



# 3 Portfolios

This Chapter provides details on portfolio composition (resource decisions) and comparative evaluations across pathways and portfolios for Duke Energy's Carbon Plan. As described in Chapter 2 (Methodology and Key Assumptions), the Companies have developed four portfolios under the two pathways that are designed to meet North Carolina Session Law 2021-165 ("HB 951")'s $CO_2$ emissions reduction targets, one achieving 70% $CO_2$ emissions reduction by 2030 and the other reaching 70% $CO_2$ emissions reduction by 2034 incorporating wind and new nuclear resources. Both pathways and all four portfolios keep the Companies on the longer-term path to achieving carbon neutrality by 2050.

The second half of this chapter evaluates the portfolios against the core Carbon Plan objectives ($CO_2$ reduction, affordability, reliability and executability) and addresses sensitivity analysis performed to assess impacts on resource selection, portfolio costs, and $CO_2$ emissions resulting from altering key input assumptions. Additional detail regarding portfolio evaluation and sensitivity analysis is also presented in Appendix E (Quantitative Analysis).

## Carbon Plan Pathways and Portfolios

As described in Chapter 2 (Methodology and Key Assumptions), the Companies identified two pathways to progress toward achieving carbon neutrality by 2050, both of which are supported by HB 951's provisions addressing the timing to achieve the interim 70% $CO_2$ emissions reduction target. Four portfolios (P1-P4) were developed and optimized based on differences in the expected availability (timing and quantity) of solar and battery storage, onshore wind, offshore wind, new nuclear resources, new pumped storage hydro and a limited number of hydrogen-capable efficient natural gas resources to further reduce system carbon emissions and support a significant deployment of intermittent renewable resources. Importantly, all portfolios deploy a diversified mix of carbon-free resources, energy storage technologies and a limited number of flexible, hydrogen-capable natural gas units to meet the 70% interim target on the path to achieving carbon neutrality by 2050. While specific variations in individual technology adoption rates and volumes between the portfolios are discussed below, the overall need for an "all-of-the-above" mix of resources is consistent across the portfolios. Each resource type has unique operational characteristics, cost projections, supply-chain dependencies, geographic limitations and requirements, along with associated transmission and distribution grid dependencies. These differences result in relative benefits and risks that are unique to each resource type as discussed throughout the Carbon Plan and detailed in the various appendices of the Plan. Consideration of these individual benefits and risks for each resource type demonstrates that a prudent and orderly transition of the Carolinas' energy system will require a balanced approach across a number of different demand-side programs and supply-side resources as outlined in the subsequent portfolio discussion. The Companies' two pathways and four portfolios utilize least-cost planning to accomplish this all-of-the-above energy transition strategy as presented in Figure 3-1 (each portfolio as of the beginning of the year in which the 70% interim target is reached) and Figure 3-2 (all portfolios as of the beginning of 2035).

## Figure 3-1: Portfolio Snapshot to Achieve 70% Interim Target (2030-2034)

<table>
<tr><th colspan="3">PORTFOLIOS</th><th>Grid Edge</th><th>Coal Retirements</th><th>New Solar</th><th>Battery</th><th>Onshore Wind</th><th>Offshore Wind</th><th>New Nuclear</th><th>New Pumped Storage</th><th>New CC</th><th>New CT</th></tr>
<tr><td>2030</td><td>P1</td><td>70% by 2030</td><td rowspan="4">EE 1% of eligible retail sales<br>IVVC growing to 96% (DEC) and 97% (DEP) circuits<br>Winter DR & CPP</td><td rowspan="2">(-4.9 GW)</td><td>5.4 GW</td><td>2.1 GW</td><td>0.6 GW</td><td>0.8 GW</td><td></td><td></td><td rowspan="4">2.4 GW</td><td rowspan="3">1.1 GW</td></tr>
<tr><td>2032</td><td>P2</td><td>70% 2032 OSW</td><td>5.6 GW</td><td>1.7 GW</td><td rowspan="3">1.2 GW</td><td>1.6 GW</td><td></td><td></td></tr>
<tr><td>2034</td><td>P3</td><td>70% 2034 SMR</td><td rowspan="2">(-6.2 GW)</td><td>7.7 GW</td><td>2.2 GW</td><td></td><td rowspan="2">0.3 GW</td><td rowspan="2">1.7 GW</td></tr>
<tr><td>2034</td><td>P4</td><td>70% 2034 OSW + SMR</td><td>6.8 GW</td><td>1.8 GW</td><td>0.8 GW</td><td>0.8 GW</td></tr>
</table>

Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of the target year of 70% reduction.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

## Figure 3-2: Portfolio Snapshot in 2035

<table>
<tr><th colspan="3">PORTFOLIOS</th><th>Grid Edge</th><th>Coal Retirements</th><th>New Solar</th><th>Battery</th><th>Onshore Wind</th><th>Offshore Wind</th><th>New Nuclear</th><th>New Pumped Storage</th><th>New CC</th><th>New CT</th></tr>
<tr><td rowspan="4">Resources by 2035</td><td>P1</td><td>70% by 2030</td><td rowspan="4">EE 1% of eligible retail sales<br>IVVC growing to 96% (DEC) and 97% (DEP) circuits<br>Winter DR & CPP</td><td rowspan="4">(-6.2 GW)</td><td>11.9 GW</td><td>4.2 GW</td><td rowspan="4">1.2 GW</td><td>0.8 GW</td><td rowspan="4">0.6 GW</td><td rowspan="4">1.7 GW</td><td rowspan="4">2.4 GW</td><td rowspan="3">1.1 GW</td></tr>
<tr><td>P2</td><td>70% 2032 OSW</td><td rowspan="2">8.6 GW</td><td>2.3 GW</td><td>1.6 GW</td></tr>
<tr><td>P3</td><td>70% 2034 SMR</td><td>2.4 GW</td><td></td></tr>
<tr><td>P4</td><td>70% 2034 OSW + SMR</td><td>7.6 GW</td><td>2.0 GW</td><td>0.8 GW</td><td>0.8 GW</td></tr>
</table>

Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of 2035.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

## Portfolio Results Summary

The Carbon Plan portfolios were developed using the three-pronged approach to planning described in Chapter 2 (Methodology and Key Assumptions). First, demand reduction contributions from grid edge resources and customer programs are assumed to be aggressively developed across all portfolios to “shrink the challenge” and do not vary across Carbon Plan portfolios. Supply-side resource additions were then optimized to serve load and to achieve targeted Carbon Plan objectives after the impacts of demand-side resources were accounted for.

All potential Carbon Plan portfolios are designed to achieve carbon neutrality by 2050, and all four resource mixes, in terms of both capacity and energy, largely converge by the time that goal is reached. That convergence begins by the mid-2030s, as illustrated in Figure 3-3 and Figure 3-4 below. Importantly, however, each portfolio requires a different pace of near-term development activities and capacity resource additions to achieve the 70% interim target (see Chapter 4 Execution Plan for discussion of required near-term activities). Figure 3-5 illustrates supply-side resource additions for each portfolio by 2030 and by 2035 (excluding projects already under development). The pace of near-term development activities and new resource additions is a key portfolio differentiator that affects performance under the core Carbon Plan objectives.

**Figure 3-3: Energy Mix by Portfolio, Combined Carolinas System (percentage basis)**

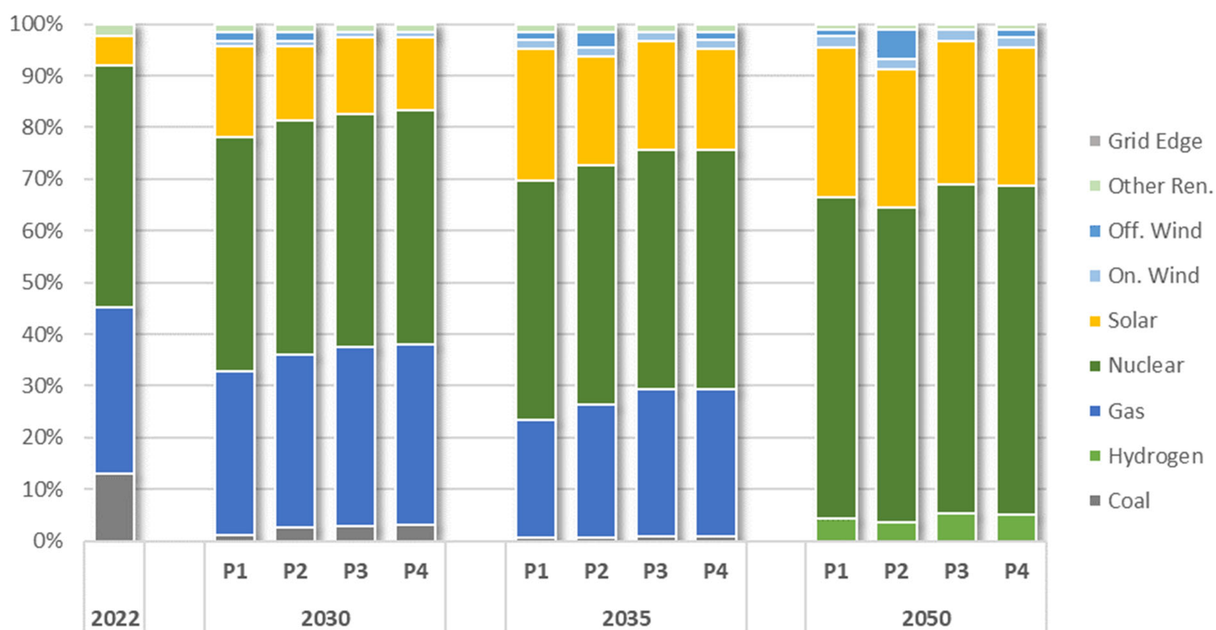
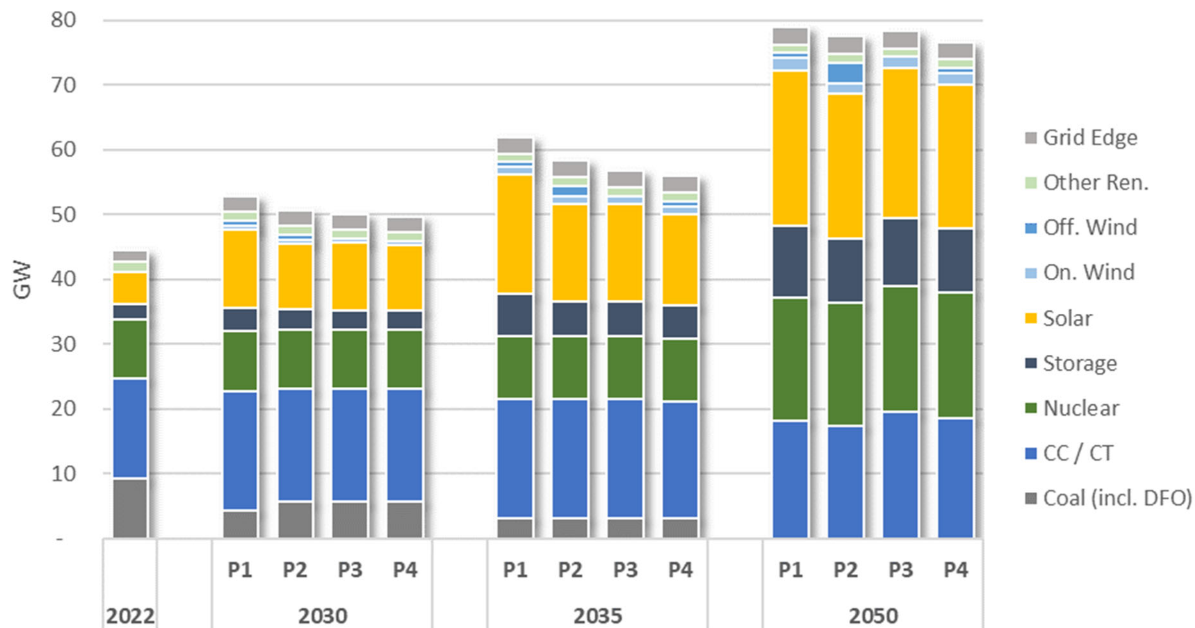


**Figure 3-4: Capacity Mix by Portfolio, Combined Carolinas System (GW basis)**



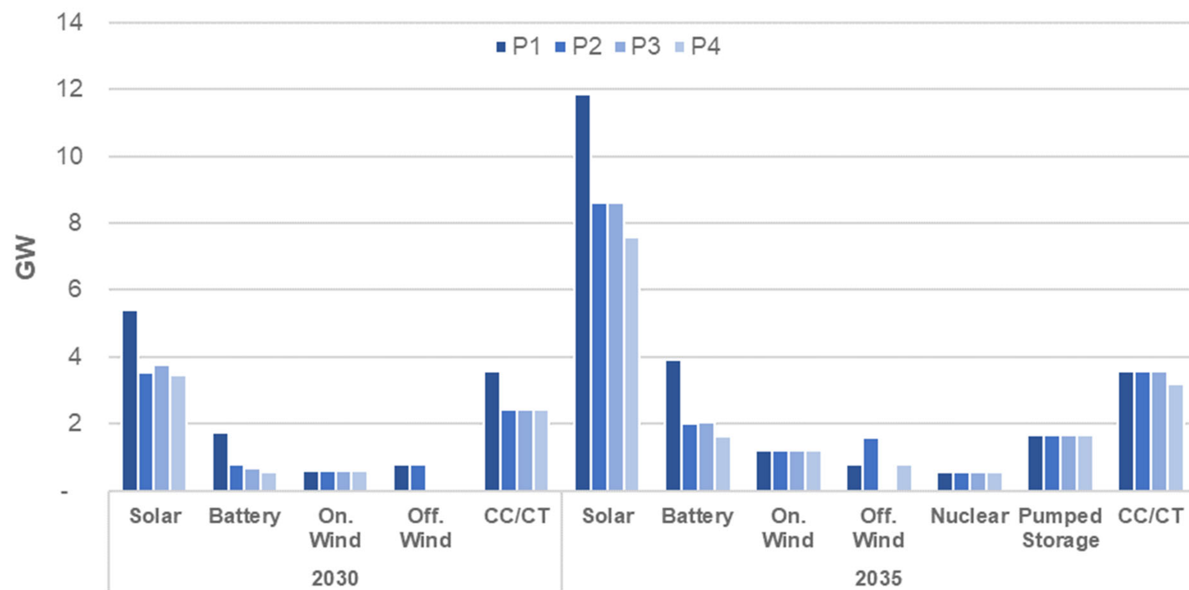

As indicated above, all portfolios result in very similar energy and capacity mixes over the long-term. By 2050, all portfolios call for an extensive expansion of solar and solar plus storage resources on the system (22,200 MW to 24,000 MW total), as well as the introduction of wind energy into the Carolinas' energy mix, along with significant amounts of both battery storage and pumped storage hydro to help manage energy variability associated with these intermittent renewable resources. The more aggressive timelines to achieve the 70% interim target under P1 and P2 require a more accelerated pace of execution and more significant capacity resource additions in the near term relative to P3 and P4.

In addition to significantly expanding renewable capacity, all portfolios also continue to rely heavily on nuclear energy as well as other baseload and dispatchable resources to provide capacity and to ensure power supply reliability for customers. Although new nuclear makes up a relatively small portion of the incremental capacity additions prior to 2035, over 60% of the Companies' energy mix by 2050 is obtained from nuclear resources in all portfolios. Combustion turbines ("CT") and combined-cycle ("CC") generators also remain key parts of the Companies' dispatchable, load-following fleets; however, their operations will shift over time. CTs and CCs will run fewer hours while simultaneously providing increasingly important system flexibility and reliability services required to meet customers' needs into the future and under all weather conditions. This change in mission is particularly important as remaining coal units are retired and the system becomes increasingly dependent on intermittent renewable resources and limited-duration storage technologies. Finally, the limited number of CTs and CCs added in the portfolios will have the ability to blend carbon-free hydrogen as a fuel source as that fuel becomes commercially available with a full transition to hydrogen by 2050.

Despite differing paces of resource additions in the late 2020s and early 2030s, the convergence that results in such similar 2050 resource mixes is observable across all portfolios by 2035. All portfolios achieve the interim 70% $CO_2$ emissions reductions target by 2034, and by the end of 2035, coal fuel is entirely phased out with the modeled retirement of Belews Creek and transition of Cliffside 6 to 100% natural gas. Vital long-duration energy storage capacity is online by that time as well following completion of the second powerhouse at the Bad Creek pumped storage facility.

In summary, the primary factor differentiating the Carbon Plan portfolios is the pace of energy transition and timing of new resource additions. The pace of new resource additions directly affects the pace of $CO_2$ emissions reduction, the cost of each portfolio, and the reliability challenges associated with operational integration of unprecedented levels of variable energy and energy-limited resources. The aggressiveness of the timeline for new resource additions is also closely linked to the likelihood that a portfolio can be executed and the 70% interim $CO_2$ emissions reductions target achieved by the planned dates. Figure 3-5 below depicts supply-side resource additions required under each portfolio by 2030 and then by 2035, illustrating the differences in the pace of resource additions over the near-to-intermediate term.

**Figure 3-5: Supply-Side Resource Capacity Additions by Technology and Portfolio by 2030, 2035, Combined Carolinas System (GW, beginning-of-year basis)**




Note: Solar excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage; battery includes batteries co-located with solar.

## Coal Unit Retirement Dates

Chapter 2 (Methodology and Key Assumptions) summarizes the coal unit retirement analysis methodology used in the Carbon Plan analysis, and Appendix E (Quantitative Analysis) provides additional detail. Table 3-1 shows a summary of the results of that analysis by portfolio. The portfolio-specific results summaries following this section also include coal retirement results for each portfolio individually. Of note, DEP's Roxboro Units 3 and 4 are the only units with variable planned retirement dates across the four portfolios. The remaining coal-capable units that continue to operate beyond these planned retirement dates will be dual-fuel units operating primarily on lower-carbon natural gas. In all portfolios, by the end of 2035, over 8,400 MW of coal capacity, representing approximately 20% of the winter capacity requirement for the combined system, would retire. Importantly, to ensure system reliability coal retirements are dependent on an equivalent amount of equally reliable replacement resources being placed into service. As a result, changes or delays to replacement generation in-service dates would affect the retirement dates shown in Table 3-1 below.

**Table 3-1: Coal Unit Retirements (effective by January 1 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] |

[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
[2]Allen 1 and 5 retirements are planned by 2024 and were not re-optimized in the Carbon Plan's Coal Retirement Analysis
[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

## Portfolio-Specific Results

This section includes summary descriptions of modeling results for each of the four Carbon Plan portfolios. Appendix E (Quantitative Analysis) provides additional detail on development of the portfolios and portfolio-specific results. A portfolio summary table is presented for each portfolio identifying (i) portfolio-specific costs (PVRR and bill impacts) and $CO_2$ emissions reductions, (ii) energy and capacity mixes in the year the 70% interim target is reached and in 2050 when carbon neutrality is attained, and (iii) supply-side capacity additions through the beginning of 2035. In most cases, capacity numbers are shown at January 1 of each year (beginning-of-year convention), but the utility-specific tables show resource capacities added or retired in each year, i.e., by the end of each year (end-of-year convention). Each figure and table includes a note indicating which convention, EOY or BOY, is used.

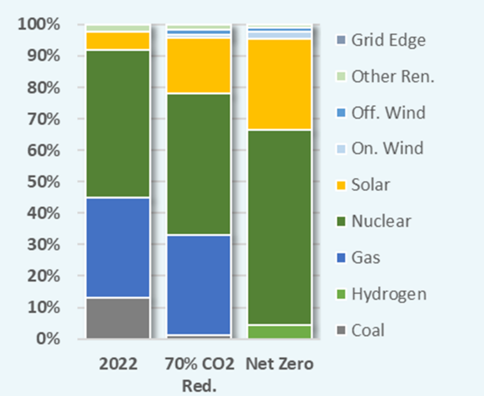
*Portfolio 1: "70% by 2030"*

Portfolio 1 targets achieving the 70% $CO_2$ emissions reductions by 2030. To meet this aggressive target, P1 requires 800 MW (one 800 MW block) of offshore wind to be placed in service by year-end 2029, new solar interconnections ramping up to 1,800 MW/year by year-end 2028 (approximately 2.5 times the maximum amount interconnected in any previous year) and the addition of nearly 1,800 MW of new battery energy storage capacity (including batteries paired with solar), up from only 13 MW in service today. Portfolio 1 also plans for a slightly accelerated retirement of Roxboro Units 3-4 (1,409 MW), with all other coal retirements consistent across the portfolios.

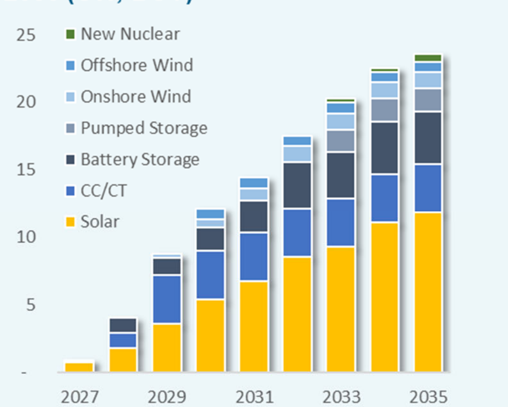
**Figure 3-6: Portfolio 1 Summary**

| | | |
|---|---|---|
| Combined System PVRR Through 2050 | $101.1B | |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [2030 \| 2035] | +$35 | +$45 |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [2030 \| 2035] | +$8 | +$33 |
| NC $CO_2$ Reduction from 2005 [2030 \| 2035] | 71% | 80% |
| Year in Which 70% Target is Reached | 2030 | |

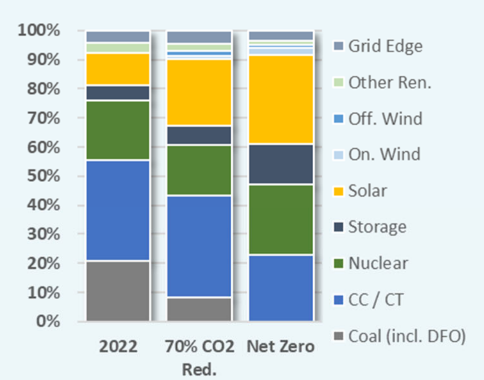
**Energy Mix**




**Supply-Side Resource Additions by 2035 (GW, BOY)**




**Capacity Mix**




**Coal Retirements by Year (MW, EOY)**

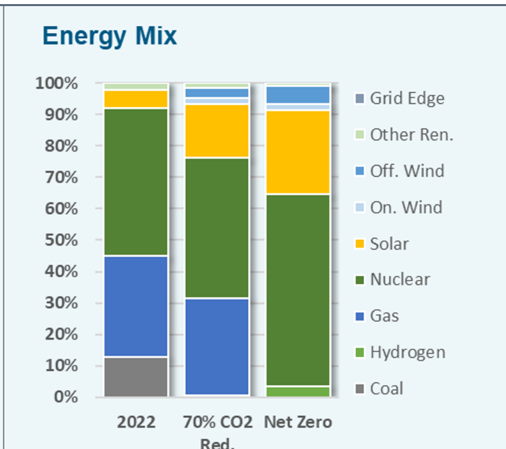
| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | 426 | -- | 546 | -- | 1,409 | 2,526 | -- | -- | -- | 1,318 | -- | -- | 2,220 |

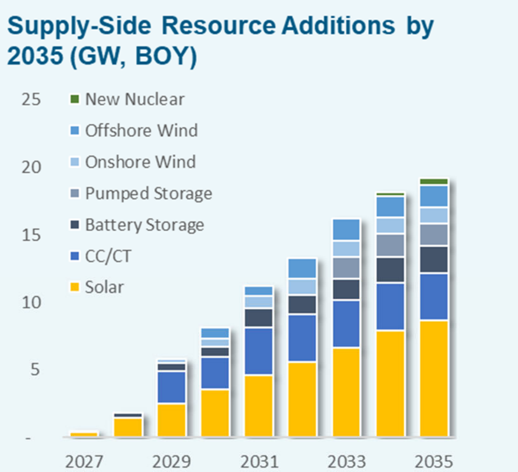
*Portfolio 2: "70% by 2032 OSW"*

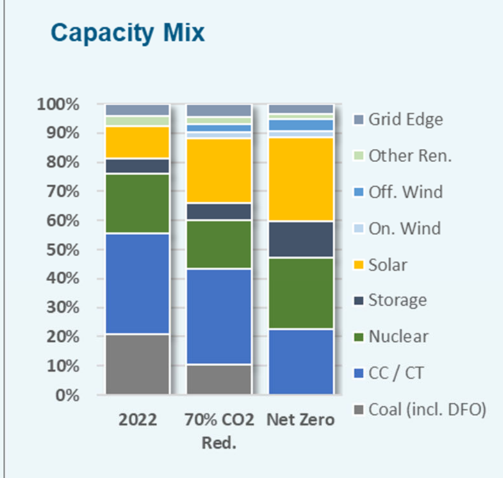
Portfolio 2 aggressively deploys two 800 MW blocks of offshore wind, the first in 2029 and the second in 2031, to achieve the 70% interim target by 2032. As described in greater detail in Appendix P (Transmission Planning and Grid Transformation), connecting the second block of offshore wind requires extensive additional transmission upgrades. Importantly, Portfolio 2 extends the timeframe for achieving the 70% interim target relative to P1, allowing time to construct needed additional transmission, enabling greater contributions from grid edge resources and customer programs, and a slightly less aggressive pace of new solar and energy storage additions. Portfolio 2 plans for the same coal unit retirement schedule as Portfolio 1, except that Roxboro Units 3-4 (1,409 MW) are proposed to be retired in 2031.

**Figure 3-7: Portfolio 2 Summary**

| | | |
|---|---|---|
| Combined System PVRR Through 2050 | $98.8 | |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [2030 \| 2035] | +$29 | +$45 |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [2030 \| 2035] | +$5 | +$30 |
| NC $CO_2$ Reduction from 2005 [2030 \| 2035] | 66% | 77% |
| Year in Which 70% Target is Reached | 2032 | |




**Coal Retirements by Year (MW, EOY)**

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | 426 | -- | 546 | -- | -- | 2,526 | -- | -- | 1,409 | 1,318 | -- | -- | 2,220 |

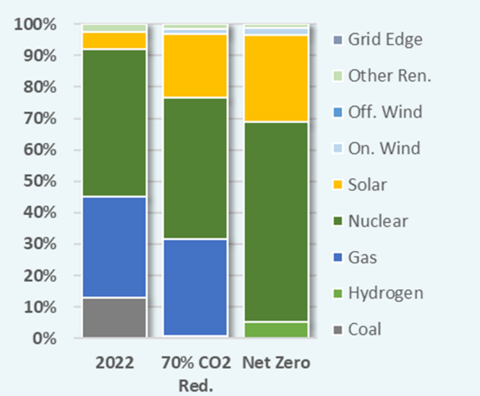
*Portfolio 3: "70% by 2034 SMR"*

Portfolio 3 targets the achievement of 70% $CO_2$ emissions reductions by 2034 with new nuclear. It is the only portfolio that does not include deployment of offshore wind. By extending the 70% interim target timeframe to 2034, this portfolio allows the first new nuclear unit (285 MW Small Modular Reactor ("SMR")), deployed in 2032, to contribute towards achieving the 70% interim target. Portfolio 3 extends the timeframe for achieving the 70% interim target relative to P1 and P2, allowing additional time for deployment of solar, wind, battery, pumped storage hydro, and grid edge resources to contribute to meeting the interim target. Portfolio 3 plans for the same coal unit retirement schedule as Portfolios 1 and 2, except for Roxboro Units 3-4 (1,409 MW) which are retired in 2033 in this Portfolio.

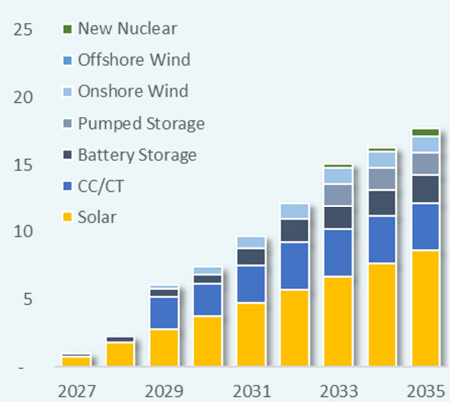
**Figure 3-8: Portfolio 3 Summary**

| | | |
|---|---|---|
| Combined System PVRR Through 2050 | $95.2 | |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [2030 \| 2035] | +$19 | +$31 |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [2030 \| 2035] | +$7 | +$29 |
| NC $CO_2$ Reduction from 2005 [2030 \| 2035] | 65% | 74% |
| Year in Which 70% Target is Reached | 2034 | |

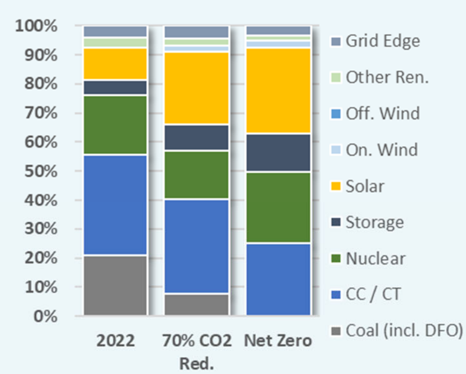
**Energy Mix**




**Supply-Side Resource Additions by 2035 (GW, BOY)**




**Capacity Mix**




**Coal Retirements by Year (MW, EOY)**

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | 426 | -- | 546 | -- | -- | 2,526 | -- | -- | -- | 1,318 | 1,409 | -- | 2,220 |

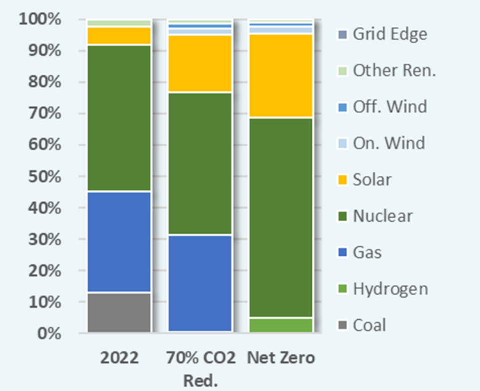
*Portfolio 4: "70% by 2034 OSW+SMR"*

Portfolio 4 deploys both offshore wind and new nuclear resources to achieve the 70% interim target by 2034. To meet this target, 285 MW (one unit) of nuclear SMR and 800 MW (one 800 MW block) of offshore wind are added in the early 2030s. The extended timeframe allows for greater contributions from grid edge resources, as well as additional time to build out required solar, onshore wind, battery, and pumped storage hydro capacity. Portfolio 4 plans for the same coal unit retirement schedule as Portfolios 1 and 2, except for Roxboro Units 3-4 (1,409 MW) which are retired in 2033 in this Portfolio.

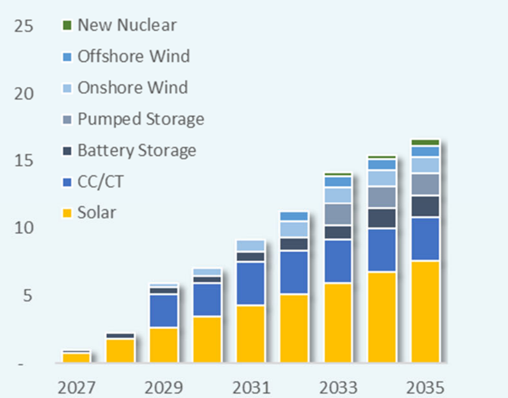
**Figure 3-9: Portfolio 4 Summary**

| | | |
|---|---|---|
| Combined System PVRR Through 2050 | $95.5 | |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [2030 \| 2035] | +$18 | +$34 |
| Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [2030 \| 2035] | +$5 | +$28 |
| NC $CO_2$ Reduction from 2005 [2030 \| 2035] | 64% | 74% |
| Year in Which 70% Target is Reached | 2034 | |

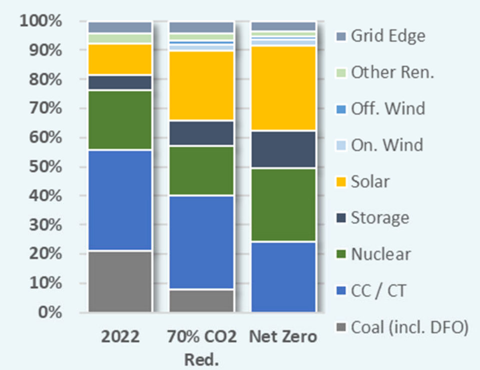
**Energy Mix**




**Supply-Side Resource Additions by 2035 (GW, BOY)**




**Capacity Mix**




**Coal Retirements by Year (MW, EOY)**

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | 426 | -- | 546 | -- | -- | 2,526 | -- | -- | -- | 1,318 | 1,409 | -- | 2,220 |

## Sensitivity Analysis

To supplement the primary Carbon Plan portfolio analysis, additional analysis was performed to assess how portfolio composition (model resource selection), as well as expected portfolio costs and $CO_2$ emissions, could be affected by changing circumstances that deviate from the base planning assumptions. Evaluation of potential changes to portfolio composition is referred to in this document as portfolio sensitivity analysis. Sensitivity analyses conducted to assess the cost impact of changing a particular input assumption are referred to as production cost sensitivity analysis or capital cost sensitivity analysis. This Chapter includes discussion of portfolio sensitivity analyses of natural gas supply and natural gas price, as well as capital cost sensitivity analysis. Appendix E (Quantitative Analysis) includes additional detail on these as well as the following additional sensitivity analyses:

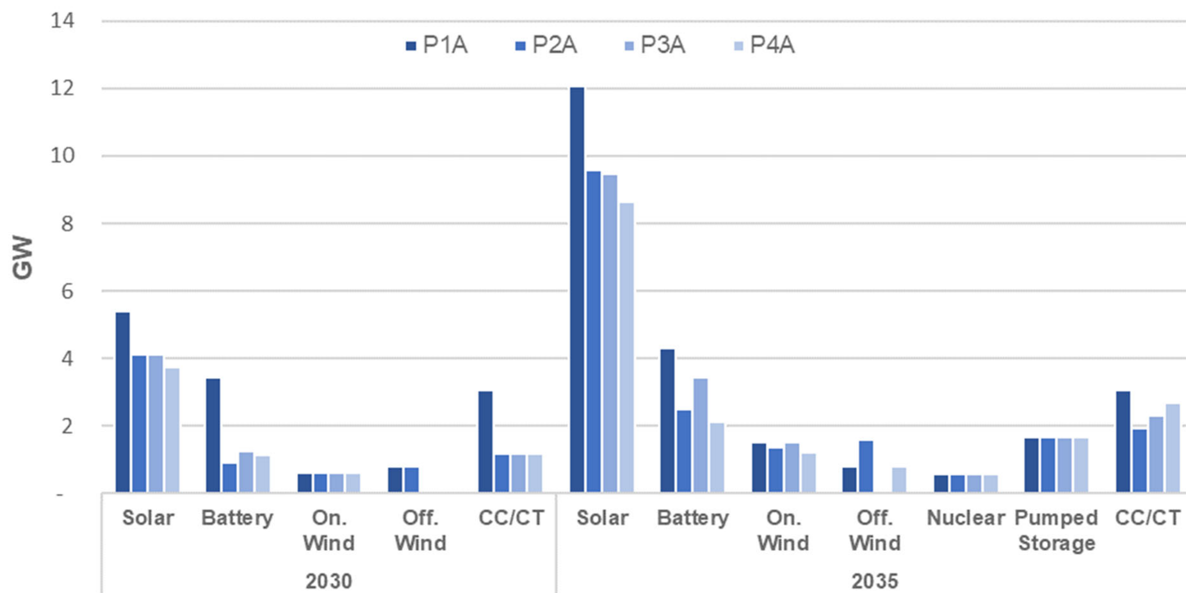
- Adjusted load forecast (portfolio sensitivity);
- Adjusted natural gas price (production cost sensitivity);
- Potential federal carbon tax policy (production cost sensitivity); and
- Hydrogen fuel supply sensitivity analysis.

### Portfolio Sensitivity Analysis: Alternate Natural Gas Supply

Carbon Plan portfolios were developed under the base planning assumption that a limited amount of additional interstate firm natural gas transportation capacity providing access to lower-cost gas from the Appalachia production region can be obtained (see Appendix N (Fuel Supply) for additional details). In recognition of the risk that this gas supply may not become available, four alternate portfolios were also developed by re-optimizing the original four portfolios under the assumption that firm transportation for Appalachian gas cannot be secured. The lack of limited direct access to lower-cost gas from the Appalachia region impacts the commodity price of natural gas, the operations of units in the fleet, and the availability of incremental CC generation. All other planning assumptions were held constant for the development of these alternate portfolios, $P1_A$-$P4_A$. Summary results of this analysis are presented below with additional details included in Appendix E (Quantitative Analysis).

Across all four alternate portfolios developed under the alternate gas supply assumption, the number and size of new CC units available for model selection was reduced from the two large units (2,400 MW total) available in the base analysis to a single smaller unit (800 MW) available in this sensitivity analysis. In all four of the alternate fuel portfolio sensitivity cases the model selected the single CC and added CTs, energy storage and, in some portfolios, additional solar resources to make up the energy and capacity lost from the second CC that was selected in P1-P4. Figure 3-10 shows supply-side resource additions by alternative portfolio through the beginning of 2030 and through the beginning of 2035 (excluding projects currently under development).

**Figure 3-10: Supply-Side Resource Additions by Technology and Alternative Gas Supply Portfolio by 2030, 2035, Combined Carolinas System (GW, beginning-of-year basis)**




Note: Solar excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage; battery includes batteries co-located with solar.

The resolution of the uncertainty regarding access to gas from the Appalachia region presents a future "pivot point," meaning the Companies will refine resource decisions over the near-term depending on the Companies' ability to obtain firm transportation from Appalachia. Future Carbon Plan updates will reflect developments in the Companies' ability to obtain this interstate firm capacity.

## Portfolio Sensitivity Analysis: Natural Gas Price

In addition to the alternate gas supply cases discussed above, natural gas price portfolio sensitivity analysis was performed on portfolios P4 and P4$_A$ to assess whether resource decisions are affected by the adoption of high or low gas price forecasts. Of the portfolios, P4 and P4$_A$ have the longest timeline to achieve the 70% interim target, to 2034, and represent the most diverse set of resources deployed to achieve that goal. The extended timeline provides the most flexibility for the model to avoid the selection of incremental CC capacity if that capacity is not economically justified. However, even under the high gas price case, new CC capacity was economically selected as part of the least-cost P4 and P4$_A$ portfolios that achieve both interim and long-term carbon reduction goals while maintaining or improving system reliability. Because no change in selected resources was observed in portfolios P4 and P4$_A$, this analysis was not repeated for the other portfolios. Appendix E (Quantitative Analysis) includes further discussion of this analysis, as well as discussion of the production cost sensitivity analysis for natural gas price.

## New Supply-Side Resource Capital Cost Sensitivity Analysis

Resource selection in the development of the Carbon Plan portfolios was driven largely by carbon reduction targets and annual limits on resource availability (development lead-times and annual interconnection limits). For this reason, high and low capital cost scenarios were run to evaluate potential changes to overall portfolio costs that could result from changes to the costs of supply-side resources. This cost sensitivity is of particular relevance in light of the potential for inflationary pressures on resource costs and further domestic and global supply-chain constraints currently impacting the installed costs for all technologies in the portfolios. Portfolios were not re-optimized for this analysis, nor were production costs re-calculated for this sensitivity in order to isolate the impact of potential changes to the installed cost of resources on total portfolio cost relative to baseline planning assumptions.

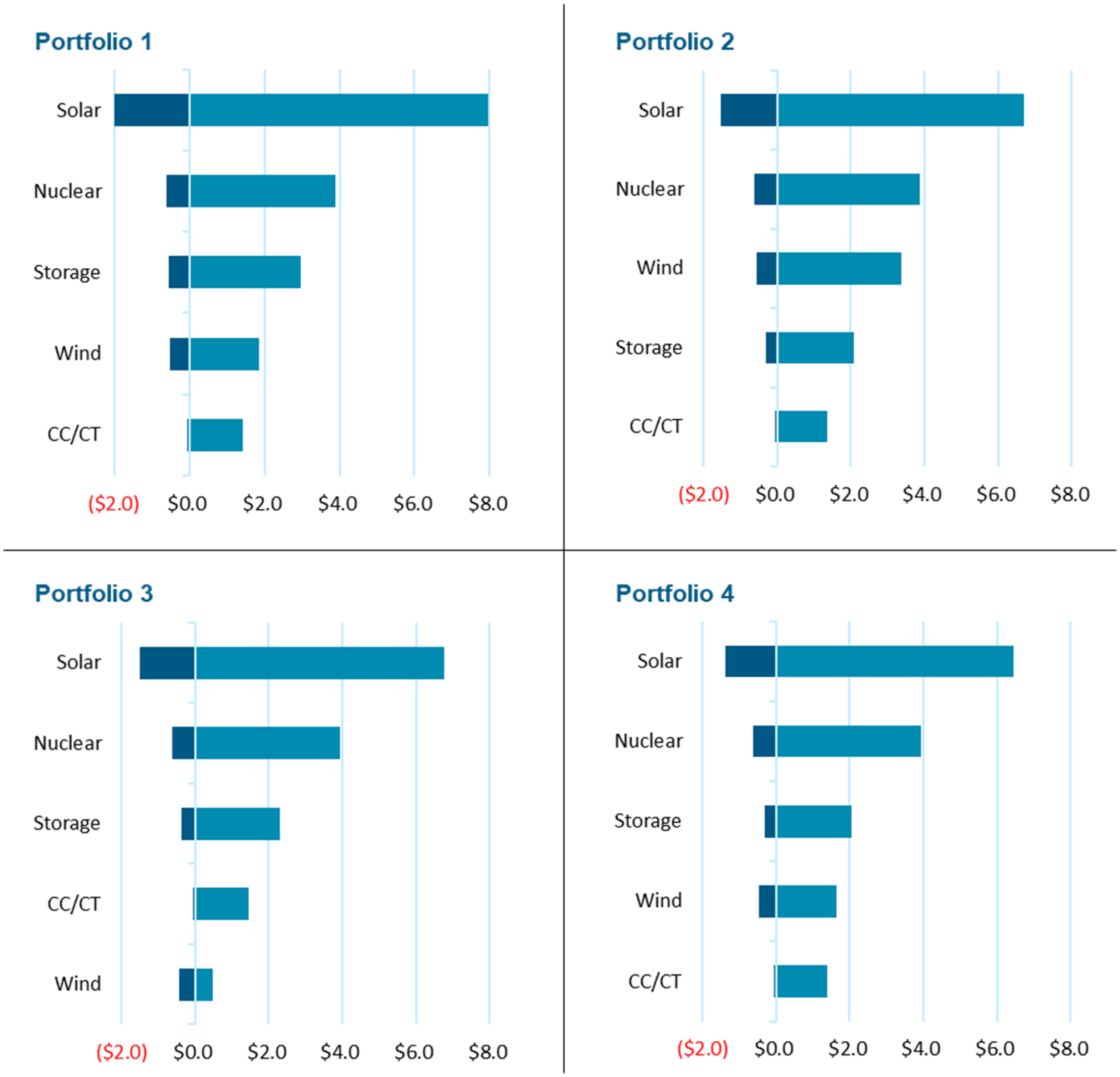
The Companies developed high capital cost forecasts for each technology using the greater of the Companies' internal estimates and EIA's 2022 projected technology costs[1] as starting points. The EIA costs are higher than the Companies' internal cost estimates for all technologies except solar and battery energy storage. These starting costs were then held constant in real terms over the planning period, except in the case of offshore wind and SMR, which were assumed to achieve modest cost declines through the mid-2030s as experience is gained with these technologies. Keeping the forecasts constant in real terms essentially flattens any technological learning curves. This approach has the largest impact on technologies with significant expected cost declines over the next decade.

Low capital cost forecasts for each technology were developed starting with the Companies' internal 2022 cost estimates as starting points. The Companies then applied NREL's Annual Technology Baseline ("ATB") most aggressive "Advanced Case" cost decline trajectories[2] for the renewable and storage technologies, and for the remaining technologies held costs constant in nominal terms, over the planning horizon. This approach resulted in more aggressive technology cost declines when compared to the Companies' base forecasts.

The high capital cost forecasts deviate from the Companies' base case forecasts more than the low capital cost forecasts, yielding asymmetrical results for this analysis. Figure 3-11 shows the impacts on total portfolio costs in PVRR terms of changing the technology-specific capital cost assumptions.

[1] U.S. Energy Information Admin., Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2022* (March 2022), ***available at*** https://www.eia.gov/outlooks/aeo/assumptions/ pdf/table_8.2.pdf.
[2] Nat'l Renewable Energy Laboratory, Annual Technology Baseline (2021), ***available at*** https://atb.nrel/electricity/ 2021/data.

**Figure 3-11: Changes from Base Case PVRR Under High and Low Capital Cost Assumptions for Each Technology by Portfolio ($B)**




As Figure 3-11 illustrates, the potential PVRR impacts of deviations from capital costs assumed in the base case modeling are greatest for technologies like solar, which have both significant expected price declines in the base case forecast and which comprise a substantial portion of total anticipated Carbon Plan investment. Appendix E (Quantitative Analysis) contains additional details on this capital cost sensitivity analysis.

## Portfolio Evaluation Against Core Carbon Plan Objectives

HB 951 directs the Commission with the Companies to develop a plan that takes all reasonable steps to achieve the 70% interim $CO_2$ emissions reductions target by 2030 while expressly affirming the Commission's discretion to determine the optimal timing and generation and resource mix to achieve the least cost path to authorized carbon reduction targets. The Commission is also tasked with "[e]nsur[ing] any generation and resource changes maintain or improve on the adequacy and reliability of the grid." To inform the Commission's assessment of these requirements, the Carbon Plan evaluates the four portfolios against the following core Carbon Plan objectives: (i) Cost and Affordability; (ii) Pace of $CO_2$ Emissions Reduction, (iii) Reliability and Flexibility; and (iv) Executability.

### Cost and Affordability

Cost for customers remains a critically important consideration, as HB 951 directs the Plan to chart the least-cost pathway for achieving the $CO_2$ emission reduction goals. For each of the portfolios analyzed, the Plan provides a high-level estimate of projected long-term present value of revenue requirements ("PVRR") across the Companies' combined Carolinas service territory, as well as separate estimates of average residential monthly bill impact for DEC and DEP.

The PVRR and bill impact cost metrics incorporate the installed cost for each resource along with fixed and variable life cycle operating costs for incremental resources on the system as well as the total system production costs for the portfolio. Each portfolio's PVRR and bill impact also include cost estimates for required transmission investments associated with the incremental resource additions and coal retirements in the Plan. Since the Plan does not actually site new resources, the incremental transmission cost estimates are high-level projections (or proxy values) and could vary greatly depending on factors such as the precise location of resource additions, specific resource supply and demand characteristics, the amount of new resources being connected at each location, interconnection dependencies, escalation in labor and material costs, changes in interest rates, and potential siting and permitting delays beyond the Companies' control.

### Pace of $CO_2$ Emissions Reductions

To mitigate long-term risks posed by continued reliance on emissions-intensive resources, the four portfolios all continue the energy transition and result in substantial $CO_2$ emissions reductions consistent with the targets set forth in HB 951. However, the pace of the $CO_2$ emissions reductions in each portfolio varies (though all are compliant with HB 951) and this evaluation criteria compares the relative pace of each portfolio. The Plan assumes weather normal load, with regular resource outage patterns for purposes of $CO_2$ emissions reductions estimating. It is important to note that actual $CO_2$ emissions reductions may be impacted by weather, economic factors, demand trends such as transportation electrification rates, and other operational conditions such as resource outages and fuel pricing and availability.

## Reliability and Flexibility

All portfolios must maintain or improve system reliability consistent with sound resource planning principles and as required by HB 951.[3] As with past IRPs and pursuant to North American Electric Reliability Corporation (”NERC“) reliability standards and requirements, the Companies must continue to maintain adequate day-to-day operating reserves and long-term planning reserves required to meet customer needs during peak demand periods, such as cold winter mornings and hot summer afternoons. As the transition to a new mix of technologies that have varying contributions to the reliability of the system at different hours continues, the Companies will continuously re-evaluate what is needed to maintain or improve reliability in future iterations of the Plan, as well as in the execution phase.

Throughout the nation, the challenges of operating an electric system comprised of increasing variable generation and energy-limited storage are real and demonstrable, as a changing resource mix leads to changed operational conditions that can impact the ability to respond during peak demand periods.[4] Recognizing these challenges, NERC, the agency responsible for bulk electric system reliability in the United States, stated that the “rapid evolution of the generation resource mix is altering the operational characteristics of the grid,”[5] and is evaluating the development of reliability standards to mitigate this risk.[6] The Companies must continue to deliver consistently reliable power to customers[7] and remain fully committed to maintaining current high levels of reliability and operational performance by ensuring the availability of flexible resources to respond to changing real-time operating conditions. While each portfolio is modeled to maintain quantitative reliability measures such as planning and operating reserve targets, each of the portfolios is also assessed against the extent to which the projected resource changes impact certain key indicative metrics regarding the reliability and flexibility of the

[3] HB 951, Section 1(3).

[4] California ISO, Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave (January 12, 2021), *available at* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf#search=Mid%2DAugust%202020%20Extreme%20Heat%20Wave.

[5] Testimony of James B. Robb, President and CEO of NERC. Before the Committee on Energy and Natural Resources, United States Senate, Washington, D.C., March 11, 2021, *available at* https://www.nerc.com/news/testimony/Pages/Robb-Testimony-fromSenateEnergy.aspx#:~:text=WASHINGTON%2C%20D.C.%20%E2%80%93%20Jim%20Robb%2C,mix%20and%20extreme%20weather%20events.

[6] NERC’s 2021 ERO Reliability Risk Priorities Report cited grid transformation as a risk to the operation of the Bulk Electric System (BES). On April 1, 2022, two NERC subcommittees submitted a Standard Authorization Request (SAR) to evaluate the need for new and revised reliability standards to address potential capacity or energy insufficiency to reliability operate the system caused by unassured deliverability of fuel supplies, inconsistent output, and volatility of forecasted load related to variable renewable energy resources. N. Am. Elec. Reliability Corp., 2021 ERO Reliability Risk Priorities Report (Aug. 12, 2021), *available at*

https://www.nerc.com/comm/RISC/Documents/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf

[7] The NERC 2021 Summer Reliability Assessment and NERC 2021-2022 Winter Reliability Assessment identified almost no risk for resource shortfall for the Carolinas-focused SERC-East subregion. N. Am. Elec. Reliability Corp., Reliability Assessments, https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited May 15, 2022).

systems. Appendix Q (Reliability and Operational Resilience Considerations) provides a detailed discussion of reliability and operational resilience.

### Executability

Maintaining reliability while executing an orderly transition away from more carbon-emissions intensive resources requires that all portfolios are not only carefully planned but also prudently executed. Ensuring portfolios are executable requires a thorough evaluation of interdependent retirements and resource needs, timing, and related risk analysis around near-term activities such as regulatory review, siting, environmental permitting, interconnection, system upgrades, supply chain and fuel supplies. The metrics used here to compare executability challenges across portfolios focus on the pace of required resource additions and degree of reliance on specific resource types without developmental and operational track records in the Carolinas.

## Portfolio Comparison and Evaluation

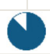
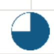
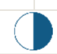
The following sections provide a comparative summary of results across portfolios followed by an evaluation of portfolio performance and tradeoffs with respect to the established core Carbon Plan objectives.

Table 3-2 provides definitions of the metrics used in portfolio comparison and evaluation, and Table 3-3 illustrates cost, $CO_2$ emissions reductions, reliability, and executability across the four portfolios, providing a high-level summary of relative portfolio trade-offs. The Companies then provide a more detailed comparative evaluation of the portfolios after the summary tables below.

Table 3-2: Metrics Used to Evaluate Portfolio Performance Against Core Carbon Plan Objectives

| METRIC | DEFINITION | ROLE IN EVALUATION |
|---|---|---|
| | **COST & AFFORDABILITY** | |
| **Average Monthly Residential Bill Impact for a Household Using 1000 kWh** | Expected change in monthly bill by year specified, relative to present | Provides snapshot of cost impact at specified future point in time |
| **Present Value Revenue Requirement (PVRR) Through 2050** | Total forecasted incremental revenue requirement over planning period, discounted back to present | Provides estimate of total cost over planning period in present value terms |
| | **$CO_2$ EMISSIONS IMPACT** | |
| **NC $CO_2$ Reduction** | Percent by which NC $CO_2$ emissions are reduced by year specified, relative to 2005 baseline | Allows comparison of NC emissions reductions across portfolios at specific points in time |
| **System $CO_2$ Reduction** | Percent by which total Carolinas system $CO_2$ emissions are reduced by year specified, relative to 2005 baseline | Allows comparison of total Carolinas system emissions reductions across portfolios at specific points in time |
| **Year in which 70% NC Target Achieved** | Year by which NC $CO_2$ emissions are reduced by 70% relative to 2005 baseline | Interim 70% target specified in legislation |
| | **RELIABILITY & FLEXIBILITY** | |
| **95th Percentile Expected Net Load Ramp [MW/hour]** | 95th percentile of forecasted daily maximum increase in net load (total load less wind and solar generation) averaged across 41 sample weather years used in loss-of-load expectation (LOLE) analysis | Indicates flexibility expected to be required of dispatchable energy resources in specified future years |
| **Average CC Starts per Unit per Year** | Number of times each CC unit is expected to be shut down and restarted, averaged across all CC units, as predicted in production cost model results | Provides indication of expected reliance on CC cycling to accommodate increased deployment of non-dispatchable resources. Starts may be clustered in certain months |
| | **EXECUTABILITY** | |
| **Annual Solar Additions Reached to Achieve 70%** | Maximum single-year solar capacity additions required to achieve 70% NC $CO_2$ emissions reductions relative to 2005 baseline | With comparison to historical maximum, provides indication of scale of required new solar additions relative to past achievements |
| **Cumulative Additions of New-to-the-Carolinas Resource types** | Cumulative additions of wind, solar, and advanced nuclear capacity added by date specified | Provides indication of required pace of transition to resource types with limited operational track record in the Carolinas |

### Table 3-3: Summary of Portfolio Results

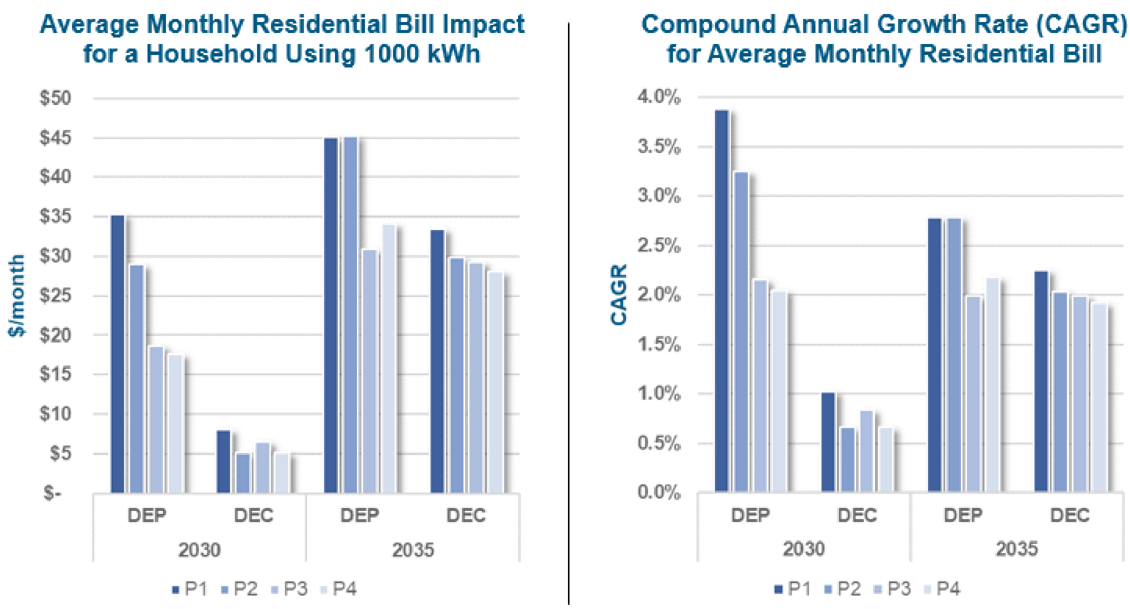
| CARBON PLAN PORTFOLIOS | P1 | | P2 | | P3 | | P4 | |
|---|---|---|---|---|---|---|---|---|
| **RESOURCES [MW] START OF YEAR (2030 \| 2035)** | | | | | | | | |
| **Total Contribution from Grid Edge and Customer Programs[1]** | 3,486 | 4,230 | 3,486 | 4,230 | 3,486 | 4,230 | 3,486 | 4,230 |
| **Total System Solar[2, 3]** | 12,307 | 18,829 | 10,432 | 15,604 | 10,657 | 15,604 | 10,357 | 14,554 |
| **Incremental System Solar (excludes projects in development)[2]** | 5,400 | 11,850 | 3,525 | 8,625 | 3,750 | 8,625 | 3,450 | 7,575 |
| **Incremental Onshore Wind[2]** | 600 | 1,200 | 600 | 1,200 | 600 | 1,200 | 600 | 1,200 |
| **Incremental Offshore Wind[2]** | 800 | 800 | 800 | 1,600 | 0 | 0 | 0 | 800 |
| **Incremental SMR Capacity[2]** | 0 | 570 | 0 | 570 | 0 | 570 | 0 | 570 |
| **Incremental Energy Storage[2, 4]** | 2,067 | 5,671 | 1,092 | 3,815 | 1,030 | 3,852 | 917 | 3,477 |
| **Incremental Gas (CC)[2, 5]** | 2,430 | 2,430 | 2,430 | 2,430 | 2,430 | 2,430 | 2,430 | 2,430 |
| **Incremental Gas (CT)[2, 5]** | 1,128 | 1,128 | 0 | 1,128 | 0 | 1,128 | 0 | 752 |
| **Remaining Dual Fuel Coal Capacity[2, 6]** | 4,387 | 3,069 | 4,387 | 3,069 | 4,387 | 3,069 | 4,387 | 3,069 |
| **Early Coal Retirements** | *Subcritical by 2030; MSS 3&4 in 2032* | | *Subcritical by 2030 except Rox 3&4 in 2031; MSS 3&4 in 2032* | | *Subcritical by 2030 except Rox 3&4 in 2033; MSS 3&4 in 2032* | | *Subcritical by 2030 except Rox 3&4 in 2033; MSS 3&4 in 2032* | |
| **Total Coal Retirements [MW] by End of 2035** | 8,445 | | 8,445 | | 8,445 | | 8,445 | |
| **COST AND AFFORDABILITY (2030 \| 2035)** | | | | | | | | |
| **Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [$/month]** | $35 | $45 | $29 | $45 | $19 | $31 | $18 | $34 |
| **Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [$/month]** | $8 | $33 | $5 | $30 | $7 | $29 | $5 | $28 |
| **Present Value Revenue Requirement (PVRR) through 2050 (DEP/DEC Combined System) [$B]** | $101 | | $99 | | $95 | | $96 | |
| **PVRR through 2050 (DEP) [$B]** | $42 | | $42 | | $38 | | $39 | |
| **PVRR through 2050 (DEC) [$B]** | $59 | | $57 | | $57 | | $56 | |
| **$CO_2$ EMISSIONS IMPACT (2030 \| 2035)** | | | | | | | | |
| **NC $CO_2$ Reduction[8]** | 71% | 80% | 66% | 77% | 65% | 74% | 64% | 74% |
| **System $CO_2$ Reduction[9]** | 70% | 78% | 65% | 76% | 63% | 72% | 63% | 72% |
| **Year in which 70% NC $CO_2$ Reduction Achieved** | 2030 | | 2032 | | 2034 | | 2034 | |
| **RELIABILITY AND FLEXIBILITY (2030 \| 2035)** | | | | | | | | |
| **95th Percentile Expected Net Load Ramp [MW/hr][9]** | 6,604 | 10,803 | 5,341 | 8,621 | 5,506 | 8,656 | 5,296 | 7,922 |
| **Average CC Starts per Unit per Year** | 53 | 99 | 35 | 77 | 34 | 75 | 29 | 67 |
| **EXECUTABILITY** | | | | | | | | |
| **Annual Solar Additions Reached to Achieve 70% (MW/year \| vs. Historical Maximum)[2, 10]** | 1,800 | 2.4X | 1,350 | 1.8X | 1,350 | 1.8X | 1,350 | 1.8X |
| **Cumulative Additions of New-to-the-Carolinas Resource Types [MW] (2030 \| 2035)[2, 11]** | 3,140 | 6,480 | 2,170 | 5,380 | 1,270 | 3,820 | 1,150 | 4,210 |
| **Overall Level of Risk to Achieving 70% $CO_2$ Reduction by Target Year** |  | |  | |  | |  | |

1. Contribution of UEE/DR (including Integrated Volt-Var Control (IVVC), Critical Peak Pricing (CPP) and Peak Time Rebate (PTR)) in 2030/2035 to peak winter planning hour.
2. Nameplate capacity.
3. Total solar nameplate capacity includes 1,453 MW in DEC and 3,561 MW in DEP projected in service by January 1, 2023.
4. Includes 4-hour and 6-hour grid-tied battery energy storage, battery energy storage at solar-plus-storage sites, and pumped storage hydro.
5. New natural gas facilities will be capable of burning carbon-free hydrogen in the future; hydrogen blending assumed to begin in 2035.
6. Remaining coal units are capable of co-firing on natural gas.
7. Combined North Carolina-specific DEC/DEP System $CO_2$ reductions from 2005 baseline.
8. Combined DEC/DEP System $CO_2$ reductions from 2005 baseline.
9. Average of 95th percentile day across 40 weather years. Net load ramp = hourly change in load net of renewable generation as indicator of fleet flexibility challenges.
10. Annual solar additions represent annual amount [MW] required beginning in 2028 to reach 70%; maximum annual total DEP/DEC solar additions to date have been 750 MW.
11. New-to-the-Carolinas includes onshore wind, offshore wind, battery energy storage, and SMR.

## Portfolio Evaluation: Cost and Affordability

Figure 3-12 below shows the total cost of each portfolio through 2050 expressed as PVRR, as well as snapshots of forecasted customer bill impacts in 2030 and 2035. The costs shown are associated with incremental resource additions and retirements contemplated in each portfolio. Cost characteristics and forecasts vary by resource type, so both the timing and amount of incremental resource additions influence total portfolio cost. Discounting in the PVRR calculation further amplifies the impact of the timing of new investments on the overall cost evaluation.

**Figure 3-12: Intermediate-Term Residential Bill Impact by Portfolio**

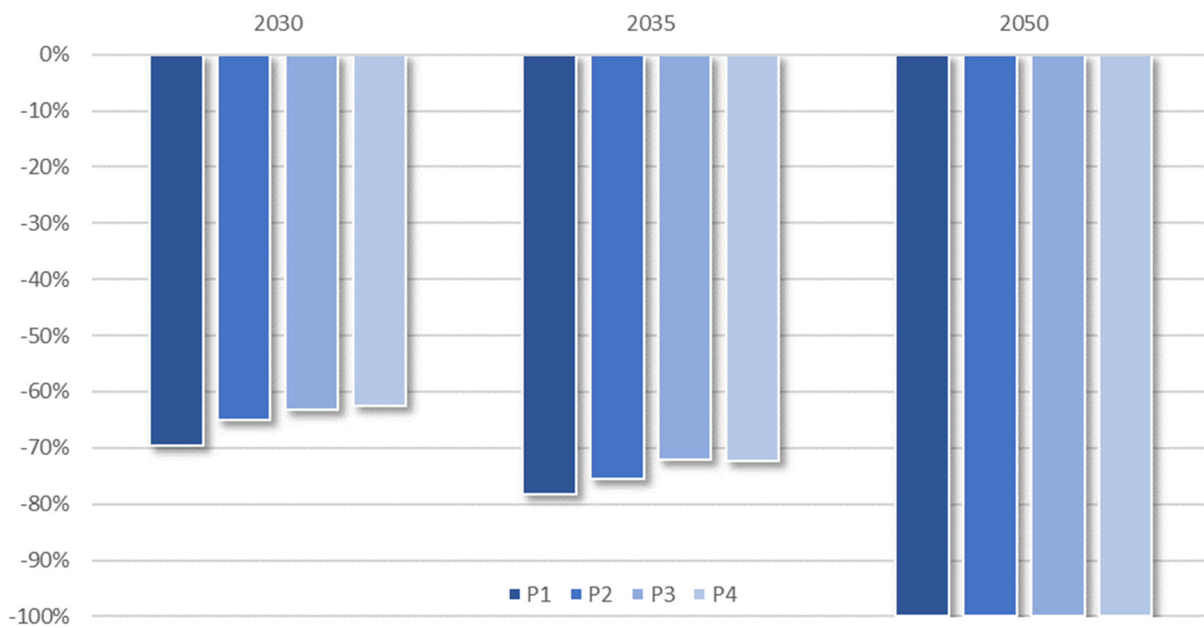



The benefit of accelerated emissions reductions achieved in Portfolio 1 requires very aggressive pre-2030 deployment (and increased levels of investment) for battery energy storage, incremental annual solar, as well as the pre-2030 siting, development and interconnection of offshore wind resources. Figure 3-12 illustrates the fact that the aggressive near-term investment in new resources required for P1 would result in a 14%-60% (DEC) or 20%-95% (DEP) greater increase in customer bills by 2030 as compared to P2-P4 during this same period. Portfolios 2 through 4 require somewhat lower total resource additions in MW terms, and those additions occur at a more moderate pace, which allows for greater realization of the benefits of expected cost declines for renewable energy and battery energy storage technologies. This dynamic is also at play in forecasted 2035 customer bill impacts and total portfolio PVRR. The addition of a second 800 MW block of offshore wind in 2032 and the associated transmission investment contemplated in Portfolio 2 increases the cost of that portfolio relative to the others, particularly in terms of DEP customer bills in the mid-2030s.

## Portfolio Evaluation: Pace of $CO_2$ Emissions Reductions

As discussed previously, the Companies' Carbon Plan presents four portfolio options developed within two overall pathways: One portfolio following the first pathway achieves 70% $CO_2$ emissions reductions by 2030, and the remaining three portfolios, following the second pathway, achieve the 70% reduction target by between 2032 and 2034 relying on OSW and/or SMR generation technologies. Figure 3-13 shows the expected $CO_2$ emissions reductions for each portfolio across the combined Carolinas system in 2030, 2035, and 2050.

**Figure 3-13: $CO_2$ Emission Reduction by Portfolio, Combined Carolinas' System**



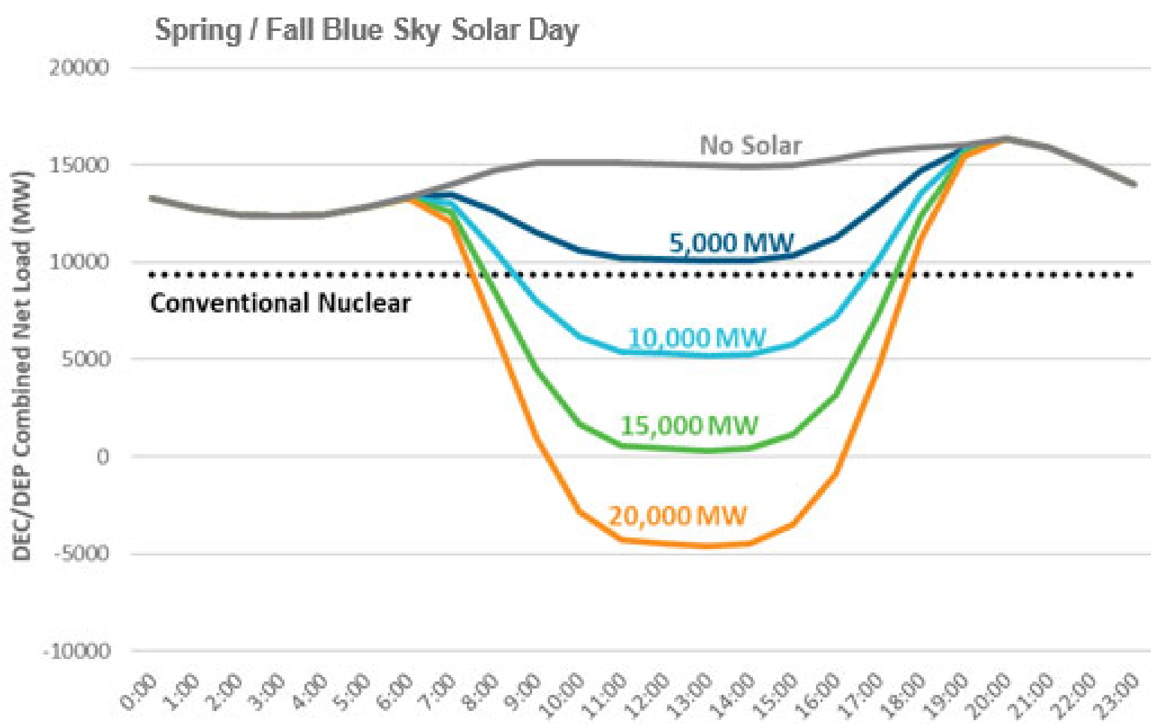

As shown in Figure 3-13, Portfolio 1, which targets 70% $CO_2$ reduction by 2030 and includes more aggressive near-term adoption of new, carbon-free generation, achieves somewhat greater emissions reductions than Portfolios 2 through 4 in 2035. Notably, all four portfolios exceed the 70% interim target by 2035 and ultimately reach carbon neutrality by 2050.

## Portfolio Evaluation: Reliability and Flexibility

Ensuring reliability during the transition to net-zero will be an ongoing process of operational integration, learning and adjustment. A detailed discussion of the challenges and risks presented by this transition, as well as the measures that will be taken to address these challenges, is presented in Appendix Q (Reliability and Operational Resilience). The portfolio comparison presented in Figure 3-14 is based on a select set of flexibility metrics that illustrates the differences across portfolios with respect to the reliability and flexibility challenges presented by the energy transition.

As intermittent renewable energy becomes an increasingly large share of generation capacity, the remaining electricity demand that must be met by dispatchable sources – that is, the electric load net of renewable energy contributions, commonly referred to as “net load” – will change in timing, shape and magnitude in ways that will place new stresses on the power system. Given the day-night (diurnal) pattern of output, high levels of solar can become increasingly difficult to manage, with two key challenges that must be met in future portfolios: accommodating very low (or even negative) net loads at midday and managing the associated increasingly rapid decreases and increases in net load as the sun rises and sets. Figure 3-14 illustrates potential net load profiles on a sunny, mild spring day with several levels of installed solar capacity.

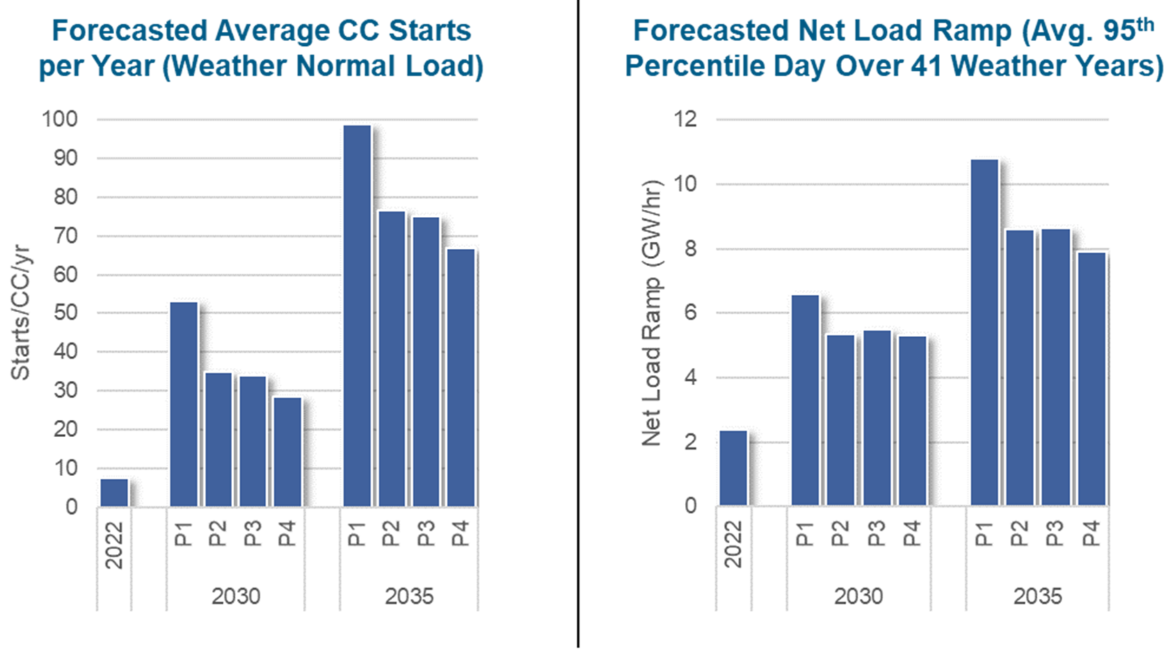
**Figure 3-14: Spring Low Net Load Examples with Different Levels of Installed Solar Capacity**




The flexibility demands of a system with significantly increased amounts of intermittent resources will require a new operational approach for the Companies’ CC units in particular. Historically, the Companies’ CC fleets have been designed and operated specifically for baseload operations and have faced a limited need to cycle given the flexibility of the remaining generators. But for certain periods of the year, some of the Carbon Plan portfolios require cycling the majority of the CC fleet on a daily basis. This operational approach will be new to the Companies’ fleet and is likely to require changes to operations and maintenance practices and investments and upgrades to increase unit flexibility. The process of re-starting the majority (and in some seasons, entirety) of the Companies’ CC fleets within a few hours has not been tested, and coordination among all units and stages will be a challenge to precisely match the rapid increases in net load into the evening hours.

Each of the potential Carbon Plan portfolios calls for substantial additions of new renewable energy capacity to meet interim and long-term $CO_2$ emissions reductions targets while maintaining or improving reliability, but potential flexibility challenges do vary across the four. Figure 3-15 illustrates expected CC starts and net load ramps for each of the portfolios in 2030 and 2035.

**Figure 3-15: Forecasted CC Starts and Net Load Ramp by Portfolio, Combined Carolinas System**

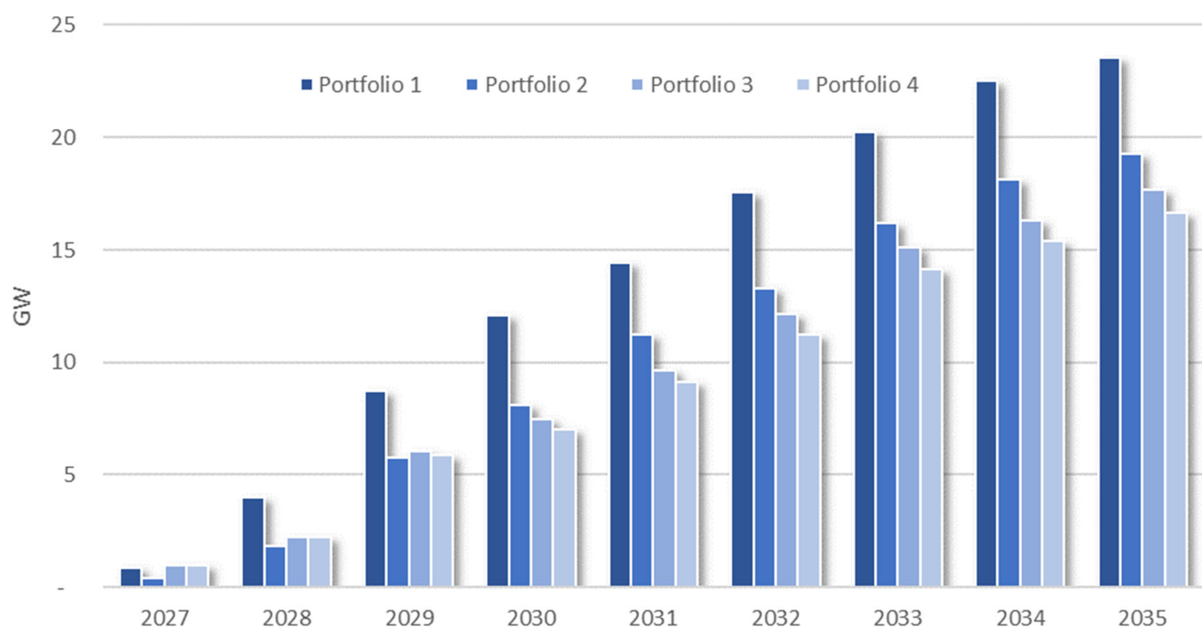



The greater net load ramp and CC starts associated with the more rapid adoption of new renewable energy resources required for Portfolio 1 will create additional flexibility challenges and operational risk. This correlation in the pace of renewable adoption and the increase in both system hourly ramping requirements and projected CC starts, points directly to the need to replace aging coal units with energy storage and flexible CT and CC capacity, as the existing coal fleet lacks the flexibility to respond to the system ramp rates or stop and start requirements shown above. As such, achieving an orderly and reliable transition of the energy system must balance and coordinate the pace of intermittent renewable resource additions, coal retirements and adoption of dispatchable storage and hydrogen-capable gas resources on the system. If these varying resource changes to the system over time are not made at the appropriate interrelated and coordinated pace, the ensuing outcome would likely be system reliability events and inordinate levels of solar curtailments.

## Portfolio Evaluation: Executability

The evaluation of portfolio executability is inherently challenging in comprehensive long-term resource planning but is increasingly important under a Carbon Plan framework to ensure the Companies can develop and deploy the resources required to achieve the interim 70% $CO_2$ emissions reduction target within the time frame set forth in each portfolio. Some of these resource needs, including new grid edge resources and customer programs, onshore wind, and new CC generation, are common across all portfolios. Certain others, particularly new solar capacity, battery energy storage and offshore wind, vary considerably in the pace at which they must be deployed to achieve projected $CO_2$ emissions reductions. Deployment of new resources is contingent upon a variety of factors including supply chain, siting and permitting, labor supply, regulatory approvals, transmission planning and interconnection, and fuel supply, as discussed in Chapter 4 (Execution Plan) and the supply-side resource-specific appendices. Deploying new resources in significant volumes at an unprecedented pace exacerbates exposure to each of these potential risks, thereby affecting the likelihood of successful portfolio execution in the timeframe envisioned for each portfolio. Figure 3-16 below presents a snapshot of supply-side capacity resource additions required under each potential Carbon Plan portfolio as an indication of the pace of new resource adoption and the associated risk to successful plan execution.

**Figure 3-16: Cumulative Supply-Side Resource Additions by 2035, Combined Carolinas System (beginning-of-year basis, excludes projects currently under development)**

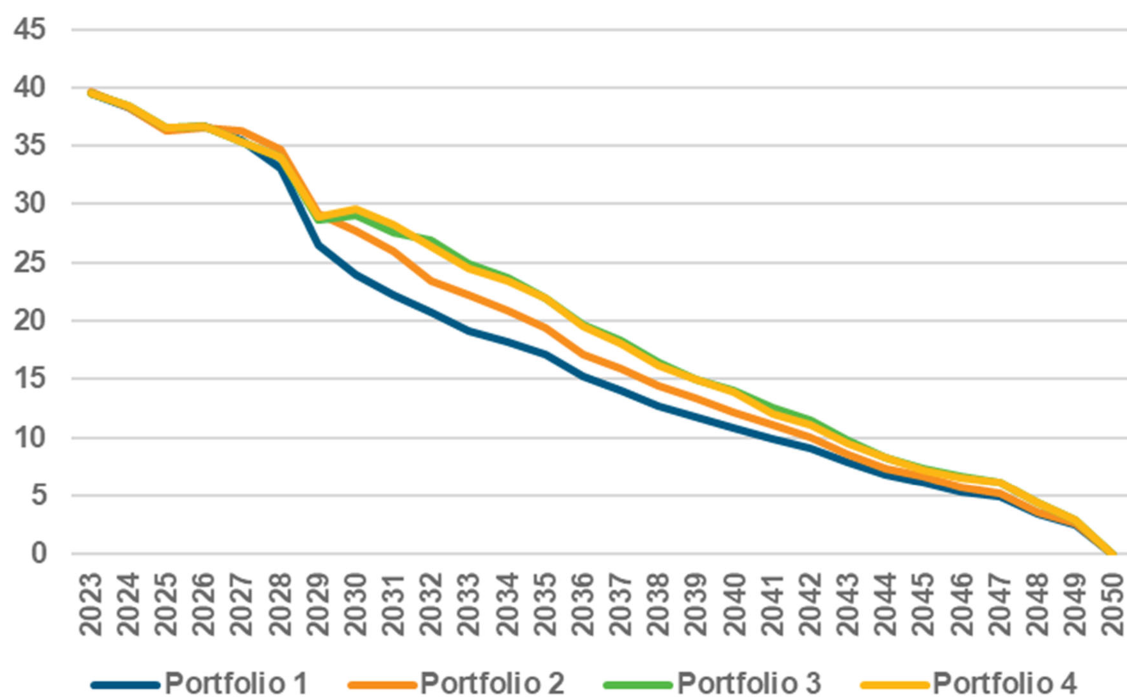



As Figure 3-16 shows, Portfolio 1 requires a significantly more rapid pace of new supply-side resource acquisition and deployment than is contemplated under any of Portfolios 2 through 4. As discussed in more depth in Chapter 4 (Execution Plan), this compressed timetable paired with significant development activities across multiple technologies carries increased risk that adverse conditions outside of the Companies' direct control could jeopardize achievement of the interim target date. These execution risks could manifest in any one of several areas including but not limited to supply chain delays, skilled labor shortages, external contractor availability limitations, extended state and federal permitting processes, legal challenges, etc. Recognition of these factors further supports the need to pursue a near-term execution strategy that envisions the potential for delays in some aspects of the Plan through the pursuit of common elements within all the portfolios while maintaining optionality to advance longer-term projects such as offshore wind and nuclear SMRs. Failing to pursue the development of these longer lead-time technologies in the near-term would limit the availability of resources potentially needed to achieve a least cost and reliable Carbon Plan that meets HB 951's targets in light of the execution risks associated with other resources in the Plan.

## Summary of Portfolio Evaluation

As discussed throughout this Chapter and in Appendix E (Quantitative Analysis), all portfolios across both $CO_2$ emissions reductions pathways require deployment of a diverse range of lower carbon intensity resources, including grid-edge resources and customer programs, renewables, energy storage, new nuclear, and hydrogen-capable gas. As shown in Figure 3-17, all portfolios are designed to achieve carbon neutrality by 2050 and to meet or exceed the 70% interim target by 2034.

**Figure 3-17: Annual $CO_2$ Emissions by Portfolio, Combined Carolinas' System (millions of short tons)**




The primary differentiator across the portfolios is the pace of transition, in terms of the relative cost and risk of executing the Carbon Plan. Portfolio 1 is designed to achieve the 70% interim target by 2030, the earliest of any potential Carbon Plan portfolio resulting in 6% (compared to P2) to 11% (compared to P3 and P4) less $CO_2$ on a cumulative basis through 2050. However, this advantage in terms of pace of $CO_2$ emissions reductions requires tradeoffs in terms of the other core Carbon Plan objectives: cost and affordability, reliability and flexibility and executability. Executing Portfolio 1 is projected to cost approximately $2 billion more than Portfolio 2 in PVRR terms, and approximately $6 billion more than Portfolios 3 and 4 through 2050. In the near term, the customer bill impact of executing Portfolio 1 versus one of the Pathway Two portfolios is also significant, especially for DEP customers, with a bill CAGR approaching 4% through 2030 for DEP residential customers as a result of Carbon Plan investments required to achieve P1. Moreover, from a system reliability and flexibility perspective, the more rapid deployment of variable and energy-limited resources in Portfolio 1 creates greater flexibility challenges in the near and intermediate-term. Portfolio 1 is expected to require 50% more CC starts and produce 20% to 25% greater hourly net load ramping than Portfolios 2-4. Finally, in addition to requiring the most rapid addition of new solar capacity of any portfolio, Portfolio 1 requires the addition to the system of over 3 GW combined of wind and battery capacity by 2030, technologies with extremely limited development and operational history in the Carolinas. This ambitious timetable also creates greater exposure to the supply-chain, permitting, and other risks to timely plan execution described above, compared to Portfolio 2 (a little more than 2 GW of wind and batteries by 2030) or Portfolios 3 and 4 (just over 1 GW of these resources by 2030).

Careful consideration of these tradeoffs is essential to determining prudent next steps as the Companies begin executing the Carbon Plan. As discussed in more detail in Chapter 4 (Execution Plan), the Companies have developed and are proposing for approval a near-term, all-of-the-above execution strategy that is generally consistent with all portfolios presented in the Plan. Near-term execution activities outlined in Chapter 4 (Execution Plan) represent meaningful and immediate progress implementing an array of carbon-reducing demand-side customer programs and supply-side technologies that are available today, while simultaneously pursuing necessary development actions to prudently advance the potential for longer lead-time resources such as offshore wind, pumped storage hydro and new SMR. Thereafter, in the 2024 Carbon Plan update, the Companies will have more refined information that the Commission can consider in updating the Carbon Plan and making further key decisions regarding resource selections with respect to the appropriate resource mix for both the interim and long-term targets.