_2 reduction targets.

System CO_2 Mass Cap Modeling

To develop the preliminary selection of resources in the portfolios, DEC and DEP used the capacity expansion model with a CO_2 mass cap constraint. This modeling approach enforces a limit on the amount of CO_2 the particular resource portfolio is permitted to emit in operating the system. The model must select resources which, when integrated in the portfolio, result in CO_2 emissions that are less than the specified limit.

As discussed in this Appendix, the DEC and DEP systems each serve customers in the Carolinas as part of the dual-state systems. However, the North Carolina CO_2 reduction targets are only expressly applicable to generation facilities located in North Carolina.

For purposes of modeling the resource portfolios, DEC and DEP used a system mass cap approach; that is, when the system mass cap is achieved, it simultaneously results in achieving the Interim Target. The system mass cap is applied to the combined emissions of both DEC and DEP for all units regardless of location. Modeling the mass cap at the system level maintains balanced economic dispatch across all units within the geographic footprint of the system irrespective of where existing generation units are located.

Consistent with integrated resource planning principles, this modeling process does not identify locations for generic resource additions. Instead, siting is determined based on an evaluation of the most cost-effective option when considering resources during the siting and execution phase as further detailed in Chapter 4 (Execution Plan). The Companies do not use the location of resources as a method for achieving the CO_2 emissions targets; rather, the modeling process assumes that any new CO_2-emitting resources would count toward applicable NC CO_2 emissions reduction targets. Said differently, for purposes of the analysis, the Resource Plan assumes all future emissions of unspecified generic resources, whether located in North Carolina or out-of-state, count against the North Carolina CO_2 emissions reduction targets.

To support the longer-term carbon neutrality target, the resource portfolios developed under this CO_2 emissions planning consideration are required to have reduced North Carolina CO_2 emissions by at least 95% by 2050. Furthermore, for simplicity in modeling carbon neutrality, the dispatch of any resource in 2050 that generates CO_2 emissions is penalized with a proxy CO_2 offset price, rather than reducing CO_2 emissions to absolute zero at the end of the planning horizon. Table C-1 below presents the system mass cap constraints used in the development of resources portfolios in the Plan.

Table C-1: System Mass Cap (CO_2 Short Tons)

	Interim 70% Reduction Target	Carbon Neutrality Target
System Mass Cap	24,908,603	3,953,747

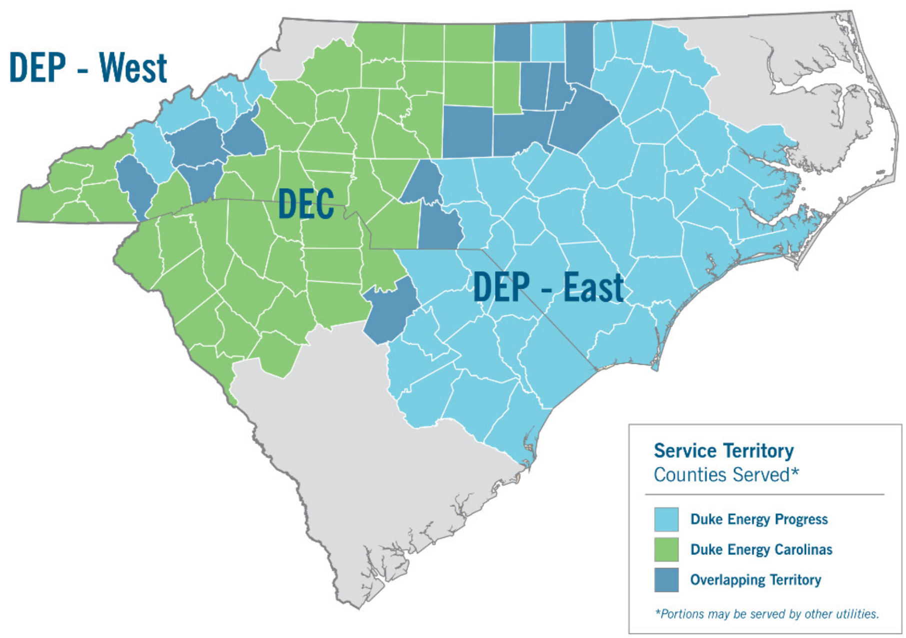
As discussed later in this Appendix and Chapter 2, the Companies developed Supplemental Portfolios for information purposes in which the optimization of resources did not include any carbon constraints. In developing these Supplemental Portfolios, the Companies removed the system CO_2 mass cap constraints as described above and selected resources with no consideration of physical or economic constraints of CO_2 emissions from existing or future resources.

Modeling the Carolinas Systems

The Resource Plan modeled the Carolinas systems in capacity expansion and production cost modeling with DEC and DEP as two separate utilities and legal entities, each operating in both South Carolina and North Carolina as part of the dual-state systems. The separate DEC and DEP systems operate across three areas (DEP-West, DEC and DEP-East, as depicted in Figure C-2 below), each with its own load, resources, and transmission limits between them. The modeling also reflects that

DEC and DEP continue to utilize joint dispatch, which allows for the utilities to optimize the dispatch of the system to provide cost savings to customers.

Figure C-2: DEC and DEP Service Territories and Balancing Authorities



The analysis assumes the implementation of a "Consolidated System Operations" model where the NERC Balancing Authority ("BA"), Transmission Service Provider ("TSP") and Transmission Operator ("TOP") functions are consolidated for DEC and DEP. This consolidated approach allows for economically dispatching the system, and furthermore, allows for optimization of 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 satisfy the system operational needs of its balancing authority area. The Consolidated System Operations 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 either company as compared with the separate Balancing Authority scenario. 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 further discussed in Chapter 4, the Companies are planning for Consolidated System Operations as part of the planned merger of DEC and DEP, which could be completed by January 2027. The Companies see consolidating system operations as a prudent and reasonable step for achieving lower cost and lower carbon emissions for customers, while maintaining or improving reliability of the consolidated system.

Each of the Companies participate in the Southeast Energy Exchange Market ("SEEM") as further discussed in Appendix L (Transmission System Planning and Grid Transformation). SEEM is a 15-minute, as-available, non-firm transmission bilateral trading platform that automates matching economic purchases and sales for SEEM participants. However, because these economic energy purchases and sales are as-available, non-firm, and completely dependent on neighboring utilities and the specific load and availability of the resources on their system as well as the availability of non-firm transmission to deliver the energy, the Companies do not include the potential economic benefit of SEEM in their resource planning modeling.

Reliability Requirements

Ensuring reliability necessarily comes first in the modeling process. Key reliability inputs needed in the Carolinas Resource Plan modeling include planning reserve margins, effective load carrying capacity ("ELCC") values, and operational reserve requirements. These inputs are foundational resource planning components that ensure the Companies are maintaining or improving upon the adequacy and reliability of the existing grid as required by both States[2] and further described below.

Additionally, through the modeling analytic framework, the Companies assess reliability of the system throughout the modeling process, ensuring there are no deviations from this primary requirement.

Planning Reserve Margin

DEC and DEP retained Astrapé Consulting[3] to conduct a new resource adequacy study to support development of the Companies' Carolinas Resource Plan. 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. Astrapé examined resource adequacy for a number of scenarios: an island scenario which assumes no market assistance is available from neighbor utilities; a base case, which reflects the reliability benefits of the interconnected system including the diversity in load and generator outages across the region; a combined case, to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority; and sensitivities to determine the impact on reserve margin due to changes in key drivers as compared to the previous 2020 Resource Adequacy Study.

Based on results of the new study, the Companies utilized a 22% minimum winter planning reserve margin in developing the Carolinas Resource Plan portfolios. As described in more detail in this Appendix and in the 2023 Resource Adequacy Study report, included as Attachment I, the planning reserve margin is based on achieving the widely accepted industry standard of "one-day-in-10-years" loss of load expectation threshold ("0.1 LOLE") and reflects an increase over the prior planning reserve margin criterion.

Furthermore, as described later in this Appendix, the Carolinas Resource Plan's analytical process includes the Reliability Verification step. This incremental modeling is conducted with the same modeling software used to conduct the resource adequacy study to ensure that the preliminary portfolios developed by the capacity expansion model maintain or improve reliability of the system.

[2] See N.C. Gen. Stat. § 62.110.9(3); S.C. Code Ann. § 58-37-40(c)(2).

[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé has conducted several Resource Adequacy Studies and Effective Load Carrying Capability Studies for DEC and DEP in recent years.

Should a portfolio identified by the capacity expansion modeling meet the planning reserve margin, but fail to meet the LOLE target, resources are added to the portfolio until the standard is met.

Effective Load Carrying Capability

Meeting the Interim Target and the carbon neutrality target requires the addition of significant levels of variable renewable resources and energy-limited storage resources to the system. Conventional thermal resources are typically dispatchable and available to meet load when not in planned maintenance or forced outage. However, due to the variable nature of solar and wind resources and the energy-limited nature of storage resources, it is critical to understand the reliable capacity contributions of these resources in the generation planning process. For example, winter peak loads for DEC and DEP occur in the early morning and late evening when the solar output is low, while peak loads in the summer occur across the afternoon and early evening, which is more coincident with solar output. The amount a resource can be counted on at periods of system stress is called its ELCC, sometimes referred to as a resource's seasonal "capacity value." The ELCC of a resource can be thought of as a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio. Like solar, onshore and offshore wind resources are also "variable energy resources", which require ELCCs to ensure the system has enough capacity to meet its forecasted peak loads, given the variability of these resources. Additionally, storage resources are considered "energy limited resources", in that once their storage energy has been used, they can no longer generate energy for the system until they can be recharged. Similarly, the Companies must account for ELCCs of storage resources to ensure peak loads can be met accounting for energy limited resources. Several factors determine a resource's ELCC including its generation profile (if determined by irradiance or windspeeds), the amount of energy a resource can store, and can change based on several factors including other resources on the system.

In developing the Resource Plan, results from recent ELCC studies were used to estimate the reliability capacity value attributable to variable energy and energy-limited resources such as solar, wind, and storage resources. Solar and storage ELCC values were based on the 2022 ELCC study conducted by Astrapé Consulting using the SERVM[4] model. The Companies also retained Astrapé to conduct a new 2023 ELCC study to determine appropriate reliability capacity values for onshore and offshore wind resources. The results of these studies reflect synergistic benefits of complementary resources on the system. ELCC is further described in the 2022 Solar and Storage ELCC Report (Attachment II) and 2023 Wind ELCC Report (Attachment III) being filed in support of the Plan.

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 the Companies, based on a

[4] The Strategic Energy & Risk Valuation Model ("SERVM") is a state-of-the-art reliability and hourly production cost simulation tool managed by Astrapé Consulting, which provides consulting services and/or licenses the model to its users.

planning and reliability tool developed by the Electric Power Research Institute ("EPRI"),[5] and is 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. Operational reserve requirements 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. Operational reserves are also included when conducting the additional portfolio Reliability Verification for each portfolio influenced by the selected levels of solar and wind capacity in each portfolio.

Electric Load Forecast

The load forecast is a critical factor in utility system planning. At its core, integrated resource planning is matching resource requirements with load projections. The load forecast can influence how many resources are added over time, what types of resources are added, and the load can have a significant impact on a portfolio's ability to achieve energy system objectives. Below are brief descriptions of the basic components included in the load forecast used in the Resource Plan, and what assumptions are made for base planning and sensitivity analysis for each component. More discussion on Load Forecasting is included in Appendix D (Electric Load Forecast).

*Base Economic F*orecast

The economic forecasts for North Carolina and South Carolina are obtained from Moody's Analytics, a nationally recognized economic forecasting firm. Based upon its modeling, Moody's prepares a series of key regional economic indicators, including history and projections of employment, income, wages, industrial production, inflation, prices, and population. This information is used to develop the customer growth and energy volumes used to generate the base load forecast. The Companies also developed economic high and low scenarios, which show the impact to the load forecast if the economic indicators were increased or decreased over the long term.

Utility Sponsored Energy Efficiency

The Utility Energy Efficiency ("UEE") forecast projects energy savings from efficiency programs that are sponsored and marketed by the Companies to assist customers in reducing their energy bill through reduced energy consumption. The Resource Plan's Base UEE forecast is developed by blending the Companies' near-term program projections with the longer-term projections from an Energy Efficiency / Demand-Side Management ("EE/DSM") Market Potential Study ("MPS"). The MPS is developed by a third-party expert consulting firm that has engaged with the Carolinas EE/DSM Collaborative through multiple meetings over the past 12 months and provides a comprehensive assessment of EE/DSM potential specific to the service territory and customer base by including all

[5] EPRI's Dynamic Assessment and Determination of Operating Reserve ("DynADOR") tool is a standalone 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 multi-year planning horizon.

currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DSM measures. The MPS first develops the technical potential of EE. This technical potential is then evaluated to determine how much of the technical potential can be economically offered to customers. Finally, the MPS creates an achievable potential of EE based on the economic potential of EE factors in customer adoption, as not all economic EE programs will be fully adopted by the customers for whom they are intended. More information about the MPS is discussed in Appendix H (Grid Edge and Customer Programs).

While this approach is a sound strategy for IRP planning and ensures reliability of the system, the Companies recognize the significant impact overall energy consumption can have on their ability meet CO_2 emissions reductions targets. Demand-side programs can also support utilities' ability to meet growing load. Accordingly, the Companies place a high priority and emphasis on shrinking the challenge through demand-side efforts to reduce anticipated load growth and system carbon emissions. The UEE forecasts developed for the Plan expand on the savings potential identified in the Companies' MPS through the identification of initiatives to address current market or policy barriers. The Companies continuously engage stakeholders via the EE/DSM Collaborative to actively explore avenues for increasing the beneficial impacts of EE measures and programs. This engagement informed an ambitious target of achieving UEE savings of 1% of eligible retail load annually.

In keeping with this ambitious target, the Companies developed three UEE forecasts for the Plan. The first, used as the base planning assumption, grows UEE savings at a minimum of 1% of eligible retail load in each year of the Plan. This continues to assume that certain customers are eligible to opt-out of Companies-sponsored UEE programs and the associated rider. The second forecast takes an increasingly aggressive approach to UEE and assumes a minimum annual savings of 1.5% of eligible load in every year of the Plan. This high UEE assumption for the Plan carries significant execution risk, as it would require, at minimum, a number of the enablers described in Appendix H to be approved and or enacted, many of which the Companies do not have control over. Alternatively, the low EE forecast was also developed assuming achievement of 1% of retail eligible load annual EE growth minimum, relative to previous initial 2022 proposed Carbon Plan's load forecast. The low EE forecast, however, reflects the 2020 MPS and more significantly bases the 1% of eligible load annual floor on a load forecast on the prior cycle's load forecast, before the significant load forecast growth seen in this plan. This effectively results in the previous planning cycle's 1% EE target, as still aggressive, but less than 1% relative to the updated load forecast for the 2023 Plan. The availability of new efficiency technologies to address new sources of load like EV also poses a potential execution risk. Ultimately, the magnitude of resulting energy savings from Grid Edge and customer programs depends on customer behavior and their electing to participate in those programs.

Summarized in Table C-2 through Table C-4 below are the incremental net impacts of these UEE forecasts on net annual energy load of the system in gigawatt-hours ("GWh").

Table C-2: Incremental Net UEE Impacts on Annual Energy, Base UEE Forecast Assumption – 1% of Eligible Retail Load (GWh)

	DEC	DEP
2030 Projection	-3,969	-2,086
2035 Projection	-5,602	-2,861

Table C-3: Incremental Net UEE Impacts on Annual Energy, High UEE Forecast Assumption – 1.5% of Eligible Retail Load (GWh)

	DEC	DEP
2030 Projection	-3,969	-2,190
2035 Projection	-6,070	-3,637

Table C-4: Incremental Net UEE Impacts on Annual Energy, Low UEE Forecast Assumption (GWh)

	DEC	DEP
2030 Projection	-3,014	-1,546
2035 Projection	-3,444	-1,732

For purposes of this document, UEE and EE terms may be used interchangeably to refer to approved utility programs unless otherwise noted. It is important to note that data regarding the change in metered energy that is attributed to UEE must be explicitly added to the forecast after estimation to properly account for how these efforts by the Companies will reduce the energy demanded by its customers.

The forecasted UEE is included in the Plan as an adjustment to load, therefore reducing the net load of the system before the selection of any supply-side resources.

Rooftop Solar

Base rooftop solar growth reflects currently approved Renewable Net Metering rate designs in the Carolinas. Rooftop solar reduces customer load by generating energy for self-consumption with excess energy put onto the grid. The forecast reflects the net impact to the load forecast as an adjustment in reduction of energy for the supply-side resources are required to meet.

Table C-5 below shows the impact of rooftop solar base assumptions on the Resource Plan's net annual energy load.

Table C-5: Rooftop Solar Impact on Annual Energy (GWh)

	DEC	DEP
2030 Projection	-771	-512
2035 Projection	-1,281	-837

Electric Vehicles

The base electric vehicle ("EV") load forecast was developed by using the Guidehouse Vehicle Analytics and Simulation Tool based on multiple inputs, including forecasted vehicle registrations, customer acceptance and utilization, efficiency characteristics, and projected vehicle miles traveled. As mentioned in Chapter 2, EVs will achieve the highest compound annual growth rate of any category within the load forecast between 2024-2038: 37.4% in DEC and 36.9% in DEP. More information on the long-term EV forecast and how EVs impact the growth in system demands and various load management and pilot programs can be found in Appendices D and H.

Table C-6 below shows the impact of EVs the Resource Plan's net annual energy load.

Table C-6: EV Charging Impact on Annual Energy (GWh)

	DEC	DEP
2030 Projection	1,845	1,145
2035 Projection	5,665	3,438

Integrated Volt-VAR Control – Conservation Voltage Reduction Forecast

DEC and DEP's Integrated Voltage/VAR Control ("IVVC") program has two modes of operations: Peak Shaving mode and Conservation Voltage Reduction ("CVR") mode. Peak Shaving mode is forecasted to operate during the peak 10% of the hours in a year while CVR mode will operate during the 90% of hours not classified as peak. The modeling of CVR mode, where Volt-VAR optimization supports continuous voltage reduction and energy conservation, is accounted for in the load forecast. The application of the integration of these programs is applied to 90% of the hours. For the remaining 10% of hours classified as peak, the load forecast does not model any impacts from IVVC and instead the benefits of the program are captured as a capacity resource. IVVC peak shaving capacity modeling is described in more detail in the forecast of demand-side resources later in this Appendix and peak impacts are discussed.

In July 2014, DEP completed the installation of the Distribution System Demand Response ("DSDR") peak-shaving program across 97% of eligible circuits in its service territory. Therefore, the only program upgrade required in DEP is to implement CVR mode across the eligible circuits that will allow a centralized Distribution Management System ("DMS") to control voltage by circuit.

The Resource Plan recognizes that the energy conservation potential of expanding IVVC to a higher level of circuits in DEC than originally forecasted could greatly reduce the load the utility needs to serve. Therefore, base modeling assumptions for the Plan assumes the DEC IVVC program will be expanded to approximately 96% of the eligible circuits across the system to eventually achieve near-parity with DEP.

Summarized in Table C-7 below are the impacts of IVVC in the load forecast on net annual energy load of the system.

Table C-7: IVVC CVR impact on Annual Energy (GWh)

	DEC	DEP
2030 Projection	-359	-413
2035 Projection	-379	-432

Time of Use Rates – Critical Peak Pricing and Peak Time Rebates

Time of Use ("TOU") rates for planning purposes is modeled as an adjustment to the load forecast. TOU includes Critical Peak Pricing ("CPP"), a financial penalty for energy consumption during Critical Peak Pricing periods in exchange from lower rates during other periods of the year, and Peak Time Rebate ("PTR"), a financial incentive for reducing energy consumption during peak periods. While these rate designs may reduce consumption at the time of peak, they have impact to the overall system loads at other times of the day, right before or right after peak periods. To capture the pre- and post-peak modifications to load, the model treats these rate designs as a load modifier to capture this change in usage. TOU rates are discussed more for their peak load impacts later in this Appendix.

Net Load Forecast

Summarized below in Table C-8 through Table C-10 are the base planning net load forecasts for DEC, DEP and the combined DEC and DEP Carolinas total ("CAR"), reflecting annual energy along with winter and summer system peaks, for the Plan. The net load forecast includes all of the impacts of all of the forecasts discussed above.

Table C-8: Base Load Forecast – Annual Energy (TWh)

Year	DEC	DEP	CAR
2024	95.8	65.4	161.2
2025	95.9	66.8	162.6
2026	96.4	67.3	163.7
2027	97.5	67.9	165.4
2028	99.3	68.9	168.2
2029	101.1	69.9	171.0
2030	102.6	71.0	173.7
2031	104.4	71.9	176.3
2032	106.3	72.8	179.1
2033	108.3	73.6	181.9
2034	109.9	74.5	184.4
2035	111.7	75.5	187.2
2036	113.6	76.6	190.2
2037	115.5	77.6	193.0
2038	117.7	78.7	196.3

Table C-9: Base Load Forecast – Winter Peak (MW)

Year	DEC	DEP
2024	17,510	14,164
2025	17,527	14,416
2026	17,631	14,441
2027	17,832	14,563
2028	18,129	14,734
2029	18,490	15,055
2030	18,718	15,160
2031	19,076	15,370
2032	19,448	15,512
2033	19,788	15,721
2034	20,006	15,821
2035	20,299	16,030
2036	20,568	16,102
2037	20,910	16,301
2038	21,255	16,472

Table C-10: Base Load Forecast – Summer Peak (MW)

Year	DEC	DEP
2024	18,079	12,874
2025	18,107	13,080
2026	18,237	13,210
2027	18,486	13,397
2028	18,836	13,549
2029	19,140	13,668
2030	19,429	14,001
2031	19,799	14,254
2032	20,135	14,439
2033	20,564	14,660
2034	20,812	14,682
2035	21,107	14,804
2036	21,650	15,037
2037	21,960	15,224
2038	22,383	15,495

Existing Resources

Over the planning horizon, the Carolinas Resource Plan modeling accounts for resources that are currently on the system. These resources continue to provide reliable and cost-effective service of energy throughout the Companies' transition to a lower carbon system. Reference Appendix B (DEC - DEP System Overview) for a list of existing generating units. Discussed below are the assumptions of how the existing generation resources change over the 2050 planning horizon.

Existing Generation Retirements

Coal retirements in the Carolinas Resource Plan vary by Pathway. The coal retirements were analyzed endogenously within the capacity expansion model based on the specific assumptions associated with each portfolio development scenario. More discussion on how the coal unit retirement dates were established for the Carolinas Resource Plan modeling is presented later in this Appendix and in Appendix F.

With respect to non-coal generating assets, the Carolinas Resource Plan assumes the retirement dates of owned generation resources. While most of the generating resources on the system today are expected to retire by 2050, a select few are assumed to continue serving the system in 2050 or beyond. This includes all of DEC's and DEP's existing nuclear fleet, representing 11 units and over 9,000 MW of owned capacity, which in 2022 generated approximately 47% of the energy used to serve DEC and DEP customers. Subsequent license renewals, which will extend the potential operating life for these units to 2050 and beyond, for most of the Companies' existing nuclear units, will keep the option open for these resources to operate affordably and reliably for up to 80 years. While not directly impacting the Carolinas Resource Plan analysis, after the 2050 planning horizon, planning will have to account for the retirement of this significant source of carbon-free energy. More information on planned subsequent license renewal for the Companies' nuclear units is included in Appendix J (Nuclear). The retirement dates assumed for all non-coal owned generation resources in the Carolinas Resource Plan are included in Appendix B.

Existing Resource Capacity Uprates

DEC and DEP continue to evaluate projects at existing generating facilities that can provide incremental benefits to customers. In the Carolinas Resource Plan analysis, projects that are currently planned or under construction have been included. Table C-11 below summarizes these projects by utility and provides the planned capacity uprate and year of project implementation. These projects include nuclear unit uprates, Bad Creek runner upgrades and gas fleet flexibility projects as further described below. In total, these projects will provide 658 MW of additional firm, dispatchable capacity. The Companies continue to evaluate cost-effective projects that would increase the output and efficiency of their generating assets.

Table C-11: Planned Unit Uprates

PLANNED UNIT UPRATES				
UNIT	GENERATION TYPE	UTILITY	WINTER (MW)	IN-SERVICE DATE
Bad Creek 3	Pumped Storage	DEC	80	Mar 2023
Bad Creek 4[1]	Pumped Storage	DEC	40	Feb 2024
Buck	Combined Cycle	DEC	20	June 2027
Dan River	Combined Cycle	DEC	20	Dec 2027
WS Lee	Combined Cycle	DEC	14	Dec 2026
McGuire 1	Nuclear	DEC	75	Sept 2029[2]
McGuire 2	Nuclear	DEC	75	Nov 2030[2]
Catawba 1	Nuclear	DEC	75	May 2031[2]
Oconee 1[3]	Nuclear	DEC	15	Oct 2023[2]
Oconee 2[3]	Nuclear	DEC	15	Feb 2024[2]
Oconee 3[3]	Nuclear	DEC	15	May 2024[2]
Asheville CC 1	Combined Cycle	DEP	15	Apr 2026
Asheville CC 2	Combined Cycle	DEP	15	Apr 2026
HF Lee CC	Combined Cycle	DEP	60	Dec 2025
Richmond PB4	Combined Cycle	DEP	20	June 2028
Richmond PB5	Combined Cycle	DEP	40	June 2028
Sutton CC	Combined Cycle	DEP	38	Dec 2026
Brunswick 1	Nuclear	DEP	13	Mar 2029[2]
Brunswick 2	Nuclear	DEP	13	Mar 2028[2]
		DEC Total	444	
		DEP Total	214	
		DEC and DEP Total	658	

Note 1 : Bad Creek 4 total uprate is 80 MW; however, the uprate is shown as 40 MW due to total plant limitation when uprates at all four units have been completed.
Note 2 : Nuclear dates represent projected work completion dates, not MNDC uprate dates.
Note 3 : Oconee MUR projects were modeled with Jan 2024 dates. Project schedules have been revised since the development of the modeling inputs.

Nuclear Unit Power Uprate and 24-month Fuel Cycle Projects

As reflected in previous planning cycles, Oconee Station is implementing Measurement Uncertainty Recapture ("MUR") projects, which uses more precise instrumentation and technology to lower the measured uncertainty and improve the calculated power level, allowing for higher generating levels. The projects are scheduled to be completed in late 2023 to mid-2024.

With the additional energy demand on the system, the Companies recently also explored options to increase carbon-free energy from within the existing nuclear generation fleet. The first option considered was the expansion of the MUR program to Brunswick Nuclear Station. By implementing

MUR at Brunswick Nuclear Station, DEP is projecting to increase the generating capacity of each unit by 13 MW (26 MW total for the station) by Spring of 2029.

The second type of project evaluated was Power Uprates ("PUR") at Catawba and McGuire Nuclear Stations. PUR projects increase the thermal output from the nuclear reactor, increasing steam flow and generating capacity. Opportunities for PURs were identified at McGuire Units 1 and 2 and Catawba Unit 1. Each project is expected to increase the capacity of the unit by 75 MW. The McGuire Unit 1 PUR project is expected to be in-service Fall 2029, with the McGuire Unit 2 PUR projected in-service date would be a year later in Fall 2030, and Catawba Unit 1 PUR is projected for in-service by the following Spring in 2031.

The Companies also evaluated extending the refueling cycle from 18 months to a 24-month fuel cycle at the sites that have not already implemented this extended refueling cycle schedule. The plants currently using an 18-month fuel cycle are Catawba and McGuire Nuclear Station in DEC and Harris Nuclear Station in DEP. Transitioning these units to the longer, two-year fuel cycle benefits the system with increased carbon-free energy and deferred outage expense. These projects are currently planned for implementation starting in 2029, with the last projected for completion in 2031.

An analysis was performed prior to the development of the Plan, using inputs and assumptions consistent with the development of the Core portfolios, to assess the costs and potential benefits of these projects. In general, each project was assessed in the capacity expansion and production cost models for its impact on both resource selection and production costs benefits. The associated system benefits were compared to the capital expenditures to determine net benefits to the system. In addition, Inflation Reduction Act of 2022 ("IRA") tax benefits were reflected for the incremental new carbon-free energy. All the projects were determined to be cost effective compared to alternative generation resources and included as a base assumption for all portfolios.

More information on each of these projects is discussed in Appendix J. Table C-12 below summarizes the units, projects, and approximate in-service dates for each of these nuclear projects.

Table C-12: Existing Nuclear Planned Projects

Unit	Project	Capacity (MW)	Approximate In-Service Date
Oconee 1[1]	MUR	15	Oct 2023
Oconee 2[1]	MUR	15	Feb 2024
Oconee 3[1]	MUR	15	May 2024
Brunswick 1	MUR	13	Mar 2029
Brunswick 2	MUR	13	Mar 2028
Catawba1	PUR	75	May 2031
McGuire1	PUR	75	Oct 2029
McGuire2	PUR	75	Nov 2030
Catawba1	24-Month Fuel Cycle	0	Apr 2029
Catawba2	24-Month Fuel Cycle	0	Apr 2030
McGuire1	24-Month Fuel Cycle	0	Sept 2029
McGuire2	24-Month Fuel Cycle	0	Oct 2030
Harris 1	24-Month Fuel Cycle	0	Nov 2031

Note 1 : Oconee MUR projects were modeled with Jan 1, 2024 project in-service dates. Project schedules have been revised since the development of the modeling inputs.

Bad Creek Runner Upgrade Projects

The Bad Creek Runner Upgrade Project commenced in 2019 and is designed to increase the capacity of Units 1-4 from 340 MW to 420 MW (80 MW per unit) by upgrading the runners combined with associated projects required to accomplish these gains in capacity. These include replacement of the main Generator Step Up ("GSU") Transformers, replacement of the Generator Breakers and Exciters, modifications to the cooling system for the Iso-Phase Bus, and modification of the planned motor-generator rewinds from in-kind rewinds to rewinds capable of supporting the uprated Pump-Turbines. Units 1-3 were upgraded one at a time between 2019-2023 with each unit taking between 12-15 months to complete. Unit 4 is the last remaining unit and was taken offline in March 2023. It is projected to be uprated and back online in February 2024. While each of the four units is projected to operate at a maximum rated capacity of 420 MW, the maximum output for all four units running simultaneously is limited to 1,640 MW, due to power tunnel limitations. The final total station output capability (post runner upgrade projects) will be confirmed following the final unit's project completion with final testing and verification.

Gas Fleet Flexibility Projects

The Companies are pursuing least cost flexibility expansion projects for the existing natural gas fleet that will maintain or improve system operability and enhance the integration of renewable resources. The Companies have identified potential unit flexibility projects across the existing CC fleet which will achieve increased turndown range, lower minimum loads, improved heat rates and efficiency, and increase firm dispatchable capacity by approximately 212 MW across seven CC power blocks.[6] Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) and Chapter 4 provide additional information regarding the capabilities and timeline for execution of the gas flexibility projects at CC assets.

Capacity PPA Expiry

DEC and DEP currently have various purchased power agreements ("PPA") for firm capacity purchases. The Resource Plan modeling generally assumes PPA expiry at the end of the current contract term for these resources, and assumes the utility is able to procure a "like-kind" resource replacement. Ultimately, all of these generic replacement market resources replacing the current PPAs are assumed to retire prior to 2050 without additional like kind replacement. Additionally, PPAs that are confirmed as unavailable beyond their current contract term are not assumed with a "like-kind" replacement and as such, the capacity is removed at the end of the current contract term.

Forecasted Demand-Side Management

Demand-side management ("DSM") programs, which include UEE, demand response ("DR"), TOU rates, and IVVC, continue to be an important part of DEC's and DEP's system operations and resource mix. The Companies considered these demand-side measures in the Plan's analysis in the load forecast as described above, but these resources also have capacity contribution during peak load conditions, which helps in maintaining reserve margins along with potential to offset high-cost energy when used. The Plan's base planning assumptions for UEE (as described above) and DR incorporate aggressive growth in both of these areas over previous IRPs' base planning assumptions.

Utility Energy Efficiency

The Plan utilizes UEE forecasts described in the load forecast section above. UEE is factored into the net load forecast as a load adjustment with EE saving year around, including at peak load conditions. While these peak energy contributions are still reflected in the load forecast, the reductions in peak load offset need for firm planning capacity to meet system peak planning reserve margins.

Summarized in Table C-13 and Table C-15 below are the peak load impacts of UEE.

Table C-13: Incremental Net UEE Impacts at Winter Net Peak Load, Base UEE Forecast Assumption – 1% of Eligible Retail Load (MW)

	DEC	DEP
2030 Projection	-631	-127
2035 Projection	-882	-192

[6] The Companies currently project a range of 212 MW – 251 MW for the total system flexibility uprates.

Table C-14: Incremental Net UEE Impacts at Winter Net Peak Load, High UEE Forecast Assumption – 1.5% of Eligible Retail Load (MW)

	DEC	DEP
2030 Projection	-631	-132
2035 Projection	-956	-239

Table C-15: Incremental Net UEE Impacts at Winter Net Peak Load, Low UEE Forecast Assumption (MW)

	DEC	DEP
2030 Projection	-493	-77
2035 Projection	-580	-94

Demand Response

DR customer programs reduce system peak load requirements by modifying customer consumption. DR consists of three types of customer programs: mechanical reduction, manual reduction and rate programs. Mechanical reduction programs consist of Duke Energy-controlled specific equipment, such as thermostats and hot water heaters, and can be called upon by the system operators to reduce the load of the system. Manual reductions, used almost exclusively by large business, occur when the Companies contact customers via phone, text and email with a message to reduce load at a particular time. Customers are compensated monthly for opting into programs to reduce demand when needed by the systems. Rate programs are generally based on price signals to incentivize customers to reduce their energy consumption during periods of higher system demand. More information on customer program is included in Appendix H.

DR capacity in resource planning counts toward the capacity planning reserve margins. The utilization of DR programs can decrease runtime of older, more expensive generation or the need to purchase power. The generation most likely to be avoided by DR is typically more carbon-intensive resources, but the primary benefit of DR to the system is reliability and system cost savings. The forecast adopts the capacity potential identified in the Companies' Winter Peak Demand Reduction Potential Assessment ("Winter Peak Study").

Table C-16 below summarizes the peak winter capacities of mechanical and manual reduction programs base DR forecast.

Table C-16: Mechanical and Manual Reduction Base Demand Response Forecast, Winter (MW)

	DEC	DEP
2030 Projection	682	369
2035 Projection	740	525

Additionally, a high and low DR forecast was developed. High DR forecasts generally reflect expanded programs and overall increased participation, while the low DR forecast reflects lower than expected participation, over all programs. Appendix H contains more for further information on how the DR forecasts were developed for the Carolinas.

Table C-17 and Table C-18 below summarizes the peak winter capacities of mechanical and manual reduction programs for the high and low DR forecast.

Table C-17: Mechanical and Manual Reduction High Demand Response Forecast, Winter (MW)

	DEC	DEP
2030 Projection	752	428
2035 Projection	815	599

Table C-18: Mechanical and Manual Reduction Low Demand Response Forecast, Winter (MW)

	DEC	DEP
2030 Projection	631	335
2035 Projection	679	468

The Plan also includes the impacts of TOU rate-based DR programs, including CPP and PTR. These rate programs are included as a DR program that reduces energy consumption at system peak times. These programs were identified in the Winter Peak Study to reduce peak winter load by utilizing rates structures. TOU is designed to send price signals to customers who opt into the program to encourage demand reduction in exchange for bill rebates or other favorable rate structures. The impacts of TOU are built into the load forecast to capture anticipated changes in customer load shape with the reductions at system peak summarized in Table C-19 below.

Table C-19: TOU Demand Response, Winter (MW)

	DEC	DEP
2030 Projection	133	132
2035 Projection	249	247

Integrated Voltage-VAR Control - Peak Shaving

IVVC is described above in the load forecast section of this Appendix. The CVR mode of IVVC is captured in the load forecast, but the Peak Shaving capacity is modeled as a DR program in the Plan modeling that can be dispatched. As stated above, DEP represents deployment across 97% of eligible circuits, while DEC will achieve the deployment target of 96% of eligible circuits by 2036.

Table C-20 below summarizes the peak winter capacities of IVVC in 2030 and 2035.

Table C-20: IVVC Peak Shaving Capacity Winter (MW)

	DEC	DEP
2030 Projection	199	152
2035 Projection	210	160

Forecasted Supply-Side Resources

Resource planning is a continuous, iterative process. As with any resource planning activity, the future planning of the system includes resource integration of projects that are currently underway or are anticipated and planned for the future. The Carolinas Resource Plan includes a limited number of resources that are anticipated to be integrated into the portfolio in coming years and are common to all portfolios. Those forecasted supply-side resources are discussed in this section. Supply-side resources that are economically selectable by the capacity expansion model in the development of portfolios are discussed in the next section, Selectable Supply-side resources.

Forecasted Solar

Solar is an important part of the DEC and DEP systems today and the Carolinas region is considered a leader in solar in the United States. Supportive policies to-date have aided the integration of solar into the Companies' service territories. While the majority of the solar included in the portfolios is economically selected in the modeling, the forecasted solar in the Plan represents existing solar capacity as well as expected capacity in various stages of advanced development and the interconnection process including Public Utility Regulatory Policies Act ("PURPA"), Green Source Advantage ("GSA") Customer-Directed Solar, 2022 Solar Procurement, and Competitive Procurement of Renewable Energy ("CPRE") Tranches 1, 2, 3, and 4 projects. The existing, incremental expected, and total existing and expected solar assumed in the Plan is included in Table C-21 below.

Table C-21: Forecasted Solar Capacities (Nameplate MW)

	DEC	DEP	CAR
Existing Solar as of January 1, 2023	1,325	3,261	4,587
Incremental Expected Solar as of January 1, 2031	1,598	1,416	3,013
Total Existing and Expected Solar as of January 1, 2031	2,923	4,677	7,600

Forecasted solar represents expected additions through 2031, though the majority of the forecasted solar is forecasted to be online by the start of 2027.

Forecasted Batteries

Battery development remains an important planning consideration for the Companies. Near-term deployments are important for finding cost-effective and reliable solutions to meet Duke Energy's customers' energy needs. The forecasted batteries are included in all portfolios and reflect projects that are in advanced stages of development and expected to be put into service ahead of model selection of incremental new battery resources (for 2028 and beyond). The forecast assumes the existing storage resources on the system and incremental deployment for a total capacity of approximately 300 MW of nameplate capacity (approximately 100 MW in DEC and 200 MW in DEP) with various storage capacity durations. These near-term forecasted battery projects are in addition to the incremental battery storage economically selected by the model.

Lincoln CT 17 Integration

Lincoln County CT 17 is a collaboration project with Siemens Energy to bring online an industry leading advanced turbine technology. The project, still under control and operation of Siemens Energy, successfully achieved first fire in 2020 and is currently in its extensive testing and extended commissioning phase as this is a first-of-its-generation combustion turbine. The Resource Plan assumes DEC will take care, custody, and control of the completed 402 MW (winter capacity) unit in 2024. This new designated network resource will provide beneficial peaking capacity and the low minimum capability combined with fast ramping capability make it a great flexible resource for integrating more solar in the Carolinas.

Bad Creek Powerhouse II

As discussed in Appendix I (Renewables and Energy Storage), pumped storage hydro is the use of two water reservoirs at different elevations to store and release energy by running water between the two. When there is surplus low-cost energy available to the system, water can be pumped from the lower reservoir to the upper reservoir, allowing the energy to be stored until needed for system peak shaving, when the water can be released from the upper reservoir and run through a turbine generator to produce electricity.

DEC currently owns and operates two pumped storage hydro facilities located in western South Carolina: Bad Creek and Jocassee. With the competition of the Bad Creek Runner Upgrade project in 2025, the two plants have a combined generating capacity of over 2,400 MW. The long-duration storage aspect of these stations continues to provide valuable dispatchable generation to cover peak customer demand and respond quickly to changes in renewable output, as well as time-shifting surplus energy from renewables to serve customers during times of greater demand when renewable output is typically low, e.g., winter mornings and evenings.

Expansion of pumped storage hydro is a unique opportunity for DEC. The required topology for pumped storage hydro is limited across the country and the Companies are fortunate to have the opportunity to pursue this proven long-duration energy storage resource. The Bad Creek II project represents an increase in capacity from the facility using the existing upper and lower Bad Creek reservoirs. The additional powerhouse would roughly double the output capacity of the station while maintaining the total storage capacity of the station overall. Moreover, the significant expanded capacity provides for increased planning reserves and helps enable retiring additional coal capacity.

Bad Creek II pumped storage hydro was included in all portfolios in 2034 as an input to the portfolio development step to simplify the complex storage analysis within the capacity expansion step. This proven resource provides critical fast-response net dependable capacity during peak periods to meet growing customer demand in the region while diversifying reliance on constrained dispatchable resources such as natural gas and battery energy storage. To ensure cost competitiveness of Bad Creek II, the Companies performed a separate economic verification step which confirmed that the inclusion of Bad Creek II in the portfolios was economic. Reference the Production Cost section later in this Appendix for more detail on the economic verification analysis. The Companies will continue to assess the value of long-duration storage on the system and its ability to provide a flexible and reliable resource that can meet changing system needs in addition to facilitating the retirement of coal capacity.

Selectable Supply-Side Resources

This section discusses each of the supply-side resources that the capacity expansion model can economically select to develop a portfolio. The capacity expansion model selects resources that minimize the cost of the system, subject to meeting the requirements of the system including energy and capacity requirements, achieving emissions reductions targets and operating reserve requirements. Each resource's unique characteristics pose value for the model to weigh against its costs and the needs of the system. Carbon-free energy production, dispatchability, operating flexibility such as ramp rates, minimum loads, cycle times, efficiency, availability (both when and how much of a resource can be integrated to the portfolio), and seasonal capacity value are all important factors that can influence the optimal set of resources. Modeling inputs are discussed for each resource in more detail below, including how they are applied throughout the Plan's modeling.

While each technology has many potential sizes, configurations and variations, the resources modeled in the Resource Plan are considered generic resources that are representative of a class of resources that serve the system in similar ways. While the Companies use sophisticated models in developing and assessing portfolios, selections of resources should be considered representative of the general types of resources that meet the requirements of the system. Generic resource assumptions such as the precise size, quantities, capability, cost, or even timing, that are developed for modeling purposes may ultimately be different during implementation based on site and technology specific details or various other practical factors when it comes to execution. As discussed in Chapter 4, these variations from generic modeling parameters could be based on pricing and economics, sourcing, technology specifications, supply chain availability (e.g., materials, labor), permitting timelines and other evolving factors during Resource Plan execution.

Each reference in this section (and future sections in this Appendix) to “years” when resources are available is on a full calendar year basis; that is, the resource is in the portfolio at the start of the year, available for both the Winter Peak in January and the Summer Peak in July.

More information about resource screening is provided in Appendix E (Screening of Generation Alternatives).

Solar and Solar Paired with Storage

As discussed previously in this Appendix, the Companies have developed a “forecast” for the amount of standalone solar and solar paired with battery energy storage (“SPS”) that is expected to come online based on current policies, programs, and procurements. While the existing and forecasted solar represent a portion of the total solar expected to come online, the majority of solar shown in the Plan is ultimately economically selected by the capacity expansion model.

In response to feedback from stakeholders, the Companies modeled a variety of solar paired with storage configurations. There are four configurations of solar that are economically selectable in the Carolinas Resource Plan modeling:

- Standalone Solar – 75 MW Single-axis tracking bi-facial solar
- Solar paired with Battery Energy Storage (~25% Battery Ratio) – 75 MW Single-axis tracking bi-facial solar with 20 MW / 80 megawatt-hour (“MWh”) battery
- Solar paired with Battery Energy Storage (~50% Battery Ratio) – 75 MW Single-axis tracking bi-facial solar with 40 MW / 160 MWh battery
- Solar paired with Battery Energy Storage (~75% Battery Ratio) – 75 MW Single-axis tracking bi-facial solar with 60 MW / 240 MWh battery

Costs for these resources generally align with industry standards and base assumptions include technology maturity over the short-term, which results in cost declines. Resource capital costs are presented in Chapter 2 and in Appendix E. Table C-22 below present the assumptions for each solar resource in the modeling.

Table C-22: Solar and Solar Paired with Storage Modeling Assumptions

	Standalone Solar	Solar Paired with Battery – ~25% Battery Ratio	Solar Paired with Battery – ~50% Battery Ratio	Solar Paired with Battery – ~75% Battery Ratio
Fuel	N/A	N/A	N/A	N/A
Selection Increment	75 MW	75 MW	75 MW	75 MW
Solar DC / AC Ratio	1.4 (105 MW / 75 MW)	1.4 (105 MW / 75 MW)	1.4 (105 MW / 75 MW)	1.4 (105 MW / 75 MW)
Capacity Factor	~27%	~27%	~27%	~27%
Battery Power Capacity	N/A	20 MW	40 MW	60 MW
Battery Storage Capacity	N/A	N/A	N/A	N/A
Dispatchability	Fully Curtailable Down	Fully Curtailable Down	Fully Curtailable Down	Fully Curtailable Down
Asset Life	30 Years	30 Years	30 Years	30 Years
First Year of Eligible Selection	2028	2028	2028	2028
Cumulative Annual Availability	N/A	N/A	N/A	N/A

With the assumption of planned Red Zone Expansion Plan 2.0 strategic transmission to enable renewable interconnection — in addition to providing reliability and resiliency benefits — as recommended by stakeholders and discussed in more detail in Appendix L (Transmission System Planning and Grid Transformation), Table C-23 below shows the annual solar resource availability for the three resource availability cases. The resource availability split between DEP and DEC was assigned at approximately 60% of the total available annual capacity in DEP and approximately 40% of the available annual capacity in DEC based on general trends and alignment with resources and land availability. The model has the option to select any of the solar and SPS configuration options up to the total amount available for each utility to select annually. To achieve the Interim Target by 2030, a solar availability case above the high case is described in the Portfolio Development section of this Appendix.

Table C-23: Solar Annual Availability Modeling Assumptions

	Base Availability			Low Availability			High Availability		
	DEC	DEP	CAR	DEC	DEP	CAR	DEC	DEP	CAR
2024-2027	0	0	0	0	0	0	0	0	0
2028	525	825	1,350	525	825	1,350	525	825	1,350
2029	525	825	1,350	525	825	1,350	750	1,050	1,800
2030	525	825	1,350	525	825	1,350	750	1,050	1,800
2031+	675	900	1,575	525	825	1,350	750	1,050	1,800

Actual solar output is variable and dependent on natural irradiance (daylight) and cloud cover. Solar profiles modeled in the Carolinas Resource Plan are based on a "typical meteorological year," or TMY, using twenty-five years of historical irradiance data from 22 sites across the Carolinas. Additionally, because solar output and system demand are correlated, the Companies match historical load and solar production to future load forecasts. This "load match" data is combined with the TMY profiles to create the final hourly solar profiles modeled in the Plan.

The ELCC of incremental solar coming onto the system is 10% or less of its nameplate capacity contributing to winter peak planning due to low irradiance in the Carolinas during winter peak events, typically early mornings before significant solar irradiance is available. Solar provides a higher capacity value in the summer, but because the Carolinas utilities are winter planning, when the winter capacity requirement is met, the summer capacity requirement is typically met as well. As discussed above in Modeling Advancements, the Companies have modeled and assume all incrementally selected SPS resources allow the battery to charge from the grid, instead of relying exclusively on the solar resource for energy. This allows the battery energy storage system ("BESS") that is paired with solar to receive a higher ELCC value due to the synergistic benefits of adding the two resources together.

One important SPS design element is whether the BESS is AC-coupled vs DC-coupled. In an AC-coupled solar and battery system, the solar and battery systems are connected, through separate inverters, to the same AC bus. In a DC-coupled system, the solar and battery components reside on the DC side of shared inverters. There are many cost-benefit tradeoffs between these two configurations, but there has not been significant differentiation between these configurations in terms of both functionality and cost. In 2022, NREL concluded in their analysis that "the dominant type of coupling between PV and battery technologies remains unknown."[7] The generic SPS units modeled here are not specifically reflective of either configuration. Hence, both AC and DC-coupled configurations should be considered in the execution/procurement stages. This assumption will be

[7] Representing DC-Coupled PV+Battery Hybrids in a Capacity Expansion Model, *available at* https://www.nrel.gov/docs/fy21osti/77917.pdf.

reconsidered in future planning cycles as trends continue to develop including information on SPS projects procured through the Companies' SPS procurement processes.

Standalone Batteries

The Resource Plan allows for the identification of economic selection of batteries in the capacity expansion model. Batteries are included in the capacity expansion model and able to be selected for their capacity and energy value. Batteries and other energy storage resources provide the ability to operate as a load, to help the system maintain minimum operating limits, or as a generator to supply energy at peak demand and times of high marginal energy cost. Perhaps most importantly, batteries provide for the ability to move excess carbon-free energy from one period to another to reduce fuel costs as well as emissions.

While batteries can also be introduced to the system via solar paired with storage (and such resources are described earlier in this Appendix), the resources described here and shown in Table C-24 are standalone batteries. Standalone storage resources charge only from and dispatch to the grid, whereas storage paired with solar is assumed be able to charge from the solar resource or the grid.

The Companies modeled standalone batteries in three configurations for transmission connected resources as presented below in Table C-24 below.

Table C-24: Standalone Battery Modeling Assumptions

	4-Hr Li-ion Battery	6-Hr Li-ion Battery	8-Hr Li-ion Battery
Charging Ability	Grid-Tied	Grid-Tied	Grid-Tied
Selection Increment	100 MW	100 MW	100 MW
Usable Storage Capacity	400 MWh	600 MWh	800 MWh
Round-Trip Efficiency	85%	85%	85%
Replenishment Strategy	Rebuild after 15 Years	Rebuild after 15 Years	Rebuild after 15 Years
Dispatchability	-100 MW to 100 MW	-100 MW to 100 MW	-100 MW to 100 MW
Asset Life	30 Years	30 Years	30 Years
First Year of Eligible Selection	2027	2027	2027
Cumulative Addition Availability	N/A	N/A	N/A

While there are no cumulative addition limits on batteries, up to 2,200 MW per year per utility are available for selection in the model. This is generally a sufficiently high enough resource availability to retire significant existing capacity on the system and replace with battery over a one-to-two year period, provided sufficient energy resources are available to charge the incremental batteries. While the annual nameplate additions are high, the capacity value does go down as more storage resources of the same duration are added to the system.

Hydrogen-Capable Simple Cycle Combustion Turbines

Hydrogen-capable simple cycle combustion turbines (“CTs” or “peakers”) are economically selectable by the capacity expansion model in the development of portfolios. Shown in Table C-25, the Companies use an advanced-class CT. This technology is the most efficient and flexible combustion technology available. The advanced class CTs also are currently more hydrogen capable than their F-Class frame CT predecessors. Importantly, this technology is suitable for conversion to 100% operation on hydrogen in the future. The CT resources are available for selection assuming operation on natural gas with ultra-low sulfur diesel (“ULSD”) back-up as the generic unit assumption for these peaking resources. By 2040, the Companies assume new natural gas-fired CTs are no longer available, but new hydrogen CTs (“H_2 CTs”) that operate exclusively on clean hydrogen are available as new peaking resources for the system. This technology is a viable placeholder for long term peaking resource needs.

The CT and H_2 CT resources modeled in the Plan are presented below in Table C-25 below.

Table C-25: CT Modeling Assumptions

	CT	H_2 CT
Primary Fuel	Natural Gas	Hydrogen
Back-up Fuel	ULSD	N/A
Selection Increment / Capacity (Max, Winter)	425 MW	425 MW
Heat Rate (Max, Winter)	9,270	9,270
Dispatchability	Min Load to Max Load	Min Load to Max Load
Asset Life	35 Years	35 Years
First Year of Eligible Selection	2029	2040
Cumulative Addition Availability	N/A	N/A

While there are no cumulative addition limits on CTs, the model is allowed to select up to five units per year per utility, or 2,125 MW per year per utility. Similar to batteries, these resource availabilities are sufficiently high enough to retire significant existing capacity on the system and replace with CTs over a one-to-two-year period and continue to meet the capacity needs of the system to complete with batteries.

DEC and DEP each has its own cost assumption for intrastate natural gas firm transportation (“FT”) service. Peaking units do not assume interstate natural gas transportation service, but instead rely on ULSD back up fuel to ensure fuel supply.

As 2050 approaches, the Companies assume hydrogen becomes a readily accessible fuel as a clean hydrogen market develops. H_2 CTs added in the 2040s are assumed to operate exclusively on hydrogen. To account for the incremental equipment, the CT cost is increased to reflect these configuration changes to allow for operating 100% on hydrogen. CTs that were added to the system before 2040 were selected assuming a conversion cost, assuming the CT selected originally as a natural gas asset is converted to a H_2 CT.

Hydrogen-Capable Combined Cycle Power Blocks

Hydrogen-capable combined cycle power blocks ("CCs") are economically selectable by the capacity expansion model in the development of portfolios. The Companies' generic CC configurations assumption is a 2-on-1 advanced class CC unit with duct firing. CCs are well understood and operated resources by both of the utilities in each of the service territories. Like CTs, CCs also reflect efficient, advanced-class turbines that are capable of operating on a blend of natural gas and hydrogen and are better suited for conversion to 100% hydrogen capable than their F-Class CC predecessor. Additionally, these units' large size and dispatchability can continue to provide for a reliable system, especially in supporting the significant coal retirements discussed in Appendix F and integrating variable energy resources like solar and wind. Finally, due to the lower carbon content of natural gas, and the highly efficient, advanced-class machines that the Companies would likely deploy, these resources are also able to provide significant CO_2 emissions reductions.

The Companies' modeled CC resources are presented below in Table C-26 below.

Table C-26: CC Modeling Assumptions

	CC
Primary Fuel	Natural Gas
Selection Increment / Capacity (Max, Winter)	1,360 MW
Heat Rate (Max, Winter)	6,490
Dispatchability	Min Load to Max Load
Asset Life	35 Years
First Year of Eligible Selection	2029
Cumulative Addition Availability	3 Units (4,080 MW)

DEC and DEP each has its own cost assumption for intrastate natural gas FT service, which is consistent with the FT rate used for the CT options for each utility. CCs, however, are assumed to require firm interstate transportation service of natural gas to ensure supply that these units would need to operate on natural gas year-around. All CCs that are selected in the Plan, similar to CTs selected before 2040, are assumed to be converted to 100% operations on hydrogen by 2050.

While cumulative CC additions are generally limited to three total units, the availability of these resources differ by utility. The availability for these resources, based on potential fuel supply, transmission constraints or other planning factors are limited to first and subsequent selections over time. An increased resource availability for CCs was assumed for Pathway 1, which is explained in more detail in the Portfolio Development section below. The base and high availability cases for CC are presented below in Table C-27.

Table C-27: CC Cumulative Availability Modeling Assumptions (CC units)

	Base Availability			High Availability		
	DEC	DEP	CAR	DEC	DEP	CAR
2024-2028	0	0	0	0	0	0
2029	0	1	1	0	1	1
2030	0	2	2	1	2	2
2031	2	2	3	2	2	4
2032+	3	2	3	3	2	4

Onshore Wind

Onshore wind is a selectable resource, as shown below in Table C-28. The Companies developed wind resource profiles for DEC and DEP based on a siting potential study completed using average annual wind speed data from multiple locations within each service territory. The siting study is discussed further in Appendix I. The development of onshore wind faces potential planning challenges as limited integration of onshore wind resources have come to the Carolinas. The implementation of this resource provides a valuable resource diversity that could provide a complementary generation profile to solar.

The Companies modeled DEC and DEP onshore wind resources are presented below in Table C-28 below.

Table C-28: Onshore Wind Modeling Assumptions

	DEC Onshore Wind	DEP Onshore Wind
Fuel	N/A	N/A
Selection Increment	150 MW	150 MW
Capacity Factor	~19%	~27%
Dispatchability	Fully Curtailable Down	Fully Curtailable Down
Asset Life	30 Years	30 years
First Year of Eligible Selection	2031	2031

Onshore wind, like solar, has less than 100% of its nameplate capacity that contributes to firm winter planning capacity. ELCCs for onshore wind were developed as part of the Wind ELCC study as discussed earlier in this Appendix. Onshore wind has differing capacity factors based on DEC and DEP service territory siting. As such these resources have different capacity factors when selected and sited in a particular utility's service territory.

Base and high resource availability assumptions allow for the first 300 MW of onshore wind to be selected in 2031, with the annual availability thereafter increasing to 450 MW per year. The low resource availability assumption allows for only 150 MW of onshore wind to be selected annually through the planning horizon. These annual resource availabilities are combined between the Companies. The cumulative limits by utility and by high and low resource availability change. Table C-29 below shows the cumulative availability of onshore wind for each of the three assumptions.

Table C-29: Onshore Wind Cumulative Availability Modeling Assumptions

	Base / Low Availability			High Availability		
	DEC	DEP	CAR	DEC	DEP	CAR
Cumulative Availability	600	1,650	2,250	1,200	3,300	4,500

Offshore Wind

Offshore wind is a selectable resource as shown in Table C-30 below. Due to its location off the Carolinas coast, this resource is only available for DEP to select. Characteristics for each of the different project size options for the model to select is based on the offshore wind non-binding request for Information ("RFI") completed as part of the NCUC directed evaluation of the three wind energy areas ("WEAs") off the coast of North Carolina ("WEA Evaluation") and performed by the Companies. Developer-provided information gathered and anonymized by an independent evaluator, DNV, was used by the Companies to create generic offshore wind generation projects (800 MW, 1600 MW, and 2400 MW) that did not show preference for certain parcels, but rather used the project size, timing, and representative project costs and energy production estimates provided by the developers. These generalized results from the WEA Evaluation informed the offshore wind modeling inputs. The costs of offshore wind include the offshore wind turbines and offshore infrastructure along with the costs for transmitting the energy from the offshore wind facility to a DEP service territory interconnection point.

The modeled DEP offshore wind resources are presented below in Table C-30 below. For modeling purposes, the Companies allow the model to select one option from the "First Tranche" offshore wind options. The offshore wind available for selection in the early to mid-2030s, was input as three mutually exclusive project options. The model could select an 800 MW, 1,600 MW, or 2,400 MW project from this First Tranche, (or none of these), but could not select more than one of these individual project First Tranche options. Each project in the First Tranche captures genericized data resulting in the specific input for each size project, correlated to the costs of each project, including transmission costs as described below. Beyond the First Tranche of available offshore wind resources, the offshore wind was available to be selected in 800 MW increments as a simplifying assumption.

Table C-30: Onshore Wind Modeling Assumptions

	First Tranche – 800 MW Option	First Tranche – 1,600 MW Option	First Tranche – 2,400 MW Option	Future Offshore Wind
Fuel	N/A	N/A	N/A	N/A
Build Increments	800 MW	1,600 MW	2,400 MW	800 MW
Capacity Factor	~40-41%	~40-41%	~40-41%	~40-41%
Assumed Location	Non-specific Offshore Carolinas	Non-specific Offshore Carolinas	Non-specific Offshore Carolinas	Non-specific Offshore Carolinas
Dispatchability	Fully Curtailable Down	Fully Curtailable Down	Fully Curtailable Down	Fully Curtailable Down
Asset Life	30 Years	30 Years	30 Years	30 Years
First Year of Eligible Selection	2032	2032	2032	2040

The Plan assumes a 2032 availability timeline for the first offshore wind resources for the Carolinas. While there are potential offshore wind lease areas and wind energy areas off the coast of the Carolinas, uncertainty in development of projects and the necessary transmission system upgrades prevent earlier integration under the base planning assumptions. A unique challenge of the Carolinas prospect of integrating offshore wind, compared to those of the Northeast and Mid-Atlantic, is that the major load centers in the Carolinas are much further inland, which requires adequate transmission to transport the energy from the coast to where customers' energy needs are most significant, when integrated in high volumes. Each of the three First Tranche offshore wind options has its own specific transmission cost with respect to the amount of transmission network upgrade costs that are required to interconnect each project size. As described in Appendix I and Appendix L, these projects can take many years to permit and construct, making earlier integration a challenge.

Due to uncertainty with future development of offshore wind, and availability of offshore wind lease areas, the Companies base planning assumes one 800 MW Tranche of offshore wind is available starting in 2032 increasing to 2,400 MW by 2034 with additional offshore wind capacity available beginning in the early 2040s. Table C-31 below provides the maximum cumulative availability of offshore wind available for economic selection.

Table C-31: Offshore Wind Cumulative Availability Modeling Assumptions (MW)

	Base Resource Availability	High Resource Availability
2024-2029	0	0
2030	0	800
2031	0	800
2032	800	2,400
2033	1,600	3,200
2034	2,400	3,200
2035	2,400	4,800
2036	2,400	4,800
2037	2,400	4,800
2038	2,400	4,800
2039	2,400	4,800
2040	3,200	5,600
2041	4,800	6,400
2042	4,800	7,200
2043	4,800	7,200
2044	4,800	7,200
2045	4,800	7,200
2046	4,800	7,200
2047	4,800	7,200
2048	5,600	7,200
2049	7,200	7,200
2050	7,200	7,200

Advanced Nuclear - Small Modular and Advanced Reactors

For the Plan, the Companies assume two different types of advanced nuclear resources will be available for achieving carbon neutrality by 2050. The first nuclear resource available for model selection is small modular reactor ("SMR") nuclear. These resources present the ability to provide the system with bulk, dispatchable carbon-free energy by the mid-2030s. Their modular design allows for advanced manufacturing and construction, allowing for lower cost nuclear resources relative to the existing fleet and large new reactors. The technology relies on water as the reactor coolant, which is similar to the technology of the rest of the existing DEC and DEP nuclear fleets, but with significant advancements in passive safety features.

The second nuclear technology assumed for the Plan is Advanced Reactors with Integrated Storage ("AR"). These advanced reactors use a non-water coolant (potentially high temperature gas or molten salt, for example), which allows for efficiency gains compared to the SMR light-water reactors.

Furthermore, the integrated thermal storage allows for increased peaking capacity and flexibility to reduce the output of the site without changes to the reactor output, providing flexibility and longer-duration and more efficient storage options for the system.

The Companies modeled advanced nuclear resources available for selection in the model are presented below in table C-32 below.

Table C-32: Nuclear Modeling Assumptions

	SMR	AR
Fuel	Nuclear Fuel	Nuclear Fuel
Max Capacity	300 MW	450 MW (300 MW base output and 150 MW peaking capacity output)
Heat Rate (Max, Winter)	10,551	8,441
Dispatchability	Dispatchability between Min and Max Capacity	Dispatchability between Min and Max Capacity
Asset Life	60 Years	60 years

Due to the different stages of research, development, demonstration, and large-scale deployment, the availability of these resources for future integration into the DEC and DEP systems differ. SMRs are modeled as first available for selection starting in 2035 and Advanced Nuclear with Integrated Storage starting in 2038, under base planning assumptions.

The model allows for the first advanced SMR nuclear unit to be selected in 2035. The Companies are planning for the first SMR nuclear unit online by beginning of 2034, but not explicitly counting on that nuclear unit to be available until 2035. Additionally in 2035, a second unit is available, assumed to be the first unit at a second site. This timing generally aligns the potential commercial operation dates of the first advanced nuclear units in DEC and DEP service territories, as discussed in more detail in Appendix J. On a long-term basis, the Companies considered time between units at the same site, staggering the development between starting new sites, and how many total advanced nuclear sites can be in development simultaneously to develop these availability assumptions. The low resource availability assumption delays the timing of the first advanced nuclear availability and the time between starting on new sites and is used in a Portfolio Variant as discussed below. The high resource availability case assumes the same execution timeline for the first SMR, however, counts on the resource being available to the system in 2034 when assessing the total resources needed to achieve the Interim Target. Thereafter, the stagger between the first unit at a new site is accelerated relative to the base case, allowing for an increase in the total cumulative advanced nuclear units available to the system by 2050. The availability of AR also varies among the availability assumptions. The model can select between SMR and AR through the planning horizon based on the allowable cumulative number of units, the number of assumed sites that are able to be developed simultaneously in each scenario and the associated staggered timelines for new resources as discussed.

Table C-33 below provides the cumulative unit availability of advanced nuclear units through 2050 for the three resource availability assumptions discussed above.

Table C-33: Advanced Nuclear Cumulative Availability Modeling Assumptions (MW)

	Base Availability			Low Availability			High Availability		
	SMR	AR	Total	SMR	AR	Total	SMR	AR	Total
2024-2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	1	0	1
2035	2	0	2	0	0	0	2	0	2
2036	3	0	3	0	0	0	4	0	4
2037	6	0	6	1	0	1	7	1	7
2038	9	1	9	3	0	3	10	2	10
2039	10	1	10	3	0	3	13	3	13
2040	15	3	15	6	0	6	17	5	17
2041	19	5	19	10	1	10	20	6	20
2042	20	5	20	10	1	10	23	7	23
2043	24	7	24	15	3	15	26	9	26
2044	27	9	27	20	5	20	28	10	28
2045	27	9	27	20	5	20	29	11	29
2046	29	11	29	24	7	24	30	12	30
2047	31	13	31	27	9	27	32	14	32
2048	33	15	33	27	9	27	34	16	34
2049	34	16	34	30	12	30	37	19	37
2050	38	20	38	31	13	31	40	22	40

Transmission Costs

The Resource Plan modeling includes two types of transmission costs. First, consistent with previous IRPs, a generic cost for interconnection facilities is factored into the cost of each generation resource, which accounts for the cost to interconnect the resource to the grid. Second, the Companies have also developed and included generic transmission network upgrade costs for all resources. This cost adder is a proxy for upgrading the transmission network for the reliable transmission of power from the resource into the networked transmission system.

Where applicable, generator interconnection study results from completed studies or results from the ongoing 2022 DISIS Phase 1 Cluster study were used to inform the transmission network upgrade proxy costs used in the modeling. New gas and nuclear resources were assigned the same transmission network upgrade proxy cost, representing costs associated with centralized generation facilities in each service territory. Transmission network upgrade proxy costs for offshore wind are provided in tranches to represent potential transmission network upgrade cost changes associated with greater project sizes and injection of these resources. Mayo station was the only coal facility identified to require a network transmission upgrade for the retirement of this unit with most unit retirements able to do so without transmission upgrade or based on potential for replacement generation at the site. Any potential replacement resources at Mayo would still require some network transmission upgrade to facilitate the retirement. DEC and DEP-specific proxy transmission costs were developed for each resource as presented in Table C-34 below.

Table C-34: Generic Transmission Network Upgrade Costs (2023 $ per W)

	DEC	DEP
Solar and SPS	0.35	0.21
Standalone Batteries	0.00	0.00
CT	0.45	0.22
CC	0.45	0.22
Onshore Wind	0.27	0.16
Offshore Wind Option 1	N/A	0.48
Offshore Wind Option 2	N/A	0.84
Offshore Wind Option 3	N/A	0.65
Future Offshore Wind	N/A	0.65
Advanced Nuclear	0.45	0.22
Bad Creek	0.37	N/A
Mayo Retirement	N/A	0.07

Transmission costs are applied to each supply-side resource in the capacity expansion model. For the capacity expansion model to select (or in the case of Mayo, retire) any resource it must incur the transmission network upgrade proxy costs in addition to the interconnection facilities costs included in the generation resource cost for each resource type. Except for batteries, all selectable resources included transmission costs to ensure all resources were evaluated on an equitable basis. Batteries paired with solar were assumed to leverage the network upgrades necessary for the solar site, while standalone batteries would be optimally site to avoid additional transmission network upgrades, with the potential to defer upgrades in some cases. Costs were inflated to reflect the generation resource's in-service year and are levelized over the life of the transmission asset.

Each of these proxy transmission related costs require additional study for actual implementation and will be further updated based on new interconnection study results in future resource plans. Furthermore, based on recent transmission-related material and labor cost trends, the transmission interconnection and associated network upgrade costs may experience inflation rates higher than represented in Table C-34 in future years.

Inflation Reduction Act of 2022 and Infrastructure Investment and Jobs Act

As discussed in Chapter 2, the Infrastructure Investment and Jobs Act ("IIJA") and the IRA represent historic opportunities to invest in clean, innovative and resilient energy. The IIJA provides opportunities to apply for funding of projects that align with Duke Energy resource needs and planning objectives. Duke Energy has submitted 17 IIJA-funded applications that, if awarded, will reduce the cost of developing and deploying clean energy technologies and grid improvements.

The IRA will primarily provide tax incentives including tax credits in the form of Production Tax Credits ("PTC") and Investment Tax Credits ("ITC"). The IRA consists of a base credit and bonus credits based on meeting certain criteria. PTCs are a 10-year, inflation adjusted United States federal income tax credit for each kWh of electricity generated. ITCs are a United States federal income tax credit based on a percentage of the capital investment and can be taken immediately upon facility completion.

As discussed in Chapter 2, plan modeling assumes that stand-alone solar, wind and advanced nuclear will receive PTCs and standalone storage and pumped storage will receive ITCs. 60% of new stand-alone batteries are assumed to be sited at retired coal sites and receive the Energy Community bonus. Solar paired with storage and Advanced Nuclear (with integrated thermal storage) will receive PTC on the generating portion and ITC on the storage portions of the project. Finally, it is assumed that hydrogen commodity prices used in the Plan reflect the $3 kg/hydrogen PTC that is produced by a carbon neutral source.

Fuel Supply and Commodity Pricing

Natural Gas Price Forecast

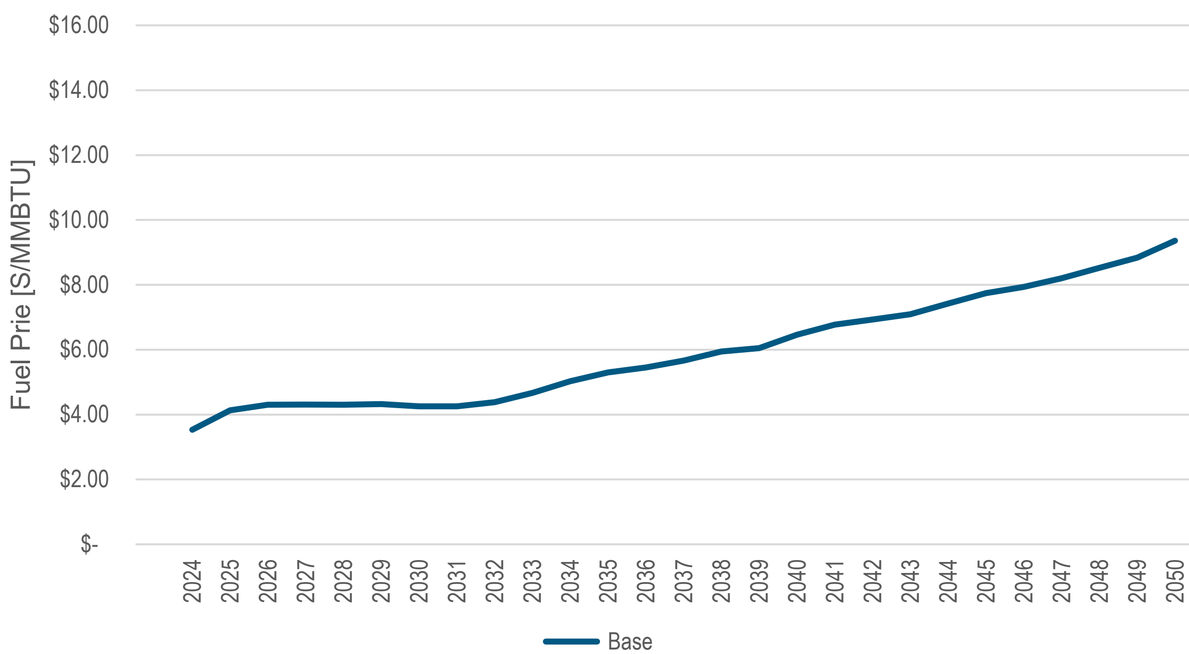
The natural gas price forecast methodology used for the Carolinas Resource Plan utilized both short-term market-based price forecasts and longer-term fundamentals-based price forecasts, as well as a transition period from market-based pricing to fundamental based pricing. The Companies' base natural gas price forecast relies upon five years of natural gas market-based pricing, followed by three years of transitioning from market-based pricing before fully utilizing fundamentals-based natural gas pricing forecast starting in 2032 for the remaining study period.

Natural gas price forecasts vary among fundamentals providers and can be significantly impacted by the assumptions made in each provider's forecast and timing of issuance. The use of a single fundamental-based natural gas price forecast has inherently more reliance on the specific assumptions used in the development of that forecast. This uncertainty of any single set of assumptions can be somewhat offset by looking at fundamental forecasts from multiple reputable fundamental forecast providers. For the purposes of the Resource Plan, the Companies developed their fundamentals-based natural gas price forecast by averaging two[8] recent natural gas Henry Hub price forecasts:

- Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") Reference Case (March 2023)
- IHS Markit Long-Term Natural Gas Outlook (February 2023)[9]

The resulting Henry Hub natural gas price forecast utilized in the Plan's modeling, consisting of the near-term market-based price forecast, the three-year transition to fundamentals-based price forecast, and finally the full fundamentals-based price forecast (an average of the price forecast of the two different fundamentals providers discussed above) is shown below in Figure C-3.

Figure C-3: Base Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



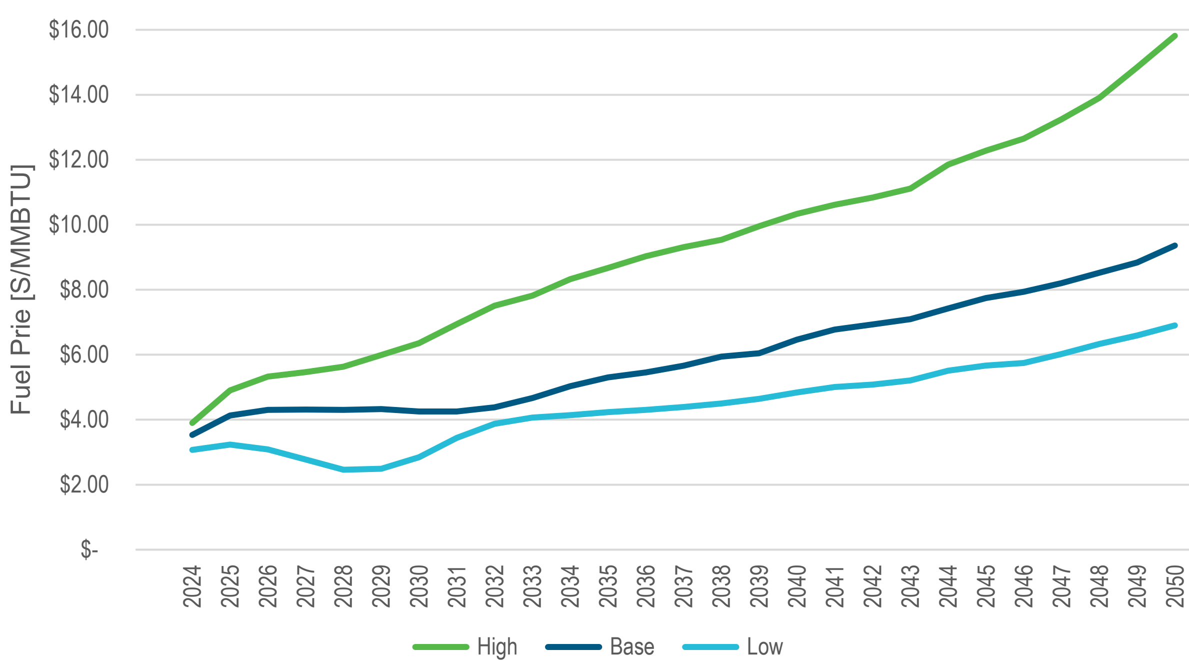
[8] Long-term fundamentals-based price forecasts by providers Wood Mackenzie and EVA, which were averaged with the EIA and IHS-Markit forecasts in developing the initial 2022 proposed Carbon Plan and the 2022 SC IRP Update, were not used in developing the 2023 Plan. The most recent forecasts available from these vendors at the time of Plan development were from June 2022 and September 2022 respectively. By filing these forecasts would be a year or more old and it was concluded that their market views are too outdated for use in upcoming regulatory filings.

[9] IHS Markit Long-Term Natural Gas Outlook (February 2023) was published by IHS Markit. However, IHS Markit has since merged with S&P Global.

Alternate Natural Gas Price Forecasts

To further quantify the impacts on resource selection, cost to the system, and achievement of emissions reduction targets, the modeling also uses high natural gas price forecasts and low natural gas price forecasts as sensitivities in the modeling. These high and low natural gas price forecasts were developed starting with the Companies' base natural gas price forecast. From there, the Companies developed high and low market price forecasts using statistical analysis of volatility representing 25th and 75th percentile probabilities. Additionally, the fundamentals-based price forecast used in the base assumptions was increased and decreased using the EIA's AEO "side cases." As part of the AEO, the EIA also develops side cases to capture uncertainty of specific impactful variables on the energy consumption and commodity prices in its forecast. The Companies applied the ratio between Low Oil and Gas Supply and High Oil and Gas Supply-side cases to the AEO Reference Case, to its base fundamentals-based natural gas price forecast to develop high and low long-term natural gas price forecasts, respectively. These high and low market curves were blended with the high and low fundamentals curves to create the high and low natural gas prices forecasts. Figure C-4 below shows the resulting high and low natural gas prices forecasts compared to the Companies' base forecast.

Figure C-4: High, Base and Low Henry Hub Natural Gas Price Forecasts (Nominal $/MMBtu)



The Companies also developed a second natural gas price forecast. The additional forecast uses the same base assumptions for near-term natural gas prices based on market prices and long-term prices based on an average of two different fundamentals-based price forecasts (EIA AEO and IHS). The period of the forecast using market prices is shortened to eighteen months and transitions from market-based pricing to fundamentals-based natural gas price forecasts over the next eighteen months, before fully using the fundamentals-based price forecast beginning in year four of the forecast (beginning at the start of 2027). This natural gas price forecast is utilized in the SC Battery and Gas Supplemental Portfolio.

Natural Gas Fuel Supply Assumptions

The Plan recognizes the significant impact that fuel supply availability and cost assumptions can have on the modeled cost of the system and the selection of resources, specifically in relation to natural gas supply from the Appalachia region via Mountain Valley Pipeline (“MVP”). Natural gas fuel supply in the Plan refers to obtaining interstate FT capacity to support the existing CC fleet’s needs (taking into account current firm supply from the Gulf Coast) and allowing for incremental generation gas supply. Because there is some uncertainty on how incremental natural gas supply to the DEC and DEP service territories will ultimately materialize, the Companies have developed a base fuel supply assumption and an alternate fuel supply sensitivity for the Plan. The project scope and in-service date of any additional interstate FT capacity accessible to the Carolinas region is not fully within the control of DEC and DEP. Thus, for modeling purposes, the Companies are evaluating multiple possible natural gas interstate transportation assumptions. See Appendix K for more details about natural gas firm transportation.

Base Fuel Supply Assumption – Gulf Coast Natural Gas Supply

The Companies’ base fuel supply assumptions for the modeling assumes that DEC and DEP do not receive access to any lower priced commodity gas due to uncertainty around competition of MVP and access to Appalachian gas or discounted Zone 5 gas. To account for potential physical and economic constraints of natural gas to the Companies’ service territories, the Companies limit operations of some generation units to coal and ULSD during times of potentially limited supply and price volatility.

Alternate Fuel Supply Sensitivity – Mountain Valley Pipeline Natural Gas Supply

The Companies also developed an alternate fuel supply case which assumes MVP is completed. In this alternative fuel supply sensitivity, the Companies obtain access to lower cost Appalachian gas and discounted Zone 5 gas. Natural gas from this Appalachian region typically trades at a discount relative to Transco Zone 5, the Carolinas region’s main pricing index, and the Companies assume in the modeling that incremental pipeline transportation will likely result in less price volatility in the Transco Zone 5 delivered price based on the diversity and increased volumes available to the region. The incremental Appalachian gas supply allows for supply diversity, increased fuel assurance, decreased customer fuel cost volatility exposure, and reliable incremental resource deployment of CC capacity to enable timely retirements of coal assets.

Coal Price Forecast

The Resource Plan assumes five years of market coal prices, and over the next three years blends to a fundamental-based price forecast, consistent with the process to develop the base natural gas price forecasts. Beginning in 2032 the coal price forecast fully utilizes the fundamentals-based price forecast for coal. Significant uncertainty persists including commodity production, transportation rates, and potential regulation on mining of and generation from coal. While the price forecast reflects increases in commodity and transportation costs into the future, the true uncertainty of how the coal market will wind down, and the effects of that transition on the cost and availability of coal, is highly speculative. See Appendix F for more information on the current state and challenges in coal supply and transportation.

Hydrogen

As a base planning assumption, the Plan assumes that hydrogen fuel will be available and used to generate electricity for the system in the future. Hydrogen fuel is assumed to be used in three ways. First, starting in 2035, a small amount of hydrogen (1% by volume, ~0.33% by heat content) is assumed to be blended into the natural gas supply for all resources using natural gas, including CCs, CTs, and natural gas co-fired coal units that are still on the system in 2035. Though in relatively small volumes, the blending of hydrogen into natural gas supply impacts both the price of the now blended fuel, and the carbon content, even if minimally impactful to overall price and CO_2 emissions. This is to represent the likelihood of hydrogen or other low-carbon fuels being introduced into the gas supply of the system over the next two decades. Over time the amount of hydrogen blended into the natural gas fuel supply grows modestly to 2% by volume (~0.67% by heat content) by 2038 and to 3% by volume (~1% by heat content) by 2041 but remains a very small fraction of total fuel supply in the pipelines.

Starting in 2040, the model can select new CTs that operate exclusively on hydrogen. The fuel is assumed to be available via a clean hydrogen market price with supporting hydrogen infrastructure that develops over the next fifteen years. The clean hydrogen is assumed to be produced from non-carbon emitting means, such as from electrolysis with surplus clean energy from renewables or nuclear generation. This hydrogen price forecast reflects anticipated economies of scale and cost declines of the technologies to produce hydrogen and the availability of low-cost energy from carbon-free resources. While the model is not required to select these units, the model does have the option to, as a proxy for future carbon-free peaking resources and assumes the hydrogen fuel is available at sufficient volumes for these peaking resources in this time frame.

By 2050, the Companies assume some of the existing and all of the new CCs and CTs selected over the planning horizon will be converted to operate exclusively on hydrogen. These resources are assumed to be fueled by the clean hydrogen market discussed above.

Supply of hydrogen carries a significant uncertainty, particularly for substantial quantities prior to 2040. There are initiatives and funding for the development of hydrogen supply hubs across the United States. While the ultimate realization of a hydrogen hub in the Carolinas is uncertain, the hydrogen economy is viewed by the Companies as an evolving potential breakthrough technology that can contribute to achieving national economy-wide CO_2 emissions reductions. Resource portfolios that are robust enough to produce hydrogen in times of excess electricity supply could be an added benefit and risk mitigation factor. More discussion on hydrogen and low-carbon fuels is included in Appendix K.

Portfolio Development

As described in Chapter 2, the Resource Plan modeled three Energy Transition Pathways. Each Pathway has multiple portfolios that achieve the Pathway's pace of energy transition. Under each Pathway is a Core Portfolio, that is developed using base planning assumptions (P1 Base, P2 Base and P3 Base) across the three Pathways, with the exception of the resource availability assumptions used to develop P1 Base, the Core Portfolio corresponding to Pathway 1. P1 Base, which targets 70% CO_2 emissions reductions by 2030, requires higher resource availability than even the amounts used to develop the high resource availability Portfolio Variants as described below.

Each Pathway also has Portfolio Variants, which are developed by changing one or more inputs or assumptions, allowing or forcing a different mix of resources to achieve the pace of transition for the Pathway. The Portfolio Variants evaluated the significance of specific variables in resource selection and provide a thorough assessment of the risks and potential opportunities that could be realized in the future. In addition to the extensive portfolio analysis through Core Portfolio and Portfolio Variant development, the Companies developed 10 additional Sensitivity Analysis Portfolios derived from the P3 Base in which certain inputs or assumptions were changed from the assumptions used to create the Portfolio Variants. Finally, the Companies developed Supplemental Portfolios. These portfolios assessed additional portfolio impacts intended for informational purposes.

To develop each of these portfolios, the Companies followed the same modeling approach with some steps in the analytical process applying to only certain types of portfolios. Those specific steps and the modeling results of the portfolios are described and presented below.

Coal Retirement Analysis

The first step in developing portfolios is to develop retirement schedules for each Energy Transition Pathway (and a no carbon constraints scenario). Each portfolio uses the Energy Transition Pathways retirement schedule for its particular pathway. The modeling and analysis conducted to establish these retirement schedules is discussed in detail in Appendix F. A summary of the results is presented below in Table C-35 below.

Table C-35: Coal Unit Retirements (effective by January 1 of year shown)

Unit	Utility	Winter Capacity (MW)	Effective Year by Pathway (Jan 1)			
			Pathway 1	Pathway 2	Pathway 3	No Carbon Constraints
Allen 1[1]	DEC	167	2025	2025	2025	2025
Allen 5[1]	DEC	259	2025	2025	2025	2025
Belews Creek 1	DEC	1,110	2030	2036	2036	2036
Belews Creek 2	DEC	1,110	2030	2036	2036	2036
Cliffside 5	DEC	546	2029	2031	2031	2033
Cliffside 6[2]	DEC	849	2049	2049	2049	2049
Marshall 1	DEC	380	2029	2029	2029	2029
Marshall 2	DEC	380	2029	2029	2029	2029
Marshall 3	DEC	658	2034	2032	2032	2035
Marshall 4	DEC	660	2034	2032	2032	2035
Mayo 1	DEP	713	2029	2031	2031	2036
Roxboro 1	DEP	380	2029	2029	2029	2029
Roxboro 2	DEP	673	2029	2029	2029	2029
Roxboro 3	DEP	698	2030	2033	2034	2034
Roxboro 4	DEP	711	2030	2033	2034	2034

Note 1 : Allen 1 & 5 retirements are planned by December 31, 2024. Retirements were not included in the Coal Retirement Analysis due to near term planned retirement dates.
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.

Capacity Expansion Modeling

Once coal unit retirement dates have been determined, resource portfolios are then optimized in the capacity expansion model utilizing the final retirements established in the coal retirement analysis for each Pathway. As discussed previously in this Chapter, the capacity expansion model seeks to develop a portfolio of resources that will minimize overall system costs inclusive of capital costs for new resources as well as ongoing operation, maintenance and fuel costs of the system. The capacity expansion model achieves this by examining numerous permutations of possible resource options that meet system reliability and carbon emissions reductions targets for each portfolio. Given the vast number of resource options examined in this phase of the analysis, the capacity expansion model uses a simplified, average representation of hourly system demand to screen for the optimal resource portfolio. For this reason, the portfolios are considered preliminary. The Core Portfolios are considered final after completion of the Reliability Verification step.

The following sections discuss the development of each portfolio under each Pathway and summarizes the preliminary resource additions and retirements from the capacity expansion modeling.[10]

Capacity Expansion Portfolio Development - Pathway 1

Pathway 1 consists of two portfolios: one Core Portfolio for the pathway achieving the Interim Target by 2030 with base planning assumptions and one Portfolio Variant which assesses the changes to the Core Portfolio assuming Belews Creek is converted to run on 100% natural gas. Each portfolio and the assumptions under which the portfolios were developed is discussed in detail below.

Core Portfolio P1 Base

This Energy Transition Pathway targets achieving the Interim Target by 2030. Portfolios in this Pathway cannot achieve the Interim Target without replacing base assumptions with highly aggressive execution assumptions related to resource availability in both timing and amounts, which would logically result in higher cost and with increased reliability risk to achieve a 70% CO_2 reduction by 2030. Specifically, this Pathway increases the solar available for selection to 1800 MW in 2028 and then increases well beyond the High Resource Availability assumption to 2,400 MW per year thereafter, representing an increase of 450 to 1,050 MW of solar per year above base assumptions. Onshore wind, which was is not available until 2031 in the base resource availability assumption for the technology, is assumed to accelerate to 300 MW available by 2030 for Pathway 1 to help in achieving the Interim Target by 2030, but does not increase the total cumulative availability for onshore wind over the planning horizon. Likewise, 1.6 gigawatts (“GW”) of offshore wind is assumed to be available to the system by 2030, significantly ahead of the base availability assumption for this volume of offshore wind and the associated transmission system upgrades. Finally, for additional resources to meet the Interim Target by 2030, the model was allowed to select up to four hydrogen-capable CCs by 2030, exceeding both the total number of CCs available by 2030 and cumulatively over the planning horizon in the base assumptions. Battery and CT availabilities were not increased, as those base resource availabilities were already sufficiently high.

Table C-36 below presents the preliminary resource additions and retirements for Portfolio P1 Base identified by the capacity expansion model.

[10] Resource additions and retirements are shown below are on a beginning of year basis (“BOY”). This assume all resources are retired or first available to serve energy and capacity needs for the system beginning January 1 for the entire year. Capacities reflected are nameplate/winter max capacity. Resource changes reflected are incremental resources selected in the Portfolio Development step of the analytical process and in addition to forecasted resources, as discussed previously in this Appendix.

Table C-36: P1 Base – Preliminary Resource Additions and Retirements (MW) for Interim Target Achievement in 2030

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
DEC	-3,952	2,700	1,720	1,360	1,700	0	0	0	0
DEP	-3,175	3,900	3,380	1,360	0	300	0	0	1,600
CAR	-7,127	6,600	5,100	2,720	1,700	300	0	0	1,600

For P1 Base, the model adds 6.6 GW of solar by 2030 to achieve the Interim Target, selecting all available solar capacity in this portfolio by 2030 (1,800 MW for 2028 and 2,400 MW for 2029 and 2030). This is in addition to the forecasted solar described previously in this Appendix. The solar additions for this portfolio bring the system nameplate solar capacity to 14.1 GW as of the start of the 2030 interim target year. P1 Base additionally selects all of the 300 MW of onshore wind available by 2030, based on the accelerated availability of this resource for the Pathway. Finally, 1,600 MW of offshore wind was assumed available by 2030 in this Pathway and was selected to meet the Interim Target by 2030.

To support these variable energy resources, 5.1 GW of batteries, combined between standalone batteries and batteries paired with solar, are selected by 2030. In addition to the battery capacity supporting variable energy renewables, 2.7 GW of CC capacity and 1.7 GW of CT capacity is also selected, providing additional emissions reductions, firm capacity, and overall system flexibility to backstand the variable energy renewables. The assumption that such rapid additions of these capacity resources would be possible also allows the model to retire 7.1 GW of coal capacity by 2030. The coal retirements represent all subcritical coal remaining on the Carolinas system as well as the Belews Creek supercritical coal plant, leaving Marshall units 3 and 4, and Cliffside 6, as the only remaining coal capacity on the system, co-fired with natural gas with increased flexibility and lower carbon emissions.

Overall, this portfolio includes significant amounts of solar, onshore and offshore wind, storage, and gas, deployed at a very rapid pace to achieve the Interim Target and meet the energy and capacity needs of the system by 2030.

Portfolio Variant P1 Belews Creek 100% Gas Conversion

As a part of Energy Transition Pathway 1, this Portfolio Variant, P1 BC Gas, evaluates the impacts to the portfolio of converting Belews Creek to operate exclusively on natural gas and delaying retirement of the 2,220 MW station to 2040. Each of the Belews Creek units are capable of operating on up to 50% natural gas at full load. This Portfolio Variant assumes both Belews Creek units are converted to operate exclusively on natural gas at the full station output of 2,220 MW beginning in 2030 to help meet the Interim Target in that year. This Portfolio Variant also assumes extending the life of the asset through 2040 as a bridge to a time when the Companies could bring fully hydrogen-fired CT or CC generating units online. This would be an alternative to investing in new natural gas generating units in the near term and then later incurring costs to convert those units to a zero-carbon fuel source.

The development of this portfolio, including the Portfolio Variant with the Belews Creek conversion and delayed retirement, has relatively minor impacts on the selection of resources through achieving the Interim Target. Delaying the retirement of Belews Creek from 2030 reduces CT additions by 425 MW. The delay also allows the portfolio to avoid an incremental offshore wind unit selected in P1 Base in 2033 in favor of incremental solar and battery.

The re-optimization of the portfolio also comes with additional costs to extend the life of the unit, convert the unit to 100% operation on natural gas, and secure firm natural gas transportation service. The increase in firm natural gas transportation service was a major driver impacting the cost effectiveness of this option. More information on the implications of this portfolio is discussed in the PVRR section of this Appendix and in Appendix K.

Pathway 1 Portfolio Variant Resource Summary through 2030

The Portfolio Development results for the Portfolio Variant discussed above is shown in Table C-37 below relative to P1 Base through the year that the Interim Target is achieved.

Table C-37: P1 Portfolio Variants Cumulative Resource Changes relative to P1 Base through 2030 (MW)

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P1 Base	-7,127	6,600	5,100	2,720	1,700	300	0	0	1,600
∆ P1 Belews Creek Gas	2,220	0	-20	0	-425	0	0	0	0

Capacity Expansion Portfolio Development - Pathway 2

The Companies developed and analyzed six portfolios under Energy Transition Pathway 2: one Core Portfolio for the pathway achieving the Interim Target by 2033 with base planning assumptions and five Portfolio Variants which assess the changes to Core Portfolio with different resource availability and fuel supply assumptions. Each portfolio and the assumption under which the portfolio was developed is discussed in detail below and the changes in selection of resources relative to the Core Portfolio in this pathway through 2033 are summarized for each portfolio.

Core Portfolio P2 Base

This Energy Transition Pathway targets achieving the Interim Target by 2033. The year targeted for achieving the Interim Target is enabled by the availability of 1,600 MW of offshore wind and the associated transmission infrastructure by the beginning of 2033. The Core Portfolio for this pathway, P2 Base, was developed assuming the base resource availability described earlier in this Appendix.

Table C-38 below presents the modeled resource additions and retirements for Portfolio P2 Base identified by the capacity expansion model.

Table C-38: P2 Base - Preliminary Resource Additions and Retirements (MW) for Interim Target Achievement in 2033

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
DEC	-3,050	3,600	1,300	2,720	1,275	0	0	0	0
DEP	-3,175	5,175	4,760	1,360	850	1,200	0	0	1,600
CAR	-6,225	8,775	6,060	4,080	2,125	1,200	0	0	1,600

For P2 Base, the model adds 8.8 GW of solar by 2033 to achieve the Interim Target, selecting all available solar capacity in this portfolio through the target year (1,350 MW per year for 2028 through 2030 and 1,575 MW per year for 2031 through 2033). The solar additions for this portfolio bring the system nameplate solar capacity to 16.4 GW as of the start of the 2033. The model also selects all of 1.2 GW of onshore wind available, all in DEP, where the resource has a higher projected capacity factor. Additionally, to achieve the Interim Target in this Pathway, 1,600 MW of offshore wind was available for selection by 2033 and the full available amount was selected to meet the needs of the system. The two 800 MW blocks of offshore wind selected in this portfolio represent the earliest base case availability for this technology.

To support these variable energy resources, 6.0 GW of batteries, combined between standalone batteries and batteries paired with solar, are selected by 2033. In addition to the battery capacity supporting variable energy renewables, 4.1 GW of CC capacity and 2.1 GW of CT capacity is also selected, providing additional emissions reductions, firm capacity, and overall system flexibility to backstand the variable renewable energy added to the system. These capacity resources also support the retirement of 6.2 GW of coal capacity, enabled by the significant addition of energy and capacity resources to meet the Interim Target. The coal unit retirements represent a significant portion of the coal capacity currently remaining on the Carolinas system, with all of the remaining coal capacity on the system after 2033 being able to be co-fired with natural gas to increase flexibility and lower carbon emissions. These resource additions allow the remaining coal only units to run sparingly throughout the year and with low annual capacity factors.

Overall, P2 Base includes significant additions of solar, onshore wind, storage, and gas resources, in addition to 1,600 MW of offshore wind, to achieve the Interim Target and meet the energy and capacity needs of the system by 2033.

Portfolio Variant P2 High Resource Availability

The High Resource Availability Portfolio Variant assumes increased availability of resources on either an annual or cumulative basis, or in terms of accelerated availability, or a combination of all three. The high resource availabilities for each portfolio are described in more detail in each technology's resource availability section.

P2 High Availability continues to target 2033 for the Interim Target with the availability of 1.6 GW of offshore wind. Annual solar availability increases in this case starting in 2029, and the model selects 9.8 GW of solar through 2033, nearly the maximum available and an increase of 1.1 GW of solar cumulatively relative to P2 Base to that point. With the additional solar, the portfolio requires fewer battery resources to time shift low-carbon energy and achieve the Interim Target, lowering the total amount of storage by 1.7 GW through 2033. By 2038, the model can further take advantage of 1.2 GW of incremental onshore wind, selecting more in DEP and offsetting some of the lower capacity factor onshore wind selected in DEC. Finally, with the increased resource availability for nuclear, the model selects the first SMR on the accelerated timeline in 2034 relative to the base resource availability assumption of the first two SMR units being available in 2035. This portfolio also takes advantage of 300 MW (1 unit) of additional nuclear by 2038. For this portfolio, the model selected the same 1.6 GW of offshore wind as P2 Base by 2033.

Portfolio Variant P2 Low Solar Availability

This Portfolio Variant, P2 Low Solar, shows how the portfolio changes with low solar availability. Several potential challenges face the industry in continued and cost-effectively sustained solar project development and interconnection, especially at the levels required to meet the growing energy needs of the Carolinas systems. This portfolio limits the selection of solar to 1,350 MW per year, a slight reduction from the 1,575 MW per year from 2031 and onward in the base assumptions, and reoptimizes the portfolio of resources. More discussion about the challenges with solar development and interconnection are discussed in Appendix I and Appendix L.

In the P2 Base Portfolio, the model selects nearly all available solar through 2036 and a total of 14.1 GW through 2038. The low solar availability assumption in the Portfolio Variant reduces total solar to 13.7 GW through 2038, and the model selects the maximum 1,350 MW of solar available per year through 2036. To make up for the 675 MW less of solar resources by 2033 relative to P2 Base, the model adds an incremental 1.2 GW of storage to P2 Low Solar to meet the Interim Target. In 2034, the model selects an additional 800 MW block of offshore wind, bringing total offshore wind in P2 Low Solar to 2.4 GW by 2034. The model selects more solar in 2037 and 2038 than in P2 Base, but cumulative solar additions remain below the levels in the Core Portfolio in this Pathway due to the offshore wind and battery addition.

Portfolio Variant P2 Low Onshore Wind Availability

Given the extended development time for assessing onshore wind sites, securing the large parcels of land necessary to construct an onshore wind site, and permitting and community impact risks, the Companies will need to continue to check and adjust plans to accommodate a lower than projected base resource availability for onshore wind. This premise is the basis for one of this Pathway's Portfolio Variants, P2 Low Onshore. This resource availability assumption change for onshore wind keeps the base cumulative availability for onshore wind of 2.3 GW but limits the annual selection availability to 150 MW per year, with the resource's first available year remaining the same in 2031. This reoptimized resource portfolio allows the model to reselect resources to ensure the Interim Target can be met by 2033 despite the reduced wind availability. More discussion about the challenges facing deployment of onshore wind is included in Appendix I along with ways to check and adjust to remain on track for the Interim Target in Chapter 3 (Portfolios).

This Portfolio Variant includes the maximum available 450 MW of onshore wind by 2033 (down from 1,200 MW available and selected in P2 Base). The model continues to select the maximum amount of available solar, 4.1 GW of CC and 1.6 GW of offshore wind by 2033 in P2 Low Onshore, and adds an additional 1.9 GW of batteries relative to P2 Base to achieve the Interim Target in 2033. After 2033, due to continued lower onshore wind availability, model selects an additional 800 MW block of offshore wind in 2034 to remain on the trajectory to the carbon neutrality target. Overall, by 2038, the portfolio is limited to 900 MW less onshore wind than the base assumption but the model continues to select the resource as available up to the cumulative maximum limit of 1.7 GW for DEP through 2041. Finally, compared to the base assumptions, the model selects slightly less solar (225 MW) and adds 1.0 GW of cumulative batteries by 2038 and the total nuclear additions are delayed by one unit for one year.

Portfolio Variant P2 Limited Gas Availability

Constraints on potential availability to add incremental gas resources to the system may also force the Companies to adjust plans to continue to achieve the Interim Target by 2033 in this Pathway. Low gas availability may arise in several ways, including limited incremental interstate natural gas transportation or challenges with permitting and developing new gas resources. For this Portfolio Variant, the Companies prioritized CC additions in a constrained gas availability scenario. The total annual and cumulative CC constraints remained the same, but the number of peaking CT resources was limited to the two planned CT resources in DEC at Marshall Station. The portfolio was reoptimized based on this total limit on CTs.

The re-optimization of this portfolio had a significant impact on the front end of the resource portfolio. P2 Base selected 2.1 GW of CT capacity in 2029 to meet planning reserve margin requirements, while for this portfolio, limited by CT availability, the model selected only 850 MW of CT in DEC in 2029 and replaced the remaining CT capacity selected in P2 Base with 800 MW of batteries. By 2033, the gap is reduced to 680 MW incremental batteries over P2 Base, reflecting the fact that battery additions were accelerated to fill the capacity need in 2029, but cumulative battery additions were largely unchanged. The model continues to select the maximum cumulative available solar, onshore wind, CC, and offshore wind resources in P2 Low Onshore. By 2038, the portfolio has little variance other than CT capacity from the cumulative resource selections in P2 Base with 300 MW more of solar, 300 MW less of onshore wind, and only 60 MW more of batteries.

Portfolio Variant P2 MVP Fuel Supply

The final Portfolio Variant considered under Pathway 2 is a natural gas supply availability alternative. Future supply of natural gas to the Carolinas remains an important factor in resource planning. As of the date the Resource Plan was developed, MVP was not in service. Given the uncertainty around MVP coming into service and the timing, the Companies developed the Core Portfolios for all three Pathways assuming that additional natural gas supply would only be available from the Gulf Coast region and that Appalachian gas would not become available in the Carolinas. To capture the benefits of a diversified natural gas supply from the Appalachia region to the Carolinas, which would supplement existing Gulf Coast supply and support reliable growth and replacement capacity, the Companies developed Portfolio Variants to evaluate how the completion of the Mountain Valley Pipeline could affect the Resource Plan.

Through 2033, P2 MVP is largely the same as P2 Base with only 600 MW more of battery selected by 2033, continuing to select 4.1 GW of CC, 2.1 GW of CT, 1.6 MW of offshore wind, 1.2 GW of onshore wind and 8.8 GW of solar. Similarly, by 2038, the model selects only 150 MW more of solar, 300 MW less of onshore wind and 120 MW less of batteries. While the resource changes are not significant in this Portfolio Variant, PVRR changes in P2 MVP reflect significant savings for customers if MVP achieves commercial operation, which is discussed in more detail in the Performance Analysis section later in this Appendix.

Pathway 2 Portfolio Variant Resource Summary through 2033

The Portfolio Development results for the Pathway 2 Portfolio Variants discussed above are presented in Table C-39 below relative to P2 Base through the year that the Interim Target is achieved.

Table C-39: P2 Portfolio Variants Cumulative Resource Changes relative to P2 Base through 2033 (MW)

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P2 Base	-6,225	8,775	6,060	4,080	2,125	1,200	0	0	1,600
∆ P2 High Availability	0	1,050	-1,740	0	0	0	0	0	0
∆ P2 Low Solar	0	-675	1,220	0	0	0	0	0	0
∆ P2 Low Onshore	0	0	1,920	0	0	-750	0	0	0
∆ P2 Limited Gas	0	0	680	0	-1,275	0	0	0	0
∆ P2 MVP	0	0	600	0	0	0	0	0	0

Capacity Expansion Portfolio Development - Pathway 3

The Companies developed and analyzed 18 portfolios under Energy Transition Pathway 3: one Core Portfolio for the pathway achieving the Interim Target by 2035 using base planning assumptions, seven Portfolio Variants which assess changes to the Core Portfolio based upon differing resource availability and fuel supply assumptions, and 10 Sensitivity Analysis Portfolios which assess changes to the Core portfolio based upon differing assumptions and inputs beyond supply-side resource availability and fuel supply. Each portfolio and the assumption under which the portfolio was developed is discussed in detail below along with the changes in selection of resources relative to P3 Base through 2035.

Core Portfolio P3 Base

Energy Transition Pathway 3 targets achieving the Interim Target by 2035. The year targeted for achieving the Interim Target is consistent with the year the Companies are planning for the first advanced SMR units to be deployed. Pathway 3 relies on two SMRs totaling 600 MW to achieve the Interim Target. The Core Portfolio for this pathway, P3 Base, was developed assuming the base resource availability described earlier in this Appendix. The details are shown below in Table C-40.

Table C-40: P3 Base - Preliminary Resource Additions and Retirements (MW) for Interim Target Achievement in 2035

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
DEC	-3,050	4,950	2,140	1,360	1,275	450	1,680	600	0
DEP	-3,175	6,975	2,120	2,720	850	1,650	0	0	0
CAR	-6,225	11,925	4,260	4,080	2,125	2,100	1,680	600	0

In P3 Base, the model adds 11.9 GW of solar by 2035 to achieve the Interim Target, selecting all available solar capacity in this portfolio through the target year (1,350 MW per year in 2028 through 2030 and 1,575 MW per year in 2031 through 2035, in addition to the forecasted solar described previously in this Appendix). The solar additions for this portfolio bring the Companies' combined system nameplate solar capacity to 19.5 GW as of the start of the 2035. P3 Base additionally selects all of 2.1 GW of onshore wind available through 2035 (selecting the final 150 MW of available onshore wind in DEC in 2036).

To support these variable energy resources, 4.3 GW of batteries, combined between standalone batteries and batteries paired with solar, are selected by 2035. In addition to the battery capacity supporting variable renewable energy resources, 4.1 GW of CC capacity and 2.1 GW of CT capacity is also selected, providing additional emissions reductions, firm capacity, and overall system flexibility to backstand the variable renewable energy resources. These capacity resources also support the retirement of 6.2 GW of coal capacity, enabled by the significant addition of energy and capacity resources to meet the Interim Target. The coal retirements represent a significant portion of the coal currently remaining on the Carolinas system, with most of the remaining coal capacity on the system being able to be co-fired with natural gas to increase flexibility and lower carbon emissions. These resource additions allow the remaining coal only units to run sparingly throughout the year and with low annual capacity factors.

Finally, to achieve the Interim Target in this Pathway, the model selects two SMR units for a combined capacity of 600 MW of available advanced nuclear by 2035. This portfolio, using base planning assumptions and all available solar and onshore wind, can meet the Interim Target in 2035 and the needs of the system without economically selecting offshore wind. Overall, this portfolio includes significant annual sustained additions of solar, wind, storage, and gas to achieve the Interim target and meet the growing energy and capacity needs of the system by 2035. The addition of the two advanced nuclear SMRs also has a significant and material impact on achieving the Interim Target in 2035.

Portfolio Variant P3 High Resource Availability

Variants for Pathway 3 assess additional scenarios beyond those examined for Pathway 2. P3 High Availability reoptimizes the selection of resources given an increase in annual, cumulative, or accelerated integration of resources.

Higher annual limits allow the model to select an incremental 525 MW of solar by 2035. However, solar additions decline substantially relative to P3 Base starting in 2036 due to increased cumulative availabilities of onshore wind and nuclear to offset the need for additional solar. Additionally, due to the increased availability of onshore wind and advanced nuclear, the model selects one less CC unit, avoiding the last CC selected in P3 Base in 2033. By 2038, the model can further take advantage of 1.1 GW of incremental onshore wind, selecting more in DEP and offsetting some of the lower capacity factor onshore wind selected in DEC. Finally, with the increased nuclear availability, the model adds 300 MW (1 additional SMR) by 2038 relative to P3 Base.

Portfolio Variant P3 Low Solar Availability

The Portfolio Variant P3 Low Solar is designed to assess what incremental resources are needed in the event of low solar availability. This P3 Variant, similar to P2 Low Solar, limits the selection of solar to 1,350 MW per year, reoptimizing the selection of resources to adjust to the lower solar availability and continue to meet the Interim Target by 2035.

In the P3 Base Portfolio, the model selects all available solar through 2036 and a total of 14.6 GW by 2038. The low solar availability assumption in this Portfolio Variant reduces total available solar to 13.2 GW through 2038. The model selects the maximum 1,350 MW of solar available per year through 2036 but, as in P3 Base, selects less than the maximum available in 2037 and 2038. To make up the 1.2 GW less of solar resources by 2035 relative to P3 Base, for P3 Low Solar the model selects 800 MW of offshore wind in 2034 to meet the capacity and carbon-free energy needs of the system and achieve the Interim Target in 2035. This addition of offshore wind, relative to P3 Base, reduces the total selection of solar and storage through the Base Planning Period by 1.4 GW and 660 MW, respectively.

Portfolio Variant P3 Low Onshore Wind Availability

Reoptimizing the Pathway 3 Portfolio Variant with 150 MW of onshore wind available per year allows the P3 Low Onshore portfolio to adapt to the reduced carbon-free energy from onshore wind. Relative to P3 Base, for this Portfolio Variant the model selects the maximum 750 MW of onshore wind available by 2035, while continuing to maximize solar additions. The model also accelerates the selection of a CC unit from 2033 to 2031 relative to P3 Base, while continuing to select significant battery capacity and the available nuclear in 2035. Finally, the model adds 800 MW of offshore wind to fill the energy and capacity gap created by the reduction in onshore wind availability. Overall, by 2038, the portfolio is limited to 1.1 GW less of onshore wind but the model continues to select the resource as available up to the cumulative maximum limit of 1.7 GW for DEP through 2041. The addition of offshore wind also offsets 375 MW cumulative of solar by 2038.

Portfolio Variant P3 Offshore Wind by 2037

To further assess the cost and risk tradeoffs of adding offshore wind (“OSW”) later in the Base Planning Period, the Companies developed a Portfolio Variant in Pathway 3 that required the model to select offshore wind by 2037. The model was required to select at least 800 MW by 2037 and an additional 800 MW by 2038 for a total of at least 1.6 GW of offshore wind by 2038. For this portfolio, P3 OSW in ’37, the model was given the option to select the offshore wind as early as 2032 if the model found it economic to do so but was required to integrate the resource starting in 2037 at the latest. All other resource availabilities aligned to the base assumptions in P3 Base.

When required to select at least 1.6 GW of offshore wind by 2038, the model opted to select the required resource at its lowest amount and as late as possible. Through 2036, there are minimal changes to the portfolio relative to P3 Base, decreasing battery storage slightly. By 2038, however, the required addition of the 1.6 GW of offshore wind offsets 1.1 GW of incremental solar, 500 MW of batteries, and delayed an SMR one year relative to P3 Base.

Portfolio Variant P3 Delayed Nuclear Availability

While Duke Energy is the largest regulated nuclear operator and owner in the country, integration of the next generation of advanced nuclear generation carries uncertainty in timing for deployment. While the Companies look to be a close follower for the deployment of the first-of-a-kind advanced nuclear technologies, delays in advancement of the projects currently being pursued by other utilities in North America could impact the time frame for first deployment for advanced nuclear for DEC and DEP in the Carolinas. To assess the options for the Companies to check and adjust if these advanced nuclear facilities are delayed, the P3 SMR Delay Portfolio Variant was developed. This portfolio utilizes the low nuclear resource availability assumption, delaying the first advanced nuclear unit from 2035 to 2037. Additionally this low resource availability assumption results in only six advanced nuclear units being available for selection through 2040, and seven fewer total units available by 2050. More information on the Companies’ approach to nuclear deployment is available in Appendix J.

To achieve the Interim Target by 2035 with delayed nuclear availability, the model necessarily adjusts resource selection, primarily after 2032. The model began adding batteries to this portfolio, relative to P3 Base, in 2033, building up to 1.1 GW more than P3 Base by 2035. These incremental batteries serve as firm capacity for the growing system while shifting energy in time to further lower the cost of the system. The added battery capacity is also leveraged to manage the variability of the 1.6 GW of offshore wind selected by 2035 to achieve the Interim Target. With the addition of these battery and offshore wind resources, the 2033 CC selected in P3 Base is delayed to 2036, coinciding with the retirement of Belews Creek Station. By 2038, after the first nuclear units are available and selected, the portfolio also includes an additional 2 GW of solar, 3.6 GW of batteries, and 1.6 GW of offshore wind, with the same amount of hydrogen-capable gas as P3 Base, to make up for adding only 900 MW of advanced nuclear to the portfolio by the end of the Base Planning Period.

Portfolio Variant P3 Limited Gas Availability

The re-optimization of the low gas availability Portfolio Variant in Pathway 3 had significant impacts to the resource portfolio throughout the Base Planning Period. The model replaces the 1.3 GW of CT capacity in P3 Base that is not available in P3 Limited Gas with 1.1 GW of batteries. To most cost-effectively meet the energy and capacity requirements of the system, the model accelerates deployment of the DEP CC selected in 2033 in P3 Base to 2031, bringing the total CC capacity to 4.1 GW by 2032. The model backfills the remaining energy and capacity needs with 800 MW of offshore wind selected in 2034, in part to replace the final retiring coal units in DEP. By 2038, P3 Limited Gas includes 750 fewer MW of solar and one SMR fewer than P3 Base.

Portfolio Variant P3 MVP Fuel Supply

The final Portfolio Variant considered under Pathway 3 is the MVP natural gas supply availability alternative as described in the Pathway 2 Portfolio Variant of the same scenario. While assuming MVP completion had minimal impact on resource selection in Pathway 2, Pathway 3, which achieves the Interim Target by 2035, allows more flexibility to economically optimize the portfolio to take advantage of the lower cost gas supply. For P3 MVP, the model accelerates the selection of the CC added in 2033 in P3 Base to 2031 while deferring selection of some solar and batteries. To achieve the Interim Target by 2035, the model adds 800 MW of offshore wind in 2034, economically meeting the energy and capacity needs of the system. By 2038, this P3 MVP includes 825 MW less of solar and 1 GW less batteries due to the addition of 800 MW of offshore wind, with no cumulative change to advanced nuclear additions.

Pathway 3 Portfolio Variant Resource Summary through 2035

The Portfolio Development results for the Portfolio Variants discussed above are shown in Table C-41 below relative to P3 Base through the year that the Interim Target is achieved.

Table C-41: P3 Portfolio Variants Cumulative Resource Changes relative to P3 Base through 2035 (MW)

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P3 Base	-6,225	11,925	4,260	4,080	2,125	2,100	1,680	600	0
∆ P3 High Availability	0	525	620	-1,360	425	0	0	0	0
∆ P3 Low Solar	0	-1,200	-600	0	0	-300	0	0	800
∆ P3 Low Onshore	0	0	80	0	0	-1,350	0	0	800
∆ P3 OSW in '37	0	0	-40	0	0	0	0	0	0
∆ P3 SMR Delay	0	0	1,080	-1,360	0	0	0	-600	1,600
∆ P3 Limited Gas	0	-1,500	680	0	-1,275	-450	0	0	800
∆ P3 MVP	0	-750	-620	0	0	-450	0	0	800

Sensitivity Analysis Portfolios P3 High Resource Cost and P3 Low Resource Cost

To assess how resource selection is affected based on macro-level impacts to technology capital costs in general across all resource types, the High and Low Resource Cost Sensitivity Analysis Portfolios utilize high and low capital cost projections for each resource to reoptimize the portfolios, given uncertainties associated with each technology.

To develop the high capital cost forecasts, the Companies started by increasing the base capital costs for each technology by 5%, except for advanced nuclear. For advanced nuclear SMR, the initial capital cost was set equal to the EIA 2023 AEO SMR cost, which is significantly above the Companies' base capital cost estimate for SMR and was then increased by an additional 10% to reflect EIA's Technology Optimism Factor, a penalty for the early deployments of a technology. The increased Year 1 costs for all technologies were then assumed to remain flat in real terms throughout the planning horizon, rather than declining as they do in the base assumptions. The additional 10% "first-of-a-kind technology" cost penalty for SMR is gradually removed between 2031 and 2040 based on expected SMR developments over that period. This methodology for developing high resource cost forecasts effectively removes the projected learning curves over the next decade for all technologies.

Low capital cost forecasts for each technology were developed utilizing the Companies' pre-inflationary impact capital cost estimates for each technology. Over the past two years, almost all technologies have experienced significant inflationary impacts. The Companies used their pre-inflationary impact capital cost estimates for each technology for the low capital cost forecasts. This low resource cost sensitivity assumes these inflationary impacts subside and prices return to pre-inflationary levels.

In P3 High Resource Cost, the model accelerates the CC selected in 2033 in P3 Base to 2031 and defers selection of solar and batteries, adding an 800 MW block of offshore wind in 2033. By 2038, the High Resource Cost portfolio includes 1.4 GW less solar and 1.3 GW less batteries than P3 Base.

The model selects more solar and battery capacity in P3 Low Resource Cost than in P3 Base over the Base Planning Period, demonstrating the impacts of recent inflation on the relative economics of those technologies. In P3 Low resource cost, the model replaces a CT added in 2029 in P3 Base with battery capacity added in 2029 and 2030. The CC selected in 2033 in P3 Base is delayed a year to 2034 with additional battery capacity allowing for the one-year delay. Of note, because the model already selects the maximum amount of solar through 2035 in P3 Base, there is no increase to overall solar selection to achieve the Interim Target. By 2038, the portfolio does include an incremental 600 MW of solar and 560 MW of batteries over P3 Base, while eliminating the selection of 425 of CT and 150 MW of onshore wind.

Sensitivity Analysis Portfolios P3 High Fuel Price and P3 Low Fuel Price

Fuel prices can impact the resources selected in a portfolio and the overall cost to maintain and operate the system. The Companies reoptimized resource selection in Pathway 3 to develop these Sensitivity Analysis Portfolios based on high and low natural gas prices as described previously in this Appendix.

In P3 High Fuel, the most significant impact to the portfolio is the acceleration of the CC selected in 2033 to 2031. The Companies' generic CC option, the advanced-class CC, is more efficient than existing gas assets and can be used to incrementally reduce the cost of the system by operating it more often than less efficient gas resources, generating more electricity for the same fuel cost. Despite accelerating CC deployment, the model did not defer the selection of any solar or onshore wind resources, which help to reduce gas burn at the increased price in this portfolio.

The low fuel price forecast has a more significant impact on resource selection as compared to the high fuel price forecast, in Pathway 3. First, due to the low gas prices, energy can be produced at a lower cost by running the most efficient gas units more often. This low fuel price portfolio takes advantage of the lower cost energy from efficient natural gas generation to offset 425 MW of peaking gas resources added in 2029 with roughly the equivalent amount of battery by 2030. To further take advantage of this low-price natural gas, the portfolio accelerates the 2033 CC to 2031. While acceleration of the CC from 2033 to 2031 in P3 High Fuel did not offset any solar, P3 Low Fuel portfolio includes 1.3 fewer GW of solar through 2031 and 1.0 fewer GW of batteries through 2032. Being able to stay on an emissions reduction trajectory in the early 2030s with efficient natural gas generation allows for solar to be economically reduced in the portfolio. The model adds 800 MW of offshore wind in 2033 in place of the solar to achieve the Interim Target by 2035. The offshore wind helps displace 1.1 GW of solar, 800 MW of battery, 425 MW of CT, and 150 MW of onshore wind by 2038.

Sensitivity Analysis Portfolios P3 High Load and P3 Low Load

High load growth presents a particularly difficult challenge with respect to the timing of the Interim Target due to the associated need for incremental capacity and energy resources required to maintain system reliability. The Companies are experiencing significant new load growth stemming from favorable economic development, residential population growth and the increasing adoption of electric vehicles. Should the load forecast continue to grow, the Companies must be prepared to identify the incremental resources to meet customers' energy needs. On the other hand, should current trends change or other economic factors negatively impact load growth in the Carolinas, it will be important to identify the marginal resources that could be reduced to align with a lower load and energy requirement for the system. The development and magnitude of the high and low economic load forecasts used in these Sensitivity Analysis Portfolios are explained in greater detail in Appendix D.

The high load forecast has an immediate impact on resource selection in Pathway 3. In the P3 High Load portfolio, an additional CT is required in 2029 in addition to the 2.1 GW of CT capacity in P3 Base. The model also accelerates the CC selected in 2033 in P3 Base to 2031, while reducing battery capacity by 1.2 GW by 2032. To keep up with incremental load growth, the portfolio adds 1.6 GW of offshore wind by 2034. By 2038, this portfolio includes an additional 675 MW of solar, 280 MW of batteries, 425 MW of CT and 1.6 GW of offshore wind to meet the increased load growth assumed in the P3 High Load Sensitivity Analysis Portfolio.

Conversely, with the lower load forecast, the P3 Low Load portfolio shows the opposite result. In the P3 Low Load portfolio, the model defers the selection of the first CC from 2029 to 2031 and backfills with 425 incremental MW of CT capacity. Through 2032, P3 Low Load requires 4.3 GW less solar and 2.1 GW less battery, with some of this capacity replaced with 850 MW of cumulative CT capacity. By 2035, to meet the Interim Target, the model selects 4.4 GW less solar, 3.1 GW less battery, and 450 MW less onshore wind, while selecting the same amount of CC and the same 850 MW of incremental CT capacity included in the portfolio through 2031. By the end of the Base Planning Period, P3 Low Load includes 5.3 GW less of solar, 3.9 GW less of storage, but an additional 300 MW of nuclear.

Sensitivity Analysis Portfolios P3 High EE and P3 Low EE

Energy efficiency reduces overall customer usage, playing an important role by "shrinking the challenge" to help meet customer needs. The Companies developed high and low utility-sponsored energy efficiency forecasts to assess the impacts on portfolio cost and resource selection. The high EE forecast assumes minimum annual savings of 1.5% of all eligible retail load in every year of the Plan. The low EE forecast, as described above, achieves aggressive amounts of EE savings, but slightly less than the base 1% of eligible retail load EE forecast. The development and magnitude of the high and low EE forecasts used in these Sensitivity Analysis Portfolios are explained in greater detail in Appendix H.

Due to the already high levels of EE in the base EE forecast influenced by the anticipated impacts of IRA-related EE opportunities, there are minimal differences in the portfolio through 2032. The cumulative impacts of the high EE forecast make the first significant impact to the portfolio in 2033, when the peak contribution of EE grows to enable the deferral of the selection of the third CC one year from 2033 to 2034. By 2035, the load reduction from EE allows for the deferral of 450 MW of onshore wind with minimal impacts to solar and battery through meeting the Interim Target. By 2038, however, the high EE forecast begins to make more significant impacts to the resource portfolio, reducing overall solar selected in the base planning period by 1.1 GW, while reducing batteries by 480 MW and onshore wind by 150 MW relative to P3 Base.

The low EE forecast used to develop P3 Low EE results in increased peak net load and by 2029, when the first CT resources can be selected, 425 MW CT is added relative to P3 Base. By 2035, the model adds an additional 740 MW of battery and 800 MW of offshore wind to help meet the increased energy needs of the system with the low EE forecast. At the end of the Base Planning Period, the impacts of low EE have increased solar by 450 MW, battery by 660 MW, CT by 425 MW, and added 800 MW of offshore wind to the portfolio relative to P3 Base.

Sensitivity Analysis Portfolios P3 High DSM and P3 Low DSM

DSM will continue to play an important role in controlling demand and reducing peak energy consumption to offset incremental peaking resources that fit into an increasingly clean resource portfolio. This Sensitivity Analysis Portfolio evaluates the impacts to the resource portfolio of high and low levels of DSM. The development and magnitude of the high and low DSM forecasts used in these Sensitivity Analysis Portfolios are explained in greater detail in Appendix H.

Due to the significant number of energy and capacity resources required to achieve the Interim Target, the High DSM forecast used to develop P3 High DSM has relatively minor impacts to the selection of resources throughout the Base Planning Period. By 2032, the higher level of DSM reduces cumulative battery selection by 120 MW, and by 2033 the incremental increase in DSM allows the deferral of the CC selected in 2033 in P3 Base by one year to 2034. By 2038, however, there are no changes in the cumulative resources added to the portfolio.

Similarly, the low DSM forecast results in only 240 incremental MW of storage required to achieve the Interim Target in 2035, and 200 MW of cumulative storage capacity selected by the end of the Base Planning Period.

Pathway 3 Sensitivity Analysis Portfolio Development Summary through 2035

The Portfolio Development results for the Sensitivity Analysis Portfolios discussed above are shown in Table C-42 below relative to P3 Base through the year that the Interim Target is achieved.

Table C-42: P3 Sensitivity Analysis Portfolios Cumulative Resource Changes relative to P3 Base through 2035 (MW)

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P3 Base	-6,225	11,925	4,260	4,080	2,125	2,100	1,680	600	0
∆ P3 High Resource Costs	0	-1,125	-740	0	0	-300	0	0	800
∆ P3 Low Resource Costs	0	0	1,160	0	-425	-450	0	0	0
∆ P3 High Fuel	0	0	0	0	0	0	0	0	0
∆ P3 Low Fuel	0	-1,275	-360	0	-425	-450	0	0	800
∆ P3 High Load	0	0	-280	0	425	0	0	0	1,600
∆ P3 Low Load	0	-4,350	-3,080	0	850	-450	0	0	0
∆ P3 High EE	0	-75	180	0	0	-450	0	0	0
∆ P3 Low EE	0	-75	740	0	425	-300	0	0	800
∆ P3 High DSM	0	0	580	0	0	-300	0	0	0
∆ P3 Low DSM	0	-75	240	0	0	0	0	0	0

Core Portfolio Resource Summary Through Base Planning Period

The Portfolio Development results discussed above show portfolio changes within the same Pathway through the year that the Interim Target is achieved. While it is insightful to view how resource availability, fuel supply, net load, and fuel and resource cost changes impact portfolios within the same pathway, it is also important to see how these portfolios converge over time. The Portfolio Development results for the Core Portfolios through Base Planning Period are shown in Table C-43 below.

Table C-43: Preliminary Resource Additions and Retirements (MW) for the Core Portfolios through 2038

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P1 Base	-8,445	15,750	6,120	2,720	1,700	2,250	1,680	3,000	2,400
P2 Base	-8,445	14,100	6,960	4,080	2,125	2,100	1,680	2,400	1,600
P3 Base	-8,445	14,625	6,020	4,080	2,125	2,250	1,680	2,400	0

The Core Portfolios through the Base Planning Period are very similar. Overall, each portfolio eliminates all coal capacity from the Companies' systems by retiring 8.4 GW of coal capacity and ceasing coal operations at Cliffside 6 by 2036. All Portfolios add a significant amount of all resources, notably averaging between 1,250 and 1,450 MW of solar and 500 to 600 MW of batteries per year. These consistently high deployment rates underscore the challenges the industry and the Companies will face to meet these levels of deployment. In addition to these elevated and regular deployments of solar and batteries, each of these Core Portfolios includes several large projects, including multiple CC and CT projects, Bad Creek II, and parallel development of multiple nuclear sites. The Core Portfolios each also call for at least 2 GW of onshore wind and P1 Base and P2 Base (as well as several of the Pathway 3 Portfolio Variants) call for integration of varying levels of offshore wind by 2038.

P1 Base relies heavily on rapid additions of solar and offshore wind to achieve the Interim Target by 2030, adds over 1 GW of solar capacity over the other portfolios and an additional 800 MW of offshore wind relative to P2 Base. These earlier incremental solar and offshore wind capacity additions allow one fewer CC to be selected. In P1 Base the model also selects 600 MW more advanced nuclear than in the other Core Portfolios, based on the increased resource availability assumed for Pathway 1.

P2 Base leverages the extended 2033 timeframe for achieving the Interim Target relative to P1 by integrating offshore wind on a more executable timeline. The offshore wind selected in this portfolio slightly reduces the need for solar but selects nearly 1 GW more storage capacity than the other Core Portfolios.

P3 Base allows for advanced nuclear to have a significant and material contribution to meeting the Interim Target by 2035. The less compressed timeline, relative to P1 Base and P2 Base, allows the Interim Target to be met without necessarily needing offshore wind, and with less reliance on battery energy storage.

This comparison demonstrates that adjusting the pace of transition across the Core Portfolios drives differences in respective portfolio costs and technology reliance risks on the energy transition path towards achieving the Interim Target and carbon neutrality target despite eventual Core Portfolio convergence across the three Pathways.

Production Cost

Once initial portfolios of resources have been developed in the capacity expansion model for each Core Portfolio, Portfolio Variant, and Sensitivity Analysis Portfolio in the Portfolio Development step, the portfolios are then run in the production cost model in the Production Cost step. As discussed in the modeling set-up section above, the capacity expansion model uses simplified system operation simulations to quickly assess combinations and permutations of incremental new resources seeking to find the mix that results in the lowest present value of revenue requirements. The production cost model then uses the specified set of resources established in the capacity expansion model in the Portfolio Development step to perform a detailed, chronological simulation of the system accounting for hour-by-hour changes in load, generation, system reliability requirements, outages, among other factors to more accurately represent the cost of operating a specific set of resources.

The Companies use the results of the production cost runs to first ensure reliability. Due to the simplifications in the capacity expansion model, when a set of resources is transferred to the detailed production cost model, projected resources can operate differently or provide different operational flexibility contributions to the system. Therefore, each portfolio is checked to ensure it is reliable in this more detailed view, ensuring there are adequate resources and energy to serve customer load in all hours of the planning horizon.

The detailed production cost model was also used to confirm that each portfolio meets the applicable emissions reduction target. Finally, the costs to maintain and operate the system are derived from the production cost modeling. These costs are used to calculate each portfolio's specific PVRR and, for the Core Portfolios, their projected customer bill impacts.

Bad Creek Powerhouse II Economic Verification

The detailed production cost modeling allows the Companies to perform economic verifications to confirm that resources were economically selected by the capacity expansion model. This additional economic verification was performed on a limited basis, as part of the Production Cost step, for Bad Creek II which was prescribed into all portfolios in the Capacity Expansion step.

As introduced above, Bad Creek II is a potentially pivotal project for the Carolinas systems leveraging the joint dispatch of the DEC and DEP systems. The project provides significant capacity of long-duration storage which brings valuable time shifting of energy to help balance the system and integrate variable energy resources. The significant capacity and long-duration storage can also help support the retirement of the Companies' coal fleet.

Due to the limitations and complexities associated with evaluating a large capacity and long duration storage resource with its corresponding costs within the capacity expansion model, based on its simplified system simulations as discussed in the Modeling Software section of this Appendix, the Companies performed additional economic analysis of this long-duration storage to confirm Bad Creek II as an economic inclusion in the portfolios.

As discussed in the Forecasted Resources section of this Appendix, Bad Creek II was included in all portfolios as a simplifying input to reduce complexity in managing model run times. To confirm the prescribed inclusion was economic, the Companies performed two economic verifications. First, the Companies performed capacity expansion modeling in Pathway 3 with base case assumptions but did not include Bad Creek II in the resource portfolio. The portfolio was reoptimized without Bad Creek II as an available resource to the portfolio. Second, the Companies performed the capacity expansion modeling again, this time allowing (but not forcing) the model to select Bad Creek II starting in 2034. The capacity expansion model was able to assess the costs and benefits of the resource to the system and make the decision to select or not select Bad Creek II like any other resource. The resulting portfolios were then both put into the production cost model to assess final costs and benefits and confirm that base levels of reliability were met.

Both of these economic verification evaluations confirmed the inclusion of Bad Creek II in the portfolio was economic. The first economic verification showed that inclusion of Bad Creek II in 2034 resulted in savings of approximately $700 MM in PVRR through 2050 relative to a portfolio without Bad Creek II.

The second economic verification, in which Bad Creek II was made a selectable option, demonstrated the economic selection of Bad Creek II. This portfolio economically selected Bad Creek II in 2036 compared to 2034, when it was integrated into portfolios before the capacity expansion step. The two-year delay in the selection of Bad Creek II corresponded to the replacement of the retiring Belews Creek coal station. The timing of this selection further confirms that the significant nameplate capacity of Bad Creek II, along with its long duration storage capabilities, allowing this resource to enable significant coal capacity to retire. Should the Bad Creek II project come into service and provide the reliable capacity to allow for the accelerated retirement of the final coal resources on the system, this resource could continue to provide significant added benefits to customers.

Bad Creek II will continue to be evaluated with more refined project cost estimates over the coming years as an important resource to help integrate renewables, provide significant capacity additions, and have an impact on the Carolinas energy system for decades to come while leveraging existing infrastructure for this unique project.

Reliability Verification

Resource Adequacy and Reliability Analysis

Resource Adequacy

Resource Adequacy, as defined by the EPRI, is an assessment of whether a power system has an appropriate set of resources to maintain continuous service to demand, with a desired level of certainty.[11] The primary outcome of a Resource Adequacy study is the planning reserve margin, which is a high-level description of the amount of additional firm capacity over that required to meet the weather normal peak load. This additional amount of firm capacity provides the system with the ability to absorb shocks such as unplanned outages or higher than expected loads due to extreme weather.

However, while each portfolio is developed to maintain acceptable reserve margin levels, portfolios with the same reserve margin may have differing risk profiles due to the mix of resources in each. As such, additional metrics are useful in further evaluating the overall adequacy of the system. As discussed in Appendix M (Reliability and Operational Resilience), the purpose of these efforts is to deliver a reliable and cost-effective system for customers.

To that end, Table C-44, below, details several reliability metrics that the Companies are reporting out on both the Resource Adequacy and Reliability Verification process. The purpose of providing this expanded reliability analysis is to provide more context to the risks the system faces. LOLE has been an industry accepted reliability metric in North America for decades. However, as the industry transitions to larger amounts of intermittent and energy limited resources there is a growing recognition that additional reliability metrics may be required. In recognition of this trend, the Companies are working with EPRI and other industry organizations to investigate potential additional reliability metrics that may be of value in future resource plan filings.

It is also important to note that the risk profile these metrics illuminate was always present, but previously was not as material to analyze in the long-term integrated resource planning process because a system comprised of dispatchable, firm-fuel resources was more predictable. As discussed in Appendix M, there are new reliability risk dimensions associated with increased penetration of intermittent and energy limited inverter-based resources (“IBRs”). Over time as penetration of these resources increases, more comprehensive risk metrics and advanced techniques will be required to further understand and quantify these reliability risks so that effective mitigation measures can be implemented.

[11] Electric Power Research Institute: Resource Adequacy for a Decarbonized Future, A Summary of Existing and Proposed Resource Adequacy Metrics, 3002023230, available at https://www.epri.com/research/products/000000003002023230.

Table C-44: Reliability Metric Definitions

Name	Abbreviation	Description	Unit	Threshold
Loss of Load Expectation	LOLE	The number of individual days with firm load shed. Does not reveal the magnitude, duration, or number of events.	event-day per year	North America: 1 event-day per ten years or 0.1 event-days per year.
Loss of Load Hours	LOLH	The number of individual hours with firm load shed. Reveals the duration of an event.	event-hour per year	None in North America. Several European countries have established thresholds varying from three to five event-hours per year.[12]
Loss of Load Frequency	LOLF	The number of continuous hour with firm load shed.	event per year	None established.
Expected Unserved Energy	EUE	The total amount of unserved energy in MWh. Reveals the magnitude or depth of event(s).	MWh	None established, but the Companies are engaged with current industry research on the role of this metric in reliability analysis.
Normalized Expected Unserved Energy	nEUE	Allows for comparison of EUE between study years and systems with differing loads.	ppm or %	None in North America. Australian states use 0.002%[13]
Negative Internal Margin	NIM	Informs on the number of hours in a year where the system would have shed load if not for external neighboring assistance. This metric is not reported for non-interconnected systems.	hour per year	None established.
All Resource Hours	ARH	Informs on the number of hours in a year where the system required all available capacity but did not require firm load-shed.	hour per year	None established.

[12] Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics, available at https://www.epri.com/research/products/000000003002023230.

[13] *Id.*

Table C-45 details these metrics for the 2023 Resource Adequacy Study including the Base Case Combined Scenario and the Island Combined Scenario. The metrics listed in Table C-45 are the probability weighted average results of the simulations.

Table C-45: Reliability Metrics for Resource Adequacy Studies, 2027

Reliability Metric	RA Base Case Combined Scenario	RA Island Combined Scenario
LOLE [event-day per year]	0.094	0.160
LOLH [event-hour per year]	0.339	0.517
LOLF [event per year]	0.095	0.161
EUE [MWh]	800	1,031
nEUE [ppm]	5	6
ARH [hour per year]	0.30	0.80
NIM [hour per year]	0.90	N/A

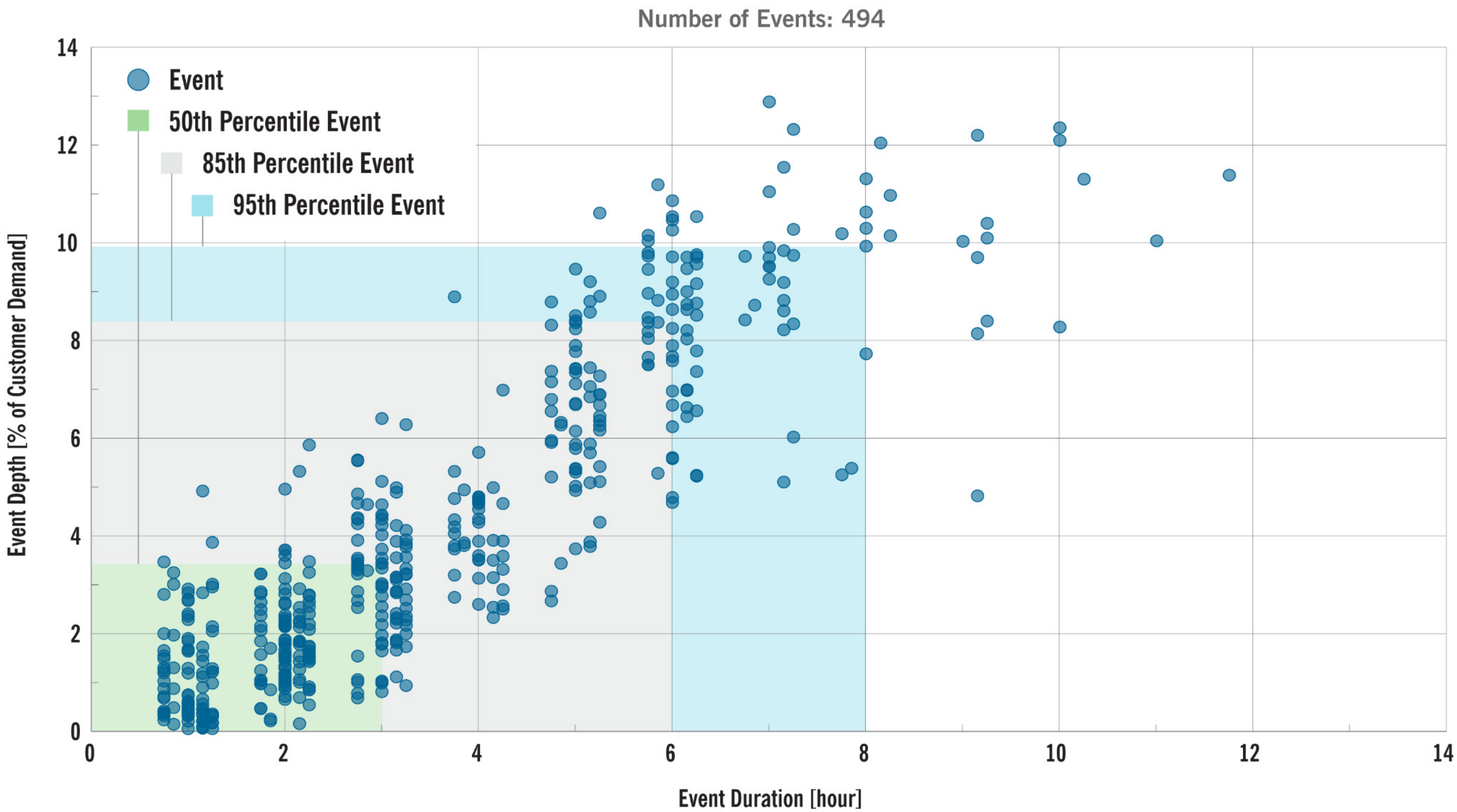
A key takeaway from Table C-45 above is how similar the Base Case Combined and Island Combined Scenarios are to each other. This implies that the interconnected system is not providing the value it once did to the Companies, a potential increase in reliability risk. This implication is further discussed in the next section on Reliability Verification.

Figure C-5, below, further illustrates the reliability risk of the Base Case Combined Scenario by showing every individual firm load-shed event depth and duration along with the fiftieth, eighty-fifth, and ninety-fifth percentile firm load shed events. The event depth in Figure C-5 is shown as a percentage of customer demand. While each event has its own associated probability, any event shown in Figure C-5 could theoretically occur.

The 50^{th} percentile event shaded area in Figure C-5 shows that approximately 50% of the loss of load events have an event duration of approximately three hours or less and impact approximately 3% or less of customer demand. Similarly, the 95^{th} percentile event shaded area indicates that 95% of the loss of load events have an event duration of approximately eight hours or less and impact approximately 10% or less of customer demand. Only 5% of events exceed the depth and duration shown in the 95^{th} percentile event shaded area.

Note that some events shown in Figure C-5 have had their x axis coordinate modified to allow for showing all events in leu of overlapping. However, as the model was run at an hourly resolution, all events shown have whole hour durations.

Figure C-5: Depth and Duration of the 2023 Resource Adequacy Combined Base Case Events



Portfolio LOLE Reliability Verification

This section outlines the analytical process undertaken to provide reasonable assurance that the final portfolios perform at levels of reliability equivalent to or better than the current system configuration based on satisfying the LOLE resource adequacy metric.

ELCC values are dependent on many factors including the load and load shape to be served, the existing resource mix, as well as the adoption level of different resource technologies. An overstatement of ELCC value in the modeling process can result in a system that has insufficient capacity planning reserves. Since it is not practical to determine ELCC values for infinite combinations of resources, nor are such inputs easily integrated into the resource planning models, the Companies conducted reliability analysis for each of the portfolios. This process utilized SERVM to evaluate the LOLE of each portfolio for the years 2033 and 2038 to ensure that the portfolios satisfy the LOLE target in later years with higher levels of renewables and energy storage resources. SERVM was used to evaluate sequential, hourly system operations across 43 weather years, 50 forced-outage scenarios, and 3 load forecast outcomes for a total of 6,450 combined weather, forced-outage and load forecast iterations for each portfolio.

The 2023 Resource Adequacy Study[14] determined that a 22% winter reserve margin is needed to satisfy the 0.1 event-day per year LOLE threshold. However, the 22% reserve margin also assumed assistance from the interconnected system would be provided during hours of system strain. In general, future market assistance for reliability planning purposes is highly speculative due to the uncertainty in the pace of neighboring utilities' transition to variable energy and energy limited resources to achieve CO_2 reduction targets. This risk is realized in the 2023 Resource Adequacy Study as neighboring systems risk has begun to shift to winter months reducing their ability to assist during periods of system strain. This reduction was a factor in the recommendation to increase the planning reserve margin from 17% to 22%. It is expected that if current trends hold, neighboring assistance could continue to decrease in the future since there may be fewer capacity reserves available during winter peak periods. Thus, it is difficult to project the level of firm market resources and available transmission for providing reliability assistance in the next decade and beyond.

Rather than speculate and buildout an assistance area for 2033 and 2038 in SERVM, the Companies assumed that the level of market assistance would neither improve nor decline from the level of assistance modeled in the 2023 Resource Adequacy Study. For the reasons noted above, the Companies believe that this assumption may overestimate their ability to rely on neighbors in the next decade; however, this simplifying assumption was undertaken to facilitate the LOLE verification step providing a general representation of how the transition of Duke Energy's system could impact resource adequacy. This approach allows the Companies to observe how reliability of the Island Combined Scenario changes with resource transition across time without speculation about future market assistance.

[14] The 2023 Resource Adequacy Study report is being provided as Attachment I to the Companies' Carolinas Resource Plan.

To establish a target LOLE metric for the Island Combined Scenario, the Companies utilized modeling data from the 2023 Resource Adequacy Study Base Case Combined Scenario. The Base Case Combined Scenario allowed preferential support between DEC and DEP to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority. The SERVM model was used to rerun the 22% reserve margin Base Case Combined Scenario, except as an island with no market assistance. The LOLE result was then compared against the interconnected study is shown in Table C-46 below.

Table C-46: Islanded and Interconnected 2023 Combined Case Results at a 22% Reserve Margin

Study	LOLE[15] [event-day per year]
Base Case Combined Scenario (Islanded)	0.160
Base Case Combined Scenario (Interconnected)	0.094

As the only difference between the two studies is the inclusion of the interconnected system, the change in the LOLE result becomes the estimated reliability value of the interconnected system to the Companies. This difference of 0.065 event-day per year[16] is then added to the standard LOLE threshold of 0.1 event-day per year to create a target to compare an islanded study against. If a portfolio has an islanded LOLE greater than 0.165 event-day per year it indicates that even with an interconnected system, the portfolio will not meet the 0.1 event-day per year threshold.

The Companies evaluated each of the portfolios for years 2033 and 2038 in an islanded study. The results of these studies were then compared to the islanded LOLE target of 0.165 event-days per year as a proxy for maintaining a 0.1 event-day per year threshold with the assistance of neighboring utilities. If a portfolio in either 2033 or 2038 had an LOLE above the 0.165 event-days per year target, additional firm capacity resources were added to the portfolios in those test years until the portfolio met the target.

To simplify the analysis, the firm capacity reliability resource was assumed to be a CT consistent with the generic CT resources modeled in the capacity expansion modeling. Table C-47 below shows the reliability metrics for 2033 while Table C-48 shows the same for 2038. These tables reflect the portfolios after any required CTs were added. As a point of comparison, the tables also contain the 2023 Resource Adequacy Study Island Combined Scenario reliability metrics with a study year of 2027. The metrics listed in Table C-47 are the probability weighted average results of the simulations.

[15] Values are rounded for presentation.

[16] Unrounded values give 0.06549983 which rounds to 0.065.

Table C-47: Reliability Metrics for Adjusted Portfolios, 2033

Reliability Metric	P1 Base	P2 Base	P3 Base	RA Island Combined Scenario
CTs Added (count)	2	0	0	N/A
LOLE (event-day per year)	0.144	0.086	0.115	0.160
LOLH (event-hour per year)	0.625	0.361	0.468	0.517
LOLF (event per year)	0.150	0.073	0.116	0.161
EUE (MWh)	2,431	1,434	1,724	1,031
nEUE (ppm)	13	8	9	6
ARH (hour per year)	0.31	0.20	0.43	0.80

The "as found" Portfolios P2 Base and P3 Base meet the reliability target in 2033; however, P1 Base which retires both Belews Creek 1 and 2 and Roxboro 3 and 4 in 2030 required the addition of 2 CTs to satisfy the LOLE target. Even though the three portfolios meet the reliability target (after CT adjustments to P1 Base), and in the case of P2 Base is close to twice as reliable in regard to the LOLE metric as the RA Island Combined Scenario ("RA Island Case"), all three portfolios have higher nEUE[17] compared to the RA Island Case. This implies that while the system is reliable, when an event does happen, it is more severe than what is found in the RA Island Case. In comparing the P1 Base, P2 Base and P3 Base results to the RA Island Case, it is important to realize that the RA Island Case reflects study year 2027 and thus has lower amounts of variable energy and energy limited resources compared to the Plan's Core Portfolios in years 2033 (Table C-47 above) and 2038 (Table C-48 below).

[17] nEUE being the appropriate depth metric to compare across study years with different load profiles.

Table C-48: Reliability Metrics for Adjusted Portfolios, 2038

Reliability Metric	P1 Base	P2 Base	P3 Base	RA Island Combined Scenario
CTs Added (count)	2	0	2	N/A
LOLE (event-day per year)	0.160	0.150	0.164	0.160
LOLH (event-hour per year)	0.804	0.770	0.895	0.517
LOLF (event per year)	0.143	0.160	0.170	0.161
EUE (MWh)	3,593	3,664	4,635	1,031
nEUE (ppm)	18	19	24	6
ARH (hour per year)	0.29	0.28	0.28	0.80

In 2038 however, P3 also requires additional firm capacity to meet the reliability target. It is again shown that while the LOLE of each portfolio is similar and satisfies the target level of reliability, the other metrics show greater reliability risks for P1 Base, P2 Base, and P3 Base compared to the RA Island Case. For example, the EUE and nEUE metrics are three to four times greater for P1 Base, P2 Base and P3 Base compared to the RA Island Case. The only exception is that the ARH metric is greater for the RA Island Case likely due to that scenario reflecting a lower level of reserves compared to P1 Base, P2 Base and P3 Base. In addition, nearly all metrics show a notable increase from 2033 to 2038. It is important to note that all portfolios are tested and adjusted if necessary to ensure that the Companies' current LOLE reliability metric is satisfied. However, the decrease in reliability as measured by other metrics highlights the out-year risk of systems with higher renewable and variable energy penetrations as is further discussed in Appendix M.

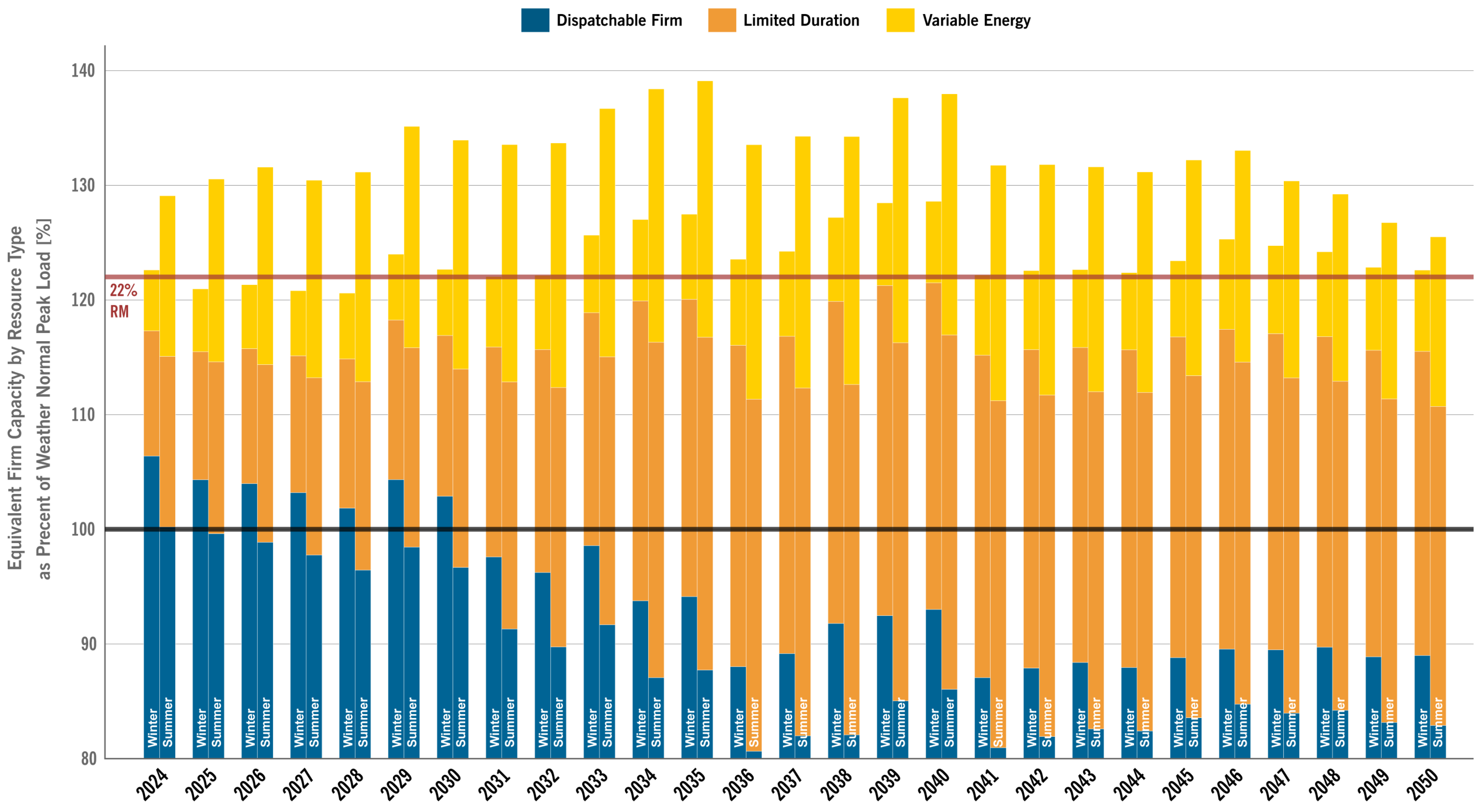
Figure C-6 provides another view of reserve margins by season and year for P3 Base. In this figure, DEC and DEP firm capacity and peak loads are combined to create reserve margin projections for the combined Carolinas' systems. Three types of resources are represented: Dispatchable Firm (gas, coal, oil, nuclear, contract purchases, biomass, etc.) – represents firm capacity available during peak load conditions, Limited Duration (pumped storage, battery storage, and DSM) – represents resources that are limited in the duration for which they can generate or modify customer load before exhausting the availability of these resources, and Variable Energy Resources (including solar, solar paired with storage, hydro, and wind) – represents non-dispatchable resources with a reduced amount of their nameplate capacity available during the peak load hour. Each segment of these resources shown in Figure C-6 below represents the equivalent firm capacity, or the relative contribution, of that resource type to the overall reserve margin as a percent of peak load. For example, in 2024, Dispatchable Firm resources have enough firm capacity to serve approximately 106% of the weather normal winter peak load, with Limited Duration resources accounting for approximately 11% of peak load and Variable Energy Resources accounting for approximately 5% of peak load for a total equivalent firm capacity of around 123% of peak load, or a reserve margin of approximately 23%.

In the summer this changes as the equivalent firm capacity contribution of Variable Energy Resources increases from 5% winter contribution to peak load to around 14% increasing the total reserve margin to approximately 29%. This is due to both the summer versus winter ELCCs of the Variable Energy Resources and the differences in peak load between the seasons. The figure clearly shows how the contribution of solar, in the Variable Energy Resources category, to the reserve margin is dependent on the season and coincidence with peak load hour, with a much lower relative contribution to winter reserves compared to summer reserves.

The figure also shows the overall decrease in dispatchable firm capacity over the planning period and the increasing reliance on variable energy and limited duration resources for a portion of maintaining a reliable system. Thus, the ability to satisfy the reserve margin and maintain system reliability will become increasingly dependent on accurate estimates of firm capacity contributions of variable energy and limited duration resources to meet the peak load.

This becomes crucial starting in 2031 where there is not enough Dispatchable Firm resource type to serve 100% of the system weather normal winter peak load. At that point, Limited Duration resources will be required to serve approximately 3% of the system winter peak load and will satisfy approximately 18% of the winter reserve margin. By 2041, Limited Duration resources will be required to serve approximately 13% of the system winter peak load and will satisfy approximately 28% of the winter reserve margin.

Figure C-6: Portfolio 3 Combined DEC and DEP Winter and Summer Reserve Margins by Resource Type



Final Portfolios

The annual resource additions and coal retirements for DEC and DEP for each final Core Portfolio are presented below in Table C-49 through Table C-54.[18] Resource changes are included through the Base Planning Period, including reliability CTs as discussed in the Reliability Verification step. Capacities in these tables below reflect nameplate capacity of resources and are limited to the resources identified in the Portfolio Development and Reliability Verification Steps. Incremental forecasted resources, such as existing unit uprates and the forecasted solar and storage resources, as discussed in the Existing Resources and Forecasted Supply-side Resources sections of this Appendix, are not included in the tables below.

[18] Consistent with data in the rest of this Appendix, resource changes are effective as of the start of the year listed.

Table C-49: P1 Base – Final DEC Annual Resource Additions and Coal Retirements (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Coal	-426	0	0	0	0	-1,306	-2,220	0	0	0	-1,318	0	0	0	0
Solar	0	0	0	0	750	975	975	975	975	975	975	150	900	0	0
Battery	0	0	0	0	0	740	980	0	780	240	0	0	0	0	0
Onshore Wind	0	0	0	0	0	0	0	0	0	0	300	300	0	0	0
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	300	300	900
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,680	0	0	0	0
CC	0	0	0	0	0	0	1,360	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	1,700	0	0	0	850	0	0	0	0	0

Table C-50: P1 Base – Final DEP Annual Resource Additions and Coal Retirements (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Coal	0	0	0	0	0	-1,766	-1,409	0	0	0	0	0	0	0	0
Solar	0	0	0	0	1,050	1,425	1,425	1,425	1,425	975	375	0	0	0	0
Battery	0	0	0	0	100	2,420	860	0	0	0	0	0	0	0	0
Onshore Wind	0	0	0	0	0	0	300	300	450	450	150	0	0	0	0
Offshore Wind	0	0	0	0	0	0	1,600	0	0	800	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	300	600	0
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	1,360	0	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table C-51: P2 Base – Final DEC Annual Resource Additions and Coal Retirements (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Coal	-426	0	0	0	0	-760	0	-546	-1,318	0	0	0	-2,220	0	0
Solar	0	0	0	0	525	525	525	675	675	675	675	525	675	0	375
Battery	0	0	0	0	140	140	0	180	300	540	180	0	0	0	300
Onshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	300	0	150
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	0	900	300
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,680	0	0	0	0
CC	0	0	0	0	0	0	0	1,360	1,360	0	0	0	0	0	0
CT	0	0	0	0	0	1,275	0	0	0	0	0	0	0	0	0

Table C-52: P2 Base – Final DEP Annual Resource Additions and Coal Retirements (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Coal	0	0	0	0	0	-1,053	0	-713	0	-1,409	0	0	0	0	0
Solar	0	0	0	0	825	825	825	900	900	900	900	900	900	0	375
Battery	0	0	0	0	220	220	160	700	640	2,820	420	0	0	0	0
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0	0	800	800	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	300	0	300
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	1,360	0	0	0	0	0	0	0	0	0
CT	0	0	0	0	0	850	0	0	0	0	0	0	0	0	0

Table C-53: P3 Base – Final DEC Annual Resource Additions and Coal Retirements (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Coal	-426	0	0	0	0	-760	0	-546	-1,318	0	0	0	-2,220	0	0
Solar	0	0	0	0	525	525	525	675	675	675	675	675	675	525	600
Battery	0	0	0	0	140	140	20	840	540	460	0	0	740	0	420
Onshore Wind	0	0	0	0	0	0	0	0	0	0	0	450	150	0	0
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	300	600	600
Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,680	0	0	0	0
CC	0	0	0	0	0	0	0	0	1,360	0	0	0	0	0	0
CT	0	0	0	0	0	1,275	0	0	0	0	0	0	0	0	850

Table C-54: P3 Base – Final DEP Annual Resource Additions and Coal Retirements (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Coal	0	0	0	0	0	-1,053	0	-713	0	0	-1,409	0	0	0	0
Solar	0	0	0	0	825	825	825	900	900	900	900	900	900	0	0
Battery	0	0	0	0	220	220	0	860	0	0	820	0	600	0	0
Onshore Wind	0	0	0	0	0	0	0	300	450	450	450	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	300	0
Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	1,360	0	0	0	1,360	0	0	0	0	0
CT	0	0	0	0	0	850	0	0	0	0	0	0	0	0	0

Tables C-55 through Table C-57 below present a summary of the final resource additions of each portfolio for the year the interim target is achieved (2030 for P1 Base, 2033 for P2 Base, and 2035 for P3 Base), through the Base Planning Period (2038), and 2050 for the combined DEC and DEP systems. For summary purposes, the solar capacity associated with solar and solar paired with storage is grouped together. Similarly, all battery capacity (standalone battery and battery paired with solar) and, for the 2050 summary data, all advanced nuclear (SMR and Advanced Reactors with Integrated Storage) additions are grouped together.

Table C-55: Core Portfolio Summary – Final Cumulative Resource Additions (MW) for year Interim Target is achieved

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P1 Base	-7,127	6,600	5,100	2,720	1,700	300	0	0	1,600
P2 Base	-6,225	8,775	6,060	4,080	2,125	1,200	0	0	1,600
P3 Base	-6,225	11,925	4,260	4,080	2,125	2,100	1,680	600	0

Table C-56: Core Portfolio Summary – Final Cumulative Resource Additions (MW) for 2038

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P1 Base	-8,445	15,750	6,120	2,720	2,550	2,250	1,680	3,000	2,400
P2 Base	-8,445	14,100	6,960	4,080	2,125	2,100	1,680	2,400	1,600
P3 Base	-8,445	14,625	6,020	4,080	2,975	2,250	1,680	2,400	0

Table C-57: Core Portfolio Summary – Final Cumulative Resource Additions (MW) for 2050

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P1 Base	-9,294	17,025	7,500	2,720	4,250	2,250	1,680	16,350	2,400
P2 Base	-9,294	17,850	9,120	4,080	4,250	2,100	1,680	15,150	1,600
P3 Base	-9,294	19,200	8,220	4,080	4,675	2,250	1,680	15,450	800

By 2050, each of the Core Portfolios includes at least 17 GW of model-selected solar, bringing the total solar on the system in 2050 to at least 21 GW of solar. P2 Base and P3 Base each include the full 4.1 GW of selectable CC capacity, while P1 Base includes one less CC unit, but relies more heavily on nuclear and offshore wind, both through 2038 and 2050. Nearly all 2.3 GW of onshore wind available is selected in each Core Portfolio. P1 Base and P2 Base each include 1.6 GW of offshore wind to achieve the Interim Target. An additional 800 MW of offshore wind is selected in P1 Base in the 2030s, while the first offshore wind block in P3 Base is added in the mid-2040s, and P2 Base does not include any incremental offshore wind after the 1.6 GW that is selected to reach the Interim Target.

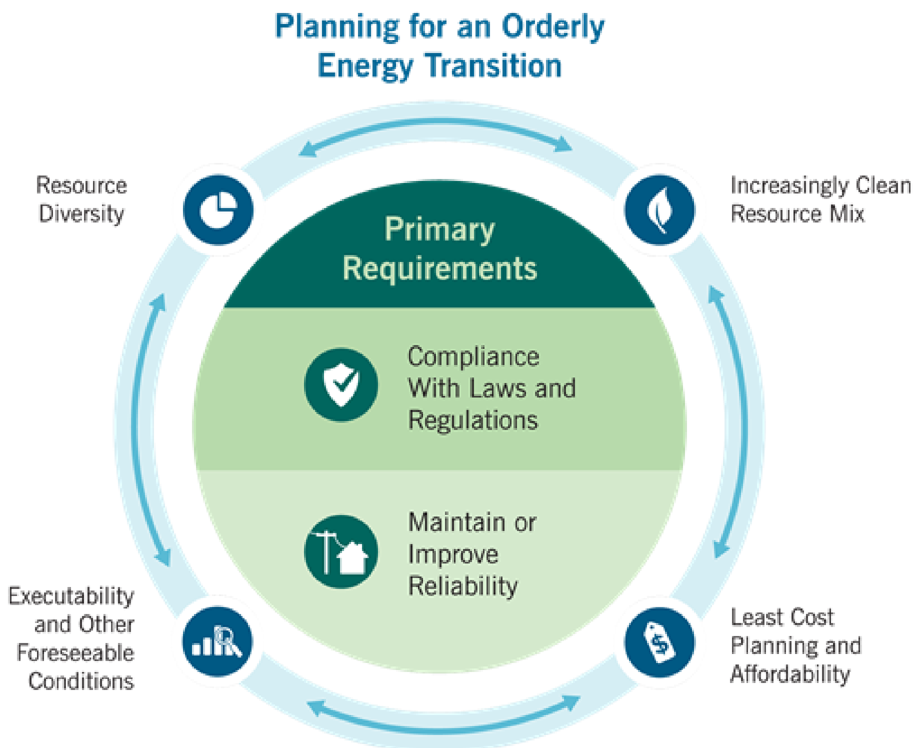
The model adds 7.5 to 9.1 GW of battery capacity in the Core Portfolios, including both standalone and batteries paired with solar. With the addition of Bad Creek II and additional peaking thermal storage capacity integrated with the advanced nuclear, this brings the incremental new storage capacity selected in the Core Portfolios to between 13.5 and 14.6 GW by 2050. To help supply backup power for variable energy and energy limited resources and meet load growth and capacity requirements of the system, the portfolios add 4.3 to 4.7 GW of CTs (that are modeled to operate exclusively on hydrogen by 2050) throughout the planning horizon. This represents a significant decrease in total peaking CT capacity on the system after retirements, down from about 8.9 GW at the start of planning horizon, to 5.2 GW by 2050.

In the 12-year period beyond 2038 (2039 through 2050), the amount of solar and battery capacity selected decreases relative to the 12-year period prior (2027 through 2038). From 2039 through 2050, P1 Base includes the least of the Core portfolios, with the model selecting only 1.3 GW of solar and 1.4 GW of storage, while P3 base includes the most at 4.6 GW of solar and 2.2 GW of storage added over this time period. To support the continued growth of the system and continue to drive to carbon neutrality, each of the portfolios turns to nuclear. Each Core Portfolio calls for continued significant build out of nuclear, adding 12.8 to 13.4 GW of nuclear capacity (combined with its peaking thermal storge at advanced reactor units) after 2038. By 2050, each of the Core Portfolios includes the maximum number of advanced nuclear units available under the corresponding Pathway's assumptions for nuclear resource availability. The difference in nuclear capacity between P2 Base and P3 Base is only in the number of advanced reactors with integrated thermal storage selected compared to the lower full load capacity SMR units. P1 Base includes the two incremental nuclear units available above the base assumptions, representing the incremental resources that may be needed to continue the trajectory to carbon neutrality. Overall, each Core Portfolio includes more than 15.2 GW of advanced nuclear to support reaching carbon neutrality for the system by 2050.

Performance Analysis

As discussed in Chapter 3, the Portfolios are evaluated against the long-term resource planning objectives as highlighted below in Figure C-7.

Figure C-7: Long-Term Resource Planning Objectives



The analysis performed in the Production Cost and Portfolio Verification steps addressed ensuring all portfolios comply with applicable laws and regulations and maintain or improve reliability throughout the planning horizon, with a heightened focus the nearer term with representative portfolio resource adequacy in 2033 and 2038.

This section highlights the relative performance of portfolios in terms of an increasingly clean and diverse resource mix, with energy and capacity mix summaries, CO_2 emissions and reduction trajectories, and carbon intensities. With respect to least cost planning and affordability, the Companies evaluated both overall PVRR for all portfolios and customer bill impacts for the Core Portfolios. Executability and other foreseeable conditions are discussed holistically in Chapter 3 and Chapter 4 and specific to each resource throughout the Appendices. The results in this section were developed based on detailed production cost modeling runs of the final portfolios, including the resource additions identified in the portfolio development and verification steps for the Core Portfolios (unless otherwise noted). Portfolio analysis is presented for all Core Portfolios for each metric and for some metrics for Portfolio Variants and Sensitivity Analysis Portfolios.

Present Value Revenue Requirement

PVRR is a common resource planning metric used to quantify the relative costs across portfolios over the planning horizons. This metric is calculated by assessing future costs that could vary across portfolios including but not limited to costs for new generation and storage resources (technology price and resource selection), EE and DSM programs, maintaining coal units through the assumed remaining lives of the resources, and fuel commodity and transportation. These annual costs are discounted to 2024 using each Company's specific discount rate. This metric captures the cost of adding new resources throughout time as well as the costs to operate the system into the future, with changing operations and fuel costs. These production costs include operating and maintaining the generation units, fuel costs, labor costs and other system costs.

As discussed in the Modeling Software section, the Companies have transitioned to leverage the Encompass model for the representation of capital costs of selected resources. The annual costs represent the levelized costs of the resources calculated using utility-specific financial inputs such as capitalization structure, debt and equity rates, and other factors, along with the technology-specific financial inputs including construction period, capital expenses, asset life, tax life, and other parameters.

The EnCompass model's production cost module provides the final capital costs for model selected resources and production costs for each portfolio. The model includes non-firm energy purchases and sales associated with the joint dispatch of the system, and as such, the model optimizes dispatch of both DEC and DEP and provides total combined Carolinas' systems production costs. The production cost results are separated to reflect system production costs that are solely attributable to each utility to account for the impacts of joint dispatch under the consolidated system operations assumption for the Plan. The utility-specific system production costs are then added to the corresponding utility's capital costs to develop the total PVRR for each portfolio in billions of dollars ("$B").

Additionally, the analysis for the Plan includes generic proxy transmission network upgrade costs associated with adding new resources, as discussed in the Selectable Supply-side Resource section of this Appendix and retiring existing ones. Also included in the PVRR are costs associated with UEE, DR, IVVC, and costs for maintaining coal units through their projected lives.

Each of the costs described above varies from portfolio to portfolio as the resource mix in each portfolio changes based on Pathway-specific resource availability and cost assumptions. Shown below in Table C-58 are the annual revenue requirements associated with these costs for each Core Portfolio, discounted to 2024 at DEC's and DEP's Company specific discount rates. A combined DEC and DEP PVRR is also shown.

Table C-58: Present Value of Revenue Requirements through 2038 and 2050 ($B)

	PVRR Through 2038			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
P1 Base	42.4	33.6	76.1	76.7	62.0	138.7
P2 Base	40.2	28.4	68.6	70.7	53.2	123.8
P3 Base	39.7	26.4	66.1	70.7	48.3	119.0

By design, Pathway 1 achieves the Interim Target at an accelerated pace relative to Pathway 2 and Pathway 3. The extraordinarily aggressive pace of energy transition contemplated in Pathway 1 is reflected in the high cost of P1 Base relative to the other portfolios. To procure and deploy new resources in the unprecedented volumes required for P1 Base, particularly by 2030 (1,600 MW of offshore wind, approximately 9,600 MW of solar, approximately 5,300 MW of batteries, 300 MW of onshore wind, two CCs, and four CTs), the Companies would expect to incur costs well above those captured in the generic unit cost forecasts used in the resource planning analysis. As a proxy for these unknown market conditions, the Companies added a 20% cost risk premium to the capital costs for the scope, scale, and pace of resource additions in P1 Base for the purposes of this comparison. Even this adjustment may be conservative. As a tradeoff for the extended timeline to achieve the Interim Target, P2 Base and P3 Base result in combined system PVRRs that are $7.5B and $10B less, respectively, than P1 Base through the Base Planning Period, and approximately $15B and $20B less, respectively, through 2050. Extending the timeline for achieving the Interim Target allows for use of base resource availability assumptions and for advanced nuclear to contribute to the Interim Target in P3 Base, instead of requiring offshore wind. Advanced nuclear is economically selected in the mid-2030s in all portfolios, but allowing time for this resource to contribute to achieving the Interim Target also allows for the avoidance of more costly resources in the near term. Furthermore, the additional years allowed to achieve the Interim Target permit the Companies to take advantage of cost declines for resources such as solar and batteries, and to maintain lower levels of annual resource integration, increasing the executability of P2 Base and P3 Base relative to P1 Base at the same time. Overall, the lowest cost Core Portfolio is P3 Base.

Shown below in Table C-59 through Table C-62 are the PVRRs for each Portfolio Variant and Sensitivity Analysis Portfolio relative to the Core Portfolio in its respective Pathway. For this comparison, the Companies are comparing these Portfolio Variants and Sensitivity Analysis Portfolios to the Core Portfolios excluding the reliability resources identified in the Reliability Verification step. The Companies calculated the PVRR deltas from the unadjusted Core Portfolios to create a comparison on an equivalent basis. The Reliability Verification step was only performed for the Core Portfolios.

Table C-59: Pathway 1 – Portfolio Variant Present Value of Revenue Requirements through 2038 and 2050 Relative to P1 Base ($B)

	PVRR Through 2038			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
P1 Belews Creek Gas	2.0	-0.1	1.9	3.0	1.0	4.0

P1 Belews Creek Gas is the only Pathway 1 Portfolio Variant. This portfolio results in an increase to the PVRR relative to P1 Base by $1.9 B overall over the Base Planning Period and $4 B more by 2050. The delta accounts for the production cost benefit realized for operating the unit on natural gas, with more flexible and less carbon intensive energy. However, these benefits are offset by the cost to convert the unit, maintain the capacity to 2041, and maintain the reliability of the resource through contracting for firm fuel supply. To ensure the 2,220 gas-fired MW of Belews Creek Station is firm capacity designated network resource, the units require firm interstate transportation of natural gas, which adds significant cost. The production cost benefits from burning 100% gas do not offset the cost of the conversion and ensuring the firm gas deliverability. As discussed in Portfolio Development, the extension of the life of this asset does not substantially defer enough capacity and energy resources to make up for the remaining net cost of the conversion.

Table C-60: Pathway 2 – Portfolio Variants Present Value of Revenue Requirements through 2038 and 2050 Relative to P2 Base ($B)

	PVRR Through 2038			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
P2 High Availability	-0.2	-0.3	-0.5	-0.7	-1.8	-2.5
P2 Low Solar	0.3	1.1	1.4	-0.2	2.0	1.8
P2 Low Onshore	0.5	1.1	1.6	0.6	2.2	2.8
P2 Limited Gas	0.1	0.0	0.1	0.2	0.1	0.3
P2 MVP	-0.7	-0.8	-1.5	-1.1	-1.4	-2.5

P2 High Availability slightly lowers the total cost of the system through 2038 by $500 MM but continues to present executability challenges due to an increased and concentrated level of major project activity. While the resource availability assumed is above the base case assumptions, there are cost adjustments factored into the analysis for this portfolio above base assumptions to account for larger procurement volumes and more rapid resource deployment. Low solar and onshore wind availability has more significant impacts on the cost of the plan than limiting incremental natural gas resources. P2 is more negatively affected by low onshore wind availability than low solar availability, especially over the long term. Because the limitation to P2 Low Onshore spreads the selection of onshore wind out over 11 years (compared to over four years in P2 Base), the impact is greater than the less restrictive limitation on solar, which across all portfolios is generally selected in smaller amounts after 2035 (when advanced nuclear is available). The loss of the energy resources in P2 Low Solar and P2 Low Onshore creates a greater need for carbon free energy than P2 Limited Gas, which primarily results in accelerated battery selection to replace the CTs, which are primarily capacity and peaking energy resources. The accelerated selection of the batteries allows more efficient system operations compared to the CTs to help offset some of the incremental costs for acceleration. Finally, P2 MVP results in a savings of $1.5 B through 2038 and $2.5 B through 2050 relative to P2 Base, with minimal changes to the resource portfolio through the Base Planning Period, showing the significant benefit this lower cost, diversified natural gas supply delivers.

Table C-61: Pathway 3 – Portfolio Variants Present Value of Revenue Requirements through 2038 and 2050 Relative to P3 Base ($B)

	PVRR Through 2038			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
P3 High Availability	0.0	-0.4	-0.4	-0.7	-0.8	-1.6
P3 Low Solar	0.1	0.1	0.3	-0.6	1.0	0.3
P3 Low Onshore	0.0	0.2	0.2	-0.4	0.9	0.5
P3 OSW in ‘37	0.1	0.3	0.4	-0.3	1.1	0.8
P3 SMR Delay	0.1	0.2	0.3	1.4	5.3	6.7
P3 Limited Gas	0.3	0.3	0.6	0.8	0.3	1.1
P3 MVP	-1.1	-0.6	-1.7	-2.3	-0.3	-2.6

P3 High Availability, similar to P2 High Availability results in a slightly lower total system cost but carries similarly increased executability challenges. P3 Low Solar and P3 Low Onshore result in relatively lower portfolio cost increases than the equivalent Portfolio Variants in Pathway 2. The major difference between the two Pathways for these two resource availability Portfolio Variants is that without solar or onshore wind in the Pathway 2 Variants, the portfolio must turn to more batteries to meet the energy and capacity needs of the system. In Pathway 3 however, which allows more time to adapt and adjust to these lower solar and onshore wind amounts, can pivot to other available resources such as offshore wind. An 800 MW block of offshore wind is selected in each of these portfolios, P3 Low Solar and P3 Low Onshore Wind, to replace the lower amount of solar and onshore wind.

Similarly, whether required to select offshore wind by 2037 or selected in 2034 and 2035 to replace delayed nuclear deployment, offshore wind is integrated into the resource portfolio at relatively minor PVRR cost impacts through the Base Planning Period. P3 OSW in ’37 and P3 SMR Delay result in the selection of 1.6 GW of offshore wind before 2040 as a supplement to or replacement of nuclear resources in the mid-2030s. P3 OSW in ’37, which requires the system to select at least 800 MW of offshore wind by 2037 and 1.6 GW of offshore wind by 2038, increases the PVRR of the system by $800 MM through 2050; however, this variant does not offset any nuclear units, only modestly decreasing solar and battery selection. Delaying nuclear has a much more significant impact to the portfolio. This portfolio results in a cumulative six less nuclear units by 2050. To make up for this decrease in carbon free dispatchable energy, P3 SMR Delay increases and accelerates the selection of offshore wind and selects 3 GW more of solar and 6.7 GW more of battery by 2050 leading to the significant increase in cost of the portfolio.

With respect to gas resource availability and gas supply, the PVRRs of these Pathway 3 Portfolio Variants change the most compared to the other Pathway 3 Portfolio Variants. Similar to P2 Limited Gas, P3 Limited Gas relies on batteries to replace the fewer available CT resources. Unlike P2 Limited Gas, however the batteries selected in P3 Limited Gas resulted in net additions overall rather than just acceleration. Furthermore, this portfolio accelerates the selection of offshore wind from the mid-2040s in P3 Base to the mid-2030s to help make up the energy and capacity deficits from the lower gas resource availability. This results in a PVRR that is $1.1B more than P3 Base through 2050. P3 MVP, however, results in a savings of $1.7B through 2038 and $2.6B through 2050 relative to P3 Base. Significantly, the lower cost gas commodity and transportation cost results in the acceleration of the selection of CC resources and the trading of more costly solar and battery resources in the early 2030s for offshore wind in the mid-2030s.

Table C-62: Pathway 3 – Sensitivity Analysis Portfolios Present Value of Revenue Requirements through 2038 and 2050 Relative to P3 Base ($B)

	PVRR Through 2038			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
P3 High Resource Costs	0.7	0.7	1.4	4.3	6.5	10.8
P3 Low Resource Costs	-1.3	-2.0	-3.3	-4.7	-5.4	-10.1
P3 High Fuel	4.0	2.8	6.8	5.9	3.3	9.2
P3 Low Fuel	-3.1	-1.9	-5.0	-4.4	-1.8	-6.2
P3 High Load	1.4	1.3	2.7	2.4	4.2	6.6
P3 Low Load	-2.8	-2.2	-5.0	-5.7	-5.6	-11.3
P3 High EE	0.3	-0.3	0.1	0.4	-1.1	-0.7
P3 Low EE	-0.3	-0.2	-0.4	-0.2	1.5	1.3
P3 High DSM	-0.1	0.1	0.0	-0.1	0.2	0.0
P3 Low DSM	0.1	0.0	0.1	0.2	-0.1	0.1

P3 High Resource Cost leverages acceleration of gas resources to meet energy and capacity needs while deferring the selection of higher-cost solar and battery resources in the early 2030s for offshore wind in the mid-2030s. Over the long term, however, the system still requires the energy and capacity to meet growing customer needs and achieve carbon neutrality so, by 2050, of the PVRR of P3 High Resource Cost exceeds that of P3 Base by $10.8B. Notably, this portfolio only eliminates one advanced nuclear unit in favor of incremental available solar or battery resources with the increased capital cost for all technologies. In P3 Low Resource Costs, the sustained low capital costs for solar and batteries resulted in only a modest increase of 1.1 GW of solar and 1.1 GW of battery selected by 2050. This offset the 800 MW offshore wind block selected in the mid-2040s in P3 Base. Nuclear selection did not change. Portfolio PVRR through 2038 for P3 Low Resource Cost is $3.3B lower than P3 Base and PVRR through 2050 is $10.1B lower.

The high fuel price assumption had relatively minor impacts on resource selection, reflecting the need for all resource types across Pathways, but resulted in PVRR increases of $6.8B through 2038 and $9.2B through 2050. The low natural gas price in P3 Low Fuel lowered the cost of the system through both lower fuel commodity price and resource tradeoffs. In this portfolio, the model reduced selection of higher cost solar and battery resources in the early 2030s and selected offshore wind in the mid-2030s due to natural gas supplying emissions reductions for the system. The lower fuel cost saves $5B in PVRR terms through 2038 and $6.2B through 2050.

Comparing PVRRs for portfolios with different load forecasts is generally not useful, as the requirements of the systems between the cases are different.

Low and high EE and DSM assumptions have relatively minor impacts on the overall resource portfolios and their costs. Interestingly, due to the time for high and low EE impacts to be realized, the high EE portfolio resulted in a PVRR that was more than P3 Base by 2038 but resulted in a lower overall cost plan by 2050, relative to P3 Base. Conversely, P3 Low EE sees the opposite effect with savings over the Base Planning Period, but overall cost increases through 2050 relative to P3 base.

Performance Sensitivity Analysis

The performance sensitivity analysis, as explained in Chapter 2, evaluates the robustness of portfolio cost, measured using PVRR, with respect to changes in resource costs and fuel prices. Portfolios that show relatively larger changes in PVRR are relatively more sensitive to the input variable that is changed, which implies greater exposure to risk related to that input variable.

P1 Base, which requires far more rapid capital investment than P2 Base or P3 Base, is the most exposed (to the upside and downside) to changes in the price environment for capital equipment. Similarly, P3 Base, which requires slightly higher fuel burn that the other Core Portfolios, is the most exposed to changes in fuel prices. In all cases, P3 Base had the lowest PVRR, regardless of the relative magnitudes of the changes across portfolios.

Minimax Regret Analysis

In addition to the single variable sensitivity analysis, the Companies also conducted performance sensitivity analysis on combinations of the high and low forecasts for resource capital costs and fuel prices. Table C-63 below shows the PVRR through 2038 across these 27 cases. In each sensitivity case, P3 Base has the lowest PVRR of the three.

Table C-63: PVRR through 2038 Across Resource Capital and Fuel Price Performance Sensitivities, Combined Carolinas System ($B)

Case	P1 Base	P2 Base	P3 Base
Base Capital/High Fuel	82	75	73
Base Capital/Base Fuel	76	69	66
Base Capital/Low Fuel	71	64	61
Low Capital/High Fuel	75	71	70
Low Capital/Base Fuel	69	65	63
Low Capital/Low Fuel	65	60	58
High Capital/High Fuel	84	77	74
High Capital/Base Fuel	78	70	68
High Capital/Low Fuel	73	65	62

Put another way, P3 Base minimizes the maximum customer exposure to cost increase. Table 3-5 below presents the "regrets" for each case, defined as the difference between the PVRR for a given portfolio in a given case and the minimum portfolio PVRR for that same case. As Table C-64 below shows, P3 Base has the lowest maximum regret across the cases. This is referred to as "minimax regrets" analysis.

Table C-64: PVRR Regret through 2038 Across Resource Capital and Fuel Price Performance Sensitivities, Combined Carolinas System ($B)

Case	P1 Base	P2 Base	P3 Base
Base Capital/High Fuel	9.3	2.2	0.0
Base Capital/Base Fuel	10.0	2.5	0.0
Base Capital/Low Fuel	10.4	2.6	0.0
Low Capital/High Fuel	5.8	1.5	0.0
Low Capital/Base Fuel	6.5	1.8	0.0
Low Capital/Low Fuel	6.9	1.9	0.0
High Capital/High Fuel	9.4	2.3	0.0
High Capital/Base Fuel	10.1	2.6	0.0
High Capital/Low Fuel	10.5	2.7	0.0

Importantly, the minimax regret analysis described above stresses market variables without consideration of future re-optimization for the portfolios in response to changing market conditions. This means that the analysis does not account for the “check and adjust” approach that is a vital part of the iterative resource planning process.

Customer Bill Impact Analysis

As previously noted, the PVRR of a portfolio is a common and useful financial metric in resource planning to measure the cost of the plan over a long period of time. The PVRR metric captures the costs and benefits of accelerating retirements, building new generation and associated transmission, and changing fuel prices and operation costs over time. While PVRR is an important metric for the long run costs of a portfolio, it is important to also evaluate the immediate cost to customers.

For the purposes of the Resource Plan analysis, customer bill impacts are developed based on the changes in annual costs to retail customers over time factoring in the growth of the system, the additions of new resources, and changes in the cost to operate the system over time. The analysis is also influenced by changes in fuel commodity prices and operations costs, as a result of the resources in each portfolio. The analysis uses currently applicable cost of service factors to allocate total system revenue requirements to retail customers. The customer bill impacts use a different methodology for calculating the annual revenue requirement for new resources, with PVRR using an economic carrying charge as the annual revenue requirement and customer bill impacts utilizing a depreciating rate base methodology.

The analysis calculates the average retail impact (total change in retail energy costs over all rate classes) and applies that average retail impact to a typical residential customer bill using 1,000 kWh of energy per month. This representative customer bill impact attempts to quantify how much a residential customer could expect to see their bill change over Base Planning Period as impacted by the changes contemplated in the Resource Plan analysis. This comparative analysis only accounts for changes captured in the Plan’s analysis and does not represent an all-inclusive bill impact analysis as other factors can also influence a customer’s bill. Many future unknowns, costs and other parameters outside of the resource planning process are also anticipated to impact revenue requirements and customer bills.

Below, Table C-65 through Table C-68 below show the projected changes to a typical residential customer’s bill for each of the Core Portfolios through 2033 and 2038. Additionally, the projected average annual percentage change from 2024 through 2033 and through 2038 is also shown representing how much a customer’s bill would be expected to increase on average annual basis over that time frame. The costs reflected in these bill impacts are consistent with the parameters to evaluate the Core Portfolios consistent with the development of the PVRRs. The customer bill impacts are presented for DEC and DEP. Additionally, an illustrative combined DEC/DEP (“CAR”) impact is presented which utilizes the weighted average impacts of the separate utility impacts for a combined Carolinas view.

Table C-65: DEC, DEP, and Illustrative Combined DEC/DEP Annual Average Retail Bill Impacts (%) through 2033

	DEC	DEP	CAR
P1 Base	3.3%	5.6%	4.5%
P2 Base	2.6%	4.9%	3.7%
P3 Base	2.6%	3.0%	2.8%

Table C-66: DEC, DEP, and Illustrative Combined DEC/DEP Cumulative Residential Bill Impacts [$ per Month] through 2033

	DEC	DEP	CAR
P1 Base	41	86	60
P2 Base	32	72	48
P3 Base	30	41	35

Table C-67: DEC, DEP, and Illustrative Combined DEC/DEP Annual Average Retail Bill Impacts (%) through 2038

	DEC	DEP	CAR
P1 Base	3.2%	3.2%	3.2%
P2 Base	2.6%	2.7%	2.7%
P3 Base	2.9%	2.2%	2.6%

Table C-68: DEC, DEP, and Illustrative Combined DEC/DEP Cumulative Residential Bill Impacts ($ per Month) through 2038

	DEC	DEP	CAR
P1 Base	65	77	70
P2 Base	51	63	56
P3 Base	59	48	55

Table C-65 through Table C-68 above show that P1 Base, with the achievement of the Interim Target in 2030, results in higher projected customer bill impacts, especially by 2033. P2 Base and P3 Base, which allow for additional time to achieve the Interim Target, lead to lower bill impacts for customers. This analysis shows that the pace of the transition in each Pathway plays a critical role in the immediate cost to consumers in the form of bill impacts, with Pathway 1 requiring more resources, sooner, impacting both the cost of the resources and the rate at which rates would increase on average.

The main differentiator by 2033 between P1 Base and P2 Base compared to P3 Base for DEP is the integration of offshore wind. Both P1 Base and P2 Base include 1.6 GW of offshore wind in the early 2030s. This investment is reflected in the significant bill impacts for DEP customers beginning in the year in which the resource is integrated. Because offshore wind is only available to be connected into the DEP service territory and DEP generally has more favorable accessible solar and onshore wind resource, the selection of these resources in DEP earlier has a more immediate impact on customer bills, but as other long lead time resources, such as nuclear and pumped storage hydro at Bad Creek II come online, DEC's impact balances out with DEP's in the long term. By 2038, each of the portfolios have achieved the Interim Target and the resource portfolios begin to look more similar, including the retirement of all coal generating capacity on the system across all portfolios.

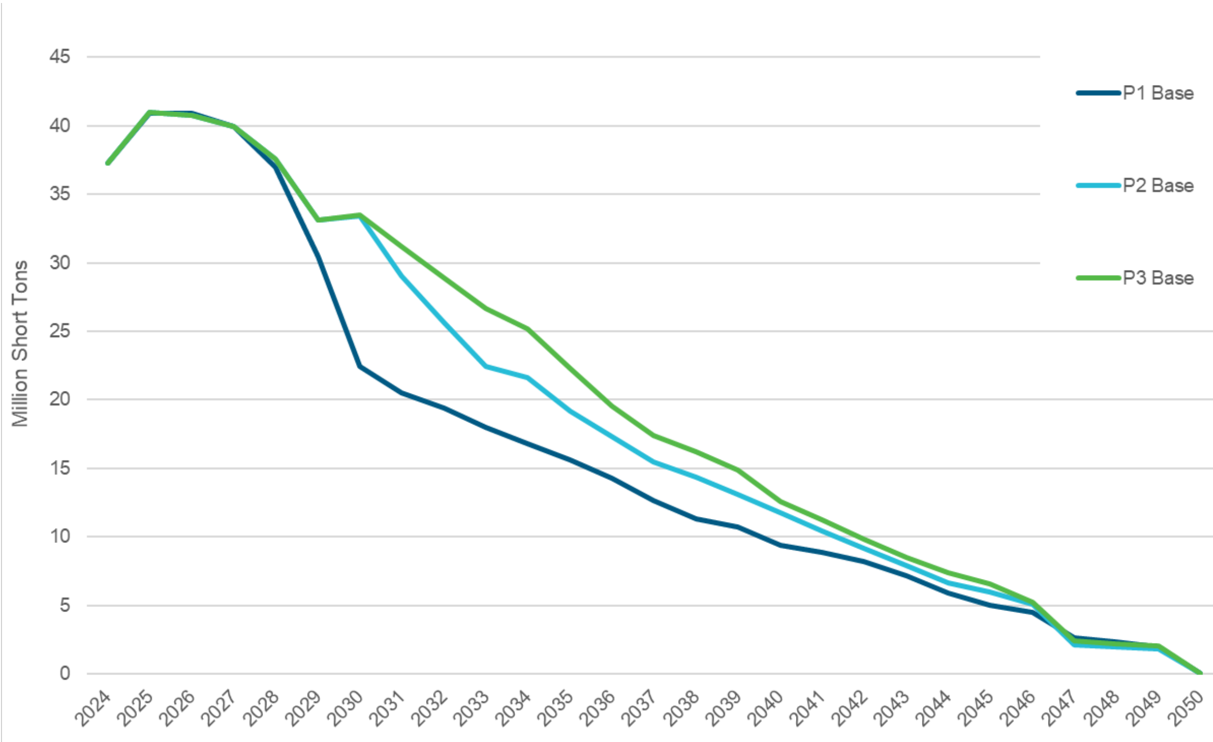
CO_2 Emissions and Reduction Trajectory

As discussed in Chapter 2 and Chapter 3, each of the Energy Transition Pathways leads to carbon neutrality by 2050, but each does so at a different pace.

The projected emissions are outputs of the production cost model, which economically dispatches the specific set of resources in each portfolio to meet the energy needs of the system. For the detailed production cost runs, no mass cap, environmental dispatch adder, or price on carbon is used to influence the operation of the system. The system mass cap was only used in the Portfolio Development step. As mentioned previously throughout this Appendix, the DEC and DEP systems are jointly dispatched. For this reason, emissions are shown for the combined systems.

Figure C-8 below charts the CO_2 reductions for the combined DEC and DEP systems for each of the Core Portfolios through 2050. Resources added in each portfolio to achieve the Interim Target influence the differences in emissions trajectories to carbon neutrality in 2050. P1 Base achieves the Interim Target first among the three Core Portfolios, with the more aggressive timing carrying substantial, perhaps insurmountable, execution challenges. However, it allows for a slightly more gradual transition from the achieving the Interim Target in 2030 to carbon neutrality in 2050. P2 Base and P3 Base conversely present more consistent glidepaths in system CO_2 emissions over the entire planning horizon. The exception to this consistent annual reduction occurs starting in 2029 when P1 adds 1.4 GW of CC capacity and retires approximately 1.8 GW of coal capacity. This makes a significant year-over-year impact to CO_2 emissions, appearing as definitive step change from 2028 to 2029. P2 Base differentiates itself from P3 Base in Annual CO_2 emissions reduction between 2030 and 2033, when this portfolio accelerates the addition of CC resources and relies on 1600 MW of offshore wind to achieve the Interim Target in 2033. P3 Base achieves compliance in 2035, adding the same cumulative solar, onshore wind, and hydrogen capable gas resources as P2 Base through 2035. However, instead of relying on the addition of offshore wind to achieve compliance, the P3 Base uses the same nuclear units selected in P2 Base to achieve the Interim target two years later.

Figure C-8: Annual CO_2 Emissions by Core Portfolio, Combined Carolinas System (Millions of Short Tons)



Below, Table C-69 through Table C-71 show the CO_2 emissions reduction percentages for the combined DEC and DEP systems. Table C-69 and Table C-70 show CO_2 reductions relative to a 2005 baseline. Table C-71 shows the difference in cumulative CO_2 emissions for each Core Portfolio, with P3 Base emitting the most cumulative tons of CO_2 of the Core Portfolios over the planning horizon.

Table C-69: Annual Combined DEC and DEP NC CO_2 Emissions Reduction in 2030, Interim Target Year, and 2038 (Percent reduction relative to 2005)

	2030	Interim Target Year	2038
P1 Base	70.4%	70.4%	85.1%
P2 Base	55.9%	70.4%	81.1%
P3 Base	55.8%	70.6%	78.6%

Table C-70: Annual Combined DEC and DEP Systems CO_2 Emissions Reduction in 2030, Interim Target Year, and 2038 (Percent reduction relative to 2005)

	2030	Interim Target Year	2038
P1 Base	68.7%	68.7%	83.5%
P2 Base	54.7%	69.0%	79.5%
P3 Base	54.6%	69.3%	77.0%

Table C-71: Cumulative Combined DEC and DEP Systems CO2 Emissions through 2050, Relative to P3 Base (Millions Short Tons)

	Cumulative CO_2 Emission Reductions
P1 Base	-92
P2 Base	-31
P3 Base	0.0

By 2030, P1 Base achieves the Interim Target while P2 Base and P3 base achieve approximately 56% CO_2 emission reduction. On a system level, in the portfolios are just short of these levels due emissions from existing generating units in South Carolina. P1 Base outpaces the other Core Portfolios, achieving 83.5% reduction by 2038 for the combined DEC and DEP systems. P2 Base achieves the Interim Target in 2033, reaching 79.5% reduction for the combined DEC and DEP systems by 2038. Finally, P3 Base achieves the Interim Target in 2035, while achieving approximately 77% for the combined DEC and DEP systems by 2038. P1 Base emits 92 million short tons less than P3 Base through 2050. P3 Base emits the most cumulative tons of CO_2 through 2050, while P2 Base emits 31 million short tons less over this same time horizon.

Importantly, there are not prescribed or authorized interim emission targets between the Interim Target and 2050. The CO_2 emission trajectory of each portfolio in each Pathway could vary and could reduce the cumulative CO_2 emission reductions benefits of Pathway 1 and Pathway 2 relative to Pathway 3.

Performance with Respect to Proposed Environmental Protection Agency's Clean Air Act Section 111 Proposed Rule

This portion of the portfolio analysis looks at the performance of the Core Portfolios with respect to the proposed EPA regulations addressing greenhouse gas ("GHG") emissions from existing coal plants and from new and existing natural gas plants ("EPA CAA Section 111 Proposed Rule"). Portions of the proposed rule, including coal capacity factors or co-firing coal units with natural gas, existing CC capacity factors (in lieu of hydrogen co-firing), new CT capacity factors, and initial CO_2 emissions rate standards on new CC units, are assessed to examine whether the Core Portfolios are already or nearly in compliance with the proposed rules. Of note, these rules are still being reviewed by the industry and will be clarified by the EPA in a final rule (expected in Q2 2024). Further, existing units' compliance plans will vary from unit to unit and site to site, with states setting the performance standards in state plans that are subject to EPA approval. Therefore, the assessment in this section is simplified for analytical purposes and subject to finalization of the rules and how, for existing units, they will be implemented by states.

First, based on projected retirement dates, coal units must meet certain emissions or operational standards beginning in 2030. Coal units retired by the end of 2031 (shown as retire by beginning of year ("BOY") 2032 for the modeling results) must have no emissions rate increases beginning in 2030. Coal units retired after BOY 2032 but by end of year ("EOY") 2034 (BOY 2035) must limit annual capacity factors to 20% and not increase their emissions rates. Coal units retired after BOY 2035 but by EOY 2039 (BOY 2040) must meet an emission limitation based on co-firing natural gas at 40% beginning in 2030. Finally, coal units retired after BOY 2040 must utilize carbon capture and sequestration ("CCS") at 90% capture rate beginning in 2030. Table C-72 below shows retirement dates and applicable standards for each Core Portfolio along with current natural gas co-firing capabilities.

Table C-72: Coal Unit Retirements (effective by January 1 of year shown) and Applicable Proposed EPA GHG Regulations Standards

Unit	Natural Gas Co-firing Capability	P1 Base Retirement	P1 Base Applicable Standard	P2 Base Retirement	P2 Base Applicable Standard	P3 Base Retirement	P3 Base Applicable Standard
Allen 1&5	0%	2025	N/A	2025	N/A	2025	N/A
Belews Creek 1&2	50%	2030	N/A	2036	40% NG Co-firing	2036	40% NG Co-firing
Cliffside 5	40%	2029	N/A	2031	No Emission Rate Increases	2031	No Emission Rate Increases
Cliffside 6[1]	100%	2049	CCS or Emissions Rate	2049	CCS or Gas Steam Emissions Rate	2049	CCS or Gas Steam Emissions Rate
Marshall 1&2	40%	2029	N/A	2029	N/A	2029	N/A
Marshall 3&4	50%	2034	40% NG Co-firing	2032	No Emission Rate Increases	2032	No Emission Rate Increases
Mayo 1	0%	2029	N/A	2031	No Emission Rate Increases	2031	No Emission Rate Increases
Roxboro 1&2	0%	2029	N/A	2029	N/A	2029	N/A

Unit	Natural Gas Co-firing Capability	P1 Base Retirement	P1 Base Applicable Standard	P2 Base Retirement	P2 Base Applicable Standard	P3 Base Retirement	P3 Base Applicable Standard
Roxboro 3&4	0%	2030	N/A	2033	Capacity Factor Limit and No Emission Rate Increase	2034	Capacity Factor Limit and No Emission Rate Increase

Note 1 : Cliffside 6 is assumed to continue operating on 100% on natural gas beyond 2035. Specific CO_2 emissions rate standards in this proposed rule apply to gas-fired steam units. However, it is not clear in the proposed rule that units that burn some coal prior to 2030 can switch to the gas-fired steam unit subcategory during the 2030s. If not allowed in the final rule to switch to natural gas and continue operation, under the proposed rule the unit would need to have installed CCS to continue operating past 2039, The Companies are seeking clarification on switching to natural gas in the final rule.

Based on the Core Portfolios' retirement dates, P1 Base does not have any applicable standards other than requiring Marshall 3 and 4 to meet a CO_2 emissions rate reflecting operation at 40% natural gas co-firing, which they are already capable of. P2 Base and P3 Base modeled retirement dates limit Cliffside 5, Marshall 3 and 4, and Mayo 1 to no emissions rate increases, Roxboro 3 and 4 to a 20% capacity factor limit (and no emission rate increase), and restricting Belews Creek 1 and 2 to operate at a CO_2 emissions rate reflecting 40% natural gas co-fire, which they are already capable of.

Based on these retirement dates, each of the coal units in each of the portfolios achieve the applicable standard,[19] except for Roxboro 3 and 4 in P3. In this instance, Roxboro 3 operates just above the 20% cap in two years; however, Roxboro 4, held to the same applicable standard, has projected capacity factors well below 20%, leaving room for more balanced operation between Roxboro 3 and 4 to remain below the applicable standard.

A capacity factor limitation on new resources will present additional challenges in meeting system energy requirements, as discussed in the Supplemental Portfolios later in this Appendix pertaining to this rule. Many of the existing CC units operate under 50% capacity factor when unconstrained in the Core Portfolios after 2035. The few CCs that do continue to operate above 50% after the 2035 timeline decrease in capacity factor over time, dropping below 50% capacity factor naturally by the late 2030s or early 2040s. Notably, many of the existing CCs are already operating below 50% capacity factor and the Companies expects to be able to manage the capacity factors of these units to ensure each of them operates under 50% capacity factor.

In general, all New CTs operate well below the 20% annual capacity factor limitation over the long term. As more renewable resources are still being brought online in the late 2020s, 20% capacity

[19] For coal units retired before 2035, the applicable standard of no emissions rate increases was not evaluated due to uncertainty in state-established baselines and compliance requirements.

factors are exceeded on these units. However, again the utilization of these advanced class CTs may be able to be managed to keep them from exceeding the applicable capacity factor limit.

Finally, given the assumed generic technology being used for advanced class CCs, these resources regularly operate under the proposed 770 lbs. CO_2 per MWh gross limit on an annual average basis[20] as a Phase 1 standard for new baseload gas resources, especially for P2 Base and P3 Base. P1 Base, however, has more dynamic operations of the new CCs due to more frequent shutting down and restarting of the units, and ramping and operating at less efficient points due to more significant variable energy resources. Active management of emissions rates, including limiting duct firing, low-load operations, startups and shutdowns, and instituting a more frequent maintenance cycle can help ensure these resources stay below the Phase 1 proposed requirement for emissions rates in all Core Portfolios. As noted above, the proposed 770 lbs. CO_2 per MWh gross limit for new baseload gas resources may be revised when EPA issues a final rule in 2024.

Additional analysis of potential pathways to compliance with the proposed rules are evaluated in the Supplemental Portfolios section on Proposed EPA GHG Regulations.

Supplemental Portfolios

Additional analysis was completed for informational purposes to address specific regulatory needs or for other informational purposes. A Supplemental Portfolio that does not specify a CO_2 target was completed to address a directive in the PSCSC's 2022 IRP update order,[21] and two additional Portfolio Variants of that portfolio to evaluate the impact of solar project ownership, and South Carolina IRP ordered battery price forecasts and natural gas fuel curve described further below. Additionally, two Supplemental Portfolios that evaluate the potential impact of EPA CAA Section 111 Proposed Rule were completed, as described further below. As these rules have only been proposed, these Supplemental Portfolios are also for informational purposes only. Finally, two additional portfolios were developed to understand the impact of high and low levels of EE/DSM based on changes in fuel costs and more or less restrictive CO_2 constraints.

Proposed EPA GHG Regulations Supplemental Portfolios

The Companies modeled potential pathways to compliance with the EPA CAA Section 111 Proposed Rule with respect to the more challenging compliance approaches to the rule. As discussed above in Portfolio Analysis, the Companies observed that the Core Portfolios were generally in line with the existing coal and Phase 1 standards for new and existing natural gas units. For Phases 2 and 3, the Companies modeled two scenarios with respect to the proposed requirements for applicable new and existing gas resources. The first scenario complied with the proposed rules by limiting the capacity factors of new natural gas units to operate in the intermediate- or low-load categories and

[20] The proposed standard is a 12-operating-month rolling average basis. The Companies used annual averages as a proxy for this standard.

[21] Order Accepting 2022 Integrated Resource Plan Updates - South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC, Docket Nos. 2019-224-E, 2021-10-E, 2019-225-E, 2021-8-E (Mar. 10, 2023).

ensuring that existing units operate below the applicability criteria for this proposal. New CCs were forced to operate at or below 50% annual capacity factor beginning when they come into service, and existing CCs above 300 MW were restricted to operate at or below 50% beginning in 2030. For all new CTs, the Companies assumed these units would be restricted to the low-load category with their capacity factors at or below 20%.

The second scenario assumed new gas units utilized hydrogen co-firing to achieve the emission limitation standards for new and existing natural gas units by assuming access to sufficient hydrogen fuel at 30% of total fuel volume by 2032 and 96% of total fuel volume by 2038. The hydrogen co-firing was applied to all applicable CCs, new and existing, while continuing to restrict new CTs to operate at or below 20% capacity factors. Both of these approaches were modeled under Pathway 3. A third pathway to compliance was presented in the EPA CAA Section 111 Proposed Rule. This centered around carbon capture and sequestration (CCS) for existing and new gas resources. CCS has not been considered cost-effective due to the lack of suitable geology to sequester significant volumes of carbon in the Carolinas, and significant costs and challenges to develop interstate pipelines, including challenges related to permitting, property rights, and public acceptance, which would need to be overcome, to transport the captured CO_2 to other regions suitable for sequestration. However, although not yet adequately demonstrated, this compliance pathway may become viable given the potential significant costs and challenges with the other compliance pathways. The Companies will continue to investigate the feasibility and viability of CCS as a compliance pathway for the EPA CAA Section 111 Proposed Rule as further information becomes known and the proposed rule is finalized. More information on the Proposed EPA GHG Regulations is discussed in Chapter 3 and in Appendix K.

In the first scenario, SP EPA 111 CF, the limitations on generation for existing and new gas resources required the Companies to have to replace that energy with significant and accelerated incremental resources to continue to reliably meet customer demand. To fill the energy gaps presented by the limitation on existing and new gas generation and continuing to meet the reliability standards of the system, the portfolio required 1,600 MW of offshore wind by 2032 and a fourth CC by 2035, both of which exceed the base resource availability for Pathway 3. In addition to exceeding base case resource availability, the capacity factor limitation added $3.6 B to PVRR through 2050 relative to P3 Base.

For the second scenario, SP EPA 111 H_2, the Companies assumed the same clean hydrogen fuel market price, consistent with the Companies' base planning assumption price for hydrogen, despite the significantly increased required hydrogen volumes needed for compliance with the proposed rule which would likely impact the price of available clean hydrogen. In this portfolio, because the CC units were able to run with unconstrained capacity factors on a blend of natural gas and hydrogen, model resource selection was similar to P3 Base (and consistent with Pathway 3 resource availability assumptions). Through achieving the Interim Target in 2035, the portfolio was able to offset resources and reduced solar by 1.4 GW, batteries by 860 MW, and onshore wind by 450 MW. The portfolio was able to offset these resource additions as a result of the hydrogen co-fired CCs reducing the CO_2 emissions of the system. However, while some solar, battery, and onshore wind resources are not needed to meet the direct electric load forecast of the systems, the carbon-free energy required to produce the clean hydrogen at the levels required would far exceed the offset resources. PVRR through 2050 increased by approximately $10.5 B relative to P3 Base. The PVRR impact of this scenario is significant with respect to the Core Portfolios' costs. Additionally, and importantly, the availability and access to the significantly increased volumes and on a significantly accelerated timeline required by the EPA CAA Section 111 Proposed Rule relative to the Companies' base assumptions for hydrogen supply are more concerning. Although the Companies believe hydrogen is an important and potentially transformational fuel for the future of the resource portfolio, the volumes necessary to utilize the hydrogen compliance pathway are not thought to be achievable on the timelines presented in the EPA CAA Section 111 Proposed Rule.

No Carbon Constraints Supplemental Portfolio

As required by the PSCSC, the Companies modeled Supplemental Portfolios without any CO_2 reduction constraints (a Base Case, a Portfolio Variant, and two Sensitivity Analysis Portfolios). While the Companies performed an informational "no carbon constraints" modeling exercise, it is not an executable pathway as it does not comply with applicable laws and requirements. Executing on a resource plan with no specified CO_2 emissions reduction target would require the Companies to violate state law that applies to their dual-state operations.

This portfolio was developed with the same Analytics Process used to develop the portfolios in Energy Transition Pathways 1, 2, and 3. This Supplemental Portfolio leverages a retirement schedule optimized utilizing economic coal retirement dates developed without carbon constraints (carbon taxes or CO_2 reduction constraints). The development of this coal retirement schedule is discussed in Appendix F.

The SP SC No CO_2 Constraint portfolio, developed without the influence of carbon emission constraints or carbon taxes, is overly reliant on coal generation through the Base Planning Period and on natural gas peaking resources to meet incremental capacity needs over time. The model selects three CC units over the Base Planning Period, later than in the Core Portfolios. CCs are selected in P3 Base in 2029, 2032, and 2033. CCs are added in SP SC No CO_2 Constraint in 2029 2034 and 2036. These dates correspond to the retirements of coal units (Roxboro 1 and 2 in 2029, Roxboro 3 and 4 in 2034, and Belews Creek 1 &2 in 2036) that were optimized in the coal retirement analysis. To meet continued load growth, the model adds 8.1 GW of peaking CT capacity over the Base Planning Period in SP SC No CO_2 Constraint, representing 19 new gas units in addition to the 4.1 GW of CC across 3 CC power blocks. The portfolio does little in the way of diversifying commodity price and capital cost risk, adding only 2.1 GW of solar, 900 MW of batteries, and 600 MW of onshore wind.

Overall, this portfolio results in a PVRR within $1B of P3 Base through 2038, while failing to mitigate commodity price and future regulatory risk or capture the benefits of resource diversity, subjecting customers to over-reliance on natural gas supply and deliverability to the region, in addition to being non-compliant with applicable laws. For these reasons, this informational portfolio cannot be the most reasonable and prudent means of meeting the Companies' resource planning requirements.

Natural Gas Pricing and NREL ATB "Low" Battery Costs Supplemental Portfolio

This portfolio, SP SC Battery and Gas Cost, was developed as a Sensitivity Analysis Portfolio of the SP No CO_2 Constraint. It optimizes the resource portfolio utilizing specific assumptions as directed in previous South Carolina IRP Orders. These assumptions include the use the NREL ATB "Low" battery costs forecast for batteries and the use of a natural gas price forecast that relies on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts.

The low-price battery forecast and natural gas forecast that transitions to higher fundamental prices earlier, compared to the base forecast, makes its impact on this portfolio immediately, deferring the selection of the 2029 CC selected in the SP No CO_2 Constraint portfolio to 2033. To support the deferral of this CC by four years, the portfolio replaces this capacity with 850 MW of CTs and 400 MW of batteries. The portfolio adds another 500 MW of batteries through 2031 at the lower battery price forecast. The portfolio adds an additional approximately 680 MW of batteries through 2038, for a total of 1.6 GW of batteries representing a 600 MW increase over SP No CO_2 Constraint. Overall, through Base Planning period this portfolio results in marginally more solar and wind that are supported by the additional battery capacity.

Supplemental Portfolios with varying UEE/DSM forecasts against Fuel Prices and Carbon Constraints

To assess the impact to resource selection with varying EE and DSM forecasts, fuels prices and carbon constraints, the Companies developed Supplemental Portfolios. Importantly, this South Carolina ordered IRP requirement addresses how high forecasts of UEE and DSM might impact resources selected in a high fuel price scenario with more restrictive carbon emissions constraints and conversely, how low UEE and DSM might impact resources selected in a lower fuel price scenario with less restrictive, or in this case no carbon emissions constraints.

For the high UEE and DSM forecast in a high fuel price scenario, the Companies developed this Supplemental Portfolio in Pathway 1, achieving the Interim Target by 2030. This portfolio, SP High EE, DSM, Fuel, CO_2, utilized the high UEE, DSM, and fuel forecasts discussed previously in this Appendix. As seen in P3 High UEE, the high UEE forecast allows for the avoidance of 425 MW of CT by 2030. Furthermore, the lower net load forecast with high UEE, and additional DSM resources are able to offset the third tranche of 800 MW of offshore wind in 2033, cumulatively replacing some of this capacity and energy with incremental batteries and solar. Overall, this portfolio eliminates 800 MW of offshore wind and defers the selection of a nuclear unit to outside the Base Planning Period.

For the low UEE and DSM forecast in a low fuel price scenario, the Companies developed this Supplemental Portfolio in a no carbon constraints scenario. This portfolio, SP Low EE, DSM, Fuel, No CO_2, utilized the low UEE, DSM, and fuel forecasts discussed previously in this Appendix. As seen in SP No CO_2 Constraint, the portfolio relies heavily on coal generation, and with the low fuel price forecast, as observed in P3 Low Fuel, the portfolio takes advantage of the low natural gas prices. This results in no solar select in this portfolio by 2038, 2.1 GW less than SP No CO_2 Constraint. The portfolio selects three incremental CTs, to offset the lower amount of DSM bringing the total selected CT capacity in this portfolio to 9.4 GW, further increasing natural gas price volatility risk, while continuing to expose customers to risk associated with continued operation of the coal fleet through the mid-2030s. In contrast to P3 Low EE, which increase solar, battery, and offshore wind relative to P3 Base, this portfolio decreases diversification in other resources and relies more on gas to service the incrementally higher load assuming the low EE. Over the long term, as coal and natural gas resources retire from the system, and fuel prices rise, the portfolio relies on significant additions of solar and nuclear to continue to meet the energy needs of the system by 2050.

Solar PV PPA Supplemental Portfolio

The Companies developed a Supplemental Portfolio to evaluate the impact of solar project ownership structure on resource selection. This portfolio includes the assumption that all new solar is procured via purchase power agreement ("PPA"). This portfolio is also included for informational purposes only against the Supplemental Portfolio that has no CO_2 constraints, because the specifics of project ownership and procurement are outside of the scope of resource planning, which is based on generic unit assumptions.

Specifically, the PPA price was developed taking the Plan's generic assumption for solar and developing a levelized cost on a dollar per MWh basis ($/MWh). With this cost recovery structure, each MWh of energy produce by the solar units would incur this levelized cost. The cost factors in the initial capital cost of the resource, the projected energy it will produce, the operations and maintenance costs, and the asset life of the project, along with the tax benefits from the IRA. The levelized cost used in this Supplemental Portfolio as a proxy solar PPA cost was generally consistent with the range of costs in the most recent solar procurement RFP. The selectable solar PPA resource assumes a contract life consistent with the life of the solar asset, 30 years, and has the same operational characteristics as CPRE projects, relative to allowable curtail ability.

This portfolio, SP SC PV PPA, results in some acceleration of solar within the base planning period but does not result in significant overall additions to the portfolio by 2038, adding only 225 additional MW of solar to the portfolio compared to the SP SC No CO_2 Constraint. The SP SC PV PPA Supplemental Portfolio does increase the total amount of solar on the system by 2035 by 1.9 GW, but as mentioned above this additional capacity is primarily an acceleration of solar selected in from 2036 through 2038 in the SP SC No CO_2 Constraint portfolio. Similarly, the change in the representation of the price of solar results in negligible change in total solar by 2050, 375 MW less, but continues to shift slightly when the solar was selected.

Recommend Portfolio – P3 Base

Careful consideration of primary planning requirements to comply with existing laws and regulations and ensuring reliability for customers along with balancing risks and trade-offs for an orderly energy transition — resource diversity, an increasingly clean resource mix, reasonable, least cost planning, and executability as well as other foreseeable conditions — is essential to determining prudent next steps as the Companies begin executing the Carolinas Resource Plan. As established in Chapter 3 portfolio analysis and outlined in more detail in Chapter 4, the Companies recommend planning for execution aligned with Pathway 3 and have developed an Execution Plan and are proposing near-term actions through 2026 that are informed by the recommended portfolio: P3 Base.

Recognizing that resource planning is an iterative process, both Commissions will have a further opportunity to “check and adjust” in the future as policies evolve, new technological developments occur, and more refined information becomes known. Over the next few years, timelines and costs assumed in the modeling will either be validated or challenged by the real-world execution path and such information will be used to refine strategies and improve benefits for customers in future Plans.

P3 Base – Capacity and Energy Mix Summary

Figures C-9 and C-11 below illustrate both the current and forecasted capacity mix for the DEC and DEP systems, as projected in portfolio P3 Base. The figures depict how the capacity mix for the Companies’ systems change with the passage of time. Over the fifteen-year period from 2024 to 2038, both DEC and DEP are expected to be out of coal and more heavily reliant on renewable resources and energy storage. Of the incremental resources added, renewable resources comprise 46% and 62% for DEC and DEP, respectively. Additionally, of incremental resources added, energy storage resources make up 23% and 15% for DEC and DEP, respectively. Clean-burning natural gas resources are expected to increase to maintain system reliability after flexible coal resources are retired, comprising 16% and 19% of DEC and DEP incremental resource additions. Finally, of incremental resources added, nuclear is also expected to be a valuable clean resource, making up 10% and 2% for DEC and DEP, respectively, by 2038.

Figure C-9: P3 Base - DEC Capacity Mix in 2024 and 2038 (Nameplate MW)

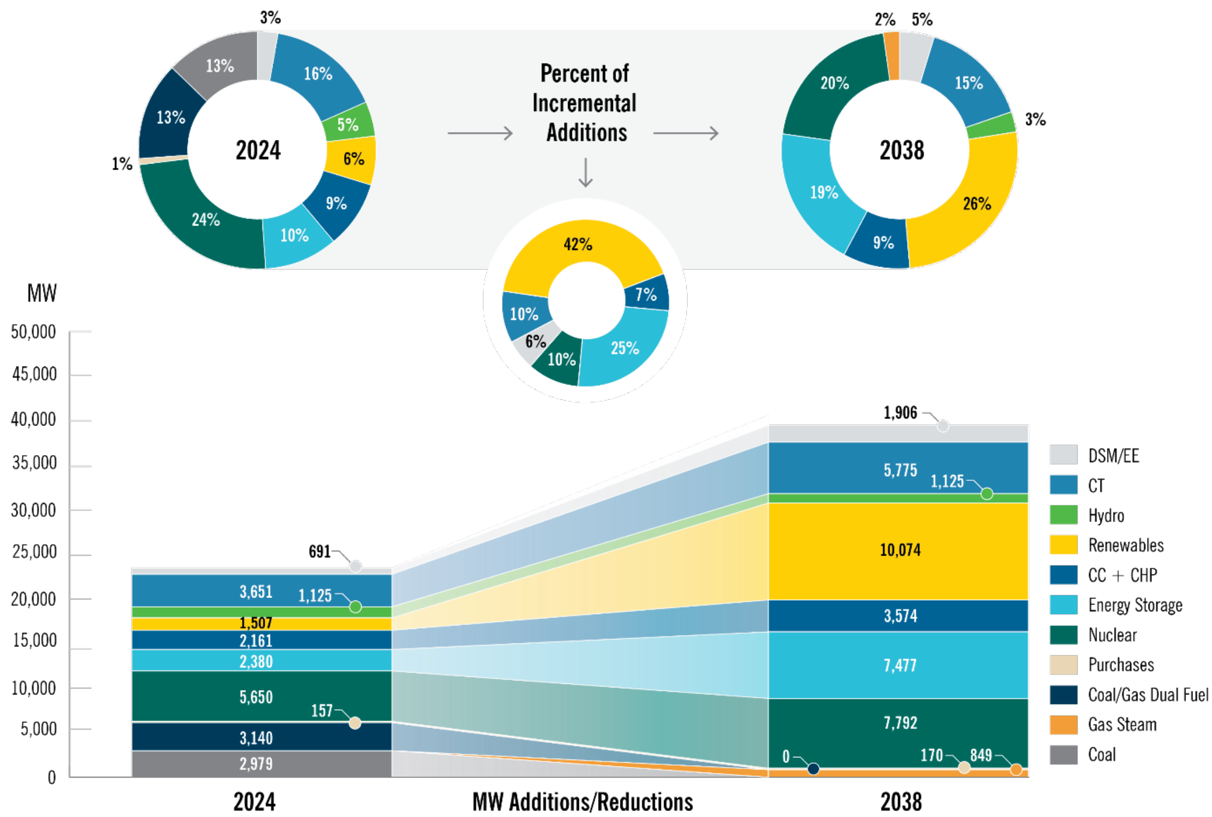


Figure C-10: P3 Base - DEP Capacity Mix in 2024 and 2038 (Nameplate MW)

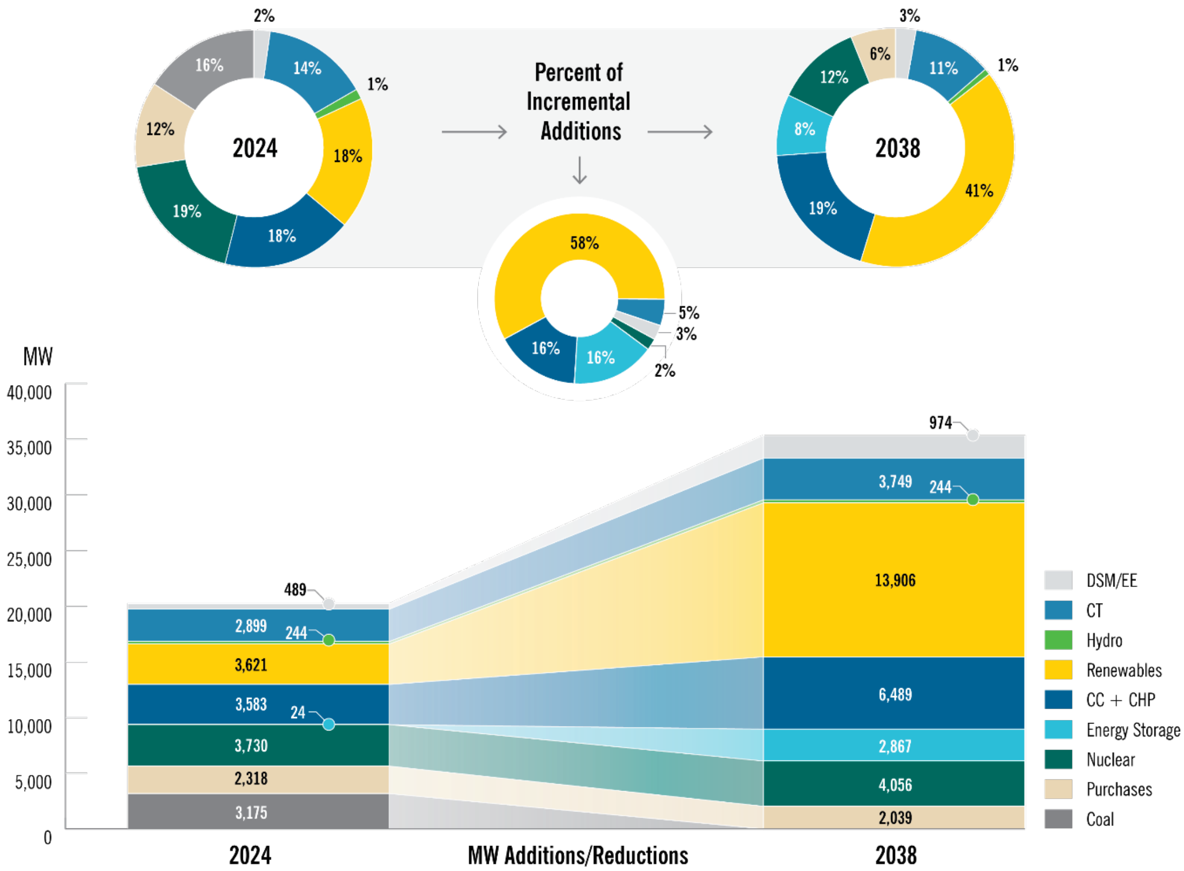
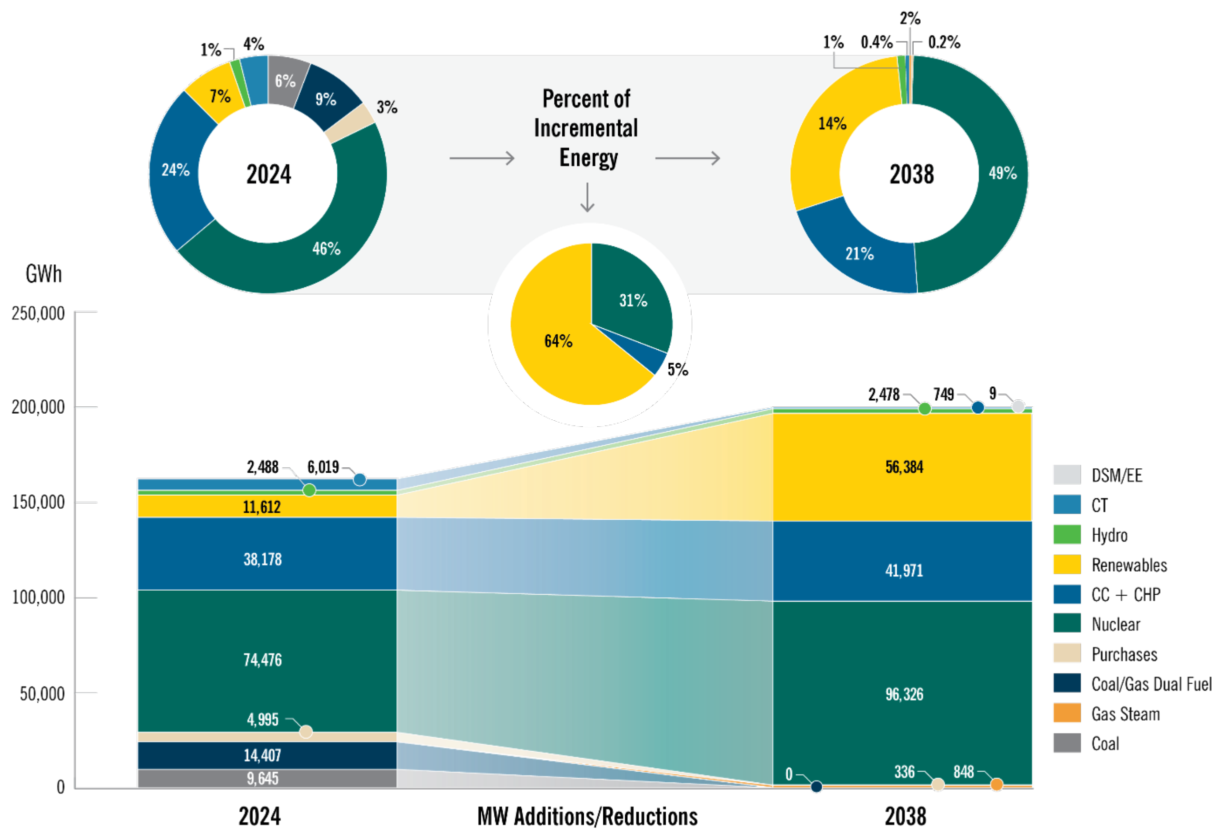


Figure C-11 below represents the combined energy mix of DEC and DEP for P3 Base over the Base Planning Period. Due to the Companies' Joint Dispatch Agreement ("JDA"), it is appropriate to combine the energy of both utilities to develop a meaningful representation of energy for P3 Base. Over this fifteen-year horizon, the figure shows that nuclear resources will continue to serve almost half of DEC and DEP's energy needs. Additionally, the figures display a substantial increase in the amount of energy served by carbon-free resources such as solar, wind and hydro. Natural gas continues to provide lower carbon intensity energy and system reliability for the Companies replacing retiring coal resources over this time period.

Figures C-11: P3 Base - DEC and DEP Combined Energy Mix in 2024 and 2038 (GWh)



Load Capacity and Reserve Summary

Tables C-73 through C-76 below present the Winter and Summer Load, Capacity and Reserves ("LCR") tables for DEC and DEP for recommended Portfolio P3 Base.

Table C-73: DEC Winter Load, Capacity, and Reserves Tables (P3 Base)

Line		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	Gross System Peak Forecast	17,597	17,699	17,893	18,185	18,612	19,038	19,349	19,785	20,228	20,615	20,865	21,181	21,467	21,812	22,147
2	Cumulative EE Contribution at Peak	-87	-172	-262	-353	-483	-548	-631	-709	-780	-827	-859	-882	-899	-903	-892
3	**Net System Peak Forecast**	**17,510**	**17,527**	**17,631**	**17,832**	**18,129**	**18,490**	**18,718**	**19,076**	**19,448**	**19,788**	**20,006**	**20,299**	**20,568**	**20,910**	**21,255**
4	**Existing Dispatchable Resources**	**21,011**	**20,627**	**20,689**	**20,706**	**20,750**	**19,990**	**20,013**	**19,490**	**18,168**	**18,168**	**18,168**	**18,168**	**15,948**	**15,948**	**15,948**
5	Nuclear	5,650	5,650	5,650	5,650	5,650	5,650	5,673	5,696	5,692	5,692	5,692	5,692	5,692	5,692	5,692
6	CC	2,145	2,145	2,145	2,159	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199
7	CT	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651	3,651
8	Coal/DFO	6,119	5,693	5,693	5,693	5,693	4,933	4,933	4,387	3,069	3,069	3,069	3,069	849	849	849
9	Gas Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Hydro	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050
11	Pumped Storage	2,380	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420
12	Standalone Battery	0	2	64	67	71	71	71	71	71	71	71	71	71	71	71
13	CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
14	**Existing Variable Resources**	**76**	**123**	**140**	**154**	**157**	**157**	**158**	**160**	**159**	**158**	**157**	**156**	**156**	**155**	**154**
15	Solar	76	123	140	154	157	157	158	160	159	158	157	156	156	155	154
16	**Purchases**	**282**	**273**	**275**	**273**	**275**	**274**	**270**	**270**	**260**	**259**	**260**	**262**	**263**	**265**	**266**
17	Non-Renewable Purchases	153	153	155	156	157	157	158	160	161	163	164	166	167	169	170
18	Compliance Renewables	108	105	105	102	102	102	97	95	84	82	82	82	82	82	82
19	Non-Compliance Renewables	22	16	16	16	16	16	16	16	16	14	14	14	14	14	14
20	**Undesignated Future Resources**	**0**	**0**	**0**	**0**	**153**	**1,580**	**1,610**	**2,434**	**4,241**	**4,617**	**6,220**	**6,965**	**7,851**	**8,456**	**10,197**
21	Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	900	1,500	2,100
22	CC	0	0	0	0	0	0	0	0	1,359	1,359	1,359	1,359	1,359	1,359	1,359
23	CT	0	0	0	0	0	1,274	1,274	1,274	1,274	1,274	1,274	1,274	1,274	1,274	2,124
24	Solar	0	0	0	0	13	25	36	47	55	63	70	78	85	90	96
25	Onshore Wind	0	0	0	0	0	0	0	0	0	0	0	137	173	173	173
26	Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,596	1,596	1,596	1,596	1,596
28	Standalone Battery	0	0	0	0	0	0	0	293	277	269	269	269	428	428	416
29	Paired Battery	0	0	0	0	140	280	300	819	1,275	1,651	1,651	1,651	2,036	2,036	2,332
30	**Production Capacity**	**21,369**	**21,023**	**21,104**	**21,133**	**21,334**	**22,002**	**22,052**	**22,354**	**22,829**	**23,202**	**24,806**	**25,551**	**24,218**	**24,824**	**26,565**
31	**Demand Side Management (DSM)**	**604**	**731**	**807**	**849**	**886**	**895**	**907**	**920**	**933**	**947**	**961**	**976**	**989**	**1,002**	**1,014**
32	DSM	576	602	630	659	691	698	708	719	731	743	754	766	777	787	797
33	IVVC Peak Shaving	27	129	177	190	195	197	199	201	203	204	206	210	212	215	217
34	**Total Firm Capacity**	**21,973**	**21,754**	**21,910**	**21,982**	**22,220**	**22,897**	**22,959**	**23,274**	**23,762**	**24,149**	**25,766**	**26,527**	**25,207**	**25,826**	**27,579**
35	**Total Reserve Capacity**	**4,463**	**4,228**	**4,280**	**4,150**	**4,092**	**4,407**	**4,241**	**4,198**	**4,315**	**4,361**	**5,760**	**6,228**	**4,640**	**4,916**	**6,324**
36	**Reserve Margin**	**25.49%**	**24.12%**	**24.27%**	**23.27%**	**22.57%**	**23.84%**	**22.66%**	**22.01%**	**22.19%**	**22.04%**	**28.79%**	**30.68%**	**22.56%**	**23.51%**	**29.75%**

Table C-74: DEP Winter Load, Capacity, and Reserves Tables (P3 Base)

Line		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	Gross System Peak Forecast	14,192	14,459	14,499	14,642	14,828	15,166	15,286	15,514	15,671	15,892	16,003	16,222	16,302	16,511	16,684
2	Cumulative EE Contribution at Peak	-27	-43	-58	-79	-95	-111	-127	-143	-158	-171	-182	-192	-200	-210	-212
3	**Net System Peak Forecast**	**14,164**	**14,416**	**14,441**	**14,563**	**14,734**	**15,055**	**15,160**	**15,370**	**15,512**	**15,721**	**15,821**	**16,030**	**16,102**	**16,301**	**16,472**
4	**Existing Dispatchable Resources**	**13,627**	**13,629**	**13,752**	**13,835**	**13,835**	**12,835**	**12,868**	**12,155**	**12,155**	**12,155**	**10,746**	**10,746**	**10,746**	**10,746**	**10,746**
5	Nuclear	3,730	3,730	3,730	3,730	3,730	3,743	3,756	3,756	3,756	3,756	3,756	3,756	3,756	3,756	3,756
6	CC	3,583	3,583	3,663	3,731	3,731	3,771	3,771	3,771	3,771	3,771	3,771	3,771	3,771	3,771	3,771
7	CT	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899	2,899
8	Coal/DFO	3,175	3,175	3,175	3,175	3,175	2,122	2,122	1,409	1,409	1,409	0	0	0	0	0
9	Gas Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Hydro	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
11	Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Standalone Battery	12	14	57	72	72	72	92	92	92	92	92	92	92	92	92
13	CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	**Existing Variable Resources**	**238**	**260**	**284**	**318**	**324**	**325**	**325**	**326**	**323**	**322**	**320**	**319**	**317**	**315**	**314**
15	Solar	238	260	284	318	324	325	325	326	323	322	320	319	317	315	314
16	**Purchases**	**2,537**	**2,596**	**2,541**	**2,544**	**2,536**	**2,346**	**2,168**	**2,168**	**2,168**	**2,168**	**2,168**	**2,168**	**2,168**	**2,168**	**2,168**
17	Non-Renewable Purchases	2,396	2,455	2,400	2,403	2,397	2,217	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039
18	Compliance Renewables	69	69	69	69	67	57	57	57	57	57	57	57	57	57	57
19	Non-Compliance Renewables	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
20	**Undesignated Future Resources**	**0**	**0**	**0**	**0**	**233**	**2,673**	**2,687**	**3,526**	**3,667**	**5,164**	**5,812**	**5,826**	**6,116**	**6,416**	**6,416**
21	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300
22	CC	0	0	0	0	0	1,359	1,359	1,359	1,359	2,718	2,718	2,718	2,718	2,718	2,718
23	CT	0	0	0	0	0	850	850	850	850	850	850	850	850	850	850
24	Solar	0	0	0	0	27	52	66	81	96	111	125	140	155	155	155
25	Onshore Wind	0	0	0	0	0	0	0	131	258	381	502	502	502	502	502
26	Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Standalone Battery	0	0	0	0	0	0	0	170	170	170	229	229	209	209	209
29	Paired Battery	0	0	0	0	206	412	412	935	935	935	1,388	1,388	1,683	1,683	1,683
30	**Production Capacity**	**16,402**	**16,485**	**16,576**	**16,697**	**16,928**	**18,179**	**18,048**	**18,175**	**18,314**	**19,810**	**19,047**	**19,059**	**19,347**	**19,645**	**19,644**
31	**Demand Side Management (DSM)**	**462**	**399**	**428**	**455**	**483**	**516**	**550**	**586**	**623**	**658**	**692**	**725**	**751**	**760**	**762**
32	DSM	274	274	301	327	354	386	419	453	488	523	555	587	611	618	620
33	IVVC Peak Shaving	189	126	127	128	129	130	131	133	134	135	137	138	140	141	143
34	**Total Firm Capacity**	**16,864**	**16,884**	**17,004**	**17,152**	**17,411**	**18,695**	**18,598**	**18,761**	**18,937**	**20,468**	**19,739**	**19,784**	**20,099**	**20,405**	**20,407**
35	**Total Reserve Capacity**	**2,700**	**2,469**	**2,563**	**2,589**	**2,678**	**3,640**	**3,438**	**3,391**	**3,424**	**4,747**	**3,918**	**3,755**	**3,997**	**4,104**	**3,934**
36	**Reserve Margin**	**19.06%**	**17.12%**	**17.74%**	**17.78%**	**18.17%**	**24.18%**	**22.68%**	**22.06%**	**22.08%**	**30.20%**	**24.76%**	**23.42%**	**24.82%**	**25.17%**	**23.88%**

Table C-75: DEC Summer Load, Capacity, and Reserves Tables (P3 Base)

Line		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	Gross System Peak Forecast	18,211	18,319	18,529	18,856	19,282	19,663	20,031	20,474	20,877	21,351	21,630	21,935	22,500	22,817	23,231
2	Cumulative EE Contribution at Peak	-133	-213	-292	-370	-445	-523	-602	-675	-743	-787	-818	-828	-851	-857	-848
3	**Net System Peak Forecast**	**18,079**	**18,107**	**18,237**	**18,486**	**18,836**	**19,140**	**19,429**	**19,799**	**20,135**	**20,564**	**20,812**	**21,107**	**21,650**	**21,960**	**22,383**
4	**Existing Dispatchable Resources**	**19,627**	**19,629**	**19,694**	**19,733**	**19,753**	**19,013**	**19,036**	**18,514**	**17,196**	**17,196**	**17,196**	**17,196**	**14,976**	**14,976**	**14,976**
5	Nuclear	5,474	5,474	5,474	5,474	5,474	5,474	5,498	5,519	5,519	5,519	5,519	5,519	5,519	5,519	5,519
6	CC	2,010	2,010	2,010	2,044	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064	2,064
7	CT	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998	2,998
8	Coal/DFO	5,666	5,666	5,666	5,666	5,666	4,926	4,926	4,382	3,064	3,064	3,064	3,064	844	844	844
9	Gas Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Hydro	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047
11	Pumped Storage	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420	2,420
12	Standalone Battery	0	2	67	71	71	71	71	71	71	71	71	71	71	71	71
13	CHP	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
14	**Existing Variable Resources**	**953**	**1,431**	**1,589**	**1,620**	**1,633**	**1,644**	**1,656**	**1,648**	**1,641**	**1,631**	**1,624**	**1,616**	**1,608**	**1,600**	**1,592**
15	Solar	953	1,431	1,589	1,620	1,633	1,644	1,656	1,648	1,641	1,631	1,624	1,616	1,608	1,600	1,592
16	**Purchases**	**282**	**273**	**275**	**273**	**275**	**274**	**270**	**270**	**260**	**259**	**260**	**262**	**263**	**265**	**266**
17	Non-Renewable Purchases	153	153	155	156	157	157	158	160	161	163	164	166	167	169	170
18	Compliance Renewables	108	105	105	102	102	102	97	95	84	82	82	82	82	82	82
19	Non-Compliance Renewables	22	16	16	16	16	16	16	16	16	14	14	14	14	14	14
20	**Undesignated Future Resources**	**0**	**0**	**0**	**0**	**320**	**1,796**	**1,983**	**2,999**	**4,866**	**5,374**	**7,096**	**7,862**	**8,799**	**9,441**	**11,143**
21	Nuclear	0	0	0	0	0	0	0	0	0	0	0	600	900	1,500	2,100
22	CC	0	0	0	0	0	0	0	0	1,265	1,265	1,265	1,265	1,265	1,265	1,265
23	CT	0	0	0	0	0	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,156	1,926
24	Solar	0	0	0	0	180	360	527	732	894	1,034	1,160	1,285	1,365	1,407	1,454
25	Onshore Wind	0	0	0	0	0	0	0	0	0	0	0	41	54	54	54
26	Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Pumped Storage	0	0	0	0	0	0	0	0	0	0	1,596	1,596	1,596	1,596	1,596
28	Standalone Battery	0	0	0	0	0	0	0	293	277	269	269	269	428	428	416
29	Paired Battery	0	0	0	0	140	280	300	819	1,275	1,651	1,651	1,651	2,036	2,036	2,332
30	**Production Capacity**	**20,862**	**21,333**	**21,558**	**21,626**	**21,981**	**22,727**	**22,946**	**23,432**	**23,963**	**24,460**	**26,176**	**26,935**	**25,646**	**26,281**	**27,977**
31	**Demand Side Management (DSM)**	**1,207**	**1,327**	**1,391**	**1,423**	**1,439**	**1,445**	**1,452**	**1,462**	**1,471**	**1,481**	**1,491**	**1,502**	**1,511**	**1,520**	**1,527**
32	DSM	1,180	1,198	1,214	1,233	1,243	1,248	1,254	1,261	1,269	1,277	1,284	1,292	1,299	1,305	1,310
33	IVVC Peak Shaving	27	129	177	190	195	197	199	201	203	204	206	210	212	215	217
34	**Total Firm Capacity**	**22,070**	**22,660**	**22,949**	**23,049**	**23,419**	**24,172**	**24,398**	**24,893**	**25,435**	**25,941**	**27,667**	**28,437**	**27,157**	**27,800**	**29,504**
35	**Total Reserve Capacity**	**3,991**	**4,553**	**4,712**	**4,563**	**4,583**	**5,031**	**4,969**	**5,095**	**5,300**	**5,377**	**6,855**	**7,330**	**5,507**	**5,840**	**7,121**
36	**Reserve Margin**	**22.08%**	**25.15%**	**25.84%**	**24.68%**	**24.33%**	**26.29%**	**25.57%**	**25.73%**	**26.32%**	**26.15%**	**32.94%**	**34.73%**	**25.44%**	**26.60%**	**31.81%**

Table C-76: DEP Summer Load, Capacity, and Reserves Tables (P3 Base)

Line		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	Gross System Peak Forecast	12,954	13,214	13,397	13,637	13,824	14,011	14,391	14,689	14,912	15,159	15,196	15,333	15,576	15,773	16,040
2	Cumulative EE Contribution at Peak	-80	-133	-187	-240	-274	-342	-390	-435	-473	-499	-514	-529	-539	-548	-545
3	**Net System Peak Forecast**	**12,874**	**13,080**	**13,210**	**13,397**	**13,549**	**13,668**	**14,001**	**14,254**	**14,439**	**14,660**	**14,682**	**14,804**	**15,037**	**15,224**	**15,495**
4	**Existing Dispatchable Resources**	**12,459**	**12,479**	**12,599**	**12,637**	**12,690**	**11,656**	**11,676**	**10,972**	**10,972**	**10,972**	**9,580**	**9,580**	**9,580**	**9,580**	**9,580**
5	Nuclear	3,593	3,593	3,593	3,593	3,606	3,619	3,619	3,619	3,619	3,619	3,619	3,619	3,619	3,619	3,619
6	CC	3,079	3,079	3,159	3,197	3,237	3,237	3,237	3,237	3,237	3,237	3,237	3,237	3,237	3,237	3,237
7	CT	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404
8	Coal/DFO	3,143	3,143	3,143	3,143	3,143	2,096	2,096	1,392	1,392	1,392	0	0	0	0	0
9	Gas Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Hydro	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
11	Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Battery	12	32	72	72	72	72	92	92	92	92	92	92	92	92	92
13	CHP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	**Existing Variable Resources**	**2,018**	**2,175**	**2,464**	**2,508**	**2,515**	**2,521**	**2,528**	**2,515**	**2,498**	**2,486**	**2,472**	**2,461**	**2,448**	**2,436**	**2,424**
15	Solar	2,018	2,175	2,464	2,508	2,515	2,521	2,528	2,515	2,498	2,486	2,472	2,461	2,448	2,436	2,424
16	**Purchases**	**2,443**	**2,502**	**2,447**	**2,450**	**2,442**	**2,091**	**2,091**	**2,091**	**2,091**	**2,091**	**2,091**	**2,091**	**2,091**	**2,091**	**2,091**
17	Non-Renewable Purchases	2,302	2,361	2,306	2,309	2,303	1,962	1,962	1,962	1,962	1,962	1,962	1,962	1,962	1,962	1,962
18	Compliance Renewables	69	69	69	69	67	57	57	57	57	57	57	57	57	57	57
19	Non-Compliance Renewables	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
20	**Undesignated Future Resources**	**0**	**0**	**0**	**0**	**434**	**2,891**	**3,045**	**3,933**	**4,113**	**5,513**	**6,137**	**6,178**	**6,493**	**6,793**	**6,793**
21	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	300	300
22	CC	0	0	0	0	0	1,265	1,265	1,265	1,265	2,530	2,530	2,530	2,530	2,530	2,530
23	CT	0	0	0	0	0	770	770	770	770	770	770	770	770	770	770
24	Solar	0	0	0	0	228	444	598	745	853	916	956	997	1,038	1,038	1,038
25	Onshore Wind	0	0	0	0	0	0	0	48	120	192	264	264	264	264	264
26	Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Standalone Battery	0	0	0	0	0	0	0	170	170	170	229	229	209	209	209
29	Paired Battery	0	0	0	0	206	412	412	935	935	935	1,388	1,388	1,683	1,683	1,683
30	**Production Capacity**	**16,920**	**17,156**	**17,510**	**17,595**	**18,082**	**19,160**	**19,340**	**19,511**	**19,675**	**21,062**	**20,281**	**20,310**	**20,613**	**20,900**	**20,889**
31	**Demand Side Management (DSM)**	**963**	**896**	**920**	**944**	**972**	**1,003**	**1,037**	**1,073**	**1,109**	**1,142**	**1,176**	**1,205**	**1,221**	**1,226**	**1,229**
32	DSM	772	770	793	816	843	873	906	940	974	1,007	1,039	1,067	1,081	1,085	1,086
33	IVVC Peak Shaving	191	126	127	128	129	130	131	133	134	135	137	138	140	141	143
34	**Total Firm Capacity**	**17,884**	**18,052**	**18,430**	**18,539**	**19,054**	**20,163**	**20,377**	**20,584**	**20,784**	**22,205**	**21,457**	**21,515**	**21,834**	**22,126**	**22,118**
35	**Total Reserve Capacity**	**5,010**	**4,971**	**5,220**	**5,141**	**5,505**	**6,495**	**6,376**	**6,330**	**6,345**	**7,545**	**6,775**	**6,711**	**6,797**	**6,902**	**6,623**
36	**Reserve Margin**	**38.91%**	**38.01%**	**39.51%**	**38.38%**	**40.63%**	**47.52%**	**45.54%**	**44.41%**	**43.94%**	**51.47%**	**46.14%**	**45.33%**	**45.20%**	**45.34%**	**42.75%**

First Year of Resource Need

Using the recommended Portfolio, P3 Base, the Companies determined the first year of resource need for DEC and DEP. In this calculation, the Companies include only incremental resource additions that are considered designated or mandated. Designated resources include those projects that are committed, already in progress, have been granted a Certificate of Public Convenience and Necessity ("CPCN") or Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN"), smaller capacity additions such as unit uprates that are included as part of the Companies' normal business operations, firm market purchases or EE/DSM programs.

Mandated renewable energy resources are renewable resources needed to meet renewable requirements such as NC REPS, CPRE requirements, or other requirements mandated by the State Utility Commissions. These resources are also included in committed resources for the first year of resource need calculation.

Undesignated resources include resources in development that have not established a legally enforceable obligation committing to sell to power to DEC or DEP for a specified future term (e.g., QF notice of commitment or purchase power contracts) as well as projected resources in the IRP that do not have a CPCN or CECPCN. Undesignated resources are not included as committed resources for the first year of resource need calculation. A resource moves from undesignated to designated or mandated if current contracts become extended or additional resources are approved by the Commissions when CPCN or CECPNs are granted. As these resources become designated, the timing of the first need may change by reflecting the additional committed resources.

Additionally, firm market purchases, which include wholesale contracts, including renewable contracts, are assumed to be committed resources through the end of their currently contracted period. There is no guarantee that the counterparty will choose to sell, or the Companies will agree to purchase its capacity after the contracted time frame. Beyond the contract period, the seller may elect to retire the resource or sell the output to an entity other than the Companies. As such, contracted resources are deemed designated only for the duration of their legally enforceable contract.

Only designated and mandated resources as described above are considered committed resources when determining the first resource need that can then be used for other regulatory purposes such as the first year of undesignated capacity need for developing avoided cost rates. As such, a list of resources included for DEC and DEP is below:

- Designated and mandated renewable resources
- Nuclear uprates
- CC uprates
- Designated wholesale contracts
- DSM/EE programs
- Bad Creek runner uprates (DEC only)
- Lincoln CT project (DEC only)

Figure C-12 demonstrates the first resource need for DEC is in 2028, while Figure C-13 demonstrates the first resource need for DEP is in 2024.

Figure C-12: DEC First Year of Resource Need (P3 Base)

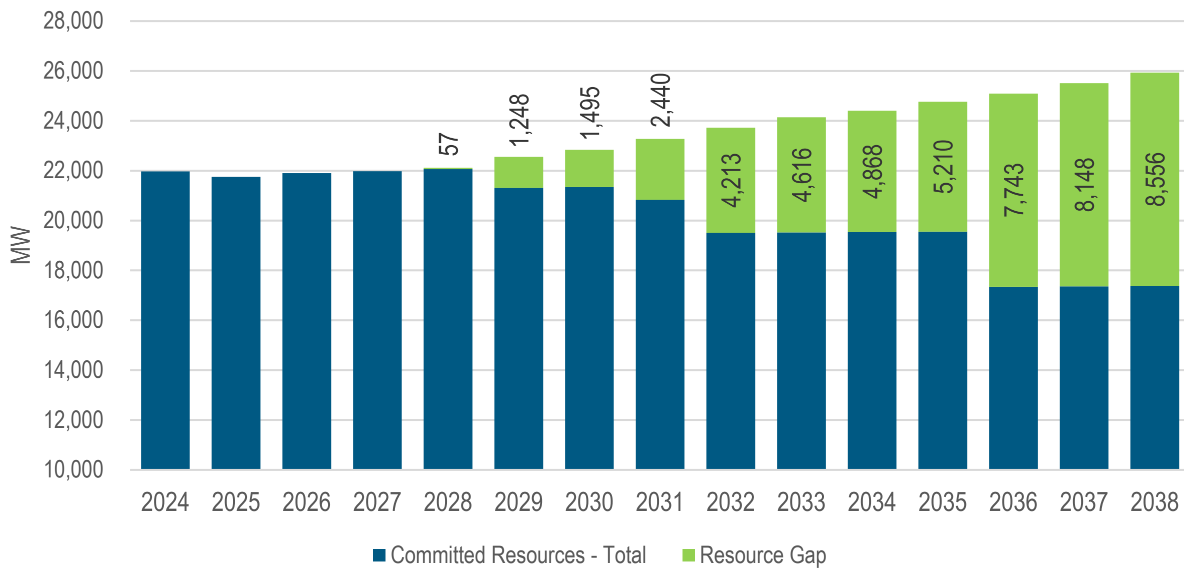


Figure C-13: DEP First Year of Resource Need (P3 Base)