DOCKET NO. E-2, SUB 1311
EXHIBIT 1A

E Quantitative Analysis

Introduction to Quantitative Analysis

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 Carbon Plan ("Carbon Plan" or the "Plan"). While the Carbon Plan is not being filed as an Integrated Resource Plan ("IRP") developed under North Carolina Utilities Commission ("NCUC" or the "Commission") Rule R8-60, the Carbon Plan is a long-term planning analysis and many of the same analytical approaches underlying past IRPs were used in developing the Carbon Plan. IRP-based analyses include use of input assumptions consistent with the rigors used in IRP, capacity expansion and production cost models, reliability models and modeling outputs such as present value of revenue requirements ("PVRR") and average retail customer bill impacts. To assist the Commission and stakeholders in evaluating this first-of-its-kind Carbon Plan, this Appendix provides unprecedented detail and discussion of the Companies' modeling inputs and assumptions, modeling approach and methodology, analytical evaluation, and observations and conclusions from the analysis performed in developing the Carbon Plan.

As will be discussed in more detail for each subject below, the Carbon 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 change over time, economic analysis of DEC's and DEP's coal unit retirement dates, and portfolio and sensitivity analyses to evaluate the robustness of portfolios. Operational and financial analysis of the modeling was used to derive observations and planning approaches for execution. Maintaining affordability and reliability for customers along the path to CO_2 reduction for the Carolinas system is a core focus of the Carbon Plan analysis.

Overview of Analytical Process

The analytical process consists of the following steps outlined in Figure E-1. Each of these steps will be discussed in more detail in later sections of this Appendix.

Analytical Process Steps:

1. Modeling Software Overview and Setup and Development of Modeling Assumptions (including identification and screening of resource options for further consideration)

2. Portfolio Development Modeling

    a. Determining Economic Retirement of Coal Generating Capacity (endogenously identified within capacity expansion model)

    b. Preliminary Capacity Expansion Results

3. Portfolio Verification Modeling

    a. Battery-Combustion Turbine ("CT") Optimization

    b. Bad Creek Powerhouse II Validation

    c. Resource Adequacy and Reliability Verification

4. Portfolio Performance Analysis

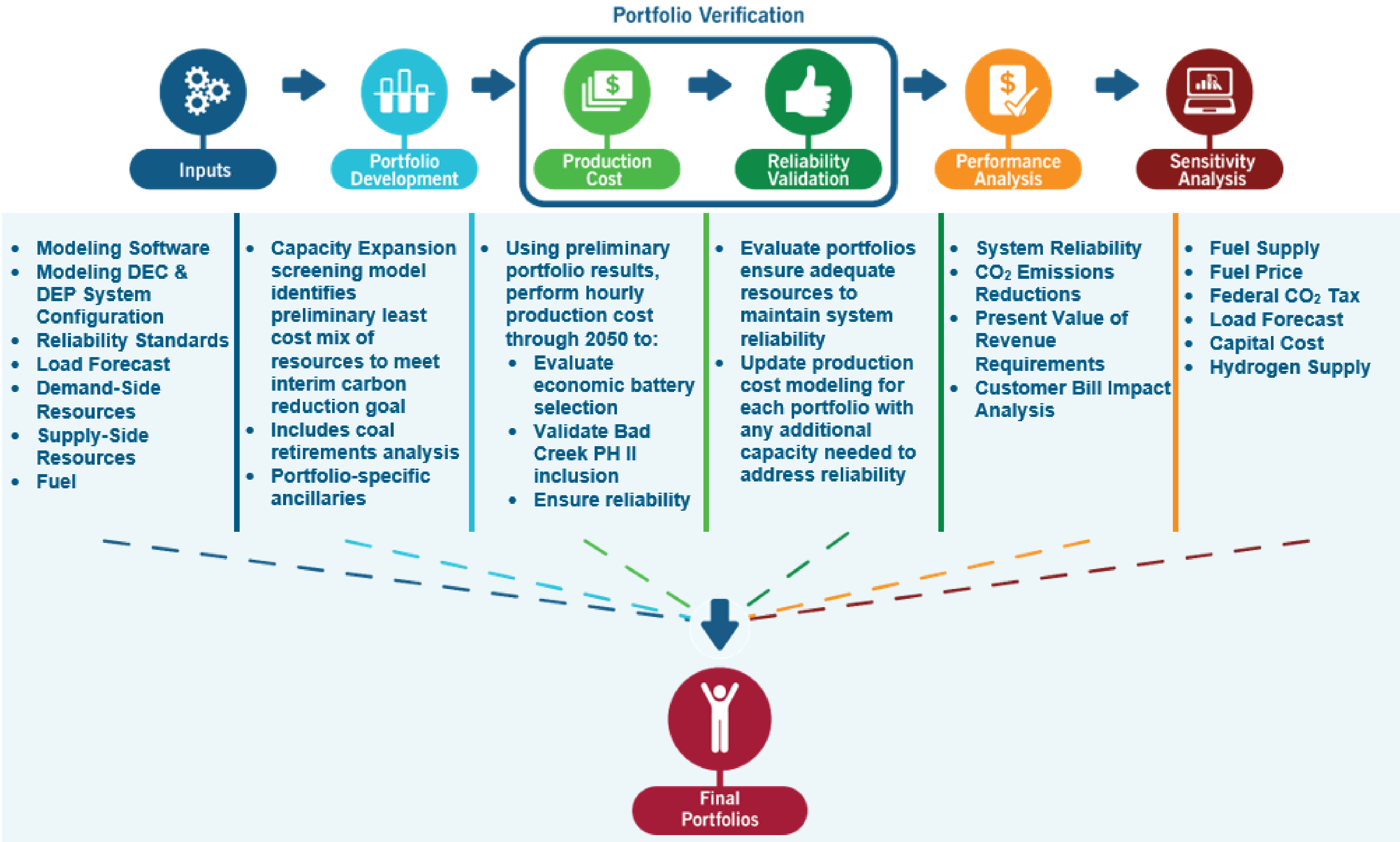
    a. CO_2 Reduction Analysis

    b. Present Value Revenue Requirement Analysis

    c. Customer Bill Impact Analysis

5. Sensitivity Modeling and Analysis

Figure E-1: Carbon Plan Analytical Process Flow Chart



Modeling Software and Development of Modeling Assumptions

The Carbon Plan deploys the same rigor in developing input assumptions to the modeling as the Companies' recent IRPs, while at the same time assessing the pace of implementation required for each resource type in order for the system to achieve both the 70% interim CO_2 emissions reductions target and 2050 carbon neutrality target as described in Chapter 2 (Methodology and Key Assumptions) and subsequently in this Appendix. The modeling assumptions presented in this Appendix represent the best available assumptions at the time of development of the Carbon Plan. The actual costs, operational abilities, and deployment timelines will change over time depending on the pace of technology, supply chain, and policy advancements as the country and global energy industry continue to transition to lower carbon generation resources.

Carbon Plan Modeling Software

The Carbon Plan modeling utilizes the same two main types of models as the Companies' IRPs: a capacity expansion model and a production cost model. For the analysis in the Carbon Plan, DEC and DEP used modeling software called EnCompass, licensed through Anchor Power Solutions. Both the capacity expansion model and the production cost model are contained within the EnCompass software as separate modules.

Capacity Expansion Model

Capacity expansion models are first and foremost screening models. These models are helpful in assessing a broad range of potential resource portfolio options, to determine which mix of resources minimize the cost of the system, adhering to imposed constraints in a manageable analytical timeframe. To accomplish this analysis, the capacity expansion models rely on various input assumptions such as load requirements, new and existing resources, generation profiles, fuel and operations costs, and various constraints. They then aggregate the detailed load requirement inputs into representative blocks. Iterations of different mixes of resources over time are applied to these simplified load requirements to determine a set of resources, which returns the lowest PVRR. 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 then develops a preliminary resource portfolio that represents a specific set of resources used to meet system energy and capacity needs over time.

While these models can be used to help identify cost-effective system resources, due to the necessary computational simplifications these models make, additional modeling in a detailed production cost model is necessary to validate the resource selections with respect to cost, reliability, and environmental compliance and 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 Carbon Plan's resource portfolios, sensitivity analyses, and the steps DEC and DEP undertook to verify and adjust the capacity expansion modeling results are contained in later sections of this Appendix.

Production Cost Model

Production cost models differ from capacity expansion models in that they do not solve for which resources to include in the portfolio, but rather 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. Contrary 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 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 Pathways

North Carolina Session Law 2021-165 ("HB 951") establishes aggressive CO_2 emissions reductions targets, including an interim target of 70% CO_2 emissions reductions from generation facilities located in North Carolina on the way to carbon neutrality by 2050. HB 951 specifies that the plan developed by the Commission should pursue all reasonable steps to achieve the initial 70% interim target by 2030 while also affording the Commission discretion in developing the least cost reliable plan for North Carolina:

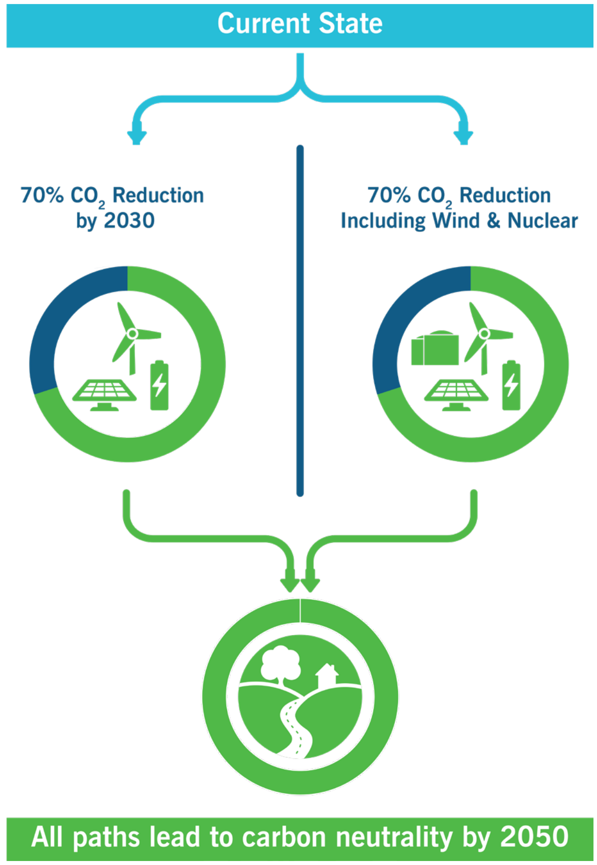
- Where optimal timing of generation and resource-mix to achieve the least cost path to compliance requires more time, up to two years;

- In the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility; or

- In the event necessary to maintain the adequacy and reliability of the existing grid.

In accordance with these provisions of HB 951, the Companies developed two pathways to achieve carbon neutrality by 2050 shown in Figure E-2.

Figure E-2: Two Pathways to Carbon Neutrality



In the Carbon Plan, DEC and DEP evaluated achieving the 70% interim CO_2 emissions reductions target by 2030, and also evaluated portfolios that allow for extension of meeting the interim target by 2034 to allow time for the deployment of nuclear and wind resource options. As discussed further below, timelines for the implementation of these resources are the basis for the targetdates evaluated in the portfolio development scenarios.

Mass Cap Modeling

To develop the preliminary selection of resources in the Carbon Plan, DEC and DEP used the capacity expansion model with a mass cap constraint. This modeling technique puts a limit on the amount of CO_2 the resource portfolio is allowed to emit through the economical simulation of system operations. The model must select resources, which, when integrated in the portfolio, result in CO_2 emissions that are less than the specified limit.

The DEC and DEP systems span both North Carolina and South Carolina. However, the CO_2 reduction targets in HB 951 are only expressly applicable to generation facilities located in North Carolina. Chapter 1 (Introduction and Background) further lays out the importance of alignment between the states and the joint system with respect to prudently planning and operating the Companies' Carolinas power systems and Appendix A (Carbon Baseline and Accounting) provides more detail on the

Companies' proposed methodology for tracking and accounting for CO_2 emissions reductions over time.

For purposes of modeling the Carbon Plan, DEC and DEP used a system mass cap approach; that is, when the system mass cap is achieved, it simultaneously results in achieving the the 70% 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, Carbon Plan modeling does not identify locations for generic resource additions. Siting will be 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). As described in Appendix A (Carbon Baseline and Accounting), the Carbon Plan does not use location of resources as a method for achieving the CO_2 emissions target and the Carbon Plan modeling assumed that any new CO_2-emitting resources would be sited in North Carolina. That is, for purposes of the analysis, the Carbon Plan assumes all future emissions of unspecified generic resources, whether in-state or out-of-state, count against the HB 951 CO_2 emissions target. The Companies have also requested the Commission opine on the appropriateness of this approach under HB 951.

While HB 951 permits carbon offsets to be used in achieving carbon neutrality (provided they do not exceed 5% of the reduction target), the Carbon Plan analysis enforces a constraint that the system will achieve zero CO_2 emissions in 2050, integrating the necessary resources to meet this constraint by the end of the planning period, without relying on carbon offsets. Table E-1 below presents the system mass cap constraints used in the development of resources portfolios in the Carbon Plan.

Table E-1: System Mass Cap [CO_2 Short Tons]

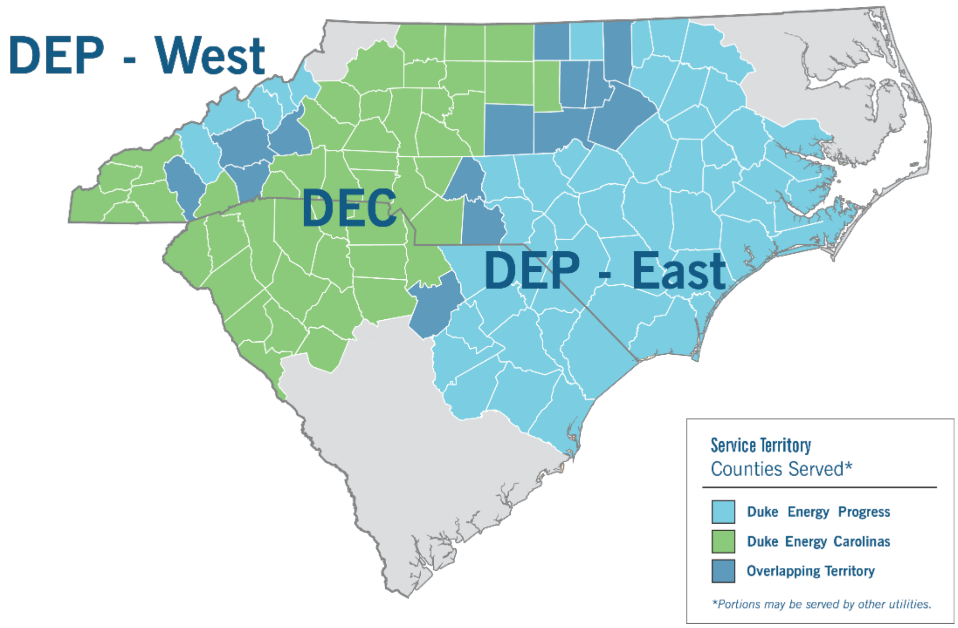
	Interim 70% Reduction Target	2050 Carbon Neutrality Target
System Mass Cap	24,908,603	0

The Companies' methodology for establishing the 2005 baseline, the HB 951 CO_2 emission reductions targets, discussion on the Carbon Plan's approach to carbon offsets, and other general carbon accounting methodologies used in the Carbon Plan are discussed in detail in Appendix A (Carbon Baseline and Accounting).

Modeling the Carolinas Systems: DEC/DEP System Configuration

In capacity expansion and production cost modeling of the Carolinas system for the Carbon Plan, DEC and DEP remain two separate utilities and legal entities, operating across three areas (DEP-West, DEC and DEP-East, as depicted in Figure E-3), each with its own load, resources, and transmission limits between them. 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 E-3: DEC and DEP Service Territories and Balancing Authorities



Operating reserve requirements reflect the availability of resources to meet hourly and intra-hour variations in load and generation to maintain the reliability of the system and ensure compliance with NERC reliability standards. For each resource portfolio in the Carbon Plan, the operating reserve requirements are calculated for the specific levels of renewable resources on the system across time. The mix of generation profiles of variable energy resources, such as solar and wind, affects the system flexibility requirements to maintain reliable operations of the grid.

As discussed in Appendix R (Consolidated System Operations), the Carbon Plan 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 meet 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 reduces the requirement 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 Carbon Plan modeling.

While not yet approved by either of the states or the FERC, the Companies see pursuing this construct of consolidated system operations to be a prudent and reasonable step for achieving lower cost and lower carbon emissions for customers, while maintaining or improving reliability of the consolidated system. A more detailed discussion of the modeling considerations for, benefits of, and steps required to achieve consolidated system operations is included in Appendix R (Consolidated System Operations).

Assessing Resource Needs

Resource planning consists of balancing load and resource requirements needed to meet future customer energy needs while maintaining cost, environmental compliance, and reliability standards. The Carbon Plan balances these parameters to plan for the transformation of the system to reduce carbon emissions along least-cost paths while maintaining or improving upon the reliability of the grid. This balance begins with determining energy demand on the system for every hour in every year over the planning horizon. Existing and new resources are then evaluated for the optimal mix of resources to meet these energy and peak capacity needs while minimizing the cost of the system, preserving reliability, and maintaining compliance with environmental rules and regulations. Finally, the system must be planned with realistic grid operating parameters, such as operating reserve requirements, as previously discussed in this Appendix, and long-term capacity planning reserves, to account for extreme weather and unexpected unit outages and underperformance.

Resource Adequacy and Planning Reserve Margin

Resource adequacy means having sufficient resources available to reliably serve electric demand especially during extreme conditions.[1] Adequate reserve capacity must be available to account for unplanned outages of generating equipment, economic load forecast uncertainty and higher-than-projected demand due to weather extremes. The Companies utilize a reserve margin target in the planning process to ensure resource adequacy. Reserve margin is defined as total resources[2] minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic reliability assessments.

2020 Resource Adequacy Study

DEC and DEP retained Astrapé Consulting to conduct new resource adequacy studies to support development of the Companies' 2020 IRPs.[3] Astrapé analyzed the planning reserve margin needed to provide an acceptable level of physical reliability based on the industry standard "one-day-in-ten-years" Loss of Load Expectation ("LOLE") metric (or, 0.1 LOLE). This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity.

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[1] NERC defines "Adequacy" as "[t]he ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components." N. American Elec. Reliability Corp., 2019 Long-Term Reliability Assessment, at 9 (2019), *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20 DL/NERC_LTRA_2019.pdf.

[2] Total resources reflect contribution to peak values for variable resources such as solar and energy limited resources such as batteries.

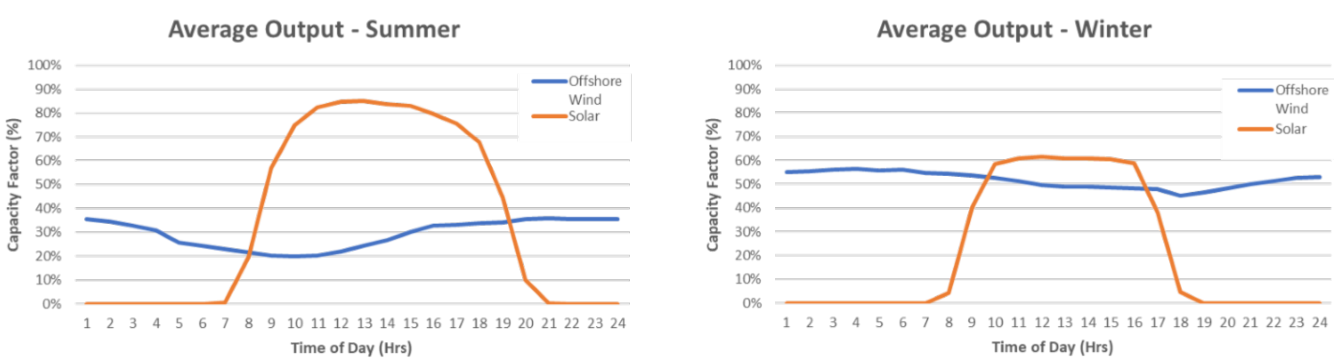
[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé has conducted several Resource Adequacy Studies and Effective Load Carrying Capability Studies for DEC and DEP in recent years.

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, which 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; and numerous sensitivities to understand which assumptions and inputs impact study results. Based on these simulations, Astrapé recommended that DEC and DEP continue to maintain a minimum 17% winter reserve margin for IRP planning purposes. The Companies used a minimum 17% winter reserve margin in the development of the Carbon Plan portfolios. The 2020 Resource Adequacy Study Reports for DEC and DEP are being provided as Attachments I and II to the Carbon Plan.

Effective Load Carrying Capability of Renewable and Storage Resources

Meeting HB 951 CO_2 reduction targets 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 forced outage or planned maintenance. 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. Like solar, onshore and offshore wind resources are also variable energy resources. However, deployment of wind resources can complement solar resources by providing energy to the system during overnight hours or winter months when solar energy is low or not available. Average summer and winter solar and offshore wind profiles are illustrated in Figure E-4 below, which shows the availability of wind generation during hours when solar generation is not available.

Figure E-4: Average Offshore Wind and Solar Generation Summer and Winter Profiles, Utilized in Carbon Plan Modeling



ELCC Study

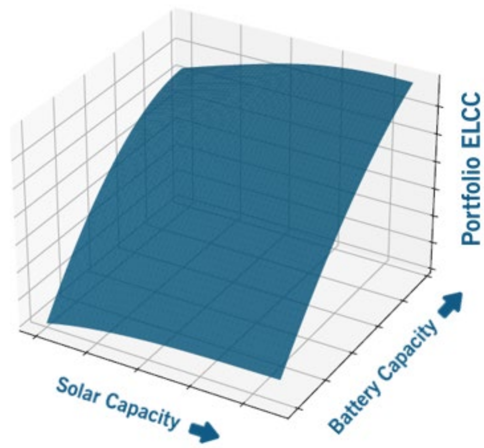
The Companies worked with Astrapé to conduct a new Effective Load Carrying Capability ("ELCC") study to understand the reliable capacity contributions of solar, onshore wind, offshore wind, and storage for use in the Carbon Plan. The ELCC or "capacity value" of a resource can be thought of as a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio. The ELCC of a resource depends on many factors including the load and load shape to be served, the existing resource mix, as well as the adoption of different resource types. A variable renewable resource typically exhibits declining capacity value as adoption increases since saturation occurs, and reliability events shift to periods when that particular resource is not available. The incremental capacity value of a resource may also change as the resource mix of the portfolio evolves around those resources.

Additionally, the capacity value of variable resources can increase as other variable resources are added to the system. To evaluate the "synergistic benefits" of adding portfolios of resources together, and in response to stakeholder feedback on the ELCC studies presented in support of the Companies' 2020 IRPs, Astrapé conducted an ELCC surface study rather than a standalone ELCC study where capacity values of resources are evaluated individually.

The surface study revealed that as the deployment of solar resources increases on the system, storage capacity value improves as more energy is available to charge the storage resource. Similarly, storage provides synergistic value to solar's capacity value as the dispatch of stored energy can shift peak demand periods from times when solar is not available to hours when the sun is shining.

Figure E-5 below illustrates a typical ELCC surface study for solar and storage with one axis representing the adoption of solar, one axis representing the adoption of storage, and the height of the surface representing the combined portfolio ELCC of the resources. The DEC and DEP ELCC Study report included as Attachment III to the Carbon Plan provides further detail regarding the ELCC modeling methodology and study results.

Figure E-5: Depiction of a Solar and Storage ELCC Surface



Application of ELCC Study in Carbon Plan Model

As mentioned previously, as the amount of any particular resource increases on the system, the capacity value of that resource declines. The EnCompass model selects resources in the capacity expansion model by evaluating the incremental capacity value that a resource provides to the system. For this reason, the ELCC results shown below represent the incremental capacity value that incremental tranches of resources were allocated in the EnCompass model.

Importantly, these ELCC results reflect the "synergistic benefits" of other variable resources present on the system. The solar and storage ELCC values used in EnCompass reflect the synergistic effect that these resources have on each other's capacity values as their deployment increases on the system. Additionally, onshore and offshore wind ELCCs were developed at increasing deployments of solar on the system in order to capture the synergistic impact that solar can have on wind capacity value. While the EnCompass model can consider a range of ELCC inputs for multiple technologies, EnCompass cannot presently use a multidimensional ELCC surface as an input. As the model attempts to optimize thousands of combinations of resource options, it can experience difficulty solving within reasonable time parameters. Attempting to integrate any such n-dimensional surface would further inhibit the model's ability and accuracy in assessing resources. For this reason, the Companies applied discreet ELCC values for solar, storage, and wind resources that still recognize the synergistic value that these technologies can provide toward each technology's capacity value.

Finally, as noted above, both DEC and DEP are winter planning utilities and plan their systems to satisfy a minimum winter reserve margin. This means that the hours in which the Companies have the most risk of not meeting demand occur during the winter period. When resources are selected in the EnCompass model for the purpose of maintaining adequate reserves, the resources are selected based on their winter capacity value. As such, the tables below represent the incremental winter ELCC values for each resource in the Carbon Plan.

Solar ELCC

Table E-2 and Table E-3 below represent the incremental capacity values attributed to solar resources in the Carbon Plan model. Capacity tranche are represented in megawatts ("MW").

Table E-2: DEC Winter Solar Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 - 2,000	6%
2,001 - 3,000	3%
3,001 - 4,000	2%
4,001 - 5,000	2%
5,001 - 6,000	1%
6,001 - 8,000	1%
8,000+	1%

Table E-3: DEP Winter Solar Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 - 3,000	8%
3,001 - 4,500	5%
4,501 - 6,000	3%
6,001 - 7,500	2%
7,501 - 9,000	2%
9,001 - 12,000	2%
12,000+	2%

Storage ELCC

Table E-4 and Table E-5 below represent the incremental capacity values attributed to standalone storage resources in the Carbon Plan model. The Companies included a variety of storage durations for the model to select from. The incremental capacity value of the next storage asset added to the system is impacted by the total storage already on the system and the duration of the storage already on the system when the next storage asset is considered. The ELCCs in the tables below reflect that impact.

Table E-4: DEC Standalone Storage Incremental ELCC Values

Capacity Tranche [MW]	Battery Duration	ELCC
0 - 1,200*	4	100%
1,201 - 2,800 (Bad Creek PH II)	12	95%
2,800 - 3,200	6	80%
3,200 - 4,000	6	70%

Note: In DEC, the proposed 1,600 MW Bad Creek Pumped Storage Hydro Station second powerhouse ("Bad Creek PH II") is assumed to be in service in 2033. By this time, in all portfolios, there are no more than 1,200 MW of standalone 4-hour storage on the system.

Table E-5: DEP Standalone Storage Incremental ELCC Values

Capacity Tranche [MW]	Battery Duration	ELCC
0 – 450	4	100%
451 – 900	4	94%
901 – 1,800	4	87%
1,801 – 2,300	4	73%
2,301 – 2,800	6	85%
2,801 – 3,300	6	68%

Solar Paired with Storage ("SPS") ELCC

The capacity value of storage paired with solar was assumed to be additive between the two resources. Table E-6 and Table E-7 below reflect the ELCC values of the total SPS facility for each of the SPS options included in the Carbon Plan model. For example, a 400 MW facility that is paired with 50%, 2-hour duration storage reflects a 400 MW solar plant paired with 200 MW of 2-hour storage. The ELCC of that facility is 26% or 104 MW (26% * 400 MW).

Table E-6: DEC Winter Solar Paired with Storage Incremental ELCC Values

Capacity Tranche [MW]	% Storage Paired with Solar	Battery Duration	ELCC
0 – 800	50%	2	26%
0 – 500	25%	4	31%
501 – 1,000	25%	4	30%
1,001 – 1,500	25%	4	29%
1,501 – 2,000	25%	4	29%
2,001 – 2,500	25%	4	28%
2,501 – 3,000	25%	4	27%

Table E-7: DEP Winter Solar Paired with Storage Incremental ELCC Values

Capacity Tranche [MW]	% Storage Paired with Solar	Battery Duration	ELCC
0 – 900	50%	2	26%
0 – 500	25%	4	32%
501 – 1,000	25%	4	31%
1,001 – 1,500	25%	4	30%
1,501 – 2,000	25%	4	29%
2,001 – 2,500	25%	4	28%
2,501 – 3,000	25%	4	27%

Wind ELCC

Table E-8 through Table E-10 below detail the capacity values for both onshore and offshore wind in the Carolinas.

Table E-8: DEC Winter Onshore Wind Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 – 1,000	37%
1,001 – 2,000	32%
2,001 – 3,000	27%

Table E-9: DEP Winter Onshore Wind Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 – 1,000	42%
1,001 – 2,000	39%
2,001 – 3,000	36%

Table E-10: Winter Offshore Wind Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 – 1,000	67%
1,001 – 2,000	62%
2,001 – 3,000	56%

Load Forecast

The load forecast is an important factor in planning the system. The primary target of 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 carbon emissions targets. Below are brief descriptions of the basic components included in the load forecast in the Carbon Plan, and what assumptions are made for base planning and sensitivity analysis for each component. More discussion on Load Forecasting included in Appendix F (Electric Load Forecast).

Base Economic Forecast

The economic forecast for the states of North Carolina and South Carolina is obtained from Moody Analytics, a nationally recognized economic forecasting firm. Based upon its modeling of the national economy, Moody's prepares a series of key economic measures, including history and projections of employment, income, wages, industrial production, inflation, prices, and population. This information serves as inputs for the models that predict energy volumes or customer growth.

Utility Energy Efficiency Forecast

The Utility Energy Efficiency ("UEE") forecast projects energy savings from efficiency programs that are sponsored and marketed by the utilities to assist customers in reducing their energy bill through reduced energy consumption. The Base IRP 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 third party expert consulting firms and provides a comprehensive assessment of EE/DSM potential using the best data available at the time to support the study with results specific to the service territory and customer base by including all currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DSM measures.

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 reduction targets. Accordingly, the Companies place a high priority and emphasis on minimizing the challenge of reducing carbon emissions of the system through demand-side efforts. The UEE forecasts developed for the Carbon 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 aspirational target of achieving UEE savings of 1% of eligible retail load annually.

In keeping with this aspirational target, the Companies developed two additional UEE forecasts for the Carbon Plan. The first, used as the base Carbon Plan planning assumption, grows UEE savings at a minimum of 1% of eligible retail load in each year of the Carbon 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 savings of 1% of *all* retail load in every year of the Carbon Plan. This high UEE assumption for the Carbon Plan is only used in the low load sensitivity and carries significant execution risk, as it would require legislative and procedural changes to customer opt-outs of UEE.

Summarized in Table E-11 and Table E-12 below are the incremental net impacts of these UEE forecast on net annual energy load of the system.

Table E-11: Incremental Net UEE Impacts on Annual Energy, Carbon Plan Base Assumption – 1% Growth in Eligible Retail Load [GWh]

	DEC	DEP
2030 Projection	-3,501	-1,976
2035 Projection	-4,440	-2,333

Table E-12: Incremental Net UEE Impacts on Annual Energy, Carbon Plan High Assumption – 1% Growth in All Retail Load [GWh]

	DEC	DEP
2030 Projection	-4,093	-2,395
2035 Projection	-6,049	-3,277

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.

Net Energy Metering forecast

Base Net Energy Metering ("NEM") growth reflects currently approved net metering rate designs in the Carolinas as of January 1, 2022. The high NEM sensitivity, which is used in the low load forecast, envisions future program offerings that would drive additional NEM growth in the Carolinas, such as extension of the solar Investment Tax Credit ("ITC"), and/or further reductions in panel prices driving higher adoption rates of rooftop solar.

The high NEM forecast is used as a load forecast sensitivity in the Sensitivity Analysis section of this Appendix to quantify resource impacts associated with incrementally lower load while complying with CO_2 emissions reductions targets.

Table E-13 and Table E-14 show the impact of NEM base assumptions and NEM high sensitivity assumptions on Carbon Plan net annual energy load.

Table E-13: NEM Impact on Annual Energy, Carbon Plan Base Assumption [GWh]

	DEC	DEP
2030 Projection	-446	-251
2035 Projection	-753	-400
2050 Projection	-1,864	-896

Table E-14: NEM Impact on Annual Energy, Carbon Plan High Assumption [GWh]

	DEC	DEP
2030 Projection	-446	-501
2035 Projection	-952	-1,067
2050 Projection	-2,394	-2,335

Integrated Voltage/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 10% of the hours in a year with CVR mode operating the other 90% of the hours. The modeling of CVR mode, where voltage/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. The remaining 10% during peak load times, the load forecast does not model any impacts from IVVC, and instead the benefits of the program are captured as a 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. DEC's current state IVVC program planning assumption is for implementation across approximately 60% of the eligible circuits on the DEC system. The Carbon Plan recognizes that the energy conservation potential of expanding IVVC to a higher level of circuits can reduce the load the utility needs to serve. Modeling assumptions for the Carbon Plan assumes the DEC IVVC program will be expanded to approximately 96% of the eligible circuits across the system, an increase from base resource planning assumptions and currently approved programs.

Summarized in Table E-15 below are the impacts of IVVC in the load forecast on net annual energy load of the system.

Table E-15: IVVC CVR impact on Annual Energy, Carbon Plan Base Assumption [GWh]

	DEC	DEP
2023 Projection	-374	-395
2030 Projection	-409	-432

Electric Vehicle Forecast

The base electric vehicle ("EV") load forecast reflects EV registration trends and adoption assumptions as of Fall 2021. The base forecast does not include any specific projection of future government programs or assistance that would further drive EV adoption. The high forecast, however, reflects commitments made by vehicle manufacturers to achieve 40% to 50% of new vehicle sales being EVs by 2030. This also aligns with President Biden's announced target of 50% of new vehicle sales being EVs by 2030. Importantly, both forecasts include projections of not only light duty EVs, but also includes projections of medium and heavy-duty EV adoption and their resulting energy demand on the system.

The high EV load forecast is used as load sensitivity, in the Sensitivity Analysis section of this Appendix quantifying resource impacts for incrementally higher load while complying with the HB 951 CO_2 emissions targets. Summarized in Table E-16 and Table E-17 below are the impacts of EV charging in the load forecast on net annual energy load of the system.

Table E-16: EV Charging Impact on Annual Energy, Carbon Plan Base Assumption [GWh]

	DEC	DEP
2030 Projection	1,210	755
2035 Projection	2,853	1,794
2050 Projection	12,857	8,099

Table E-17: EV Charging Impact on Annual Energy, Carbon Plan High Assumption [GWh]

	DEC	DEP
2030 Projection	2,806	1,464
2035 Projection	5,110	3,497
2050 Projection	25,714	16,198

Net Load Forecast

Summarized below in Table E-18 through Table E-20 is the base planning net load forecast, annual energy along with winter and summer system peaks, for the Carbon Plan. The net load forecast includes all of the impacts of all of the forecasts discussed above.

Table E-18: Carbon Plan Base Load Forecast – Annual Energy [TWh]

Year	DEC	DEP	Carolinas Combined
2023	92.0	64.3	156.2
2024	92.3	64.6	156.9
2025	92.3	64.5	156.9
2026	92.7	64.4	157.1
2027	93.1	64.5	157.6
2028	93.8	64.8	158.6
2029	94.6	65.1	159.7
2030	95.5	65.4	160.8
2031	96.5	65.8	162.3
2032	97.4	66.4	163.8
2033	98.4	66.9	165.3
2034	99.3	67.6	166.9
2035	100.3	68.3	168.5
2036	101.3	69.0	170.3
2037	102.3	69.8	172.2
2038	103.6	70.7	174.3
2039	104.8	71.6	176.5
2040	106.2	72.6	178.7
2041	107.4	73.5	180.9

Year	DEC	DEP	Carolinas Combined
2042	108.7	74.4	183.1
2043	110.0	75.4	185.4
2044	111.4	76.5	187.9
2045	112.8	77.5	190.3
2046	114.3	78.6	192.9
2047	115.8	79.8	195.6
2048	117.3	80.5	197.9
2049	118.9	81.6	200.5
2050	120.6	82.8	203.4

Note : Terawatts ("TW") represent 10^{12} watts.

Table E-19: Carbon Plan Base Load Forecast – Winter Peak [MW]

Year	DEC	DEP
2023	17,231	14,206
2024	17,333	14,387
2025	17,383	14,387
2026	17,442	14,335
2027	17,461	14,432
2028	17,562	14,365
2029	17,724	14,532
2030	17,779	14,487
2031	18,024	14,644
2032	18,244	14,714
2033	18,436	14,821
2034	18,553	14,909
2035	18,893	15,212
2036	19,008	15,255
2037	19,286	15,461
2038	19,512	15,700
2039	19,780	15,829
2040	19,980	16,001
2041	20,308	16,208
2042	20,553	16,413
2043	20,854	16,563
2044	21,153	16,847
2045	21,267	16,958
2046	21,670	17,344
2047	21,970	17,434
2048	22,347	17,719

Year	DEC	DEP
2049	22,284	17,865
2050	22,404	18,124

Table E-20: Carbon Plan Base Load Forecast – Summer Peak [MW]

Year	DEC	DEP
2023	17,522	12,655
2024	17,569	12,726
2025	17,640	12,763
2026	17,710	12,805
2027	17,788	12,904
2028	17,915	12,881
2029	18,089	12,961
2030	18,326	13,067
2031	18,556	13,203
2032	18,786	13,303
2033	18,993	13,437
2034	19,401	13,748
2035	19,609	13,832
2036	20,038	13,977
2037	20,273	14,175
2038	20,583	14,475
2039	20,841	14,578
2040	21,178	14,687
2041	21,693	14,949
2042	21,904	15,082
2043	22,139	15,305
2044	22,474	15,491
2045	22,766	15,661
2046	23,027	15,866
2047	23,693	16,106
2048	24,011	16,348
2049	24,171	16,586
2050	24,480	16,831

Existing Resources

Over the planning horizon, the Carbon Plan modeling accounts for resources that are currently on the system. These resources are included in the resource plans and continue to provide reliable and cost-effective service of energy throughout the Companies' transition to a lower carbon system. Discussed below are the assumptions of how the existing generation resources change over the planning horizon.

Existing Resource Capacity Uprates

DEC and DEP continue to evaluate projects at existing generating facilities that can provide incremental benefit to customers. In the Carbon Plan analysis, projects that are currently planned or under construction have been included. Table E-21 below summarizes these projects by utility and provides the planned capacity uprate and year of project implementation. The Carbon Plan does not include any projected uprates to existing DEP units, though Duke Energy continues to evaluate cost-effective projects that would increase the output and efficiency of its generating assets.

Table E-21: Planned Unit Uprates

Unit	Utility	Winter Capacity [MW]	Year
Oconee	**DEC**	45	2023
Bad Creek	**DEC**	320*	2024

Note: Bad Creek Runner Upgrade Project results in uprates for each unit, completed sequentially. The collective project uprate across all units is modeled to total 320 MW for the station at the competition of the project. As of the development of the Carbon Plan two of the four units have been completed. Final uprate capacities may vary at project completion with final testing and verification of the project.

Existing Generation Retirements

Coal retirements in the Carbon Plan vary by portfolio. The coal retirements were identified endogenously within the capacity expansion model based on portfolio development scenarios. More discussion on how the coal unit retirement dates were established for the Carbon Plan modeling is presented later in this Appendix.

With respect to non-coal generating assets, the Carbon 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 in the Carbon Plan to continue service to 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 2021 generated approximately 50% of the energy used to serve DEC and DEP customers. Subsequent License Renewal, 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 Carbon Plan analysis, after the 2050 planning horizon, additional planning of the system will have to account for the retirement of this significant source of carbon-free energy.

More information on Subsequent License Renewal is included in Appendix L (Nuclear) and the retirement dates assumed for all non-coal owned generation resources in Carbon Plan is included in Appendix D (DEC-DEP Owned Generation).

Conversions to Hydrogen

A limited number of natural gas resources currently on the system are expected to continue operating in 2050 and beyond. These include the WS Lee CC, the Asheville CCs, Sutton CTs 4 and 5, and Lincoln CT 17. For these combustion units that are planned to remain on the system in 2050, the Carbon Plan assumes these units are converted to hydrogen-fired units near the end of the planning horizon. In the Carbon Plan modeling, these units operate exclusively on hydrogen to comply with the 2050 carbon neutrality target.

Capacity PPA Expiry

DEC and DEP currently have various purchase power agreements ("PPA") for capacity purchases. The Carbon Plan modeling assumes PPA expiry at the end of the current contract term for these resources, but that the utility is able to procure a "like-kind" resource replacement. Ultimately, all of these generic market resources are assumed to retire and expiry of the replacement PPA is assumed prior to 2050 without additional like kind replacement.

Forecasted Demand-Side Management

Demand-side management ("DSM") programs, which include UEE, demand response ("DR"), 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 Carbon Plan analysis in the load forecast as described above, but these resources also have peak load capacity, which helps in maintaining reserve margins. The Carbon Plan 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 Carbon Plan utilizes an aggressive UEE forecast well above the Companies' most recent IRP planning assumptions for UEE growth as described in the load forecast section above. UEE is factored into the net load forecast, but UEE also reduces peak energy consumption, impacting the net load forecast.

Summarized in Table E-22 and Table E-23 below are the peak load impacts of UEE.

Table E-22: Incremental Net UEE Impacts at Winter Net Peak Load, Carbon Plan Base Assumption – 1% Growth in Eligible Retail Load [MW]

	DEC	DEP
2030 Projection	-574	-332
2035 Projection	-781	-390

Table E-23: Incremental Net UEE Impacts at Winter Net Peak Load, Carbon Plan High Assumption – 1% Growth in All Retail Load [MW]

	DEC	DEP
2030 Projection	-670	-402
2035 Projection	-1,065	-547

Demand Response

DR customer programs reduce system peak load requirements by modifying customer consumption. DR consists of two types of customer programs: mechanical/manual reduction programs and rate programs. Mechanical and manual reduction programs consist of controlling 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. Customers are compensated monthly for opting into programs to reduce demand when needed by the system. Rate programs are price signals sent to customers to incentivize a reduction in their energy consumption through different energy rates.

DR capacity in resource planning counts toward 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 are typically more carbon-intensive resources, but the primary benefit of DR to the system is reliability and system cost savings. The forecast adopts the measures recommended by the Companies' Winter Peak Demand Reduction Potential Assessment ("Winter Peak Study") in addition to existing programs offered by the companies.

Table E-24 below summarizes the peak winter capacities of mechanical and manual reduction programs in the Carbon Plan.

Table E-24: Mechanical and Manual Reduction Demand Response, Winter [MW]

	DEC	DEP
2023 Projection	468	305
2030 Projection	583	468
2050 Projection	789	652

The Carbon Plan also includes the impacts of rate-based DR programs, including Critical Peak Pricing ("CPP") and Peak-time Rebate ("PTR"). These rate programs are included as DR programs that lower energy consumption at system peak times. These programs were identified in the Winter Peak Study as a way to reduce peak winter load using rates structures. CPP and PTR programs are designed to send price signals to customers who opt into the program to encourage them to reduce load during peak periods to avoid use during high price periods in exchange for bill rebates or other favorable rate structures. The impacts of CPP and PTR are built into the load forecast to capture anticipated changes in customer load shape with the reductions at system peak summarized in Table E-25 below.

Table E-25: CPP/PTR Demand Response, Winter [MW]

	DEC	DEP
2030 Projection	229	131
2040 Projection	514	298

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 Carbon Plan modeling. As stated above DEP represents deployment across 100% of circuits, while DEC represents an increase over the base planning assumption of 60% of circuits to approximately 96% of circuits at full implementation.

Below in Table E-26 are the peak load reduction capacity of the program in 2025 and 2035.

Table E-26: IVVC Peak Shaving Capacity, Winter [MW]

	DEC	DEP
2025 Projection	175	161
2035 Projection	212	175

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 Carbon 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. Solar that is currently installed on the system and the near-term expected growth due to these supportive policies are included as forecasted solar in the Carbon Plan. While the majority of the solar included in the portfolios of the Carbon Plan is economically selected in the modeling, forecasted solar represents existing solar capacity as well as projects in various stages of the interconnection process including HB 589 Green Source Advantage ("GSA") and Competitive Procurement of Renewable Energy ("CPRE") Tranches 1 and 2 projects. The Carbon Plan modeling also anticipate that current uncontracted projects under CPRE Tranche 3 would be connected prior to 2026, and the remaining uncontracted HB 589 GSA solar would connect throughout the remainder of the decade. The existing, incrementally forecasted, and total forecasted solar assumed in the Carbon Plan is included in Table E-27 below.

Table E-27: Existing and Forecasted Solar Capacities [Nameplate MW]

	DEC	DEP	DEC/DEP Combined
Projected Installed Solar as of January 1, 2023	1,452	3,561	5,013
Incremental Forecast	1,633	305	1,938
Total Forecasted Solar	3,086	3,865	6,951

Forecasted solar represents expected additions through 2030, though the majority of the forecasted solar is forecasted to be online by the start of 2026.

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 in the Carbon Plan represents a limited amount of grid-connected battery storage projects that will allow for a more complete evaluation of potential benefits to the distribution, transmission, and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale. The experience gained in these early installations will support the acceleration of storage additions toward meeting the clean energy targets in this decade.

To account for these battery projects that are in mid- and late-stage development, and those projected to be in-service at the start of the planning horizon, the Carbon Plan assumes the deployment of approximately 350 MW of nameplate capacity (approximately 110 MW in DEC and 240 MW in DEP) with various storage capacity durations through 2027. These near-term forecasted battery projects are in addition to the incremental battery storage economically selected by the model.

Lincoln CT17 Integration

Lincoln County CT17 is a collaboration 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 Carbon Plan assumes DEC will take care, custody, and control of the completed 402 MW (winter capacity) unit in 2024.

Bad Creek Powerhouse II

Pumped storage hydro ("PSH") is the use of two water reservoirs at different elevations to store and release energy by running water between the two. When there is excess low-cost energy available to the system, water can be pumped from the lower reservoir to the upper reservoir by consuming electricity from the grid. At times of high-cost energy or demand, 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 or load to the system to provide peak energy to customers or time shift excess energy from renewables to be available during times of greater demand.

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 be able to take advantage of this resource option. The Bad Creek PH II project represents an increase in power capacity from the facility using the existing upper and lower Bad Creek reservoirs. The additional power house 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 PH II was prescribed into all portfolios. As discussed later in this Appendix, the capacity expansion model alone is not sufficient for evaluating energy storage resources. For this reason, the Companies performed a separate comparative economic analysis for Bad Creek PH II utilizing the production cost model to validate inclusion in the modeling was economic against other long-duration storage options. More discussion on this analysis is included in the portfolio verification section of this Appendix. The Companies will continue to evaluate the value of long-duration storage on the system and its ability to provide significant power capacity in addition to facilitating reliable 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 model is designed to select “least cost” portfolios of supply-side resource that minimize the cost of the system, subject to meeting constraints such as CO_2 emissions reductions, capacity planning reserve margins and operating reserve requirements. Each resource’s unique characteristics present valuable tradeoffs for the model to weigh. 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 capacity value are all important factors that can influence the optimal set of resources to meet future energy and capacity needs. Modeling parameters are discussed for each resource in more detail below, including how they are applied throughout the Carbon Plan modeling.

The resources below are categorized into mature technologies in the DEC/DEP service territories, and new-to-the-Carolinas technologies. Mature technologies represent those supply-side resource resources which the Companies have experience in integrating and operating in their service territories. The new-to-the-Carolinas technologies have a higher level of uncertainty when it comes to integrating and operating these resources. The assumptions made for modeling purposes for these resources compared to their eventual deployment may vary and present an area of technology risk for the Companies. The one set of resources that straddle the two categories is new nuclear. The

Companies have a long history of operating and maintaining nuclear generation on the system and integration of new nuclear is a better understood technology compared to other emergent technologies. However, small modular reactor ("SMR") nuclear technology is a technology that is new to the DEC/DEP service territories, and for that reason, it straddles both categories.

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 H (Screening of Generation Alternatives).

Mature Technologies in DEC/DEP Service Territories

Solar

As discussed previously in this Appendix, the Companies have developed a "forecast" for the amount of solar that is expected to come online based on current policies and programs. While the existing and forecasted solar represent a portion of the total solar expected to come online, the majority of solar shown in the Carbon Plan is ultimately economically selected by the capacity expansion model.

There are three (3) configurations of solar that are economically selectable in the Carbon Plan modeling:

- Standalone Solar – 75 MW Single-axis tracking bi-facial solar
- Solar paired with Storage (50% Battery Ratio) – 75 MW Single-axis tracking bi-facial solar with 40 MW / 80 MWh ("megawatt-hour") battery
- Solar paired with Storage (25% Battery Ratio) – 75 MW Single-axis tracking bi-facial solar with 20 MW / 80 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. Table E-28 through Table E-30 below describe the assumptions for each solar resource in the Carbon Plan modeling.

Table E-28: Standalone Solar Modeling Assumptions

Modeling Parameter	DEC	DEP
Fuel	N/A	N/A
Build Increments	75 MW AC	75 MW AC
DC / AC Ratio	1.4	1.4
Capacity Factor	27.8%	28.5%
Dispatchability	Fully Curtailable Down	Fully Curtailable Down
ELCC	See ELCC section	See ELCC section

Modeling Parameter	DEC	DEP
Asset Life	30 Years	30 Years
First Year of Eligible Selection	2027	2027
Cumulative Addition Limit	N/A	N/A

Table E-29: Solar paired with Storage (50% Battery Ratio) Modeling Assumptions

Modeling Parameter	DEC	DEP
Fuel	N/A	N/A
Build Increments	75 MW AC	75 MW AC
DC / AC Ratio	1.6	1.6
Capacity Factor	32.4%	33.5%
Battery Power Capacity	40 MW	40 MW
Battery Storage Capacity	80 MWh	80 MWh
Dispatchability	Fully Curtailable Down	Fully Curtailable Down
ELCC	See ELCC section	See ELCC section
Asset Life	30 Years	30 Years
First Year of Eligible Selection	2027	2027
Cumulative Addition Limit	450 MW	750 MW

Table E-30: Solar paired with Storage (25% Battery Ratio) Modeling Assumptions

Modeling Parameter	DEC	DEP
Fuel	N/A	N/A
Build Increments	75 MW AC	75 MW AC
DC / AC Ratio	1.6	1.6
Capacity Factor	31.8%	32.7%
Battery Power Capacity	20 MW	20 MW
Battery Storage Capacity	80 MWh	80 MWh
Dispatchability	Fully Curtailable Down	Fully Curtailable Down
ELCC	See ELCC section	See ELCC section
Asset Life	30 Years	30 Years
First Year of Eligible Selection	2027	2027
Cumulative Addition Limit	N/A	N/A

With the assumption of strategic transmission to enable renewable interconnection, as discussed in more detail in Appendix P (Transmission System Planning and Grid Transformation), below in Table E-31 and Table E-32 are the annual solar interconnection limits for both the Carbon Plan Base Case and Carbon Plan High Case. The resource availability split between DEP and DEC was assigned at ~60% in DEP and ~40% in DEC based on general trends and alignment with resources and land availability.

Table E-31: Solar Economic Annual Selection Constraints [MW], Carbon Plan Base Case

Year	DEC	DEP	DEC/DEP Combined
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	300	450	750
2028	450	600	1,050
2029	525	825	1,350
2030+	525	825	1,350

Table E-32: Solar Economic Annual Selection Constraints [MW], Carbon Plan High Case

	DEC	DEP	DEC/DEP Combined
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	300	450	750
2028	450	600	1,050
2029	750	1,050	1,800
2030+	750	1,050	1,800

Actual solar output is variable and dependent on natural irradiance (daylight) and cloud cover. Solar profiles modeled in the Carbon Plan are based on a "typical meteorological year," or TMY, using twenty 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 Carbon Plan.

Simple Cycle Combustion Turbines

Simple Cycle Combustion Turbines ("CTs" or "peakers") are economically selectable by the capacity expansion model in the development of portfolios. As shown in Table E-33, the Companies use a J-Class Frame CT with an SCR, with dual-fuel operations on natural gas and ultra-low sulfur diesel ("ULSD") as the generic unit assumption for these peaking resources. This technology is a more efficient and flexible combustion technology than the F-Class Frame CTs that represent the majority of the Companies' existing peaking CT technologies. The J-Class Frame CTs also are currently more hydrogen capable than the F-Class Frame CTs and compatible for conversion to 100% operation on hydrogen in the future.

Table E-33: CT Modeling Assumptions

Modeling Parameter	DEC/DEP
Primary Fuel (pre-2040)	Natural Gas
Back-up Fuel	ULSD
Post 2040 Net Zero Carbon Fuel	Hydrogen
Capacity (Max, Winter)	376 MW
Heat Rate (Max, Winter)	9,150 Btu/kWh
Dispatchability	Dispatchability between Min and Max Capacity
ELCC	100%
Asset Life	35 Years
First Year of Eligible Selection	2028
Annual Addition Limit	4 Units per Utility
Cumulative Addition Limit	N/A

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. CTs that are selected in the Carbon Plan before 2040 are assumed to be converted to 100% operations on Hydrogen by 2050 to comply with the 2050 carbon neutrality target.

As 2050 approaches, the Companies assume hydrogen becomes a readily accessible fuel as a green hydrogen market develops. In anticipation of the Carbon Plan's target of zero CO_2 emission by 2050, CTs added in the 2040s are assumed to operate exclusively on hydrogen. These "H_2 CTs" that are selected post 2040 have the same operating characteristics of their primarily natural gas predecessors but are assumed to have the components to operate on exclusively hydrogen when built. To account for the incremental equipment, the CT cost is increased to reflect these configuration changes to allow for operating 100% on hydrogen.

Combined Cycle Power Blocks

Combined Cycle Power Blocks ("CCs") are economically selectable by the capacity expansion model in the development of portfolios. The Companies have two CC configurations for the Carbon Plan; application of each is dependent on the natural gas fuel supply assumption described later in this Appendix. The Companies use a 2x1 J-Class CC with Duct Firing ("CC-J") as the generic unit assumption under the Companies' base fuel supply assumption, which assumes access to limited volumes of Appalachian gas. In the alternate fuel supply sensitivity, natural gas supply is assumed to be more limited and therefore the Companies limit the selection of CCs to a single new CC unit. Additionallly in this sensitivity, the assumption for generic CC is a 2x1 F-Class CC with dual fuel capabilities ("CC-F"), operating on both natural gas and ULSD. The CC-F modeled in this sensitivity is a generic placeholder for a smaller sized CC unit to reflect uncertainty and risk of fuel supply in the alternate gas supply sensitivity and the smaller CC could be different configurations of CC-Fs or CC-Js.

Under both fuel supply assumptions, the total amount of CC capacity is limited as shown in Table E-34 and Table E-35 below. This modeling assumption accounts for uncertainty in natural gas fuel supply and responsive planning to assure reliable operation of the system.

Table E-34: CC-J Modeling Assumptions

Modeling Parameter	DEC/DEP
Fuel (pre-2050)	Natural Gas
2050 Net Zero Carbon Fuel	Hydrogen
Capacity (Max, Winter)	1,216 MW
Heat Rate (Max, Winter)	6,260 Btu/kWh
Dispatchability	Dispatchability between Min and Max Capacity
ELCC	100%
Asset Life	35 Years
First Year of Eligible Selection	2029
Cumulative Addition Limit	2 Power Blocks

Table E-35: CC-F Modeling Assumptions

Modeling Parameter	DEC/DEP
Primary Fuel (pre-2050)	Natural Gas
Back-up Fuel	ULSD
2050 Net Zero Carbon Fuel	Hydrogen
Capacity (Max, Winter)	812 MW
Heat Rate (Max, Winter)	6,540 Btu/kWh
Dispatchability	Dispatchability between Min and Max Capacity
ELCC	100%
Asset Life	35 Years
First Year of Eligible Selection	2029
Cumulative Addition Limit	1 Power Blocks

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. Under the base fuel supply assumption, the potential for additional supply allows for the highly efficient CC units that are expected to operate at intermediate and high capacity factors to secure firm interstate transportation service of natural gas to ensure supply that these units would need to operate on natural gas year-around. In the alternate fuel supply sensitivity, with limits on natural gas supply, the new CC is assumed to operate on ULSD in potentially natural gas limited periods, responsive to supply constraints and price volatility, and on natural gas the remainder of the year when supply is less limited. All CCs that are selected in the Carbon Plan, regardless of the fuel supply assumption, are assumed to be converted to 100% operations on Hydrogen by 2050 to comply with the 2050 carbon neutrality target.

New-to-the-Carolinas Technologies

Standalone Batteries

An enhancement introduced for the Carbon Plan modeling is 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 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 offset marginal carbon 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 E-36 are standalone batteries. Standalone storage resources can charge from and dispatch to the grid, whereas storage paired with solar is assumed in the Carbon Plan to be DC-tied, and thus, only able to charge from the solar facility and dispatch to the grid when solar is not already using all of the interconnection limit.

Table E-36: Standalone Battery Modeling Assumptions

Modeling Parameter	4-Hr Battery	6-Hr Battery	8-Hr Battery
Charging Method	Grid-Tied	Grid-Tied	Grid-Tied
Build Increments	50 MW	50 MW	50 MW
Usable Storage Capacity	200 MWh	300 MWh	400 MWh
Round-Trip Cycle Efficiency	85%	85%	85%
Degradation Strategy	Annual Replenishment	Annual Replenishment	Annual Replenishment
Dispatchability	-50 MW to 50 MW	-50 MW to 50 MW	-50 MW to 50 MW
ELCC	See ELCC section	See ELCC section	See ELCC section
Asset Life	15 Years	15 Years	15 Years
First Year of Eligible Selection	2025	2025	2025
Cumulative Addition Limit	N/A	N/A	N/A

Small Modular Nuclear and Advanced Nuclear

For the Carbon Plan, the Companies assume two different types of new nuclear resources will be available for achieving carbon neutrality by 2050. The first available is SMR nuclear technology, as shown in Table E-37. These resources present the ability to provide the system with bulk, dispatchable carbon-free energy by the early-to-mid 2030s. Their modular setup allows for distributing the resource across the system and allows small sets of these resources to be added over time as needed by the system.

The second nuclear technology assumed for the Carbon Plan is Advanced Nuclear with Integrated Storage, as shown in Table E-38. These advanced reactors use a moderator other than water, which allows for efficiency gains compared to 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.

Table E-37: SMR Modeling Assumptions

Modeling Parameter	DEC/DEP
Primary Fuel (pre-2050)	Nuclear Fuel
Capacity (Max)	285 MW
Heat Rate (Max)	10,130 Btu/kWh
Dispatchability	Dispatchability between Min and Max Capacity
ELCC	100%
Asset Life	60 Years
First Year of Eligible Selection	2033

Table E-38: Advanced Nuclear with Integrated Storage Modeling Assumptions

Modeling Parameter	DEC/DEP
Primary Fuel (pre-2050)	Nuclear Fuel
Capacity (Peaking Max)	500 MW
Capacity (Base Max)	345 MW
Heat Rate (Max)	8,025 Btu/kWh
Thermal Storage Capacity	960 MWh
Dispatchability	Dispatchability between Reactor Min and Peaking Max Capacity
ELCC	100%
Asset Life	60 Years
First Year of Eligible Selection	2038

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 2033 and Advanced Nuclear with Integrated Storage starting in 2038. The generic SMR unit assumed in the Carbon Plan is constant throughout the planning horizon, but the gap in availability for the model to select SMRs between the 2030s and the 2040s (as shown in Table E-39 and Table E-40 below) represents the potential for this technology to become an advanced reactor SMR with improved efficiencies and potential for large scale hydrogen production, while leveraging its modular scale.

The model was limited to one incremental new nuclear unit in 2033, 2034, 2036 and 2037. While the modeling adds resources on an annual basis for an entire calendar year, this schedule of SMR availability generally aligns the potential commercial operation dates of the first four new nuclear units in DEC and DEP service territories, as discussed in more detail in Appendix L (Nuclear), essentially limiting additions to two units added every three years. Thereafter, the model was constrained to limit additions to one new nuclear unit per year through 2042 and two units per year through the remainder of the planning horizon. Cumulative constraints were also put on the capacity expansion model, limiting economic selection to 21 total nuclear units through 2050 while simultaneously maintaining the annual additional limits.

Table E-39: New Nuclear Annual Selection Constraints [Units]

Year	DEC/DEP SMR	DEC/DEP Advanced Nuclear with Integrated Storage	DEC/DEP New Nuclear
2023-2032	0	0	0
2033	1	0	1
2034	1	0	1
2035	0	0	1
2036	1	0	1
2037	1	0	1
2038	0	1	1
2039	0	1	1
2040	0	1	1
2041	0	1	1
2042	0	1	1
2043	2	1	2
2044	2	0	2
2045	2	0	2
2046	2	0	2
2047	2	0	2
2048+	2	1	2

Table E-40: New Nuclear Cumulative Selection Constraints [Units]

Year	DEC/DEP SMR	DEC/DEP Advanced Nuclear with Integrated Storage	DEC/DEP New Nuclear
2023-2032	0	0	0
2033	1	0	1
2034	2	0	2
2035	2	0	2

Year	DEC/DEP SMR	DEC/DEP Advanced Nuclear with Integrated Storage	DEC/DEP New Nuclear
2036	3	0	3
2037	4	0	4
2038	4	1	5
2039	4	2	6
2040	4	3	7
2041	4	4	8
2042	4	5	9
2043	6	6	12
2044	8	6	14
2045	10	6	16
2046	12	6	18
2047	14	6	20
2048+	14	7	21

Onshore Wind

Onshore Wind is a selectable resource for the Carbon Plan modeling, as shown in Table E-41. Numerous factors potentially limit integration of onshore wind resources into the Companies' resource portfolios, including development restrictions precluding access to quality wind resource in the mountains of North Carolina, sub-optimal wind resources in the central parts of both North Carolina and South Carolina, limited amount of quality onshore wind resource near the coast, as well as potential transmission limitations and constraints.

DEC and DEP use the same assumption for onshore wind technology and capacity factor as a proxy for onshore wind resource which might be available to each utility. DEP assumes high-capacity factor wind along the Carolinas coast. DEC assumes the same generation profile, but as a proxy for high-capacity factor wind imported from regions such as PJM or Midcontinent Independent System Operator ("MISO").

Table E-41: Onshore Wind Modeling Assumptions

Modeling Parameter	DEC	DEP
Fuel	N/A	N/A
Build Increments	150 MW	150 MW
Capacity Factor	30%	30%
Assumed General Location	Imported	Coastal Carolina
Dispatchability	Fully Curtailable Down	Fully Curtailable Down
ELCC	See ELCC section	See ELCC section

Modeling Parameter	DEC	DEP
Asset Life	30 Years	30 Years
First Year of Eligible Selection	2029	2029
Annual Additions Limit	300 MW (DEC/DEP Combined)	
Cumulative Additions Limit	600 MW	1,200 MW

Offshore Wind

Offshore Wind is a selectable resource for the Carbon Plan modeling, as shown in Table E-42. Due to its location off the Carolinas coast, this resource is only available for DEP to select. Costs assume generic offshore wind turbine facility technology with costs for transmitting the energy from the offshore wind facility to a DEP service territory interconnection point, based on Duke Energy-specific assumptions.

Table E-42: Offshore Wind Modeling Assumptions

Modeling Parameter	DEP
Fuel	N/A
Build Increments	800 MW
Capacity Factor	42%
Assumed general location	Offshore Carolinas
Dispatchability	Fully Curtailable Down
ELCC	See ELCC section
Asset Life	25 Years
First Year of Eligible Selection	2030
Annual Additions Limit	800 MW

The Carbon Plan assumes an aggressive integration timeline of offshore wind availability for the Carolinas. While there are potential offshore wind lease areas and wind energy areas in the Carolinas, development of the project and the necessary transmission system upgrades prevent earlier integration. 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. As described in Appendix J (Wind), 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 assume a limited amount of offshore wind is available starting in 2030 with additional offshore wind capacity available beginning in the early 2040s. Table E-43 provides the maximum cumulative availability of offshore wind available for economic selection.

Table E-43: Offshore Economic Cumulative Selection Constraints [MW]

Year	DEP
2023-2029	0
2030	800
2031	800
2032	1,600
2033-2040	1,600
2041	2,400
2042	3,200
2043	4,000
2044+	4,800

Transmission Costs

The Carbon 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 regional transmission network for the reliable transmission of power from the resource into the networked transmission system.

Where available, actual generator interconnection study results or the results of other transmission planning studies were used to inform the transmission network upgrade proxy costs used in the Carbon Plan modeling. As shown in Table E-44, transmission cost estimates were derived for network transmission upgrades where prior studies had indicated the path and likely transmission needs for interconnecting a specific supply-side resource. Otherwise, prior studies or similar analysis for a greenfield generator such as a CC generator was used to establish a proxy cost for network transmission upgrades. New gas, nuclear, and battery resources were all assigned the same transmission network upgrade proxy cost, representing costs associated with centralized generation facilities in each service territory. Bad Creek PH II utilizes a specific transmission network upgrade proxy cost, based on estimates to facilitate the additional capacity of the expansion project. Transmission network upgrade proxy costs for offshore wind and new solar are provided in tranches to represent potential transmission network upgrade cost changes associated with greater adoption of these resources, based on where these resources are likely to be interconnected and associated network upgrade costs. DEC and DEP-specific proxy transmission costs were also developed for integrating onshore wind into the Companies' service territory.

Table E-44: Generic Transmission Network Upgrade Costs [2022 $/W]

Resource Type / In Service Year	DEC	DEP
Capacity Resources	0.19	0.22

Resource Type / In Service Year	DEC	DEP
Bad Creek PH II	0.22	N/A
Offshore Wind First 800	N/A	0.45
Offshore Wind Second 800	N/A	0.79
Offshore Wind 1600+	N/A	0.22
Solar 2026	0.17	0.17
Solar 2027-2030	0.19	0.19
Solar 2031-2037	0.21	0.21
Solar 2038-2045	0.24	0.24
Onshore Wind	Note 1	0.24

Note: DEC Onshore wind is assumed to be imported. As a proxy transmission cost, the DEC used the PJM Border Charge. The current PJM rate for 2022 is $67,625/MW-yr. Based on historic trends of this rate, the annual cost is inflated 5% per year.

Transmission costs are applied to each supply-side resource in the capacity expansion model. For the capacity expansion model to select 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. All selectable resources included transmission costs to ensure all resources were evaluated on an equitable basis. 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 for each Carbon Plan update cycle. 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 E-44 in future years.

Fuel Supply and Commodity Pricing

Natural Gas

Natural Gas Price Forecast

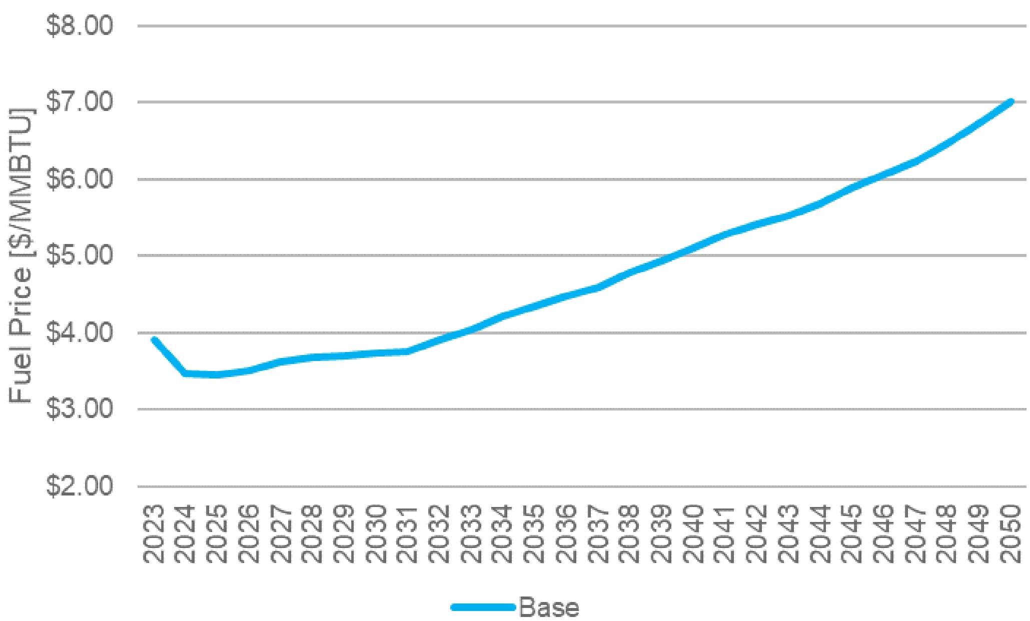
The natural gas price forecast methodology used for the Carbon Plan utilized both short-term market-based price forecasts and longer-term fundamentals-based price forecasts, as well as a transition period from market-based pricing to fundamental based pricing. The Companies natural gas price forecast relies upon five (5) years of natural gas market-based pricing, followed by three (3) years of transitioning from market-based pricing before fully utilizing fundamentals-based natural gas pricing forecast starting in 2031 for the remaining study period.

Recent natural gas price forecasts have also varied 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 Carbon Plan, the Companies' developed their fundamentals-based natural gas price forecast by averaging four recent natural gas prices forecasts:

- Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") Reference Case (2021 AEO)
- Wood Mackenzie North American Power Markets (Base Case) (2021)
- EVA FuelCast (2021)
- IHS Markit Long-Term Natural Gas Outlook (August 2021)

The resulting Henry Hub natural gas price forecast utilized in the Carbon Plan 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 four different fundamentals providers discussed above) is shown below in Figure E-6.

Figure E-6: Base Henry Hub Natural Gas Price Forecast [$/MMBtu]

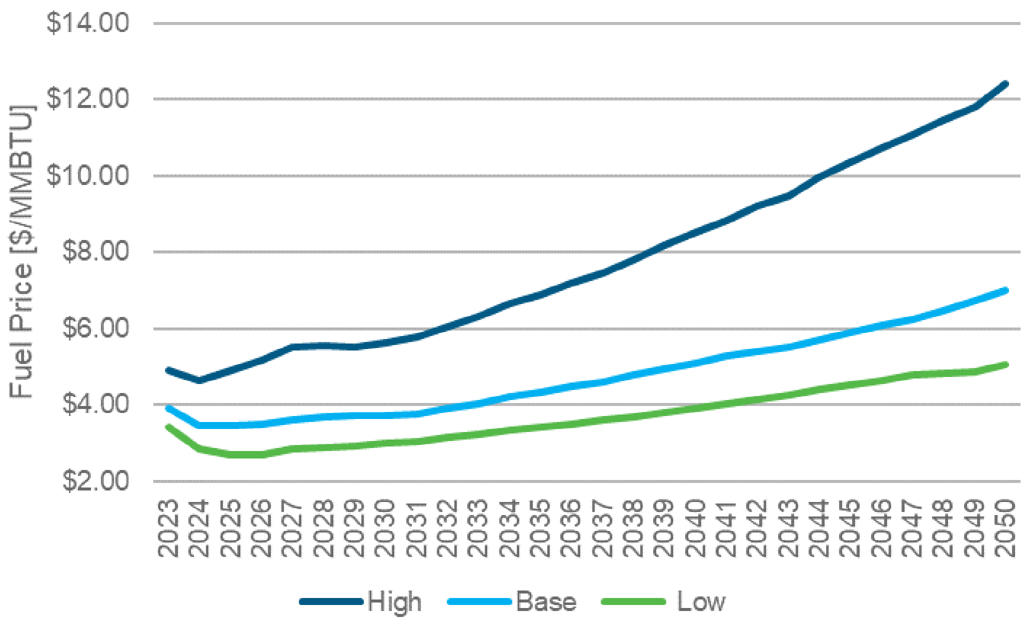


High and Low Natural Gas Price Forecast Sensitivities

To further quantify the impacts on resource selection, cost to the system, and achievement of reduction targets, the Carbon Plan 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 utilized 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, respectively, to the AEO Reference Case, to its base natural gas price forecast to develop its high and low natural gas price forecasts for the Carbon Plan. High and low natural gas price forecasts were developed for each fuel supply case according to the specific fuel supply and commodity pricing assumptions and impacts used in each case. Figure E-7 below shows the resulting high and low natural gas prices forecasts compared to the Companies' base forecast.

Figure E-7: High, Base and Low Henry Hub Natural Gas Price Forecasts [$/MMBtu]



Natural Gas Fuel Supply Assumptions

The Carbon 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 interstate FT of natural gas from the Appalachia region. Natural gas fuel supply in the Carbon Plan refers to obtaining interstate FT capacity for existing CC units (that do not already have firm supply from the Gulf Coast) and allowing for incremental generation supply. Because there is uncertainty on how incremental natural gas supply to the DEC and DEP service territories will materialize, the Companies have developed a base fuel supply assumption and an alternate fuel supply sensitivity for the Carbon Plan. While the siting and in-service date of any additional interstate FT capacity accessible to the Carolinas region is not within the control of DEC and DEP, the Companies are evaluating multiple possible natural gas transportation assumptions to ensure reliable service at least cost. See Appendix N (Fuel Supply) for more details about natural gas firm transportation.

Portfolios are developed based on respective achievement dates of the 70% interim target and the resources used to meet that target. To observe how fuel supply impacts resources selected and cost to reach targets, the Companies developed an “alternate” natural gas fuel supply assumption to assess how the Companies may pivot if fuel supply develops differently.

Base Fuel Supply Assumption - Limited Appalachian Gas Supply

The base fuel supply assumption for DEC and DEP in the Carbon plan assumes the Companies obtain a limited amount of firm transportation service to access lower cost Appalachian gas. Natural gas from this region typically trades at a discount relative to Transco Zone 5 delivered, the Carolinas region’s main pricing index. This incremental firm supply allows for the Companies’ existing CC fleet to be fully supported by interstate firm transportation and with the potential for capacity for a limited amount of new CC units to also operate at this gas price. 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.

Alternate Fuel Supply Sensitivity - No Appalachian Gas Supply

The Companies also developed an alternate fuel supply sensitivity, which assumes that DEC and DEP do not receive access to any Appalachian gas via firm transportation capacity. This sensitivity further restricts the amount of CC capacity selectable by the model, based on the risks associated with natural gas supply and price volatility exposure in Transco Zone 5, particularly in the winter. Given the risks of obtaining incremental large volumes of Transco Zone 5 delivered gas in the winter, the model requires any new CC in this fuel supply sensitivity to have dual-fuel capability. This sensitivity also delays securing the remaining portion of DEC’s and DEP’s existing combined cycle fleets with firm interstate capacity for non-Appalachian natural gas supply. The continued lack of supply diversity also impacts the natural gas price forecasts into the future, reflected through price volatility in this sensitivity. To account for potential physical and economic constraints of natural gas to the Companies service territories, this sensitivity limits operations of some generation units to coal and ULSD during times of potentially limited supply and price volatility.

Coal Price Forecast

The Carbon Plan assumes five (5) years of market coal prices, and over the next three (3) years blends to a fundamental-based price forecast. Finally, beginning in 2031, the coal price forecast fully utilizes the fundamentals-base 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 increases in commodity and transportation costs into the future, the true uncertainty of how the coal market will wind down is highly speculative (see Appendix N (Fuel Supply) for more details).

Hydrogen

As a base planning assumption, the Carbon Plan includes hydrogen as a fuel used to generate electricity for the system. Hydrogen fuel is assumed to be used in two ways. First, starting in 2035, a small amount of hydrogen (1% by heat content, ~3% by volume) is assumed to be blended into the natural gas supply for all resources. 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 carbon 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 moderately (to 3% by heat content or approximately 10% by volume by 2038 and to 5% by heat content or approximately 15% by volume by 2041) but remains a small fraction of total fuel supply in the pipelines.

By 2050, the remaining combustion units on the system are assumed to operate exclusively on hydrogen to meet the Carbon Plan modeling target of zero carbon emissions by 2050. The Carbon Plan assumes a green hydrogen market develops, by which hydrogen is produced from non-carbon emitting means, such as from excess energy from renewables or nuclear. This hydrogen price forecast is developed based on anticipated economies of scale and cost declines of the technologies to produce hydrogen and the availability of low-cost energy from carbon-free resources.

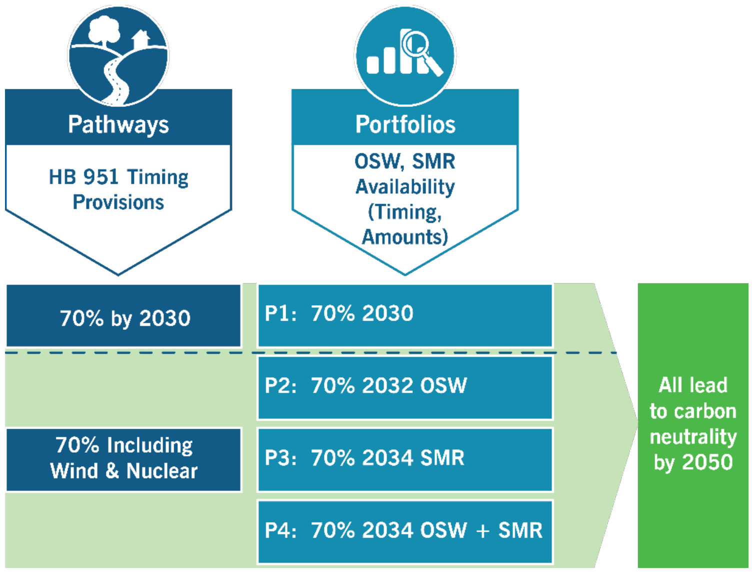
Supply of hydrogen carries a significant uncertainty. There are initiatives and funding for the development of hydrogen supply hubs across the United States. While the ultimate realization of a hydrogen hub in the Carolinas is uncertain, the hydrogen economy is viewed by the Companies as a potential 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. To identify potential for the Companies to self-supply a significant portion of hydrogen used by 2050, the Companies performed a Hydrogen Supply Analysis, which is discussed later in this Appendix.

More discussion on Hydrogen and Low Carbon Fuels is included in Appendix O (Low-Carbon Fuels and Hydrogen).

Portfolio Development

As previously discussed and illustrated in Figure E-8, the Carbon Plan portfolios follow two pathways: 1) achieving HB 951's interim 70% CO_2 emissions reductions target from generators modeled to be located in North Carolina by 2030 and 2) achieving HB 951's 70% interim target from generators modeled to be located in North Carolina by at latest 2034 incorporating new wind and/or nuclear resources. The first pathway consists of one least-cost portfolio option for achieving the interim target by 2030 ("Portfolio 1" or "P1"). The second pathway has multiple options for complying with the interim target utilizing offshore wind ("Portfolio 2" or "P2"), new nuclear ("Portfolio 3" or "P3"), or both ("Portfolio 4" or "P4"). All potential Carbon Plan portfolios are designed to achieve carbon neutrality by 2050. The "portfolio development scenarios," as described for each portfolio in this section, refers to the portfolio-specific assumptions used to develop the portfolio including the year in which and resources (offshore wind and new nuclear) used to achieve the interim 70% CO_2 emissions reduction target.

Figure E-8: Portfolio Development Overview



This section describes the preliminary development of these portfolios including determination of economic coal retirements and resources added to comply with the CO_2 reduction targets.

Determining Economic Retirement of Coal Generating Capacity

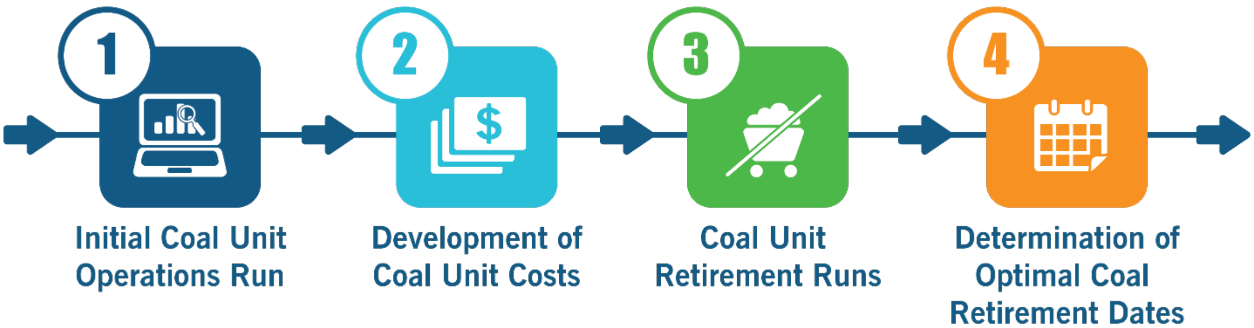
The Carbon Plan identifies the timing of future coal retirements endogenously within the capacity expansion model.[4] The capacity expansion model weighed the continued operational benefits to the system and costs to operate and maintain the coal units over time against the retirement and potential replacement of the coal units by selection of available supply-side resources described above, while also meeting the operational and planning constraints of the system, including achievement of emissions reductions targets.

Importantly, retirement dates selected by the endogenous analysis are limited to a single and static view of costsand therefore, should be treated as representative and directional in nature due to these limitations. To more accurately reflect the complex interdependencies of resource additions and retirements, the coal retirement analysis consists of multiple steps to determine costs to operate and maintain each unit and to determine optimal retirement dates for each unit. Specifically, the Companies' Coal Retirement Analysis Process presented in Figure E-9 and discussed in greater detail below accounts for the dynamic nature of costs associated with maintaining each coal unit, and used

[4] This analysis meets the 2020 IRP Order's directive to analyze coal unit retirement dates endogenously in EnCompass. *Order Accepting Integrated Resource Plans, REPS Plans with Conditions and Providing Further Direction for Future Planning*, Docket No. E-100, Sub 165, at 12 (November 19, 2021).

the endogenously identified retirement dates, along with professional engineering judgement to establish optimal retirement dates for each unit

Figure E-9: Coal Retirement Analysis Process



Initial Coal Unit Operations Runs

The costs to operate and maintain generation units over time are determined by how long the unit is expected to remain in the resource portfolio and how much the unit will run over that time. Investments are generally driven by operational characteristics dictated by how a unit is utilized and how much it is utilized. To accurately reflect the operations of these units, given the constraints of the system, an initial capacity expansion model run, referred to as the "Initial Coal Unit Operations Run," was completed for each portfolio development scenario. This initial capacity expansion modeling yielded unique projected coal unit operations for each specific 70% interim target year and with the associated resources needed to meet the emissions reductions target. The simulation of the system provides the inputs needed to develop the costs of maintaining and investing in these coal units over the projected lives of the assets. These Initial Coal Unit Operations Runs modeled fixed retirement dates of each coal unit though its depreciable life, with two exceptions. Belews Creek was modeled to cease operations at the end of 2035 consistent with Duke Energy's target to be out of coal by 2035 in an effort to mitigate fuel security risks as addressed in Appendix N (Fuel Supply). Additionally, the remaining Allen units, units 1 and 5, were modeled to be retired by the beginning of 2024, consistent with transmission project under construction in DEC to enable the retirement of these units. Below in Table E-45 is a comparison of the coal units Probable Depreciable Lives, per the most recently approved DEC and DEP depreciation studies[5], and the fixed retirement dates modeled in the Initial Coal Unit Operations Runs.

Table E-45: Coal Unit Depreciable Lives Cost Determination Run Retirement date (effective by January 1st of year shown)

Unit	Utility	Probable Depreciable Life	Initial Coal Unit Operations Run
Allen Station	DEC	2027	2024[1]
Belews Creek Station	DEC	2038	2036[2]
Cliffside 5	DEC	2033	2033

[5] The most recently approved depreciation studies for DEC and DEP are the 2016 Depreciation Studies.

Unit	Utility	Probable Depreciable Life	Initial Coal Unit Operations Run
Cliffside 6[3]	DEC	2049	2049
Marshall Station	DEC	2035	2035
Mayo 1	DEP	2036	2036
Roxboro 1	DEP	2029	2029
Roxboro 2	DEP	2029	2029
Roxboro 3	DEP	2034	2034
Roxboro 4	DEP	2034	2034

Note 1: Allen Station retirement is accelerated from its Probable Depreciable Life to 2024 in the Initial Coal Unit Operations Runs to reflect the transmission enabled plans for retirement by 2024.
Note 2: Belews Creek Station retirement is accelerated from its Probable Depreciable Life to 2036 in the Initial Coal Unit Operations Runs to reflect Duke Energy's target to be out of coal by 2035 and address fuel security risks.
Note 3: Cliffside 6 is assumed to cease coal operations by the beginning of 2036.

Development of Coal Unit Costs

The costs for operating and investing in these units over time to maintain reliable operations over the projected lives of the resources were then developed from the operational results of the Initial Coal Unit Operations Runs. Each run provides a representation of how the coal units might be utilized over the planning horizon, should they continue to operate through their depreciable lives (or adjusted retirement date). The operations of the units may change from one portfolio development scenario to another based on the other resources added to the portfolio, and achievement of the emissions reductions targets. Based on these operational projections, including capacity factors and operation on natural gas at the Companies' natural gas co-fired coal units, the Companies developed cost projections for each portfolio development scenario. These sets of investments and ongoing maintenance and operation costs could then be put back into the capacity expansion model to determine economic retirement dates endogenously.

The Companies have previously performed retirement analyses agnostic of remaining net book value of units at the time of modeled retirement. However, for the Carbon Plan, the Companies have factored into the coal retirement analysis, the benefits associated with securitization of the remaining net book value of subcritical coal at time of modeled retirement. HB 951 states that early retirement of subcritical coal-fired electric generating facilities to achieve the authorized CO_2 reduction targets shall have costs be securitized at fifty percent (50%) of the remaining net book value of the facilities with any remaining non-securitized costs being recovered through rates. The accelerated retirement of these units allows for lower costs to customers associated with the securitized portion of the remaining net book value of the units if retirement is to achieve the authorized emissions reductions targets. To capture this benefit in the coal retirement analysis, the Companies modeled a securitization benefit for subcritical coal units that would have to be forgone if the unit were modeled to continue to be operated each successive year.[6]

Coal unit characteristics that impact the costs considered endogenously in the identification of coal unit retirements are shown in Table E-46.

Table E-46: Coal Unit Characteristics Impacting Continued Operation Costs

Unit	Steam Generator Technology	Natural Gas Co-firing Capability
Allen 1[1]	Subcritical	0%
Allen 5[1]	Subcritical	0%
Belews Creek 1	Supercritical	50%
Belews Creek 2	Supercritical	50%
Cliffside 5[2]	Subcritical	40%
Cliffside 6	Supercritical	100%
Marshall 1[2]	Subcritical	40%
Marshall 2[2]	Subcritical	40%
Marshall 3	Supercritical	50%
Marshall 4	Supercritical	50%
Mayo 1	Subcritical	0%
Roxboro 1	Subcritical	0%
Roxboro 2	Subcritical	0%
Roxboro 3	Subcritical	0%
Roxboro 4	Subcritical	0%

Note 1: Though Allen 1 & 5 are subcritical coal technology, they were not considered for accelerated retirement to achieve the carbon reduction targets as their retirement has previously been planned for by 2024 and was not re-optimized in the Carbon Plan's Coal Retirement Analysis.
Note 2: Cliffside 5 and Marshall 1 and 2 are capable of co-firing on natural gas at 40% capacity. However, these units are only able to do so when the other units at these sites are not fully utilizing their natural gas capability. In the Carbon Plan modeling, Cliffside 5 assumes 10% natural gas co-firing capability and Marshall 1 and 2 removes natural gas co-firing as a simplifying model computational assumption for site natural gas availability.

Coal Unit Retirement Runs

Once the cost projections for each coal unit for each portfolio development scenario had been input into the capacity expansion model, the Companies conducted the "Coal Unit Retirement Runs." These model runs allowed the capacity expansion model to retire the coal units along side continuing to allow the model to select new resources, while maintaining achievement of the emissions reductions targets.

[6] The coal retirement analysis, and therefore securitization benefit calculations for the retirement analysis, was performed before the Commission issued its Rulemaking to Implement Securitization of Early Retirement of Subcritical Coal-fired Generating Facilities, which could affect the eligibility for securitization in certain circumstances. Therefore, the modeling may be considered somewhat conservative toward retirement, to the extent that some units retired in certain years in certain cases may not actually be eligible for securitization under the Commission's order.

The model's objective function is to minimize the cost of the system over time while adhering to external constraints such as a system CO_2 mass cap for the Carbon Plan. If the model deems it is lower cost to retire the coal capacity, avoiding the future investments in these units, and to incur potential cost for adding incremental resources to maintain the planning reserve margins of the system, the model has the option to do so. Coal units were eligible for retirement starting in 2026, generally aligning with timelines to procure replacement resources or ensure grid stability with necessary network system upgrades in relation to retiring coal units. Some units were required to be retired together based on engineering recommendations consistent with joint operations, maintenance, and common equipment and to help with computional processing. Additionally, Allen and Cliffside 6 were not made eligible for retirement optimization, as the remaining Allen units are planned for retirement by 2024 and Cliffside 6 is able to operate 100% on natural gas and assumed in the Carbon Plan to cease coal operations by the start of 2036.

Determination of Optimal Coal Retirement Dates

While the capacity expansion model was used to endogenously identify retirement dates economically on a level comparison with new resources and in keeping with CO_2 reduction targets, relying exclusively on results from the capacity expansion model is not best practice for resource planning, neither for selecting resource additions nor retirements. As discussed in the Carbon Plan model overview section, capacity expansion is a screening model. The capacity expansion model's simplification of the simulation of the system can distort the value of resources to the portfolio, such as replacement resources that are energy limited or weather dependent. Additionally, the the capacity expansion model's inability to reflect dynamic costs associated with each unit's on-going operations and maintaintenance schedule and to assess such costs for units with different projected retirement dates is an inherent limitation that cannot be captured with static cost inputs into the model. Furthermore, in line with Carbon Plan approach, the coal retirements must be executable, ensuring reliability of the system upon retirement. To optimize unit retirement dates based availability of new capacity additions while also ensuring the Companies meet the statutory requirement to maintain or improve upon the adequacy and reliability of the system when accounting for retirement of these resources, the Companies made minor adjustments to the coal retirement dates for certain units to allow for more orderly and executable retirement schedules.

As an example of this optimization process, in developing the 2030 target date Coal Unit Retirement Run, Roxboro 3 and 4 were endogenously identified by the model to be retired by the start for 2030. The Companies accelerated the retirement of these units to the start of 2028 to coincide with the economic selection of new CC capacity in this timeframe. In the same run, conversely, due to the aggressive demand-side reductions assumed in the base Carbon Plan load forecast, the model selected the retirement of Marshall 1 and 2 in 2026 based on excess capacity created by the Carbon Plan load forecast. However, execution of the retirement of these units is dependent upon transmission projects to enable these units' retirement or replacement generation is required on site. To allow sufficient time for the transmission projects to support the retirement to be constructed or generation replacement resources to be built at the site, Marshall 1 and 2's retirement date was delayed to 2029.

Importantly, endogenous capacity expansion modeling was used in the identification of coal retirement dates. The screening model, however, has limitations and does not consider execution factors, important to the Carbon Plan modeling. For this reason, the Companies view the endogenous results as representative and directional in nature, and therefore applied limited professional engineering judgements making minor adjustments to coal retirements used in development of the Carbon Plan portfolios. These retirement dates used in the Carbon Plan, themselves are also directional in nature are ultimately dependent on procurement of adequate replacement resources to allow the for their retirements.

Table E-47 below summarizes the final results of the coal retirement analysis.

Table E-47: Coal Unit Retirements (effective by January 1st of year shown)

Unit	Utility	Winter Capacity [MW]	Effective Year (Jan 1)
Allen 1[2]	**DEC**	167	2024
Allen 5[2]	**DEC**	259	2024
Belews Creek 1	**DEC**	1,110	2036
Belews Creek 2	**DEC**	1,110	2036
Cliffside 5	**DEC**	546	2026
Marshall 1	**DEC**	380	2029
Marshall 2	**DEC**	380	2029
Marshall 3	**DEC**	658	2033
Marshall 4	**DEC**	660	2033
Mayo 1	**DEP**	713	2029
Roxboro 1	**DEP**	380	2029
Roxboro 2	**DEP**	673	2029
Roxboro 3	**DEP**	698	2028-2034[3]
Roxboro 4	**DEP**	711	2028-2034[3]

Note 1: Cliffside 6 is assumed to cease coal operations by the beginning of 2036 and was not included in the Carbon Plan's Coal Retirement Analysis because the unit is capable of operating 100% on natural gas.
Note 2: Allen 1 and 5 retirements are planned by 2024 and were not re-optimized in the Carbon Plan's Coal Retirement Analysis.
Note 3: Retirement year for Roxboro Units 3 and 4 vary by portfolio, with retirement of those units effective 2028 in P1, 2032 in P2, and 2034 in P3 and P4.

As discussed in Appendix N (Fuel Supply), continued operation of the DEC and DEP coal fleets presents increasing risk over time. These risks must be balanced with minimizing cost and ensuring reliability. Additionally, actual retirement dates for the Companies' coal units may change from those projected in this analysis based on the Companies abilities to procure and bring online adequate and reliably equivalent resources.

Preliminary Capacity Expansion Results

As discussed throughout this Appendix there are various parameters in developing resource portfolios for the Carbon Plan. Achievement of CO_2 reduction targets was the driving factor for differentiation of how resources would be included in the portfolio. The following sections discuss the four portfolio development scenarios and present a summary of the preliminary resource additions and retirements from the capacity expansion modeling. After the initial capacity expansion results are developed, the Companies performed a variety of portfolio verification steps to ensure cost effective inclusion of resource and reliability standards are maintained, which are discussed in later sections of this Appendix.

Results in the following sections are rounded for summary purposes and may not sum based on actual unit modeling assumptions.

Portfolio Development Scenario 1

Portfolio 1 (P1) is developed to achieve the interim CO_2 reduction target in 2030 as prescribed in HB 951. Based on iterative analysis to achieve the CO_2 reduction targets, the base assumptions for solar integration are not sufficient for meeting the interim CO_2 reduction target system mass cap in 2030. Therefore, this development scenario uses the Carbon Plan high case annual solar integration limits, as described in the Solar assumption section above. Additionally, the first 800 MW of offshore wind is modeled to be available by the start of 2030, as a selectable resource for achieving the CO_2 reduction targets.

Below in Table E-48 is the preliminary resource additions and retirements for Portfolio 1 identified by the capacity expansion model.

Table E-48: Portfolio 1 - Preliminary Resource Additions and Retirements [MW] for Interim Target Achievement in 2030

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
DEC	-1,700	3,800	0	800	1,200	0	0	0	0
DEP	-3,200	3,400	600	2,400	1,200	0	800	0	0
Car	-4,900	7,200	600	3,200	2,400	0	800	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: includes battery capacity both standalone and paired with solar.

Portfolio 1 adds 7.2 GW of solar through the start of 2030 to achieve the 70% interim emissions reductions target in the year. This includes economically selecting 5.4 GW of standalone solar and solar paired with storage. The economical solar addition is constrained by the annual interconnection limits, with the system adding the maximum amount of solar in every year through 2030, selecting 750 MW in 2027, 1,050 MW in 2028, and 1,800 MW in 2029 and again in 2030. The solar additions for this portfolio bring the system nameplate solar capacity to 12.3 GW as of the start of the 2030 interim target year. This portfolio also integrated 600 MW of onshore wind, all of which was added in DEP by 2030.

To support these variable energy resources, 3.2 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, 2.4 GW of CC capacity is also selected, proving additional firm capacity and overall system flexibility to backstand the variable energy renewables. These capacity resources also support the retirement of 4.9 GW of coal capacity. The coal retirements represent all subcritical coal remaining on the Carolinas system, with the only remaining coal capacity on the system being able to be co-fired with natural gas to increase flexibility and lower carbon emissions. No new CT capacity is selected in the preliminary resource identification by the capacity expansion model for Portfolio 1.

Finally, with interim target achievement in 2030, 800 MW of offshore wind was available for selection, and was selected to meet the 70% interim target. Overall, this portfolio added significant amounts of solar and wind by 2030 to comply with the CO_2 reduction targets.

Portfolio Development Scenario 2

Portfolio 2 (P2) is developed to achieve the 70% interim target in 2032 based on projected availability of offshore wind resources. This development scenario uses the Carbon Plan base case with respect to annual solar integration limits, as described in the Solar assumption section above. Additionally, this development scenario aggressively deploys two 800 MW blocks of offshore wind, the first in 2030 and the second in 2032 as a means of achieving the CO_2 reduction targets in 2032.

Below in Table E-49 is the preliminary resource additions and retirements for Portfolio 2 identified by the capacity expansion model.

Table E-49: Portfolio 2 - Preliminary Resource Additions and Retirements [MW] for Interim Target Achievement in 2032

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
DEC	-1,700	4,100	0	1,100	1,200	0	0	0	0
DEP	-3,200	3,100	1,200	1,900	1,200	0	1,600	0	0
Car	-4,900	7,200	1,200	3,000	2,400	0	1,600	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Portfolio 2 adds 7.2 GW of solar through the start of 2032 to achieve the interim CO_2 reduction target in that year. This includes economically selecting 5.3 GW of standalone solar and solar paired with storage. Targeting 2032 for achievement of the interim CO_2 reduction target provides the system with time to add approximately the same amount of solar capacity as Portfolio 1 while adhering to the Carbon Plan's base solar annual integration limits. The solar additions for this portfolio bring the system nameplate solar capacity to 12.2 GW for the start of 2032. This portfolio also integrates 1.2 MW of onshore wind, all of which was added in DEP by 2032.

To support these variable energy resources, 3.0 GW of batteries, combined between standalone batteries and batteries paired with solar, are selected by 2032. In addition to the battery capacity supporting variable energy renewables, 2.4 GW of CC capacity is also selected, proving additional firm capacity and overall system flexibility to backstand the variable energy renewables. These capacity resources also support the retirement of 4.9 GW of coal capacity. The coal retirements represent all subcritical coal remaining on the Carolinas system, with the only remaining coal capacity on the system being able to be co-fired with natural gas to increase flexibility and lower carbon emissions. No new CT capacity is selected in the preliminary resource identification by the capacity expansion model for Portfolio 2.

Finally, with interim target achievement in 2032, 1.6 GW of offshore wind was integrated into the portfolio in two 800 MW blocks of offshore wind, the first in 2030 and the second in 2032 as a means of achieving the CO_2 reduction targets in 2032. Overall, this portfolio allows for two additional years for interim target achievement, relative to Portfolio 1, allowing for the integration of additional wind resources to achieve the CO_2 reduction targets and providing more time to integrate similar levels of solar at a more executable annual amount.

Portfolio Development Scenario 3

Portfolio 3 (P3) is developed to achieve the 70% interim target in 2034 based on projected availability of new nuclear resources. This development scenario uses the Carbon Plan base case annual solar integration limits, as described in the Solar assumption section above. This development scenario allows for the economic selection of up to 1.6 GW of offshore wind and for the selection of two nuclear SMRs for the start of 2034, as a means of achieving the CO_2 reduction targets.

Below in Table E-50 is the preliminary resource additions and retirements for Portfolio 3 identified by the capacity expansion model.

Table E-50: Portfolio 3 - Preliminary Resource Additions and Retirements [MW] for Interim Target Achievement in 2034

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
DEC	-3,100	5,000	0	900	1,200	0	0	300	1,700
DEP	-3,200	4,600	1,200	2,600	1,200	0	0	0	0
Car	-6,300	9,600	1,200	3,500	2,400	0	0	300	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Portfolio 3 adds 9.6 GW of solar through the start of 2034 to achieve the 70% interim target in that year, while adhering to the Carbon Plan's base solar integration limits. This includes economically selecting 7.7 GW of standalone solar and solar paired with storage. Targeting 2034 for achievement of the interim CO_2 reduction target based on the additional availability of nuclear resources provides the system with time to add an additional 4.5 GW of solar capacity after 2030. The solar additions for this portfolio bring the system nameplate solar capacity to 14.6 GW for the start of 2034. This portfolio also integrates 1.2 GW of onshore wind, all of which was added in DEP by 2034.

To support these variable energy resources, 3.5 GW of batteries, combined between standalone batteries and batteries paired with solar, are selected by 2034. In addition to the battery capacity supporting variable energy renewables, 2.4 GW of CC capacity is also selected, proving additional firm capacity and overall system flexibility to backstand the variable energy renewables. In addition to the approximately 4.9 GW of coal capacity retired in Portfolios 1 and 2, an additional 1.3 GW of coal are retired in Portfolio 3 by 2034 to support the system's CO_2 reduction target. The additional retirement of Marshall 3 and 4 in 2033 brings the total coal retired for to achieve the interim target to approximately 6.3 GW. The Marshall retirement is also supported by the addition of Bad Creek PH II, added in 2033, which also provides considerable energy storage capacity to the system. With 3.5 GW of batteries and the 1.7 GW of pumped storage hydro, the incremental new storage totals 5.2 GW by 2034 to comply with the CO_2 reduction targets. No new CT capacity is selected in the preliminary resource identification by the capacity expansion model for Portfolio 3.

With interim target achievement in 2034, this portfolio, unlike Portfolios 1 and 2, has the option to comply with the 70% interim target utilizing either offshore wind or new nuclear (or both). Portfolio 3 ultimately opts to add one SMR in 2034 and continued addition of solar and onshore wind resources to meet the CO_2 reduction target, while not selecting any offshore wind.

Portfolio Development Scenario 4

Portfolio 4 (P4) is developed to achieve the interim CO_2 reduction target in 2034. This development scenario uses the Carbon Plan base case annual solar integration limits, as described in the Solar assumption section above. Because the offshore wind was not economically selected by the capacity expansion model in Portfolio 3 to achieve the 70% interim target in 2034, to quantify the cost impacts of a diversified resource portfolio in achieving the reduction targets, offshore wind was included in this portfolio. This development scenario prescribes into the portfolio, one 800 MW block of offshore wind in 2032, but allows for the economic selection of an additional 800 MW of offshore wind and for the selection of two SMRs for the start of 2034, as a means of achieving the CO_2 reduction targets.

Below in Table E-51 is the preliminary resource additions and retirements for Portfolio 4 identified by the capacity expansion model.

Table E-51: Portfolio 4 - Preliminary Resource Additions and Retirements [MW] for Interim Target Achievement in 2034

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
DEC	-3,100	5,000	0	900	1,200	0	0	300	1,700
DEP	-3,200	3,700	1,200	1,800	1,200	0	800	0	0
Car	-6,300	8,700	1,200	2,700	2,400	0	800	300	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Portfolio 4 adds 8.7 GW of solar through the start of 2034 to achieve the 70% interim target in that year, while adhering to the Carbon Plan's Base Solar integration limits. This includes economically selecting 6.8 GW of standalone solar and solar paired with storage. Targeting 2034 to achieve the 70% interim target with a more diversified set of resources provides the system with time to add the additional 3.6 GW of solar capacity after 2030. The solar additions for this portfolio bring the system nameplate solar capacity to 13.7 GW for the start of 2034. This portfolio also integrates 1.2 GW of onshore wind, all of which was added in DEP by 2034.

To support these variable energy resources, 2.7 GW of batteries, combined between standalone batteries and batteries paired with solar, are selected by 2034. In addition to the battery capacity supporting variable energy renewables, 2.4 GW of CC capacity is also selected, proving additional firm capacity and overall system flexibility to backstand the variable energy renewables. Consistent with the coal retirements in Portfolio 3, an additional 1.3 GW of coal are retired in Portfolio 4 by 2034 to support the system's CO_2 reduction targets. The additional retirement of Marshall 3 and 4 in 2033 brings the total coal retired to approximately 6.3 GW. The Marshall retirement is also supported by the addition of Bad Creek PH II, added in 2033, which also provides considerable energy storage capacity to the system. With 2.7 GW of batteries and the 1.7 GW of pumped storage hydro, that brings the incremental new storage in this portfolio to 4.4 GW to comply with the CO_2 reduction targets. No new CT capacity is selected in the preliminary resource identification by the capacity expansion model for Portfolio 4.

As stated in the description of the portfolio development scenario, 800 MW of offshore wind is prescribed into the portfolio in 2032. Additionally, with interim target achievement in 2034, this portfolio has the option to meet the CO_2 reduction target utilizing either more offshore wind or new nuclear (or both). The portfolio takes advantage of the extended timeline to add one SMR to achieve the interim target in 2034, but no additional offshore wind. With the 800 MW of offshore wind and the new SMR, this portfolio offsets a portion of the solar and battery capacity selected for Portfolio 3. Portfolio 4, with its extended timeline and inclusions of 800 MW of the available offshore wind, represents the portfolio with the most resource diversity in complying with the interim CO_2 emissions reductions target.

Portfolio Results Summary through 2035

The results discussed above show portfolio changes through the year that the interim target is achieved, and what resources are needed in each portfolio to comply with the CO_2 reduction targets. While it is useful to view which resources are needed to meet the interim targets, it is also useful to show resources at a consistent point in time for comparison purposes with respect to additions over time and total portfolio costs. To evaluate resources on the path to carbon neutrality, a comparison is provided below in Table E-52 summarizing the four portfolios' resource additions and retirements through 2035.

Table E-52: Preliminary Resource Additions by Portfolio [MW] by 2035

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
P1	-6,300	13,800	1,200	5,500	2,400	0	800	600	1,700
P2	-6,300	10,600	1,200	3,600	2,400	0	1,600	600	1,700
P3	-6,300	10,500	1,200	3,700	2,400	0	0	600	1,700

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
P4	-6,300	9,500	1,200	2,800	2,400	0	800	600	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar

By 2035, each portfolio has continued to add resources to transform the resource mix of the system to ultimately meet carbon neutrality by 2050. After achieving the interim CO_2 reduction target, the portfolios continue to converge, as more resources become available and are needed to maintain a trajectory to carbon neutrality with an orderly transition of the system. Looking across the different portfolios, the earlier the achievement of the interim CO_2 reduction target, the more solar, onshore wind, and batteries are added to the portfolio by 2035. In the portfolios that meet the 70% interim CO_2 reduction target before new nuclear is available (Portfolios 1 and 2), offshore wind is a key resource for reducing carbon emissions of the system. Common among all portfolios by 2035 is the inclusion of 2.4 GW of CC and 600 MW of new nuclear capacity. These resources provide firm capacity commensurate with their nameplate capacities and are able to provide dispatchable and lower-carbon energy around the clock, if needed. Additionally, each portfolio also adds at least 2.8 GW of battery and 1.2 GW of onshore wind.

While not shown in Table E-53, in the very next year, consistent with the Duke Energy target to exit coal by the end of 2035, the amount of coal capacity retirement increases from 6.3 to 9.3 GW. In all of the carbon plan modeling, the retirement of 2.2 GW at Belews Creek and ceasing coal operations at the 850 MW Cliffside 6 are effective for the start of 2036.

No new CT capacity is selected by the capacity expansion model through 2035 in any portfolio in the preliminary identification of resources. More discussion of this specific modeling result and the inclusion of economic CTs in the portfolio are discussed in the Portfolio Verification section.

Solar is an important resource in providing carbon-free energy across all portfolios. Below is a table showing, for each portfolio, the annual additions of solar. The table shows both the forecasted standalone solar and forecasted solar paired with storage, which is common among all portfolios. Additionally, it presents for each portfolio the amount of economically selected standalone solar and solar paired with storage to comply with the CO_2 emissions reductions targets in the model.

Table E-53: Forecast and Economically Selected Solar through 2050

	Forecasted Standalone Solar	Forecasted SPS	P1 Standalone Solar	P1 SPS	P2 Standalone Solar	P2 SPS	P3 Standalone Solar	P3 SPS	P4 Standalone Solar	P4 SPS
2024	422	75	0	0	0	0	0	0	0	0
2025	410	40	0	0	0	0	0	0	0	0
2026	586	60	0	0	0	0	0	0	0	0
2027	69	0	300	450	375	0	300	450	300	450
2028	69	0	0	1,050	450	600	450	600	450	600
2029	69	0	1,200	600	150	0	0	0	0	0
2030	69	0	0	1,800	525	825	825	525	825	525
2031	69	0	750	600	525	825	525	825	675	600
2032	0	0	750	1,050	975	0	525	825	525	375
2033	0	0	750	0	600	750	825	0	525	375
2034	0	0	750	1,050	525	750	525	450	525	0
2035	0	0	750	0	525	225	525	450	525	300
2036	0	0	750	375	525	675	525	600	525	675
2037	0	0	225	825	525	825	525	675	525	825
2038	0	0	0	1,050	525	225	525	375	525	450
2039	0	0	750	0	525	525	525	825	525	750
2040	0	0	675	0	525	300	525	225	525	150
2041	0	0	750	0	0	750	375	600	0	1,275
2042	0	0	750	0	0	750	450	225	525	600
2043	0	0	0	0	150	0	525	0	150	0
2044	0	0	0	0	225	0	525	0	150	0
2045	0	0	0	0	525	0	450	0	375	0
2046	0	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0	0
2049	0	0	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0	0	0
Total	1,763	175	9,150	8,850	8,175	8,025	9,450	7,650	8,175	7,950

The nameplate solar capacities listed in Table E-53 above represents the incremental solar add by the start of the year listed. These resources are online at the beginning of the year to contribute carbon-free energy throughout the entire year and contribute to meeting both summer and winter peak capacity planning reserve margins. Therefore, the solar listed in this chart as “2027” refers to what is added during the year 2026, consistent with the 2022 Solar procurement target.

Portfolio Verification

As discussed above in the coal retirement section, sole reliance on the capacity expansion screening modeling is not resource planning best practice or industry standard. Using results strictly from the capacity expansion model can lead to potentially sub optimal resource inclusion. For this reason, the Companies have run a variety of Portfolio Verification runs. These additional detailed runs assess optimal resource inclusion, maintaining reliability standards, and appropriate CO_2 reduction to meet the 70% interim and 2050 carbon neutrality targets.

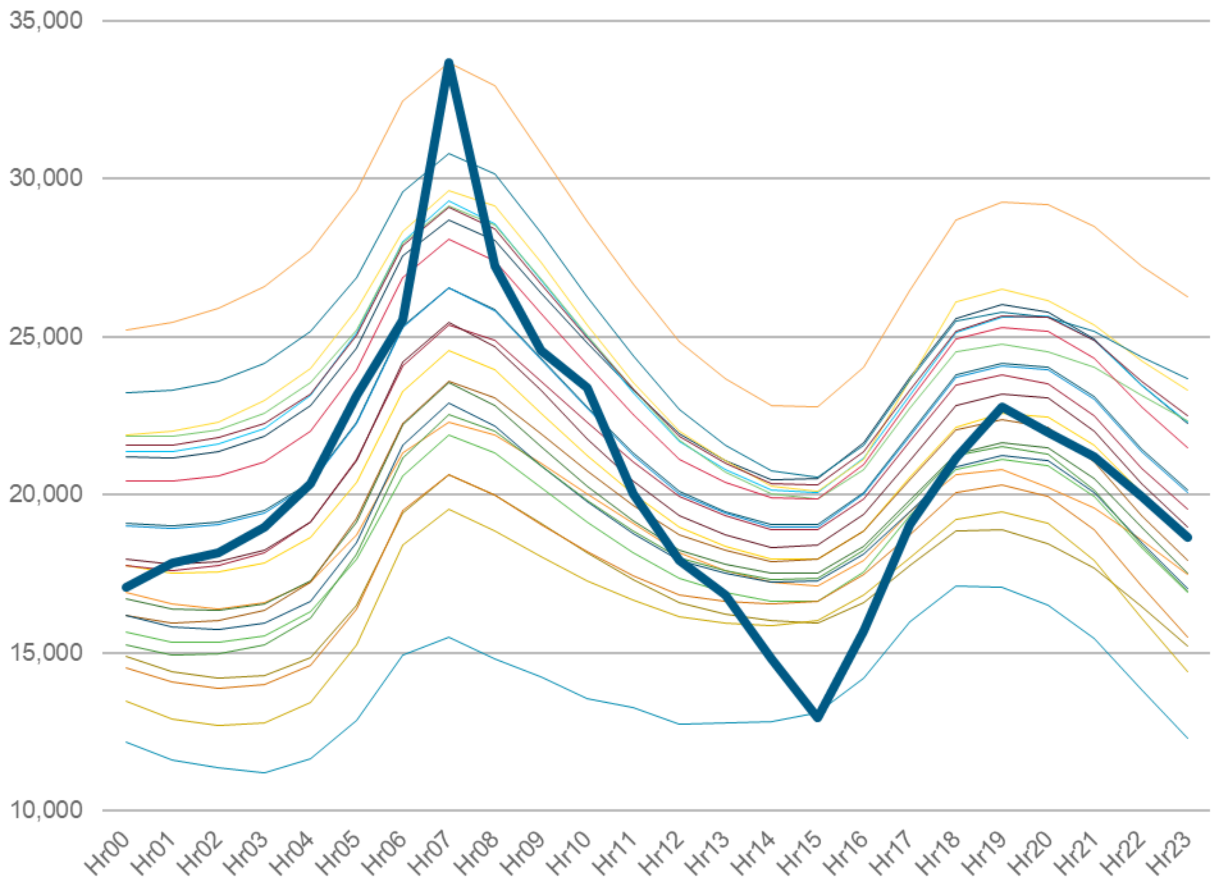
Battery-CT Optimization

Capacity Expansion Model Load Aggregation and Representative “Typical Day” Load Shapes

The selection of dispatchable CTs compared to energy-limited energy storage resources can be difficult for the capacity expansion model to assess. As discussed in detail previously in this Appendix, the capacity expansion model is a screening model that simplifies parameters of the modeling to accelerate model processing time. One of those simplifications is to the analysis of the representative load used by the capacity expansion model, discussed in more detail below. For more in-depth analysis of the system, the Companies develop a detailed, hourly weather normal load forecast for every hour of the study period, which is input into the model for use in both capacity expansion and detailed production cost modeling.

The capacity expansion model, however, does not look at the performance of prospective portfolios in every hour of every day over the entire planning horizon when selecting resources. Doing this, while evaluating tens of thousands of combinations of portfolio configurations would be computationally impractical. Instead, the screening model groups similar days in each month of each year together (i.e., an “On-Peak” day for January 2030, or an “Off-Peak” day for October 2037). The model identifies the peak load in the peak hour from the aggregated days. Similarly, it identifies the minimum load in the minimum hour from the aggregated days. Finally, the model creates a representative daily load shape to simulate intraday chronology that maintains the previously identified peak and minimum loads while maintaining the average daily load amount for the aggregated days. In doing so, however, the capacity expansion model distorts the load shape from what would reasonably be reflective of the actual system load shape on any given day for DEC or DEP. Figure E-10 below demonstrates this phenomenon, showing an example of the load shape produced by the capacity expansion model to screen resources into the portfolio relative to the individual daily load shapes it aggregated to create the load shape.

Figure E-10: Capacity Expansion "Typical Day" Load Shape, Example



Because of this modeling artifact for quickly evaluating resource options within the capacity expansion model, the EnCompass Model tends to overly ascribe value to short duration storage at system daily peak loads. This can be observed by the narrow, "needle peak" followed by a deep, midday valley in the simplified load shape that creates an optimal daily shape for energy storage resources. This load shape allows short duration batteries to fully discharge over a very brief peak and then immediately recharge with the midday valley, especially when solar output is high and other resources on the system would have to operate near minimum output levels. Finally, it must be noted that all capacity expansion screening models use simplification techniques to accelerate the computational process for the evaluation of resources within a portfolio. While the Companies' capacity expansion model presents this unique way of simplifying the computations, other capacity expansion models would likely have similar unintended results. The EnCompass Model's enhanced ability to preserve some chronology in the capacity expansion step is a significant improvement over other modeling software. Regardless of the model's simplifications, the Companies validate the output of the capacity expansion model with additional analysis including the use of detailed, hourly production cost models to simulate the operation of the system in every hour of the load forecast.

Battery-CT Optimization Modeling

As seen from the individual forecasted load shapes in Figure E-10, there is never as steep of a transition between daily peak and minimum system load levels as the model assumes over the course of any individual daily load shape. While there are certainly opportunities for batteries to operate between daily peaks and minimums, the aggregation and simplification of the load shape in the capacity expansion model overstates this differential and allows for inequitable evaluation of supply-side resources. Said another way, if the bold blue line in Figure E-10 represented actual system conditions on an hourly basis battery storage would correctly be selected in the system optimization model. However, since actual weather normal hourly loads look more like the daily loads represented in Figure E-10 further analysis is required to determine the appropriate mix of energy limited energy storage and dispatchable CT capacity that has longer run time capabilities. This need for a balance of shorter duration energy storage and CTs with longer duration capabilities becomes even more important to assuring system resource adequacy and reliability when the possibility of extreme weather days that have much longer duration peaks with minimal low load periods to allow for battery charging is taken into account. For these reasons the Companies performed the Battery-CT Optimization step that utilized additional detailed analyses that considered hourly loads for each hour of the year to arrive at a balanced portfolio that meets carbon reduction targets while simultaneously minimizing costs and ensuring system reliability 24 hours a day, every day of the year.

As mentioned, this validation step evaluated the cost effectiveness of the batteries selected by the capacity expansion model. To do so, the Companies ran the portfolio output from the preliminary identification of resources in the capacity expansion model through the detailed production cost model. Next the Companies ran an additional production cost model run, but this time replaced a fraction of the batteries with the equivalent capacity of CTs. The differences in the production costs between the two runs were then compared to the differences in new resource costs. Through this process the Companies determined that it was economic to replace approximately 35% of the battery capacity with CTs in each portfolio and also enhanced reliability by replacing shorter-duration batteries with CTs with longer duration capabilities.

The Companies were careful to observe the impact to system carbon emissions in this optimization analysis. Replacing more batteries with CTs may have economic benefits, but the replacements do have the potential to inhibit the system from meeting its CO_2 emissions reductions targets. When performing the analysis, the Companies were careful not to replace battery capacity that caused the system to exceed the CO_2 reduction targets by the year the interim target is achieved.

Table E-54 below shows the results of the Battery-CT Optimization, showing for each portfolio how much battery capacity was economically replaced with CT capacity through 2050. Results below are rounded for summary purposes.

Table E-54: Battery-CT Optimization Results through 2050 [Nameplate MW]

Portfolio	Battery Capacity Removed	CT Capacity Added
P1	2,000	1,900
P2	2,000	1,900
P3	2,000	1,900
P4	1,600	1,500

Bad Creek Powerhouse II Validation

Bad Creek PH II is a potentially pivotal project for DEC and the joint dispatch of the DEC and DEP systems. The project provides significant capacity of long-duration storage bringing valuable time shifting of energy potential 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 of the capacity model with evaluating energy storage, as discussed in the Battery-CT Optimization step, the Companies performed additional comparative economic analysis of this long-duration storage to confirm Bad Creek PH II as an economic inclusion in the portfolios.

As discussed in the Forecasted Resources section of this Appendix, Bad Creek PH II expansion was prescribed into all portfolios. To confirm the Companies' prescribed inclusion was economic, the Companies compared the project's cost effectiveness to other longer-duration storage options. Portfolios 1 and 4 were run through the production cost model including Bad Creek PH II. Bad Creek PH II was then removed and the portfolios were run through the Production cost model again, this time replaced with the equivalent amount of 8-hr lithium-ion batteries. The results of this analysis showed production cost value of the Bad Creek PH II relative to 8-hr batteries from $200 million to $350 million across P1 to P4 on a PVRR basis over the Carbon Plan planning horizon. Additionally, the different asset lives played into the analysis, as batteries have a much shorter projected life as compared to the Bad Creek expansion project and would effectively have to be replaced multiple times over the equivalent life of Bad Creek PH II. After comparing the differences in production and levelized capital costs over the planning horizon, it was determined that Bad Creek PH II's inclusion in the portfolios was economic.

The project will continue to be evaluated over the coming years as a potential 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.

Resource Adequacy and Reliability Verification

Overall Portfolio Reliability and 2050 CO_2 Reduction Verification

While each of the portfolios maintained the required capacity planning reserve margin and met the CO_2 reduction constraints in the capacity expansion model, each of the portfolios was also tested in a production cost model to confirm the results under a more detailed simulation of the prospective future system. In this final step of verification in the EnCompass model, each of the portfolios were run through the production cost model through 2050, to ensure operations of the system within the detailed, hourly simulation, meet CO_2 and energy requirements. This step assessed achievement of the 70% interim target, the 2050 carbon neutrality target and overall ability of the portfolio to meet energy needs throughout the planning horizon. Through this process, the Companies identified resource insufficiencies to meet the zero CO_2 emissions constraint and energy requirements in 2050. The Companies added additional resources at the end of planning horizon to fill these deficits, where needed. Below in Table E-55 is a summary of the additional resource capacities needed for each portfolio to ensure energy and CO_2 reduction requirements are met in 2050. In future Plan updates, the Companies will continue to evaluate emerging technologies required to achieve long-term resource balancing and reliability in achieving net zero CO2 emissions.

Table E-55: Portfolio Reliability and CO_2 Reduction Requirement Resources for 2050 [MW]

Portfolio Reliability and CO_2 Reduction Requirement Resources for 2050	
P1	900
P2	900
P3	1,100
P4	1,100

These energy insufficiencies identified in this Portfolio Verification step may be in part a modeling artifact and potentially exacerbated due to forecasting and extrapolation of trends out 30 years. For example, the EV forecast in the Carbon Plan model assumes that future load profiles are only impacted by the future mix of EV types on the system through 2050 (i.e., higher percentage of heavy duty EVs in the future). The forecast does not account for future EV load management programs that would likely incentivize charging behavior that would shift charging from peak periods to off-peak periods thereby likely eliminating some of the resources identified in this portfolio verification step (more information about how load management programs can influence future peak energy requirements is discussed in Appendix G (Grid Edge and Customer Programs)). Furthermore, the simplified simulations of the system in the screening model may contribute to the original inadequate identification of resources based on higher penetrations of variable energy and energy limited resources to ensure the energy and CO_2 reduction requirements are met in every hour across the planning horizon, which make validation steps like this important. The planning and modeling at the end of the Carbon Plan planning horizon carries significant uncertainty especially with respect to market uncertainty and how the resource mix will change over time. Higher adoption of variable energy resources, increased reliance on energy limited resources, and retiring numerous smaller, firm and dispatchable resources will require further study of portfolio resource adequacy, incremental resource specific ELCC, and appropriate reserve margin requirements to maintain a reliable system.

Solar Levelization

Additionally, cumulative solar economically selected by the capacity expansion model, between 2028 and the mid-2030s was levelized on an annual basis to represent more consistent additions of solar resources across this timeframe. As other resources are added to the portfolio and costs of resources decline, the capacity expansion model may elect to forgo selecting solar in certain years and add more in others. The addition of solar was levelized to allow more orderly annual procurements of relatively consistent volumes over time, especially as solar costs are projected to continue to decline. This more orderly procurement approach also diversifies cost risk of solar in any particular year. Due to its integration limits and solar being primarily an energy resource that generally has a small fraction of firm winter capacity for planning purposes compared to its nameplate capacity, the Companies observed it could spread the solar build for each portfolio over time without impacting planning reserve margin requirements. Therefore, the total solar selected between 2028 and the mid-2030s, depending on portfolio, was more equally spread over the years leading up to and through achievement of the 70% interim target to facilitate this more orderly procurement and interconnection of solar additions.

Portfolio LOLE and Resource Adequacy Validation

HB 951 requires that "any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid." This section outlines the analytical process undertaken to provide reasonable assurance that the final Carbon Plan portfolios perform at levels of reliability equivalent to or better than the current system configuration based on satisfying the LOLE[7] resource adequacy metric.

As previously noted, 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 LOLE analysis for each of the Carbon Plan portfolios. This process utilized the Strategic Energy Risk Valuation Model ("SERVM")[8] to evaluate the LOLE of each portfolio for the years 2030 and 2035 to ensure that the portfolios satisfy the LOLE target in later years with higher levels of renewables and energy storage resources.

The 2020 Resource Adequacy Study determined that a 17% winter reserve margin is needed to satisfy the 0.1 event-days per year LOLE target. However, the 17% reserve margin also assumed "moderate to aggressive" modeling of neighbor assistance.[9] In general, future market assistance for reliability planning purposes is highly speculative due to the uncertainty in the pace of neighboring utilities'

[7] LOLE is the expected number of days in a year for which there is loss of load at least once per day (units are in days). LOLE counts the days having loss of load events, regardless of the number of consecutive or nonconsecutive loss of load hours in the day.
[8] The Strategic Energy & Risk Valuation Model ("SERVM") is a state-of-the-art reliability and hourly production cost simulation tool managed by Astrapé Consulting who provides consulting services and/or licenses the model to its users.
[9] 2020 Resource Adequacy Study Report, at 7, filed as Attachment I (DEC) and Attachment II (DEP) to the Companies' 2020 IRPs in Docket No. E-2, Sub 165.

transition to variable energy and energy limited resources to achieve CO_2 reduction targets. It is expected that if current trends hold, as neighboring systems continue to install solar and storage resources, the neighbors' LOLE risk may shift to the winter months as it has for Duke Energy. This could potentially lower the amount of neighbor assistance available 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 2030 and 2035 in SERVM, the Companies assumed that the level of market assistance would neither improve nor decline from the level of assistance modeled in the 2020 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 validation 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 combined islanded system changes with resource transition across time without speculation about future market assistance.

To establish a threshold LOLE metric for an island scenario, the Companies utilized modeling data from the 2020 Resource Adequacy Study Combined Case. The Combined Case from the 2020 Resource Adequacy Study 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 17% reserve margin Combined Case, except as an island with no market assistance. The LOLE result was then compared against the interconnected study as shown in Table E-56:

Table E-56: Islanded and Interconnected 2020 Combined Case Results at a 17% Reserve Margin

Study	LOLE Value [Event-Days / Year]
Islanded	0.235
Interconnected	0.082

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 worth of the interconnected system to the Companies. This difference of 0.153 event-days / year (0.235 - 0.082 = 0.153) is then added to the standard LOLE threshold of 0.1 event-days / year to create a new threshold to compare an islanded study against. If a Carbon Plan portfolio has an islanded LOLE greater than 0.253 event-days / year it indicates that even with an interconnected system, the portfolio would not meet the 0.1 event-days / year standard.

In addition, the results of this simulation provided other reliability metrics for a Combined DEC and DEP Island Case for use in measuring the reliability of the Carbon Plan portfolios. Table E-57 below provides the resulting island scenario metrics as a basis for comparison to the Carbon Plan portfolios.

The table includes islanded data Loss of Load Hours ("LOLH")[10] and Expected Unserved Energy ("EUE")[11] reliability metrics.

Table E-57: Combined DEC and DEP Island Case Reliability Metrics

Reliability Metric	Value
LOLH [Event-Hours / Year]	0.659
EUE [MWh]	932

The Companies evaluated each of the Carbon Plan portfolios for years 2030 and 2035 in an islanded study. The results of these studies were then compared to the islanded LOLE threshold of 0.253 event-days / year as a proxy for maintaining a 0.1 event-days / year standard with the assistance of neighboring utilities. If a portfolio in either 2030 or 2035 had an LOLE above the 0.253 event-days / year threshold, additional firm capacity resources were added to the portfolios in those test years until the portfolio met the threshold. To simplify the analysis, the firm capacity reliability resource was assumed to be a CT consistent with the CTs modeled in the capacity expansion modeling. Table E-58 shows the as-found reliability metrics for 2030 resulting from the EnCompass portion of the Portfolio Verification modeling. The table also shows the reliability threshold metrics developed based on the 2020 islanded case. The table shows that each of the portfolios satisfied the LOLE threshold in 2030 and thus no additional CTs were added to maintain reliability. Each portfolio also satisfied the threshold value for the LOLH and EUE metrics. Note that the LOLH and EUE data is shown for informational purposes and is discussed further in the Energy Adequacy section below.

Table E-58: Reliability Metrics for As-Found Portfolios, 2030

Portfolio	LOLE [Event-Days / Year]	LOLH [Event-Hours / Year]	EUE [MWh]	Winter Reserve Margin [%]
Reliability Metric Threshold	0.253	0.659	932	17.0%
P1	0.044	0.120	136	26.3%
P2	0.071	0.176	214	23.9%
P3	0.128	0.371	571	22.1%
P4	0.138	0.377	506	21.7%

Table E-59 below shows the as-found reliability metrics for 2035. As shown, all portfolios satisfied the LOLE threshold in 2035 and no additional CTs were needed to maintain reliability. All portfolios also satisfied the threshold values for LOLH and EUE.

[10] LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (units are hours).

[11] EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period, calculated in megawatt hours ("MWh").

Table E-59: Reliability Metrics for As-Found Portfolios, 2035

Portfolio	LOLE [Event-Days / Year]	LOLH [Event-Hours / Year]	EUE [MWh]	Winter Reserve Margin [%]
Reliability Metric Threshold	0.253	0.659	932	17.0%
P1	0.047	0.126	274	29.0%
P2	0.066	0.190	320	24.9%
P3	0.192	0.567	1,291	22.0%
P4	0.183	0.561	1,229	21.2%

In summary, no additional CTs were needed to maintain reliability in 2030 and 2035 for Portfolios 1-4. The results of the LOLE validation ensure that each portfolio meets or exceeds the islanded LOLE threshold of 0.253 event-days / year. The same resource adequacy and LOLE assessments were run for the Alternate Fuel Supply Sensitivity Portfolios and resulted in the need for additional resources in some portfolios to ensure resource adequacy in 2035.

Energy Adequacy

With the ongoing transformation of the power system including retirement of dispatchable fossil fueled resources and replacement with variable energy and energy limited resources, energy adequacy has become an important area of interest and study in the electric industry. LOLE is a industry-standard reliability metric for systems consisting largely of dispatchable resources with reliable fuel supplies; however, LOLE does not account for the duration or magnitude of a reliability event. The transition to significant levels of variable energy and energy limited resources requires the need for new metrics, methods, and models to consider the "energy adequacy" associated with a portfolio of resources. To further this effort, Duke Energy is participating as a project advisor for EPRI's Resource Adequacy for a Decarbonized Future initiative. The purpose of the initiative is to develop new metrics, methods, and models to ensure energy adequacy for the transition to portfolios with significantly higher adoption of variable and energy limited resources and decreasing levels of dispatchable generation.

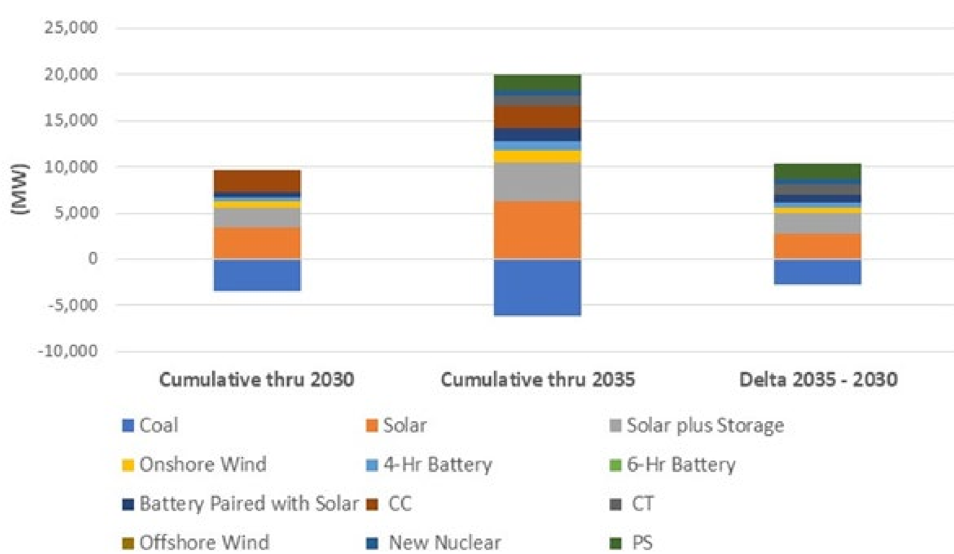
As an example, Table E-60 compares reliability metrics for Portfolio 3 for the years 2030 and 2035, along with the combined island threshold values. The table shows that the reserve margin for P3 is approximately the same in 2030 (22.1%) and 2035 (22.0%) and is approximately 5% above the minimum winter reserve margin target of 17.0%. The LOLE, which counts the number of days with a loss of load event, is satisfied in 2030 and 2035 based on the combined island threshold value. However, LOLE increases approximately 50% from 2030 to 2035 although it is still below the threshold value. The LOLH, which counts the number of hours in the year when a system's hourly demand exceeds available generating capacity, shows a similar trend with an approximate 50% increase and also remains below the threshold LOLH value. The EUE, which measures the energy not served during the year, shows the most dramatic movement with the 2035 value (1,291 MWh) more than double the 2030 value (571 MWh), and exceeding the EUE threshold value in 2035 by approximately 40%.

Table E-60: Portfolio P3 Reliability Metrics Comparison, 2030 and 2035

Portfolio	LOLE [Event-Days / Year]	LOLH [Event-Hours / Year]	EUE [MWh]	Winter Reserve Margin [%]
Reliability Metric Threshold	0.253	0.659	932	17.0%
2030 Data				
P3	0.128	0.371	571	22.1%
2035 Data				
P3	0.192	0.567	1,291	22.0%

Figure E-11 shows the cumulative resource additions and retirements for Portfolio 3 through 2030 and 2035 as well as the change in resource mix between 2030 and 2035. By 2035, Portfolio P3 includes approximately 2,700 MW of additional coal unit retirements and an increase in solar and solar plus storage of approximately 4,900 MW compared to 2030. By 2035, Portfolio 3 also includes an additional 600 MW of onshore wind, 600 MW of 4-hr battery storage, 1,100 MW of additional CT capacity, and 600 MW of new nuclear capacity compared to 2030. The cumulative CC capacity remains the same for 2030 and 2035. Although Portfolio P3 has an approximate 22% reserve margin in 2030 and 2035, the resource mix changes dramatically. Portfolio 3 has significantly higher levels of renewables and energy storage by 2035 compared to 2030, which results in a significant increase in EUE as well as increases in LOLE and LOLH. Final resource addition summaries for Portfolios 1-4 are provided in the next section.

Figure E-11: Comparison of Portfolio P3 Resource Mix in 2030 and 2035



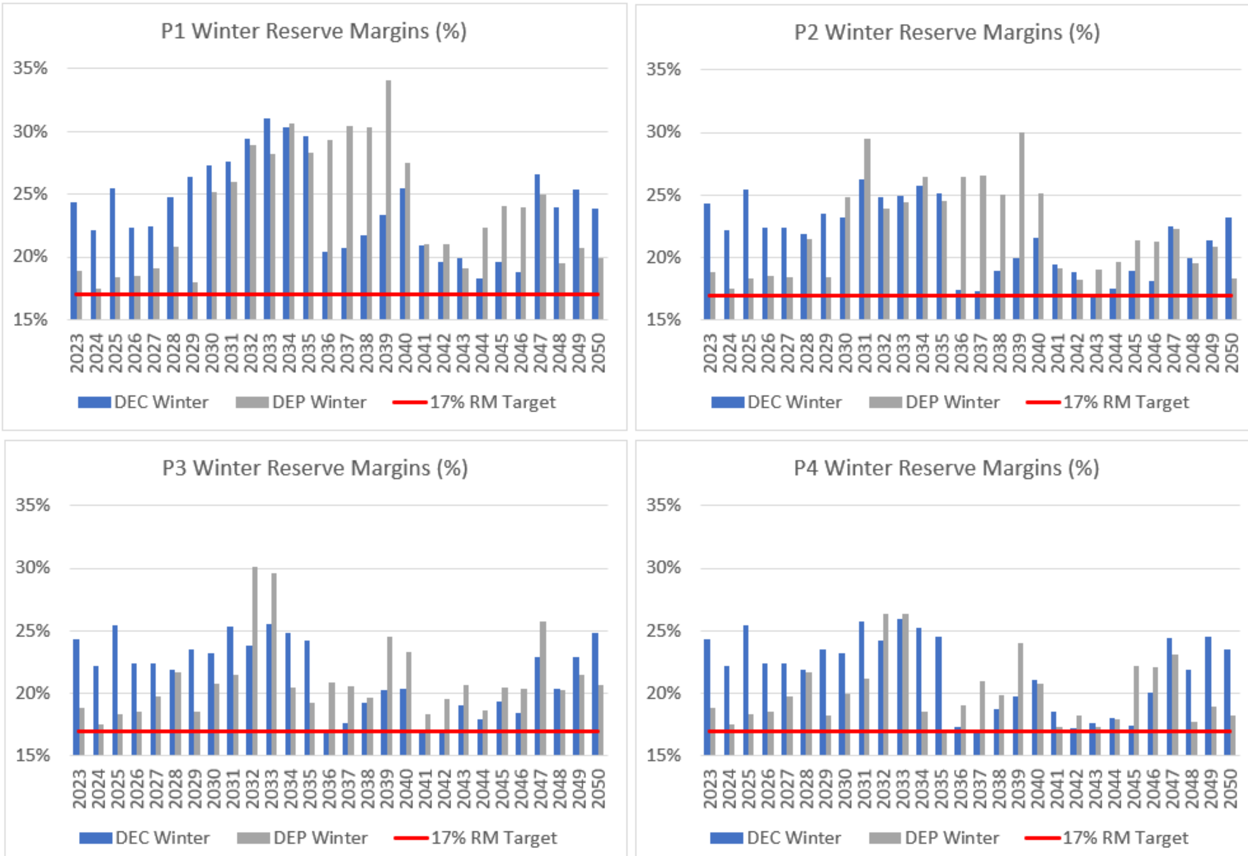
This analysis of P3 shows that higher reserve margins may be needed to maintain the same customer reliability, especially from an EUE perspective, with higher adoption of renewables and storage resources. The 0.1 event-days / year LOLE standard is currently widely used in the electric industry for measuring resource adequacy. However, additional reliability metrics may be needed when assessing portfolios that rely on a high adoption of variable energy and energy storage resources. Further analysis is needed to determine if it would be appropriate to incorporate other metrics in resource adequacy assessments, including LOLH and EUE; however, neither Duke Energy, nor other US utilities to Duke Energy's knowledge, has adopted any additional metrics at this time. Finally, the current framework utilizes historic data on the distribution of unit availability, load, temperature, irradiance, wind speed, neighbor assistance etc. as input parameters to statistically characterize energy adequacy risk. To the extent the range of historic outcomes for these variables may not be fully representative of future distributions for each of these inputs, new methods may be needed to further assess energy adequacy risk. Reference Appendix Q (Reliability and Operational Resilience Considerations) and Section II.H of the 2022 DEC and DEP ELCC Study report (being provided as Attachment III to the Carbon Plan) for further discussion of ensuring energy adequacy.

Adequacy of Projected Reserves

Resource planning provides general guidance in the type and timing of resource additions. Projected reserve margins will often be somewhat higher than the minimum target in years immediately following new generation additions since capacity may be added in large blocks to take advantage of economies of scale. Large resource additions are deemed economic only if they have a lower PVRR over the planning horizon as compared to smaller resources that better fit the short-term reserve margin need. In addition, imposing a significant carbon constraint can have the indirect effect of increasing reserve margins due to the need to add carbon-free and lower-carbon resources to displace higher-carbon intensity resources. The higher-carbon resources have continued usefulness to backup renewable resources even as they operate at progressively lower capacity factors as more renewables are added to support the trajectory toward carbon neutrality. In effect, the EnCompass capacity expansion model is solving to meet CO_2 emissions reductions targets while also maintaining a minimum 17% winter reserve margin.

Figure E-12 below shows DEC and DEP projected winter reserve margins for Portfolios 1-4. Portfolios 1-4 generally show increasing reserve margins resulting from the addition of carbon-free and lower carbon resources required to meet carbon reduction targets, with reserve margins trending back down beginning 2040 as older gas-fired resources are retired during the 2040's. Portfolio 1 generally has higher reserve margins than the other portfolios due to the resources required to meet the earlier 2030 70% carbon reduction target date.

Figure E-12: Portfolios 1-4 Winter Reserve Margins [%]



DEC peak demand (system peak demand net of UEE, NEM and other demand-side impacts, but before impacts of non-dispatchable supply-side solar and wind resources) is projected to occur in the summer while DEP peak demand is projected to occur in the winter. Solar output aligns more closely with afternoon summer peak demands compared to winter peak demands which occur in the early morning hours when solar output is low. Thus, it is notable that DEC and DEP are both winter planning utilities since the annual peak demand net of non-dispatchable solar and wind is projected to occur in the winter for both Companies, which drives the timing need for new reliability resources capable of serving the winter morning peak. With the significant level of solar additions for DEC and DEP, the difference in winter versus summer reserve margins can be significant. This is especially true for DEP since both winter load peaking and winter resource planning exacerbates the summer versus winter reserve margin difference.

Figure E-13 below shows a comparison of the winter and summer reserve margins for DEC and DEP, using Portfolio 4 for illustration purposes (Portfolios 1-3 show similar trends as Portfolio 4). The figure shows DEC and DEP reserve margins on the same y-axis scale to contrast the difference between the two Companies. DEC summer reserve margins are generally a few percentage points greater than the winter reserve margins. However, DEP summer reserve margins exceed winter reserve margins by 20% to over 40%, resulting in DEP summer reserve margins of approximately 40% to over 60% in some years. For example, in 2050, DEP is projected to have a winter peak load of 18,124 MW and a summer peak load of 16,831 MW. The total firm capacity of solar, solar paired with storage, and wind resources in Portfolio 4 is projected to be 3,382 MW and 9,245 MW in the winter and summer respectively. So, while the peak load has decreased 1,293 MW from winter to summer, the amount of firm renewable capacity has increased by 5,863 MW. This means that there is an approximate net impact on the reserve margin of 7,156 MW (summer reserve margin improving relative to winter reserve margin). Thus, high levels of solar with a greater capacity contribution toward summer reserves versus winter reserves results in a shift of LOLE from the summer period to the winter period.

Figure E-13: Portfolio 4 Winter and Summer Reserve Margins [%]

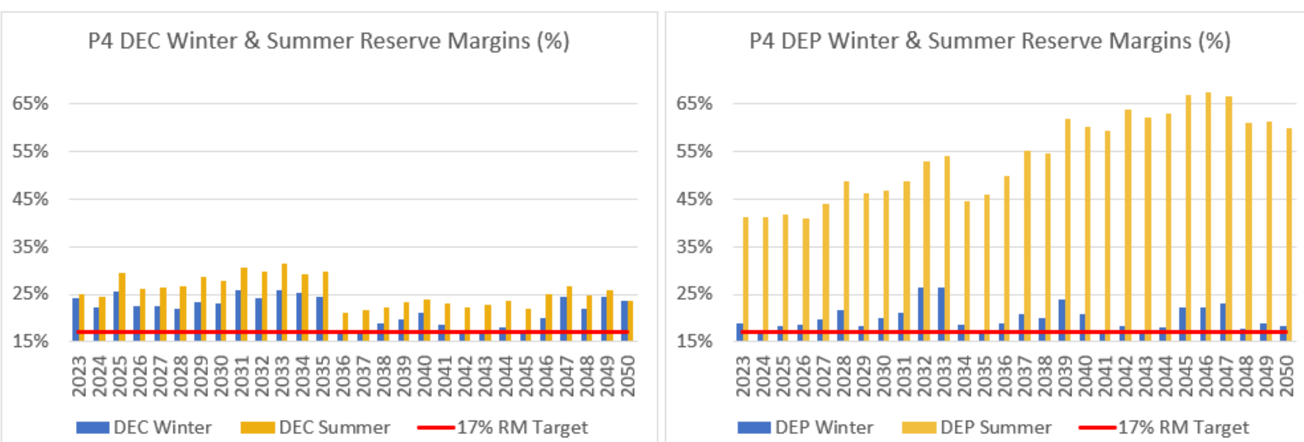
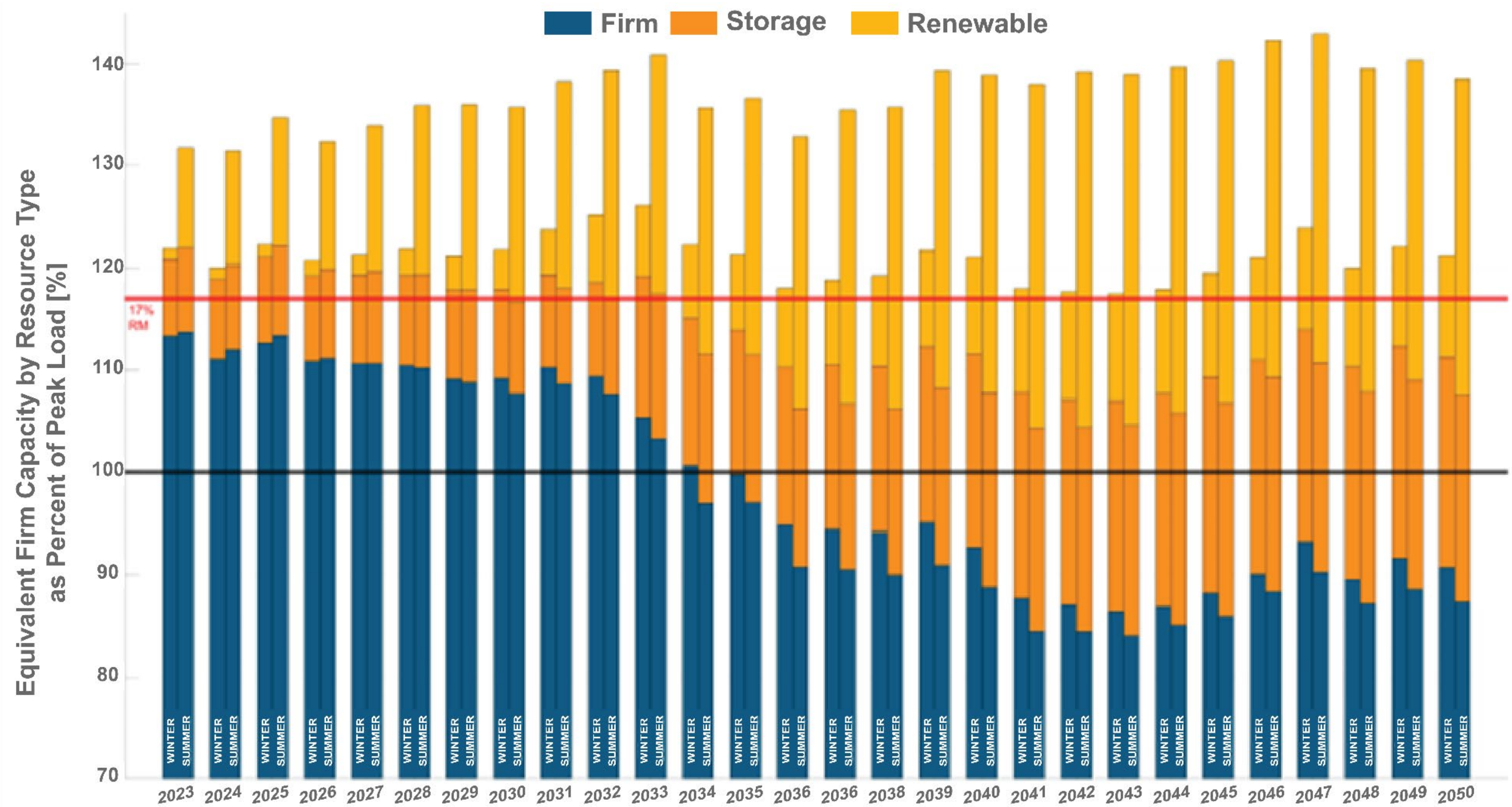


Figure E-14 provides another view of reserve margins by season and year for Portfolio 4. In this figure, DEC and DEP firm capacity and peak loads are combined to create reserve margin projections for the combined Carolinas' systems. Three types of resources are represented: Firm (gas, coal, oil, nuclear, hydro, DSM, etc.) – represents firm capacity available during peak load conditions, Storage (including pumped storage) – represents energy limited resources that can only generate for a limited amount of time before they need to be recharged, and Renewables (including solar, solar paired with storage, and wind) – represents non-dispatchable variable energy resources with a reduced amount of their nameplate capacity available during the peak load hour. Each segment of these resources shown in Figure E-14 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 2023, Firm resources have enough firm capacity to serve approximately 113% of the weather normal winter peak load, with Storage accounting for approximately 8% of peak load and Renewables accounting for approximately 1% of peak load for a total equivalent firm capacity of around 122% of peak load, or a reserve margin of approximately 22%. In the summer, this changes as the equivalent firm capacity contribution of Renewables increases from 1% winter contribution to peak load to around 10% of the peak load in the summer, increasing the total reserve margin to approximately 32%. This is due to both the summer versus winter ELCCs of the Renewable resources and the differences in peak load between the seasons. The figure clearly shows how the contribution of solar, in the Renewables 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 firm capacity over the planning period and the increasing reliance on variable energy and energy limited storage 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 energy limited storage resources to meet the peak load.

Figure E-14: Portfolio 4 Combined DEC and DEP Winter and Summer Reserve Margins by Resource Type [%]



Note: For each year, the left bar represents winter resources and the right bar represents summer resources.

In summary, planning to meet carbon reduction targets results in higher reserve margins due to the addition of increasing variable energy and energy limited carbon-free and lower carbon resources required to meet those targets. Thus, projected reserve margins for Portfolios 1-4 satisfy the minimum 17% reserve margin target and are projected to be well above the target in some years, with reserve margins trending back down as older gas fired generation is retired. Summer reserve margins are projected to be higher than winter reserves margins and to a significant degree for DEP. Across time, firm resources will make up less of the resource portfolio and the Companies will rely more on variable energy and energy limited resources to satisfy reserve margin requirements. Finally, the LOLE validation step previously described was undertaken as part of the Carbon Plan analytics to ensure that the portfolios satisfied the 0.1 LOLE standard with higher levels of variable energy and energy limited resources. Further analysis is needed to determine the appropriateness of incorporating additional metrics in resource adequacy assessments, including LOLH and EUE.

Final Carbon Plan Portfolios

The annual resource additions and coal retirements for DEC and DEP for each final Carbon plan portfolio are presented below in Table E-61 through Table E-68. Consistent with data in the rest of this Appendix, resource changes are effective as of the start of the year listed. Resource changes are included through 2036 consistent with the Companies' target to cease coal operations by the end of 2035. For the start of 2036, all portfolios retire Belews Creek and Cliffside 6 ceases coal operations, but continues to operate past this date without relying on coal. Cliffside 6's capacity is reflected in the coal retirements column, as its coal capacity is retired, though the unit continues to operate as a unit co-fired on natural gas.2035 on natural gas). Capacities in these tables below reflect nameplate capacity of resources including the forecasted solar and storage resources.

Table E-61: Portfolio 1: Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	334	0	0	0	0	0	0	0	0	0
2028	0	34	450	0	0	120	0	376	0	0	0
2029	-760	784	0	0	0	0	1,216	0	0	0	0
2030	0	34	750	0	0	200	0	0	0	0	0
2031	0	784	0	0	350	0	0	0	0	0	0
2032	0	750	0	0	600	0	0	0	0	0	0
2033	-1,318	750	0	0	0	0	0	0	0	285	1,680
2034	0	750	0	0	0	0	0	0	0	0	0
2035	0	750	0	0	0	0	0	0	0	285	0
2036	-3,069	750	0	300	200	0	0	0	0	285	0

Table E-62: Portfolio 1: Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	35	450	0	28	120	0	0	0	0	0
2028	-1,409	35	600	0	700	160	0	752	0	0	0
2029	-1,766	485	600	300	0	160	1,216	0	0	0	0
2030	0	35	1,050	300	0	280	0	0	800	0	0
2031	0	35	600	300	0	320	0	0	0	0	0
2032	0	0	1,050	300	100	320	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	1,050	0	200	280	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	375	0	100	100	0	0	0	0	0

Table E-63: Portfolio 2: Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	334	0	0	0	0	0	0	0	0	0
2028	0	484	0	0	0	0	0	0	0	0	0
2029	-760	484	0	0	0	0	1,216	0	0	0	0
2030	0	484	0	0	0	0	0	0	0	0	0
2031	0	484	0	0	100	0	0	752	0	0	0
2032	0	450	0	0	0	0	0	0	0	0	0
2033	-1,318	450	0	0	0	0	0	0	0	0	0
2034	0	525	0	0	0	0	0	0	0	285	0
2035	0	525	0	0	0	0	0	0	0	285	0
2036	-3,069	525	0	150	550	0	0	0	0	285	0

Table E-64: Portfolio 2: Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	110	0	0	78	0	0	0	0	0	0
2028	0	35	600	0	200	160	0	0	0	0	0
2029	-1,766	35	600	300	0	160	1,216	0	0	0	0
2030	0	35	600	300	0	200	0	0	800	0	0
2031	0	35	600	300	200	320	0	376	0	0	0
2032	-1,409	525	0	300	0	0	0	0	800	0	0
2033	0	0	600	0	0	160	0	0	0	0	0
2034	0	0	750	0	200	200	0	0	0	0	0
2035	0	0	225	0	0	60	0	0	0	0	0
2036	0	0	675	0	150	180	0	0	0	0	0

Table E-65: Portfolio 3: Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	334	0	0	0	0	0	0	0	0	0
2028	0	484	0	0	0	0	0	0	0	0	0
2029	-760	484	0	0	0	0	1,216	0	0	0	0
2030	0	484	0	0	0	0	0	0	0	0	0
2031	0	484	0	0	300	0	0	376	0	0	0
2032	0	450	0	0	0	0	0	0	0	0	0
2033	-1,318	450	0	0	0	0	0	0	0	285	1,680
2034	0	450	0	0	0	0	0	0	0	0	0
2035	0	450	0	0	0	0	0	0	0	285	0
2036	-3,069	525	0	0	350	0	0	376	0	285	0

Table E-66: Portfolio 3: Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	35	450	0	128	120	0	0	0	0	0
2028	0	35	600	0	50	160	0	0	0	0	0
2029	-1,766	35	525	300	0	140	1,216	0	0	0	0
2030	0	185	375	300	0	100	0	0	0	0	0
2031	0	35	525	300	0	260	0	0	0	0	0
2032	0	0	525	300	300	140	0	752	0	0	0
2033	0	450	75	0	0	20	0	0	0	0	0
2034	-1,409	0	525	0	0	220	0	0	0	0	0
2035	0	0	525	0	0	140	0	0	0	0	0
2036	0	0	525	0	150	140	0	0	0	0	0

Table E-67: Portfolio 4: Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	334	0	0	0	0	0	0	0	0	0
2028	0	484	0	0	0	0	0	0	0	0	0
2029	-760	484	0	0	0	0	1,216	0	0	0	0
2030	0	484	0	0	0	0	0	0	0	0	0
2031	0	484	0	0	0	0	0	752	0	0	0
2032	0	450	0	0	0	0	0	0	0	0	0
2033	-1,318	450	0	0	0	0	0	0	0	285	0
2034	0	450	0	0	0	0	0	0	0	0	0
2035	0	450	0	0	0	0	0	0	0	285	0
2036	-3,069	525	0	0	300	0	0	376	0	285	0

Table E-68: Portfolio 4: Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	35	450	0	128	120	0	0	0	0	0
2028	0	35	600	0	50	160	0	0	0	0	0
2029	-1,766	35	375	300	0	100	1,216	0	0	0	0
2030	0	335	75	300	0	20	0	0	0	0	0
2031	0	185	225	300	150	100	0	0	0	0	0
2032	0	0	375	300	50	120	0	0	800	0	0
2033	0	0	375	0	0	100	0	0	0	0	0
2034	-1,409	0	375	0	250	200	0	0	0	0	0
2035	0	0	375	0	0	120	0	0	0	0	0
2036	0	0	675	0	150	180	0	0	0	0	0

Presented below in Table E-69 through Table E-71 is a summary of the final resource additions of each portfolio for the year the interim target is achieved, 2035, and 2050. For summary purposes, the solar capacity associated with solar and solar plus storage is grouped together. Similarly, all battery capacity (standalone battery and battery paired with solar) and, for the 2050 summary data, all new nuclear (SMR and Advanced Nuclear with Integrated Storage) additions are grouped together. Additionally, capacity changes have been rounded for summary purposes and may not sum to data in the previous data presented in this Appendix.

Table E-69: Final Resource Additions by Portfolio [MW] for year interim target is achieved

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
P1	-4,900	7,200	600	2,100	2,400	1,200	800	0	0
P2	-4,900	7,500	1,200	1,800	2,400	1,200	1,600	0	0
P3	-6,300	9,600	1,200	2,300	2,400	1,200	0	300	1,700
P4	-6,300	8,700	1,200	1,900	2,400	800	800	300	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-70: Final Resource Additions by Portfolio [MW] for 2035

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
P1	-6,300	13,800	1,200	4,300	2,400	1,200	800	600	1,700
P2	-6,300	10,600	1,200	2,400	2,400	1,200	1,600	600	1,700
P3	-6,300	10,500	1,200	2,500	2,400	1,200	0	600	1,700
P4	-6,300	9,500	1,200	2,100	2,400	800	800	600	1,700

Note 1:Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-71: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
P1	-9,300	19,900	1,800	7,400	2,400	6,800	800	9,900	1,700
P2	-9,300	18,200	1,700	5,900	2,400	6,400	3,200	9,900	1,700
P3	-9,300	19,000	1,800	6,400	2,400	7,500	0	10,200	1,700
P4	-9,300	18,100	1,800	6,100	2,400	6,800	800	10,200	1,700

Note 1:Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.
Note 3: Includes SMR and advanced nuclear with integrated storage.

By 2050, the Carbon Plan portfolios add least 18.1 GW of solar and as much as 19.9 GW in Portfolio 1. Each portfolio adds the 2.4 GW CC capacity available with the limited access to Appalachian natural gas supply. Nearly all 1.8 GW of onshore wind available is selected in each portfolio. Portfolio 2 is the only portfolio that adds additional offshore wind after achievement of the 70% interim CO_2 emission reductions target, an additional 1.6 GW by 2050. This is likely due to the tiered transmission network system upgrade costs associated with offshore wind. The first two 800 MW tranches of offshore wind require more expensive transmission network system upgrades than additional capacity added thereafter. Therefore, by integrating the first 1.6 GW of offshore wind earlier, future additions of offshore wind are assumed to be interconnected at a lower cost in this portfolio.

Each portfolios adds 5.9 to 7.4 GW of battery capacity, including both standalone and batteries paired with storage. With the addition of Bad Creek PH II included in every portfolio and additional peaking thermal storage capacity associated with the new nuclear advanced reactors with integrated storage, this brings the incremental new storage capacity to between 9.8 and 11.2 GW by 2050. To help supply backup power for variable energy and energy limited resources, 6.4 to 7.5 GW of CTs that operate excusively on hydrogen by 2050 are added thoughout the planning horizon. This amount is generally consistent with the amount existing peaking CT capacity on the system today that is expected to retire by 2050.

Finally, each portfolio adds approximately 10 GW of new nuclear, including the peaking capacity associated with advanced reactors with integrated storage, by 2050 to achieve carbon neutrality providing firm, dispatchable, and bulk carbon-free energy for the system. While each of the portfolios vary modestly by 2050, all portfolios have similar a similar make-up by 2035 to continue on a trajectory to zero CO_2 emissions by 2050 as presented in Figure E-15 below.

Portfolio Performance

As discussed in Chapter 3 (Portfolios), the Carbon Plan portfolios are evaluated against the core Carbon Plan targets of CO_2 emissions reduction, cost and affordability, reliability including resource adequacy, and executability. The previous analysis in the Portfolio Verification step addressed ensuring all portfolios maintained a standard of reliability throughout the planning horizon, with a heightened focus the nearer term with representative portfolio resource adequacy in 2030 and 2035. The verification analysis also confirmed economic inclusion of resources with respect to cost of the portfolios.

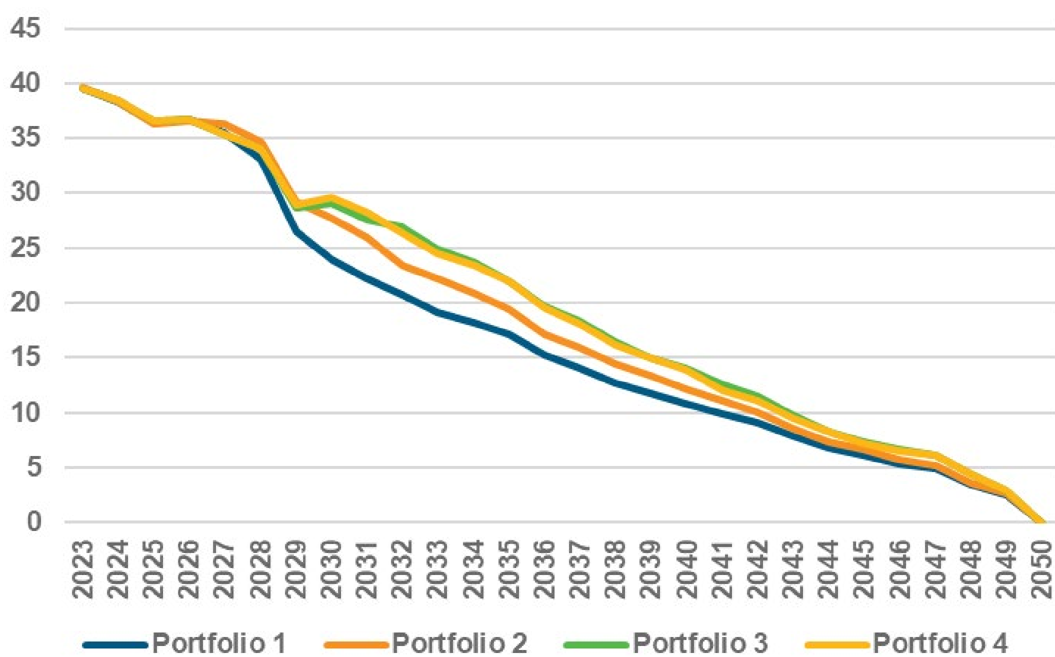
This section highlights the relative performance of each of the final portfolios in terms of CO_2 reductions and cost, both in terms of overall PVRR and customer bill impacts. The results in this section were developed based on detailed production cost modeling runs of the final portfolios, including the resource additions identified in the portfolio development and verification steps. Discussion of exectability of Carbon Plan portfolios, however, is included in Chapter 4 (Execution Plan).

CO_2 Reduction Analysis

The primary objective of the Carbon Plan is to present portfolios that comply with the CO_2 emissions reductions targets in a least cost manner, while maintaining or improving Duke Energy's compliance with reliability standards. This includes assessing the trade-off between interim target achievement dates and resources used to achieve the CO_2 emissions reductions targets. The projected emissions are outputs of the production cost model, which occur through economically dispatching 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 utilized in the development of portoflios and selection of resources. As mentioned previously throughout this Appendix, the DEC and DEP system are jointly dispatched. For this reason, emissions are shown for the combined systems.

The graph below charts the CO_2 reductions for the combined DEC and DEP systems for each of the portfolios through 2050. Resources added in each portfolio to comply with the 70% interim target throughout time influence the differences in carbon emissions trajectories to carbon neutrality in 2050. Portfolios 1 and 2 with earlier interim target timelines have more aggressive fleet transition in the next decade, but slightly more gradual transitions from the interim target to 2050. Portfolios 3 and 4, on the other hand, present more consistent glidepath in system CO_2 emissions over the planning horizon. The exception to this consistent annual reduction is in 2029 when all portfolios add 2.4 GW of CC capacity and retire approximately 2.5 GW of coal capacity, which makes a significant year-over-year impact to CO_2 emissions, appearing as definitive step change from 2028 to 2029.

Figure E-15: Combined DEC and DEP Systems Annual CO_2 Emissions [Millions of Short Tons]



Below, Table E-72 through Table E-74 show the CO_2 reduction percentage with respect to meeting the HB 951 CO_2 emissions reductions targets and for the combined DEC and DEP systems. Table E-72 and Table E-73 show CO_2 reductions relative to a 2005 baseline. Table E-74 shows the difference in cumulative CO_2 emissions for each portfolio, with Portfolio 3 emitting the most cumulative tons of CO_2 over the planning horizon.

Table E-72: Annual HB 951 CO_2 Emissions Reduction in 2030, the Portfolios Interim Target Year, and 2035 [Percent reduction relative to 2005]

	2030	Portfolio Interim Target Year	2035
P1	71.1%	71.1%	79.8%
P2	66.3%	71.8%	77.2%
P3	64.6%	71.6%	73.7%
P4	63.9%	71.9%	73.8%

Table E-73: Annual Combined DEC and DEP Systems CO_2 Emissions Reduction in 2030, the Portfolios Interim Target Year, and 2035 [Percent reduction relative to 2005]

	2030	Portfolio Interim Target Year	2035
P1	69.6%	69.6%	78.3%
P2	65.0%	70.4%	75.5%
P3	63.3%	70.0%	72.2%
P4	62.6%	70.3%	72.3%

Table E-74: Cumulative Combined DEC and DEP Systems CO_2 Emissions through 2050, Relative to Portfolio 3 [Millions Short Tons]

	Cumulative CO_2 Emissions Reduction
P1	-69
P2	-32
P3	0
P4	-2

By 2030, Portfolio 1 achieves the 70% interim HB 951 target as designed while Portfolios 2, 3, and 4 achieve 64%-66% CO_2 emissions reduction. On a system level, in 2030 the combined DEC and DEP systems nearly achieve 70% reduction in Portfolio 1, while Portfolios 2, 3, and 4 achieve 63%-65% reduction. By each portfolio's targeted year, each portfolio meets the 70% interim target required by HB 951, consistently exceeding it. This is due to the resource additions in the final year of interim target achievement having a significant and material impact on the CO_2 reduction of the system, with additions of either offshore wind or new nuclear to achieve the 70% interim target. By 2035, Portfolio 1 continues to outpace the other portfolios achieving 78% reduction as a combined DEC and DEP systems. Portfolio 2 achieves HB 951 interim emissions reductions targets in 2032 and achieves 75.5% as an overall system by 2035. Finally, the portfolios with latest target date, Portfolios 3 and 4, achieve the 70% interim target in 2034 as designed, while achieving approximately 72% for the combined DEC and DEP systems by 2035. The differences in interim target timelines and resources added to achieve those targets results in greater reductions early for Portfolios 1 and 2, that are generally sustained over the planning horizon, before all portfolios converge to zero CO_2 emissions by 2050. Due to this difference, Portfolio 1 emits 69 million short tons less and Portfolio 2 emits 32 million short tons less over the planning horizon on a combined DEC and DEP systems basis, relative to Portfolio 3. Portfolios 3 and Portfolio 4 essentially emit the same over the planning horizon, with a steady and consistent emissions reduction trajectory over the planning horizon.

Present Value of Revenue Requirements

PVRR is a common resource planning metric used to quantify the relative costs across portfolios over the planning horizon. This metric is calculated by assessing all future costs that could vary across portfolios sensitivities (differences in the resources included in a portfolio) and production cost and capital cost sensitivities (what those resources cost or how those resources perform given the assumptions of the system such as technology cost, fuel price, or carbon price), discounted to present day costs using each Company's specific discount rate. This metric captures the cost of adding new resources throughout time, relative to their price forecast, 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.

The EnCompass model's production cost module provides the 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 Carbon 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.

Resource planning PVRR analysis is typically limited to costs associated with projected resources and operations of the generation system to serve customer load, but the analysis for the Carbon Plan includes additional projected 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 with the targeted year. Shown below in Table E-75 are the annual revenue requirements of these costs, discounted to present value at DEC's and DEP's Company specific discount rate. A combined DEC and DEP PVRR is also shown.

Table E-75: Present Value of Revenue Requirements through 2050 [2022, $B]

	DEC	DEP	DEC + DEP
P1	$58.7	$42.4	$101.1
P2	$56.4	$42.3	$98.8
P3	$56.8	$38.4	$95.2
P4	$56.3	$39.2	$95.5

As discussed in the CO_2 reduction analysis, Portfolios 1 and 2 achieve the interim CO_2 reduction targets at an accelerated pace relative to Portfolios 3 and 4. As a tradeoff for the extended timeline to achieve the interim CO_2 reduction target, Portfolios 3 and 4 result in a combined system PVRR that is $3.3 to $5.9 billion less. The extended timeline allows for the use of new nuclear to meet the reduction target, providing high capacity factor, carbon-free energy. New nuclear is economically selected in the mid-2030s in all portfolios but allowing time for this resource to contribute to the interim reduction target allows for the avoidance of more costly resources in the near term. Furthermore, the additional years allowed to achieve the interim target permits the Companies to take advantage of cost declines of resources such as solar and batteries and maintain lower annual solar integration, increasing the executability of the portfolios at the same time. Overall, the lowest cost portfolio is Portfolio 3, but the inclusion of offshore wind in Portfolio 4, only slightly increases the cost of the portfolio while, importantly, providing resource diversity to mitigate technology cost and timing risk. The most costly plan is Portfolio 1, but this portfolio achieves the interim CO_2 reduction target the soonest, while emitting the least cumulative system CO_2 emissions over the planning horizon.

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. This 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, the Companies are also concerned with the immediate cost to customers and emphasize the ability to provide affordable energy to customers as a core target of this Carbon Plan.

The analysis of estimating the average residential monthly bill impact attempts to quantify how much a residential customer using 1,000 kWh of energy per month can expect to see their bill change over planning horizon as impacted by the Carbon Plan analysis. While many costs and other parameters outside of resource planning impact revenue requirements and customer bills, the impacts evaluated in the Carbon Plan only account for changes captured in the Carbon Plan analysis and do not represent an all-inclusive bill impact analysis as other factors can also influence a customer’s bill.

Below, Table E-76 through Table E-79 show the projected changes to a typical residential customer’s bill for each of the portfolios through 2030 and 2035. Additionally, the projected average annual percentage change from 2023 through 2030 and through 2035 is also shown representing how much a customer’s bill would increase on average annual basis over that time frame. The costs reflected in these bill impacts are consistent with the parameters to evaluate the CO_2 reductions of the system and development of the PVRRs.

Table E-76: DEC Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035

	2030	2035
P1	$8	$33
P2	$5	$30
P3	$7	$29

	2030	2035
P4	$5	$28

Table E-77: DEC Annual Average Residential Bill Impacts [%] through 2030 and 2035

	2030	2035
P1	1.0%	2.3%
P2	0.7%	2.0%
P3	0.8%	2.0%
P4	0.7%	1.9%

Table E-78: DEP Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035

	2030	2035
P1	$35	$45
P2	$29	$45
P3	$19	$31
P4	$18	$34

Table E-79: DEP Annual Average Residential Bill Impacts [%] through 2030 and 2035

	2030	2035
P1	3.9%	2.8%
P2	3.2%	2.8%
P3	2.2%	2.0%
P4	2.0%	2.2%

Table E-76 through Table E-79 show that the portfolios that comply with the 70% interim target earlier result in higher projected customer bill impacts, especially by 2030. The portfolios that have additional time to comply with the CO_2 reductions generally lead to lower bill impacts for customers. With projected declining cost curves for future carbon-free resources such as solar, batteries, wind and new nuclear, the pace of adoption plays a critical role in the immediate cost to consumers in the form of bill impacts.

The main differentiator by 2030 between Portfolios 1 and 2 and Portfolios 3 and 4 for DEP is the integration of offshore wind. Both Portfolios 1 and 2 integrate the first block of offshore wind by the start of 2030 and this investment is reflected in the bill impacts for DEP where the resource is integrated. There is also discernable difference between the bill impacts for Portfolio 1 in both DEC and DEP by 2030 compared to Portfolio 2. This differential in customer bill impact for Portfolio 1 compared to Portfolio 2 is the result of the higher solar integration required to meet the interim reduction target by 2030 for this portfolio. The higher and faster interconnection of solar to meet the 2030 date for Portfolio 1 is noticeable in the 2030 snapshot in both utilities.

By the end of 2035, DEC, in each portfolio, has added the same amount of CC and Nuclear SMR along with the Bad Creek PH II expansion project. These resource additions provide adequate firm capacity to retire DEC's remaining coal fleet, an incremental 3.5 GW of capacity that requires replacement between 2030 and the end of 2035 and help achieve the CO_2 emissions reductions targets of the system. The addition of these resources creates the basis for the increase in customer bill impacts between 2030 and 2035.

Similarly, for DEP, Portfolios 2, 3, and 4 also see significant bill impacts between 2030 and 2035 that coincide with the replacement of the final DEP coal units. The difference from 2030 to 2035 for Portfolio 1 for DEP is less pronounced than the other portfolios because all of the DEP coal units are retired by 2030 in Portfolio 1 to meet the CO_2 reduction target in that year. The final DEP coal retirements (Roxboro 3 and 4) for the portfolios with extended interim target timelines are not accelerated to before 2030, therefore the impact of the retirements is primarily seen in the 2035 snapshot. Finally, by 2035 Portfolio 2 rises to similar customer bill impact levels compared to Portfolio 1 in DEP. Portfolio 2 is the only portfolio that adds both 800 MW blocks of offshore wind available by this time, resulting in the additional increase in customer bill impact between 2030 and 2035.

Portfolio, Production Cost, and Capital Cost Sensitivity Analysis

To quantify the robustness of portfolios in the Carbon Plan, that is, how is the resource selection or cost of the portfolio is affected by changes in Carbon Plan modeling assumptions, the Companies performed a variety of sensitivity analyses. For the purposes of the discussion in this section, "portfolio sensitivities" are assessed in the capacity expansion model to determine potential resource selection changes, and where applicable through the production cost model to quantify portfolio performance changes. "Production cost sensitivity" and "capital cost sensitivity" refers to modeling or analysis evaluating the carbon emissions and overall costs of the final portfolios, after portfolio verification, under different input assumptions in the production cost model or with changes to the capital cost of new resources. These sensitivities do not change the resources in each portfolio, rather quantify the performance changes of the portfolios, with the change in input assumptions.

These analyses help quantify the risks for portfolios given the key areas of uncertainty including natural gas and hydrogen fuel supply, natural gas fuel commodity pricing, federal carbon emissions policy ("CO_2 tax"), load, and new supply-side resource capital costs.

Alternate Fuel Supply Sensitivity Analysis

As discussed earlier in this Appendix, natural gas fuel supply is currently an area of considerable uncertainty and the way fuel supply develops can have impacts to the least cost portfolio of resources selected to achieve CO_2 reduction targets, the cost to achieve targets, and the ability of a portfolio to robustly perform in fuel price sensitivities. For the Alternate Fuel Supply Sensitivity Analysis, the Companies replaced their base planning assumption for natural gas fuel supply with an alternate assumption in which the Companies do not secure intrerstate FT service to the Companies' existing CC units (which do not already have firm supply from the Gulf Coast Region) until later in the planning horizon. In this portfolio sensitivity, the lack of supply diversity also impacts the commodity price of natural gas, the operations of units in the fleet, and the availability of incremental CC generation. The results illustrate how the Companies might pivot if fuel supply were to develop differently and assumed in the base Carbon Plan assumption

Alternate Fuel Supply Sensitivity Portfolio Summary

This sensitivity reoptimizes the resources selected in each of the portfolios with the new natural gas supply assumptions. The cost to operate the system under this fuel supply sensitivity is recalculated and the ability for each portfolio to achieve the interim CO_2 reduction target is reevaluated. The process for developing portfolios under the base fuel supply assumption was repeated for the alternate fuel supply sensitivity and the portfolio results are shown below in Table E-80 through Table E-85. These alternate fuel portfolios will be designated as follows: Portfolio 1 with Alternate Fuel ("Portfolio 1_A" or "$P1_A$"), Portfolio 2 with Alternate Fuel ("Portfolio 2_A" or "$P2_A$"), Portfolio 3 with Alternate Fuel ("Portfolio 3_A" or "$P3_A$") and Portfolio 4 with Alternate Fuel ("Portfolio 4_A" and "$P4_A$").

Table E-80: Final Resource Additions by Alternate Fuel Supply Sensitivity Portfolio [MW] for Interim Target Achievement Year

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
$P1_A$	-4,900	7,200	600	3,900	800	2,200	800	0	0
$P2_A$	-4,900	8,200	1,200	2,400	800	1,200	1,600	0	0
$P3_A$	-6,300	10,200	1,200	3,600	800	800	0	600	1,700
$P4_A$	-6,300	9,600	1,200	2,200	800	1,200	800	600	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-81: Final Resource Additions by Portfolio [MW] for Interim Target Achievement Year, Alternate Fuel Supply Sensitivity Portfolios Delta from Final Carbon Plan Portfolios

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
$P1_A$	0	0	0	1,800	-1,600	1,000	0	0	0
$P2_A$	0	700	0	600	-1,600	0	0	0	0
$P3_A$	0	600	0	1,300	-1,600	-400	0	300	0
$P4_A$	0	900	0	300	-1,600	400	0	300	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-82: Final Resource Additions by Alternate Fuel Supply Sensitivity Portfolio [MW] for 2035

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
$P1_A$	-6,300	14,000	1,500	4,700	800	2,200	800	600	1,700
$P2_A$	-6,300	11,600	1,400	2,800	800	1,200	1,600	600	1,700
$P3_A$	-6,300	11,400	1,500	3,800	800	1,600	0	600	1,700
$P4_A$	-6,300	10,600	1,200	2,400	800	1,900	800	600	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-83: Final Resource Additions by Alternate Fuel Supply Sensitivity Portfolio [MW] for 2035, Delta from Final Carbon Plan Portfolios

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
P1*A*	0	200	300	400	-1,600	1,000	0	0	0
P2*A*	0	1,000	200	400	-1,600	0	0	0	0
P3*A*	0	900	300	1,300	-1,600	400	0	0	0
P4*A*	0	1,100	0	300	-1,600	1,100	0	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-84: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
P1*A*	-9,300	19,500	1,800	7,600	800	7,900	800	9,900	1,700
P2*A*	-9,300	17,700	1,800	5,300	800	7,500	4,800	9,900	1,700
P3*A*	-9,300	18,700	1,800	6,500	800	10,900	0	10,200	1,700
P4*A*	-9,300	18,200	1,800	5,900	800	10,900	800	10,200	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.
Note 3: Includes SMR and advanced nuclear with integrated storage.

Table E-85: Final Resource Additions by Portfolio [MW] for 2050, Delta from Final Carbon Plan Portfolios

	Coal Retirements	Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
P1*A*	0	-400	0	200	-1,600	1,100	0	0	0
P2*A*	0	-500	100	-600	-1,600	1,100	1,600	0	0
P3*A*	0	-300	0	100	-1,600	3,400	0	0	0
P4*A*	0	100	0	-200	-1,600	4,100	0	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.
Note 3: Includes SMR and advanced nuclear with integrated storage.

Due to the fuel supply limitations, only 800 MW, or one CC-F, is available for selection in this sensitivity. To maintain capacity planning reserve margins and CO_2 reduction level, the alternate portfolios generally require more capacity resources in the selection of additional batteries and CTs, and energy resources, predominantly in the form of more solar resources.

By 2050, all alternate fuel supply sensitivity portfolios add least 18.2 GW of solar and as much as 19.5 GW in Portfolio 1*A*. Each portfolio adds the 800 MW CC available in this sensitivity and the maximum of 1,800 MW of onshore wind. The portfolios vary modestly by 2050 from the primarily fuel supply assumption. Portfolio 2*A* is the only portfolio that adds additional offshore wind, an additional 1.6 GW more than Portfolio 2, bringing the total offshore wind deployed in this portfolio to 4.8 GW. This is likely due to the tiered transmission network system upgrade costs associated with offshore wind. The first two 800 MW tranches of offshore wind transmission network system upgrades are more expensive than additional capacity added thereafter. Therefore, by integrating the first 1.6 GW of offshore wind earlier, future additions of offshore wind can be added at a lower cost in this portfolio.

Each of the alternate fuel supply portfolios add more CTs relative to Final Carbon Plan Portfolios, in part to back fill capacity due to less CC capacity in these alternate portfolios. Portfolio 3_A and Portfolio 4_A add the most CT capacity relative to their respective Final Carbon plan portfolios. One reason, as referenced above in the Portfolio Verification section, is that these alternate fuel supply portfolios initially developed by the capacity expansion model, when run through the Resource Adequacy Validation step, resulted in portfolios that did not meet the reliability standard. As such, a limited amount of capacity resources were added to these portfolios to maintain resource adequacy standards.

Finally, in addition to the 18.2 to 19.5 GW solar and other renewables added to these portfolios, each portfolio adds approximately 10 GW of new nuclear with firm capacity and bulk quantities of zero-carbon energy by 2050 to achieve carbon neutrality, while leveraging the Bad Creek PH II expansion project to balance the large amount of variable energy renewables on the system.

Alternate Fuel Supply Portfolio Sensitivity Performance

This section highlights the performance of each of the alternate fuel supply sensitivity portfolios in terms of CO_2 reductions and cost, both overall present value of revenue requirements and customer bill impacts. The results in this section are a result of detailed production cost modeling runs of the final portfolios, including the resource additions identified in the portfolio development and verification steps.

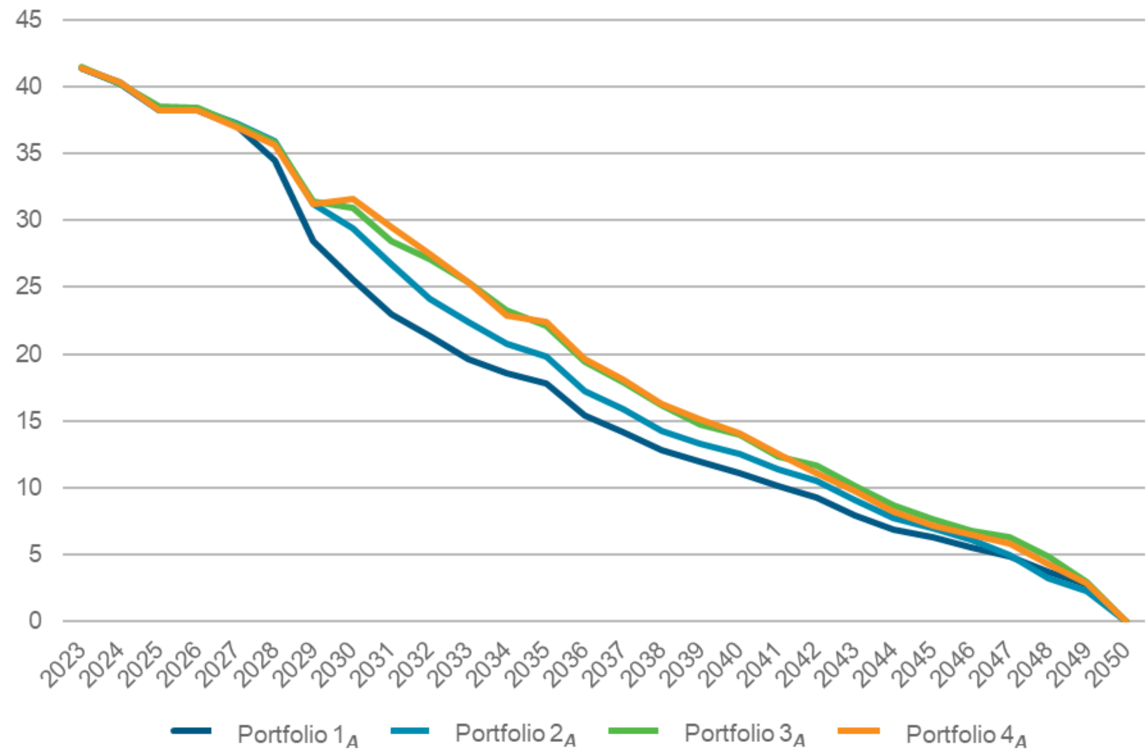
CO_2 Reduction Analysis

As discussed in the performance of the final portfolios, assessing the trade-off between interim target achievement dates and resources used to achieve the CO_2 reductions targets is critical to developing the Carbon Plan. Consistent with the results from the final portfolios, the projected emissions are outputs of the production cost model, which occur through economically dispatching the specific set of resources in each portfolio to meet the energy needs of the system. For the detailed production cost runs, mass cap, no environmental dispatch adder or price on carbon is used to influence the operation of the system. As stated previously in this Appendix, the system mass cap was only utilized to develop the portfolio resources, but was not used in the production cost modeling to ensure the portolfios met their respective CO_2 emissions reductions targets.

Figure E-16 below charts the CO_2 reductions for the combined DEC and DEP systems for each of the alternate fuel supply sensitivity portfolios through 2050. The differences in resources added in each of the alternate portfolios impact the projection in carbon emissions from the final portfolios. As with the final portfolio, however, Portfolios 1_A and 2_A with earlier timelines have more aggressive fleet transition in the next decade, but slightly more gradual transitions from the interim target to 2050. Portfolios 3_A and 4_A, on the other hand, present a more consistent glidepath in system CO_2 emissions over the planning horizon. The exception to this consistent annual reduction is in 2029 when all portfolios add

800 MW of CC capacity and retire approximately 2.5 GW of coal capacity, which makes a significant year-over-year impact to CO_2 emissions, appearing as definitive step change from 2028 to 2029.

Figure E-16: Combined DEC and DEP Systems Annual CO_2 Emissions, Alternate Fuel Supply Sensitivity Portfolios [Millions of Short Tons]



Below, Table E-86 through Table E-88 show the CO_2 reductions percentage with respect to meeting the HB 951 CO_2 emissions reduction targets and for the combined DEC and DEP systems for the Alternate Fuel Supply Sensitivity. Table E-86 and Table E-87 show CO_2 reductions relative to a 2005 baseline. Table E-88 shows the difference in cumulative CO_2 emissions for each portfolio, with Portfolio 3_A emitting the most cumulative tons of CO_2 over the planning horizon of the Alternate Fuel Supply Sensitivity portfolios.

Table E-86: Annual HB 951 CO_2 Emissions Reduction in 2030, the Portfolios Interim Target Achievement Year, and 2035 [Percent reduction relative to 2005], Alternate Fuel Supply Sensitivity

	2030	Portfolio Interim Target Year	2035
$P1_A$	69.2%	69.2%	79.2%
$P2_A$	64.1%	70.9%	76.5%
$P3_A$	62.1%	72.3%	73.6%
$P4_A$	61.3%	72.6%	73.3%

Table E-87: Annual Combined DEC and DEP Systems CO_2 Emissions Reduction in 2030, the Portfolios Interim Target Achievement Year, and 2035 [Percent reduction relative to 2005], Alternate Fuel Supply Sensitivity

	2030	Portfolio Interim Target Year	2035
P1*A*	67.7%	67.7%	77.5%
P2*A*	62.8%	69.5%	75.0%
P3*A*	60.9%	70.6%	72.1%
P4*A*	60.1%	71.0%	71.7%

Table E-88: Cumulative Combined DEC and DEP Systems CO_2 Emissions through 2050, Relative to Portfolio 3*A* [Millions Short Tons]

	Cumulative CO_2 Emissions Reduction
P1*A*	-67
P2*A*	-32
P3*A*	0
P4*A*	-1

As seen in Table E-86, Portfolio 1*A* notably falls short of achieving the interim 70% CO_2 reduction target by 2030 by approximately 600,000 tons. This portfolio adds all of the carbon-free resources that are eligible for selection by the capacity expansion model by 2030, including utilizing the high solar integration limits, totaling 7.2 GW of solar additions, 600 MW of onshore wind, 800 MW of offshore wind, and aggressive UEE projections, by the start of 2030. The portfolio does achieve the interim target in 2031, with one additional year for solar and wind resources to be added. The initial capacity expansion results did meet the 70% interim target in 2030, but when the portfolio was run through the production cost model, the portfolio was not able to meet the target with the detailed, hourly granularity of the production cost model. No additional resources were added to this portfolio by 2030 to be consistent with the constraints on resource additions imposed on Portfolio 1. One contributing factor to the inability for the portfolio to meet its target includes the lack of the additional 1.6 GW of CC capacity, which provides more lower-carbon energy in Portfolio 1. Additionally, this alternate fuel supply sensitivity does not obtain incremental FT natural gas supply to diversify the supply to the Companies' service territories. This limitation on access to lower-cost natural gas, compared to Transco Zone 5 delivered, effectively lowers the price spread between economical dispatch of coal resources compared to less carbon-intensive natural gas resources. Because the lack of fuel supply diversity in this sensitivity, natural gas delivered to the Carolinas continues to see price volatility, and supply constraints that dictate the system operate on other, higher CO_2-emitting fuels, contributing to higher carbon emissions of the system. More discussion of the interaction between natural gas prices and carbon emissions is discussed later in this Appendix in the Fuel Production Cost Sensitivity Analysis.

By 2030, Portfolios 2*A*, 3*A*, and 4*A* achieve 61%-64% CO_2 emissions reductions. In 2030, the combined DEC and DEP systems achieves approximately 68% reductions for Portfolio 1*A*, while Portfolios 2*A*,

3_A, and 4_A achieve 60%-63%. With the extended timelines for Portfolio 2_A, 3_A, and 4_A, in each portfolio's interim target year, these portfolios do achieve the interim 70% CO_2 reduction target required by HB 951, with more time to add additional solar, battery, and new nuclear resources to ensure the reduction targets are met in accordance with the portfolios development.

By 2035, however, Portfolio 1_A, like Portfolio 1 in the final portfolios, continues to outpace the other portfolios achieving 78% reduction for the combined DEC and DEP systems. Portfolio 2_A achieves the HB 951 interim reduction target in 2032 and achieves 75% as a combined DEC and DEP system by 2035. Finally, the portfolios with latest interim target achievement date of 2034, Portfolios 3_A and 4_A, achieve the 70% interim target in 2034 as designed, while achieving approximately 72% for the combined DEC and DEP systems by 2035. The differences in timelines and resources added to achieve those targets result in greater reductions early for Portfolios 1_A and 2_A, that are generally sustained over the planning horizon, before all portfolios converge to zero CO_2 emissions by 2050, consistent with Portfolios 1 and 2 in the final portfolios. Due to this difference, Portfolio 1_A emits 67 million short tons less and Portfolio 2_A emits 32 million short ton less over the planning horizon, relative to Portfolio 3_A, which emits the most cumulative tons through 2050 in the alternative fuel supply sensitivity portfolios. Portfolios 3_A and Portfolio 4_A essentially emit the same over the planning horizon, with a steady and consistent emissions reduction trajectory over the planning horizon, similar to the performance of Portfolios 3 and 4 in the final portfolios through 2050.

*Present Value of Re*venue Requirements

The PVRRs for the Alternate Fuel Supply Sensitivity portfolios are calculated consistent with the calculations for the final portfolios. Below in Table E-89 is the PVRR for each of the Alternate Fuel Supply Sensitivity portfolios.

Table E-89: Present Value of Revenue Requirements through 2050, Alternate Fuel Supply Sensitivity [2022, $ B]

	DEC	DEP	DEC + DEP
$P1_A$	$60.0	$44.1	$104.1
$P2_A$	$57.8	$43.5	$101.3
$P3_A$	$58.7	$39.9	$98.6
$P4_A$	$58.1	$40.9	$98.9

As discussed in the CO_2 reduction analysis for the Alternative Fuel Supply Sensitivity, Portfolios 1_A and 2_A achieve the interim CO_2 reduction targets at accelerated dates relative to Portfolios 3_A and 4_A. As a tradeoff for the extend timeline to achieve the interim CO_2 reduction target, Portfolios 3_A and 4_A result in a combined system PVRR that is $2.4 to $5.5 billion less. The extended timeline allows for the use of new nuclear to meet the reduction target, providing high capacity factor, carbon-free energy. New nuclear is economically selected in the mid 2030's in all portfolios but allowing the time for it to contribute to the 70% interim target allows for the avoidance of more costly resources in near term, consistent with the results of the final portfolios. While the cost delta has narrowed between the 2034 portfolios and the earlier target date portfolios in the Alternate Fuel Supply Sensitivity, it is not because the costs of the earlier target cases have decreased but because all of the portfolios have increased in cost and the lack of fuel supply diversity results in less opportunity to take advantage of pricing differentials from separate supply sources.

Furthermore, the additional years allowed to achieve the interim target permits the Companies to take advantage of cost declines of resources such as solar and batteries and maintain lower annual solar integration, increasing the executability of the plan at the same time, consistent with the results from the final portfolios. Overall, the least cost plan is Portfolio 3_A, but the inclusion of offshore wind in Portfolio 4_A, similar to Portfolio 4 in the final portfolios, only slightly increases the cost of the plan while providing resource diversity, important for technology cost and operational risk. The most costly portfolio in the Alternate Fuel Supply Sensitivity is Portfolio 1_A. This portfolio achieves the interim CO_2 emissions reductions target the earliest and emits the least cumulative system CO_2 emissions over the planning horizon but fails to achieve the reduction by the targeted year.

Customer Bill Impact Analysis

The Customer Bill Impacts for the Alternate Fuel Supply Sensitivity portfolios are calculated consistent with the calculations for the final portfolios. Below in Table E-90 through Table E-93 is the PVRR for each of the Alternate Fuel Supply Sensitivity portfolios.

Table E-90: DEC Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035, Alternate Fuel Supply Sensitivity

	2030	2035
$P1_A$	$17	$41
$P2_A$	$11	$37
$P3_A$	$11	$37
$P4_A$	$11	$36

Table E-91: DEC Annual Average Residential Bill Impacts [%] through 2030 and 2035, Alternate Fuel Supply Sensitivity

	2030	2035
$P1_A$	2.0%	2.7%
$P2_A$	1.4%	2.5%
$P3_A$	1.4%	2.5%
$P4_A$	1.3%	2.4%

Table E-92: DEP Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035, Alternate Fuel Supply Sensitivity

	2030	2035
$P1_A$	$37	$44
$P2_A$	$29	$43
$P3_A$	$21	$29

	2030	2035
$P4_A$	$19	$34

Table E-93: DEP Annual Average Residential Bill Impacts [%] through 2030 and 2035, Alternate Fuel Supply Sensitivity

	2030	2035
$P1_A$	4.1%	2.7%
$P2_A$	3.3%	2.7%
$P3_A$	2.4%	1.9%
$P4_A$	2.2%	2.2%

The customer bill impacts for the Alternate Fuel Supply Sensitivity Portfolios are directionally consistent with the results and discussion from the final portfolios. General customer bill impact increases relative to the final portfolios consistent with the cost increases observed in the PVRRs, due to the natural gas pricing differences.

Fuel Price Forecast Portfolio Sensitivity Analysis

The forecasted price of natural gas like other fuels can have an impact on resource selection. The Carbon Plan portfolio development shows that CC and CT capacity are cost effective resource additions. To account for uncertainty in the price of natural gas, the Companies performed a sensitivity analysis where the base natural gas price forecast was replaced with the high natural gas forecast and the portfolio development was reevaluated to observe if the selection of the resources was still economic.

Selection of CC resources in High Natural Gas Price Forecast

This sensitivity reoptimized the development of Portfolios 4 and 4_A to see if a higher gas price would change the resource selection of the CC capacity. The base natural gas price forecast was replaced with the high natural gas price forecast and the capacity expansion model was rerun. Even with the higher natural gas price, the capacity expansion model still found the selection of the CC capacity in both portfolios to be economic relative to other resources.

Economic Replacement of Battery Capacity with CT capacity

This sensitivity evaluated if the replacement of batteries selected by the capacity expansion model with CTs was still economic when the base natural gas price forecast was replaced with the high natural gas price forecast. This sensitivity was again performed for Portfolios 4 and 4_A. Similar to the selection of the CC capacity in the capacity expansion model in the high gas price forecast, even with the higher natural gas price, the replacement of a fraction of the batteries selected by the capacity expansion model with CTs was found to be economical in both portfolios when verified with the production cost model.

Fuel Price Forecast Production Cost Sensitivity Analysis

While demonstrated in the previous sensitivities that the high natural gas price forecast does not change the economic inclusion of the CCs and a limited amount of CTs that replaced a portion of the capacity expansion selected batteries, the price of natural gas can also have a significant impact on plan cost and carbon emissions. The Companies conducted production cost sensitivity analysis for each of the Portfolios, P1 through P4 and $P1_A$ through $P4_A$ and quantified the portfolios' performance and cost in high and low natural gas price forecasts. None of the resources were reoptimized; only the response of the portfolio's performance to the higher natural gas price was quantified. Because the two fuel supply assumptions have different natural gas price forecasts, separate high and low natural gas price forecasts were developed for each. Table E-94 and Table E-95 below show the impacts on PVRR through 2050 and carbon emissions 2030 and 2035 for each of the portfolios in each of the gas price sensitivities. Under both fuel supply assumptions, the portfolios that target the interim reduction target for 2030, Portfolio 1 and Portfolio 1_A, present the lowest impact to the high natural gas price forecast.

Table E-94: Combined DEC and DEP PVRR through 2050, Final Carbon Plan Portfolios, Delta from Base Fuel Supply Base Gas Price Assumption [2022, $B]

	High Gas Price Forecast	Low Gas Price Forecast
P1	$7.7	-$3.4
P2	$8.1	-$3.7
P3	$8.6	-$3.9
P4	$8.5	-$3.8

Table E-95: Combined DEC and DEP PVRR through 2050, Alternative Fuel Supply Sensitivity Portfolios, Delta from Alternative Fuel Supply Base Gas Price Assumption [2022, $B]

	High Gas Price Forecast	Low Gas Price Forecast
$P1_A$	$7.2	-$3.4
$P2_A$	$7.6	-$3.6
$P3_A$	$7.9	-$3.7
$P4_A$	$8.0	-$3.7

Table E-96: CO_2 Reduction in Interim Target Year, Final Carbon Plan Portfolios

	High Gas Price Forecast	Base Gas Price Forecast	Low Gas Price Forecast
P1	63.8%	71.1%	71.5%
P2	61.6%	71.8%	72.7%
P3	62.7%	71.6%	72.3%
P4	63.0%	71.9%	72.6%

Table E-97: CO_2 Reduction in Interim Target Year, Alternate Fuel Supply Sensitivity Portfolios

	High Gas Price Forecast	Base Gas Price Forecast	Low Gas Price Forecast
P1*A*	57.6%	69.2%	70.0%
P2*A*	57.5%	70.9%	72.2%
P3*A*	62.0%	72.3%	73.6%
P4*A*	62.7%	72.6%	73.9%

Over the past decade, base and intermediate load natural gas resources have largely dispatched ahead of more carbon intensive energy from coal, due to the relative fuel prices and generation technology efficiencies. Based on the Companies' base natural gas price forecast, that order of dispatch is largely held through the Carbon Plan planning horizon. However, in a high natural gas price environment, the economic dispatch of coal shifts in front of natural gas. As shown in Tables E-96 and E-97 above, the high natural gas price forecast sensitivity results in all portfolios falling well short of achieving the 70% interim CO_2 emissions reductions target in the intended year. Because natural gas generation largely dispatches ahead of coal in the base natural gas price forecast, in a low natural gas price forecast, there is not a lot of opportunity to further offset CO_2 emissions. The lower natural gas price may incentivize the operations of some peaking natural gas units ahead of coal, or incrementally more natural gas operations on the Companies' natural gas co-fired coal units, but there is little upside opportunity for additional CO_2 emissions reductions with a low natural gas price forecast.

There is, however, just enough benefit in Portfolio 1*A* to shift this portfolio from narrowly missing achieving the CO_2 emissions reductions target in 2030, as previously discussed, to narrowly achieving that target with the low gas forecast. Relying on the relative economics between fuel prices to ensure achieving the desired portfolio outcome is not sound planning, however. Instead of depending on favorable economics in an area as uncertain as fuel pricing, the relative economics between coal and natural gas can be adjusted through an environmental dispatch shadow price. An additional factor to be considered is that management of limited coal supply (discussed further in Appendix N (Fuel Supply)) could potentially reduce or eliminate the need for an environmental dispatch shadow price.

Effects of an Environmental Dispatch Shadow Price

Based on the sensitivity results above, the ability for a portfolio to achieve the intended CO_2 reduction targets may positively be impacted by an environmental dispatch adder to influence the dispatch of resources for dispatching in CO_2 emissions merit order. With ever-present uncertainty in natural gas prices and the time needed to procure replacement resources for the remaining coal units on the system, a high natural gas price is a risk for continued CO_2 reductions. A dispatch adder, or CO_2 shadow price, could be one way to influence dispatch to continue to dispatch natural gas lower CO_2 emitting natural gas ahead of coal. This dispatch adder, which only impacts the dispatch of units and is not a direct and explicit cost passed on to customers, would reduce generation from higher CO_2 emitting resources. The dispatch adder, given the same relative economics between natural gas and coal prices, would reprioritize generation utilization of less CO_2-intensive energy. Furthermore, recognizing that CO_2 emissions are influenced by a number of factors beyond fuel prices that are not possible to predict for a given year ahead, such as weather and generation availability, an environmental dispatch shadow price could help to achieve incremental carbon reduction in response to emergent situations.

Federal CO_2 Tax Production Cost Sensitivity Analysis

The PVRR differential between the portfolios that achieve the CO_2 emissions reductions earlier (Portfolios 1 and 2), and those that are allowed more time to integrate new nuclear and wind facilities to contribute to achieving the reductions targets (Portfolios 3 and 4), viewed as an additional tradeoff between interim target achievement dates. Achieving the interim CO_2 emission reductions target earlier and consistent progress towards zero carbon emission in 2050 reduces the cumulative emissions of Portfolio 1 and 2 over the planning horizon compared to Portfolios 3 and 4 which achieve the CO_2 emissions reductions two to four years later. The gap in CO_2 reductions diminishes steadily after the interim target is achieved, slowing the growth of the cumulative CO_2 reduction benefit, which comes at a nearer term cost premium to customers.

To quantify the impact of a lower CO_2 emissions profile over the course of the planning horizon, the Companies performed a production cost sensitivity analysis on Portfolios 1 and 4, to bookend the analysis. These two portfolios add approximately the same amount of nuclear, offshore wind, CC/CT, and pumped storage hydro through 2050 with the main difference in resource additions between the two being the solar and storage resources added to achieve interim CO_2 emission reduction target earlier. The production cost sensitivity analysis applies a hypothetical federal CO_2 tax policy to the operations of the system where every ton of CO_2 emitted is taxed at the Social Cost of CO_2.[12] The price assigned to CO_2 emissions represents a high cost estimate on these emissions and therefore ascribing value to every incremental ton of CO_2 avoided. The Companies used the 2016 Social Cost of CO_2 as the proxy for federal policy taxing the CO_2 emissions of each of these portfolios. As such, the tax explicitly impacts customers costs in the revenue requirement.

The Companies are not endorsing nor rejecting the Social Cost of CO_2 price forecast used in this analysis but are simply demonstrating the impact that an explicit federal cost CO_2 could have on cost to customers. Table E-98 below show how the two portfolios' PVRRs change between no price on CO_2 emission, as assumed in the Portfolio Analysis of the final portfolios and applying the Social Cost of CO_2 as a Federal CO_2 Tax.

Table E-98: Federal CO_2 Tax Production Cost Sensitivity Analysis PVRR through 2050 [2022, $B]

	No Price on CO_2 Emission	Proxy Federal CO_2 Tax
P1	$101.1	$124.2
P4	$95.5	$121.3
Delta	$5.6	$2.9

[12] U.S. Gov't, Interagency Working Group on Social Cost of Greenhouse Gasses, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866, at 16 (August 2016), *available at* https://epa.gov/site/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

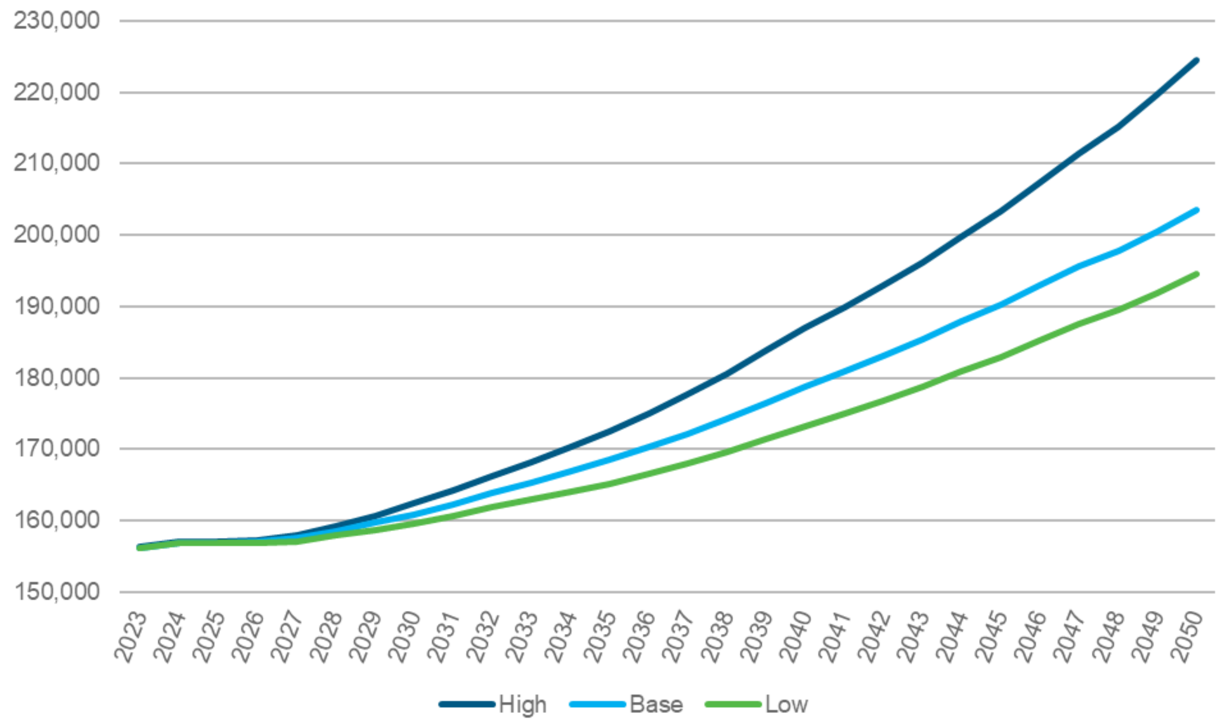
As shown in Table E-98 above, the incremental cumulative CO_2 emissions reductions between Portfolio 1 and Portfolio 4 do not fully close the PVRR cost differential between the portfolios with this CO_2 emissions price. This means that the earlier incremental cost to enable CO_2 emission reductions is not fully offset by applying the Social Cost of CO_2 through 2050. This analysis applies the tax to every ton of emissions beginning in 2023. It would be difficult to imagine such a tax being enacted by the start of 2023, and every year that passes without an explicit tax enacted, the cost delta between the two would continue to widen.

Load Forecast Sensitivity Analysis

As described earlier in this Appendix, load can have a significant impact on complying with the CO_2 emissions reductions targets, and the cost associated with running units more, or what resource changes are needed for capacity and carbon-free energy. The Carbon Plan, as is customary in resource planning, uses a weather normal load forecast. The impacts of non-weather normal load are quantified in the Portfolio LOLE and Resource Adequacy Validation step in the Quantitative Analysis's Portfolio Verification step. For this portfolio sensitivity, the Companies examined the impact on resource requirements relative to increases and decreases in load forecast due to opportunity and uncertainty associated with different aspects of how the net load forecast will develop, while complying to the same CO_2 reduction targets. Because it is a minimum standard that portfolios meet the CO_2 reduction targets, the Companies only quantified the changes in resources needed for achieving with the CO_2 reduction if the load forecast were higher or lower.

For the high load forecast sensitivity, the Companies used the high EV load forecast which represents significant increase in load for the Companies. This forecast may also serve as a proxy for a faster growing economic forecast, a more electrified economy, lower achievement of demand-side initiatives, some combination of the these. For the low load forecast sensitivity, the Companies use both a high net energy metering forecast, where rooftop solar adoption is increased, along with use of the higher UEE forecast that represents 1% of growth in UEE for *all* retail load. The use of these parameters could represent how demand-side initiatives can be used to offset supply-side resource needs. Hurdles exist for both of these load lower forecasts, notably the change in UEE opt-outs, but the results of this sensitivity are representatives of an overall lower load, no matter how it materializes. A comparison of the high EV, high NEM, and 1% total retail UEE forecasts to the Carbon Plan's base assumptions for each of these variables is included in the assumptions section of this Appendix. Below in Figure E-17 is the resulting high and low load forecasts in comparison to the Carbon Plan base load forecast used in this portfolio sensitivity analysis.

Figure E-17: Load Sensitivity Analysis - Total System Load Comparison [GWh]



The load forecast sensitivity was performed on Portfolio 1 and Portfolio 4. These portfolios originally selected similar resources in the capacity expansion modeling, with the biggest difference in the development of the portfolios being the targeted interim reduction target year, and therefore resources needed to meet the reduction targets. For these sensitivities, the capacity expansion model was run again replacing the Carbon Plan base load forecast with the high and low load forecast sensitivities. The high sensitivity was allowed a limited number of additional new nuclear units and addition onshore wind resources in DEC over the base assumption due to the higher load forecast and likelihood to accelerate development carbon-free resources to meet to the increased load forecast. The capacity expansion model's net resource changes in 2035 and 2050 from the base Portfolio 1 and Portfolio 4 are presented below in Table E-99 through Table E-102.

Table E-99: High Load Sensitivity Resource Changes from Base [MW] by 2035

	Solar[1]	Onshore Wind	Battery[2]	CT	Offshore Wind	SMR
P1-High Load	+700	+300	-100	0	+800	0
P4-High Load	+1,900	+150	+450	0	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-100: High Load Sensitivity Resource Changes from Base [MW] by 2050

	Solar[1]	Onshore Wind	Battery[2]	CT	Offshore Wind	SMR
P1-High Load	+1,700	+600	+500	+1,500	+1,600	+1,100
P4-High Load	+3,500	+600	+2,600	+800	0	+1,100

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-101: Low Load Sensitivity Resource Changes from Base [MW] by 2035

	Solar[1]	Onshore Wind	Battery[2]	CT	Offshore Wind	SMR
P1-Low Load	-1,125	-150	-640	0	0	0
P4-Low Load	-1,350	0	-790	0	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table E-102: Low Load Sensitivity Resource Changes from Base [MW] by 2050

	Solar[1]	Onshore Wind	Battery[2]	CT	Offshore Wind	SMR
P1-Low Load	-3,000	0	-970	+752	0	0
P4-Low Load	-2,475	0	-820	+752	0	0

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

The high load sensitivity requires more resources to meet the energy and CO_2 emissions reductions targets. Notably, the high load sensitivity to Portfolio 1 identifies the economic addition of 800 MW of offshore wind by 2035 and 1.6 GW of offshore wind by 2050 to keep up with the unchanged CO_2 emissions constraints in this sensitivity despite the higher load requirements. The high load sensitivity to both Portfolio 1 and Portfolio 2 result in additional solar battery and wind resources, and notably each portfolio also adds both of the additional allowable new nuclear units by 2050. The high load sensitivities also identify limited amount of incremental CTs by 2050 to help meet peak capacity requirements, along with the additional batteries in each of these sensitivities.

The low load sensitivity, conversely, results in the selection of fewer solar, wind, and battery resources. Of note, each of the portfolios selected the same amount of offshore wind and SMR with respect to base portfolios even with the reduced load. The capacity expansion model, in low load sensitivities, does replace a limited amount of battery capacity with CT capacity by 2050. Batteries, as discussed above, generally operate between daily peak and minimum system loads to offset higher cost and higher CO_2 emitting energy. The lower load forecast results in less favorable peak and minimum daily load levels for batteries to cost effectively operate and shifts cost and CO_2 benefits throughout the day, even in the capacity expansion model with the simplified load shape. This results in a shift to CT resources, which are lower capital cost as compared to batteries.

These portfolio sensitivities were not run through the production cost and reliability modeling verification steps to ensure resource and energy adequacy. However, as was seen with the final Carbon Plan portfolio, these load sensitivities, especially the high load sensitivity may also require more resources to satisfy reliability standards and energy requirements throughout the planning horizon. Furthermore, as discussed in the Overall Portfolio Reliability and CO_2 Reduction Verification section, forecasting and extrapolating trends out 30 years without adjustment to future projections on the development of load and resources, could forecast more resources than might otherwise be required with continual evaluation and adjustments to the planning and operating of the system.

New Supply-Side Resource Capital Cost Sensitivity Analysis

Resources are largely selected to reduce CO_2 emissions on the system and to maintain adequate capacity reserve margins, subject to annual and cumulative resource availability limits. Therefore, different resource price assumptions may have limited impact on resource selection relative to the base planning technology cost assumptions. While resources are needed to maintain a reliable system while achieving CO_2 reduction targets, the uncertainty associated with the price of each of the resources, especially related to the price forecast of the resources over time remains a significant risk in terms of cost to customers. To quantify the capital costs risks associated with new supply-side resources, the Companies performed a capital cost sensitivity analysis on Portfolios 1 through 4.

The Companies performed this analysis by applying high and low capital price forecast for each technology one at a time to the resources in the Portfolio 1–4. The PVRR cost impact that technology price has on each portfolio illustrates the risk and opportunities with the inclusion of resources in the portfolio. Furthermore, the Companies applied the high and low technology price forecasts for all resources simultaneously to every portfolio. This shows the upward cost potential associated with items such as macro supply chain and inflationary impacts, or downward potential if technology improvements across the industry happen faster than the base planning assumptions.

The Companies developed high capital cost forecasts for each technology. The starting cost of each technology was selected between the higher of the Companies' and the EIA's 2022 projected technology cost.[13] The EIA costs are higher than internal estimates for technologies for all resources except solar and battery storage. In the high technology price forecast the initial costs are then assumed to remain flat in real terms throughout the planning horizon, except for offshore wind and SMR which experience gradual and modest cost declines in real terms through the first major deployments of these technologies in the US over the next 15 to 20 years. This methodology effectively removes the projected steep technological cost declines over the next decade that technologies such as solar and storage experience in the base cost forecast.

Low capital cost forecasts for each technology were developed starting with the Companies' current cost estimates for each technology. For developing the price forecast over time, the Companies

[13] U.S. Energy Information Admin,, Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2022* (Mar. 2022), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

applied NREL's 2021 Annual Technology Baseline ("ATB")[14] Advanced Case's cost declines for the renewable and storage technologies. This cost decline is more aggressive than the Companies' base cost decline assumptions for these technologies. For other technologies the Companies maintained a flat projection for future costs in nominal terms over the planning horizon, representing more aggressive technology cost improvements compared to the Companies' base technologies costs.

Figure E-18 through Figure E-21 show the individual PVRR impacts through 2050 of each technology price forecast, high and low, on each of the portfolios. The negative impacts represent the impacts of low technology price forecasts on the PVRR of each portfolio relative to the base technology price forecasts used in the portfolio analysis of each of the portfolios. Similarly, the positive impacts represent the impacts of the high technology price on the PVRR with respect to the base price forecasts.

Figure E-18: Portfolio 1 Capital Sensitivity Analysis Results, Technology-Specific PVRR Impacts [2022, $B]

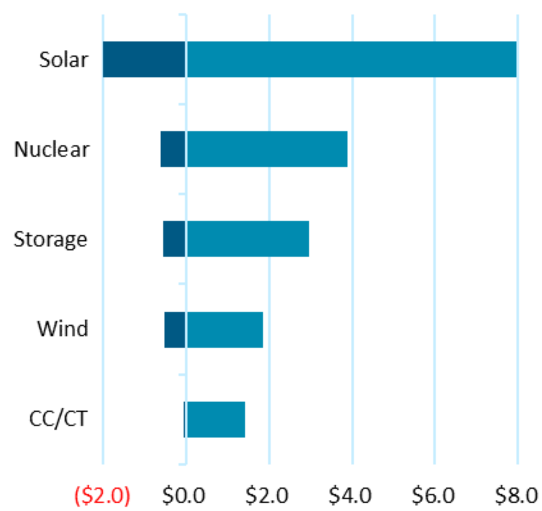
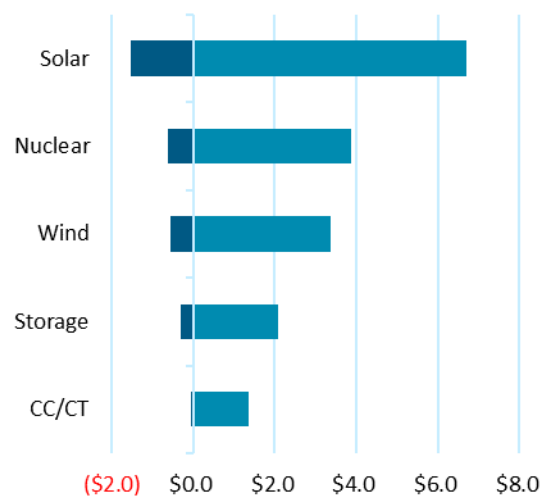


Figure E-19: Portfolio 2 Capital Sensitivity Analysis Results, Technology-Specific PVRR Impacts [2022, $B]



[14] Nat'l Renewable Energy Laboratory, Annual Technology Baseline (2021), *available at* https://atb.nrel/electricity/2021/data.

Figure E-20: Portfolio 3 Capital Sensitivity Analysis Results, Technology-Specific PVRR Impacts [2022, $B]

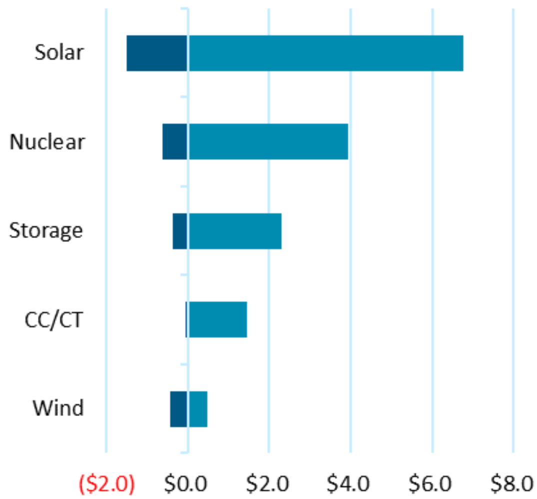
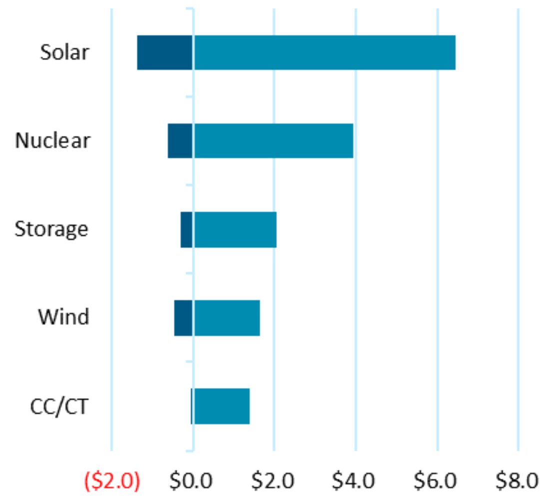


Figure E-21: Portfolio 4 Capital Sensitivity Analysis Results, Technology-Specific PVRR Impacts [2022, $B]



As illustrated in the figures above, the potential for declining or increasing solar capital costs presents the largest potential impact on the PVRRs of the portfolios. Solar is deployed at relatively high levels in each portfolio. The Companies' base solar price forecast already includes a significant price reduction over the next decade. While the low solar price forecast represents lower cost solar over the planning horizon, the differential between the two forecast is not drastic. Therefore, a small cost savings over a high-level adoption of solar can have a significant impact on PVRR. In the alternative, solar's price decline factored into the base price forecast means there is significant risk if the price declines do not materialize as forecasted, and this risk is amplified by the solar volumes forecast in each portfolio. Similar impact, but to lesser levels, are shown for new nuclear, storage, wind (including both onshore and offshore wind), and CCs/CTs as these resources are deployed at lesser levels, and in some cases do not factor in significant price declines of the technologies. Nuclear presents the next largest potential range of impacts in all portfolios. Each portfolio similarly relies on large amounts of nuclear to supply significant carbon-free energy to the system, while providing firm capacity to serve load continuously around the clock.

The relative uncertainty ranges for technologies varies between portfolios. For example, Portfolio 3 shows wind as the lowest uncertainty range and lowest PVRR impact in the high capital cost sensitivity based on the limited amount of wind resources included in those portfolios. Wind, however, rises to the third largest range of uncertainty in Portfolio 2 due to its high deployment of offshore wind in this portfolio. CCs and CTs represent the lowest range of uncertainty and lowest PVRR impact in the high capital cost sensitivities in the other three portfolios. CCs and CTs are mature technologies and the Companies' technology base price forecast does not incorporate significant price declines. Furthermore, CC deployment is restricted in all portfolios. The limited deployment of these technologies across all portfolio lead to the lowest capital risk in these portfolios.

Shown in Table E-103 below is the impact to PVRR on each portfolio applying the high or low capital price forecasts for all technologies. This analysis shows the potential impact if larger trends are consistent across all technologies such as inflationary pressures or technology improvements.

Table E-103: Capital Cost Sensitivity Analysis, Final Carbon Plan Portfolios, All Technologies PVRR Impact through 2050 [2022, $B]

	High Capital	Low Capital
P1	$18.1	-$3.6
P2	$17.4	-$3.0
P3	$15.0	-$3.0
P4	$15.5	-$2.8

As seen in the individual technology impacts, the high price risk is much higher than the potential benefit opportunity of costs coming in lower than the Companies' projected price forecasts. Portfolio 1 represents the highest impacts in both the high and low capital price forecast sensitivities. This is again primarily due to the amount of solar in this portfolio, which is the most among the four Carbon Plan Portfolios. Portfolio 2 similarly is the next highest impact on the high capital side. These portfolios with the most amount of offshore wind present considerable technology price risk. The portfolio with the lowest capital cost impact is Portfolio 3. This portfolio, however, is less diversified than Portfolio 4 which adds offshore wind to diversify the technology risk of the lowest cost portfolio, Portfolio 3.

Hydrogen Supply Sensitivity Analysis

The Carbon plan assumes that all CCs and CTs added to the portfolio through 2050, and a limited number of existing CCs and CTs, operate on hydrogen in 2050 to achieve zero carbon emissions by the end of the planning horizon. The Companies' assumption that a green hydrogen market will develop by 2050 carries uncertainty, in both price and execution. To account for this uncertainty, the Companies performed analysis on Portfolios 1-4 to quantify how much hydrogen could be produced from curtailed carbon-free energy on the system in 2050.

To do this, the Companies calculated the curtailed energy from renewables and nuclear resources in 2050. The Companies then calculated if that curtailed or unutilized energy were used to produce green hydrogen through electrolysis, how much of the Companies' 2050 hydrogen consumption could theoretically be produced from excess carbon-free energy generated on the DEC and DEP systems.

The Companies calculated that all hydrogen needs, including blending starting in 2035 and new hydrogen needs through 2049, could be produced annually from excess and unutilized carbon-free energy on the DEC and DEP systems. Additionally, on average across the final Carbon Plan portfolios, nearly 50% of the 2050 hydrogen consumed by the remaining CCs and CTs on the system, operating exclusively on hydrogen in 2050, was able to be produced from excess and unutilized carbon-free energy on the DEC and DEP systems in the final year of the Carbon Plan.