2 Methodology and Key Assumptions

This Chapter provides an overview of the modeling process utilized to develop the Carolinas Carbon Plan ("Carbon Plan" or the "Plan") as well as a summary of key assumptions and inputs to the modeling framework. Growing customer demand, the retirement of aging coal facilities and the need to decarbonize the energy system require adoption of a new portfolio of demand-side and supply-side resource options over the planning horizon. At its core, the modeling process is structured to develop and analyze portfolio options that first and foremost maintain strong power system reliability while simultaneously meeting carbon reduction targets in the most economic manner for customers.

This Chapter discusses the new EnCompass modeling tool used for capacity expansion, coal unit retirement and production cost modeling in development of the Carbon Plan, and highlights the primary steps involved in the modeling process and many of the key inputs and assumptions relied upon in the development of the portfolios presented in the Plan. Additional detail is provided in Appendix E (Quantitative Analysis), as well as in the supply-side and demand-side resource-specific appendices and other appendices to the Carbon Plan referenced herein as appropriate.

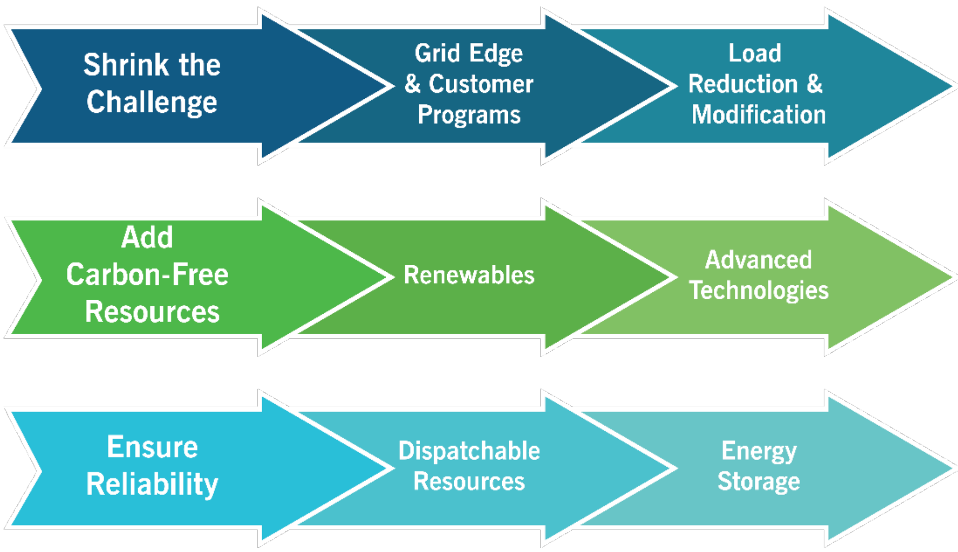
Of note, the inputs, assumptions, and modeling framework utilized to develop the Plan represent a snapshot in time as of late 2021 to early 2022 and are subject to change in future Plan updates given the extremely dynamic nature of the energy industry and supply chain both domestically and globally. Fundamentally, the planning process must rely upon reasonable inputs and assumptions that are appropriate and available at the time the modeling is undertaken, recognizing that project-specific technology performance characteristics, costs and transmission requirements will only be fully known and available during Plan execution when specific projects are actually sited and developed. Plan execution is further discussed in Chapter 4 (Execution Plan).

Approach to Portfolio Modeling

As introduced in the Executive Summary and discussed more fully below and in Chapter 3 (Portfolios), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or the "Companies") intend to take a multi-pronged approach to maintaining reliable service while also meeting CO_2 emissions reductions targets. As depicted in Figure 2-1 below, the

Companies' first step in the process is to "shrink the challenge" by reducing and modifying system annual energy and peak-demand requirements through grid edge and customer programs[1] allowing more tools to respond to fluctuating energy supply and demand. The second and third prongs focus on development of diverse portfolios of both carbon-free and flexible, dispatchable capacity resources and energy storage to facilitate CO_2 emissions reductions while maintaining power system reliability.[2] Supply resource diversity provides flexibility to meet reliability and resilience requirements as the energy transition changes how the Companies operate the grid.

Figure 2-1: Three-Pronged Approach to Planning

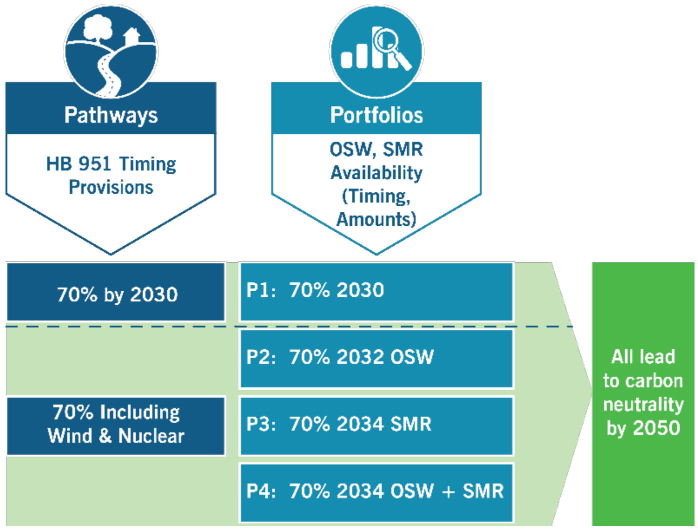


In preparing the Carbon Plan, the Companies utilized the three-pronged approach presented in Figure 2-1 and designed resource planning pathways and portfolios for the Commission's consideration to achieve core Carbon Plan objectives (CO_2 reduction, affordability, reliability and executability) at the pace of energy transition envisioned in Session Law 2021-165 ("HB 951"). In particular, HB 951 sets out an interim target of taking all reasonable steps to achieve 70% CO_2 emissions reductions from a 2005 baseline level by 2030 while achieving carbon neutrality by 2050, subject to specific discretion afforded the Commission, which allows for adjustments to the timeline for achieving the 70% interim target should additional time be needed to accommodate development of wind or new nuclear resources as part of the Companies' least-cost energy transition pathway or in the event necessary to maintain the adequacy and reliability of the existing grid.[3]

As presented in Figure 2-2 below, the Companies have developed the following pathways and portfolios to execute the energy transition and achieve the CO_2 emissions reductions targets contemplated by HB 951.

[1] *See* Appendix G (Grid Edge and Customer Programs) for additional information.
[2] *See* Appendix I (Solar), Appendix J (Wind), Appendix K (Energy Storage), Appendix L (Nuclear), Appendix M (Natural Gas), Appendix N (Fuel Supply), Appendix O (Low-Carbon Fuels and Hydrogen) for additional information.
[3] HB 951, Section 1(4).

Figure 2-2: Summary of Carbon Plan Proposed Pathways and Portfolios



The 70% by 2030 Pathway presents Portfolio 1 that was specifically developed based upon more aggressive execution assumptions, at a higher cost and with increased reliability risk to achieve a 70% CO_2 reduction by 2030 as described in more detail below and in Chapter 3 (Portfolios) and Appendix E (Quantitative Analysis). The 70% by 2034 Including Wind and Nuclear Pathway presents Portfolios 2, 3 and 4, which rely more heavily on wind and new nuclear technologies that are projected to require additional time to bring into service due to a variety of siting, permitting, regulatory approvals, supply chain and construction timelines. The portfolios in this Pathway, while similar in many respects, are distinct resource plans due to variations in the assumed availability, timing and volumes of new wind and nuclear resources. The three portfolios in this Pathway achieve the interim target of 70% CO_2 reductions between 2032 for Portfolio 2 and 2034 for Portfolios 3 and 4, which are all consistent with Section 1(4) of HB 951 which states:

> [T]he Utilities Commission shall retain discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction; provided, however, the Commission shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, except 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.[4]

Of important note, all portfolios were developed using established least-cost planning principles and are designed to achieve carbon neutrality by 2050, which is consistent with HB 951 and the expectations of many customers, industries, local governments and communities, and equity investors

[4] *Id.*

in the Carolinas. Specifically, the capacity expansion and production cost modeling in EnCompass ensures the selection of a least cost mix of resources while achieving the pathway to carbon reduction and maintaining system reliability. Finally, as part of the sensitivity analysis discussed in Chapter 3 (Portfolios) and in Appendix E (Quantitative Analysis), all portfolios were also analyzed under an alternative fuel supply sensitivity that examined how the portfolios would change if future access to a limited amount of Appalachian gas supply does not materialize.

Carbon Plan Modeling Software

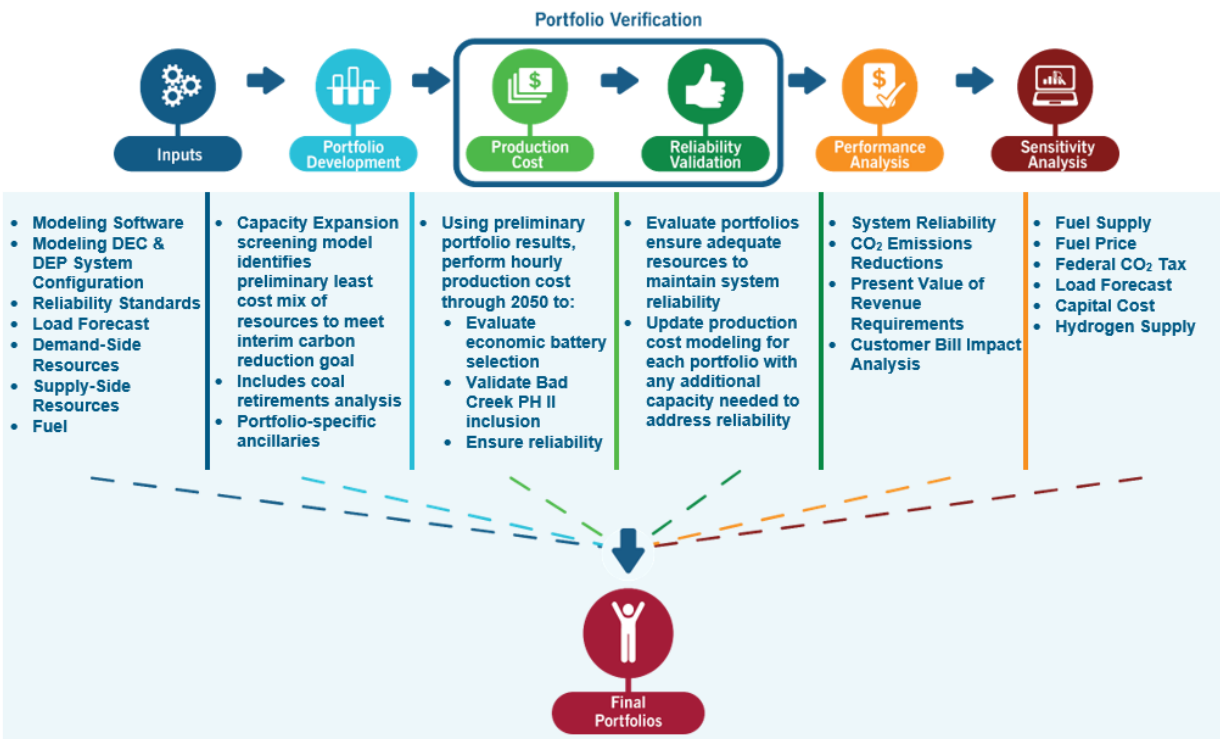
The Companies used the EnCompass capacity expansion and production cost simulation software package ("EnCompass") as the primary modeling tool for the development and analysis of the Carbon Plan portfolios.[5] The capacity expansion model and the production cost model are separate modules within Encompass as described in this section and Appendix E (Quantitative Analysis). In addition to these primary tools, the Companies utilized more granular reliability modeling tools as part of the overall modeling process as described below. These additional tools ensure day-to-day and long-term system reliability as the system transitions to larger levels of carbon-free variable energy resources.

Carbon Plan Analytical Process – Overview

The Carbon Plan analytical process involves several important steps as illustrated in Figure 2-3 below. Each step in the process summarized in Figure 2-3 (Inputs, Portfolio Development, Production Cost, Reliability Validation, Performance Analysis, and Sensitivity Analysis) is described in greater detail in the following sections of this Chapter and in Appendix E (Quantitative Analysis).

[5] The EnCompass software package is licensed through Anchor Power Solutions.

Figure 2-3: Carbon Plan Analytical Process Flow Chart



Inputs

This section outlines key inputs to the Carbon Plan modeling process. These inputs include, but are not limited to, updates to the Companies' load forecasts, including impacts of energy efficiency savings from utility programs ("UEE"), new rate offerings, voltage control programs and other customer demand-side programs along with updates to numerous supply-side technology modeling input data and other key reliability inputs as needed for the portfolio development and analysis process. These additional reliability inputs include planning reserve margin, Effective Load Carrying Capability ("ELCC") values for renewable and energy storage resources and operational reserve requirements.

Note that UEE specifically refers to the Companies' approved utility-sponsored programs where participants actively take part in demand response ("DR") and conservation measures offered under the EE/DSM riders within their service territory. Naturally occurring energy efficiency recognizes load reductions resulting from customers adopting efficiency improvements not associated with utility-sponsored programs. Appendix G (Grid Edge and Customer Programs) details the Companies' ongoing efforts to identify opportunities to expand the reach of UEE programs.[6]

[6] Within this document, UEE and energy efficiency ("EE") terms may be used interchangeably to refer to approved utility programs unless otherwise noted.

Inputs – Reliability

Ensuring reliability necessarily comes first in the modeling process. Key reliability inputs needed in the Carbon Plan modeling include planning reserve margin, ELCC values and operational reserve requirements. These inputs are foundational resource planning components that ensure the Companies are maintaining or improving upon the adequacy and reliability of the existing grid as required under HB 951 and as further described below.

Planning Reserve Margin

Consistent with the Companies' 2020 Integrated Resource Plans ("IRPs"), the Companies used a 17% minimum winter planning reserve margin in developing the Carbon Plan portfolios based on results from the 2020 Resource Adequacy Study conducted by Astrapé Consulting.[7] The planning reserve margin is based on achieving the "one-day-in-10-year" industry standard Loss of Load Expectation ("0.1 LOLE"). As described later in this Chapter and in Appendix E (Quantitative Analysis), the Carbon Plan analytical process includes a reliability validation step to ensure that the LOLE standard is maintained for each portfolio and, if required, adds additional capacity to keep the portfolio at the standard. The 2020 Resource Adequacy Study reports for DEC and DEP are included as Attachments I and II to the Carbon Plan.

Effective Load Carrying Capability

The Companies also worked with Astrapé Consulting to conduct a new 2022 ELCC study using the SERVM[8] model. This new ELCC study was used to estimate the reliability capacity value attributable to variable energy and energy-limited resources such as solar, wind and storage resources. ELCC can be thought of as a measure of reliability equivalence for intermittent renewable and energy-limited storage resources being added to an existing generation portfolio. ELCC is further described in Appendix E (Quantitative Analysis) and in the 2022 ELCC study report provided as Attachment III to the Carbon Plan.

Operational Reserve Requirements

The Companies include operational reserve requirements in the expansion plan modeling process to capture the variance in load and renewables due to forecast error, intra-hour volatility and system ramping needs. The operational reserve model was developed by Duke Energy, based at a high level

[7] 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.

[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 which provides consulting services and/or licenses the model to its users.

on a new planning and reliability tool developed by the Electric Power Research Institute ("EPRI"),[9] and is used to calculate hourly operational reserves required to ensure that the Companies will have sufficient flexible resources available to mitigate the risk of load and renewable output uncertainty.

Operational reserve requirements are heavily influenced by the level of intermittent resources on the system. An initial set of operational reserve requirements is used in the capacity expansion process for a base case of expected renewable growth. Once the portfolios are developed, operational reserve requirements are recalculated for the selected levels of solar and wind capacity in each portfolio.

Inputs – Electric Load Forecast

Key inputs and assumptions used within the modeling framework include assumptions regarding the Companies' peak demand and annual energy load forecast inclusive of significant demand-side activities impacting the forecast. This section provides an overview of these demand-side assumptions impacting the Carbon Plan, which as previously mentioned, "shrinks the challenge" by reducing the magnitude of energy, capacity and CO_2 reductions required in the portfolio development process. More detail is contained in Appendix F (Electric Load Forecast) and Appendix G (Grid Edge and Customer Programs). A summary of several of the key assumptions in this area is shown below.

The Carbon Plan requires a projection through 2050 of the yearly energy and seasonal peak demands of the customer base within the DEC and DEP service areas. The econometric process to derive the retail load forecast is described in detail in Appendix F (Electric Load Forecast). Tables 2-1 to 2-4 below provide an overview of the DEC and DEP annual energy and peak winter capacity components of the net load forecast and the assumptions that are made in the Carbon Plan for base planning around this important topline parameter.

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

Table 2-1: Forecasted Energy Sales – System Obligation at Generator – DEC [GWh]

YEAR	GROSS RETAIL SALES	ENERGY EFFICIENCY	NEM ROOFTOP SOLAR	ELECTRIC VEHICLES	VOLTAGE CONTROL (IVVC)	CRITICAL PEAK PRICING / PEAK TIME REBATE	NET RETAIL SALES AT METER	LINE LOSS + CO USE	GROSS RETAIL AT GEN	WHOLESALE	SYSTEM OBLIGATION AT GEN
2023	80,665	(659)	(86)	62	(37)	(1)	79,945	3,714	83,658	8,325	91,983
2024	81,321	(1,097)	(136)	120	(74)	(2)	80,132	3,720	83,852	8,452	92,304
2025	81,997	(1,537)	(181)	202	(374)	(3)	80,105	3,718	83,824	8,525	92,349
2026	82,583	(1,967)	(229)	320	(377)	(4)	80,326	3,728	84,054	8,613	92,667
2027	83,220	(2,387)	(279)	484	(381)	(6)	80,651	3,743	84,394	8,706	93,100
2028	84,042	(2,789)	(333)	697	(384)	(8)	81,226	3,769	84,995	8,820	93,815
2029	84,945	(3,163)	(389)	940	(388)	(10)	81,937	3,805	85,741	8,888	94,629
2030	85,780	(3,501)	(446)	1,210	(391)	(12)	82,639	3,842	86,481	8,973	95,454
2031	86,745	(3,800)	(505)	1,498	(395)	(14)	83,530	3,877	87,406	9,060	96,466
2032	87,614	(4,039)	(566)	1,813	(398)	(17)	84,407	3,914	88,321	9,126	97,447
2033	88,365	(4,225)	(626)	2,137	(402)	(19)	85,231	3,950	89,181	9,190	98,372
2034	89,043	(4,354)	(689)	2,486	(405)	(21)	86,060	3,987	90,047	9,265	99,313
2035	89,690	(4,440)	(753)	2,853	(409)	(22)	86,919	4,029	90,948	9,341	100,289
2036	90,273	(4,482)	(820)	3,246	(413)	(24)	87,781	4,073	91,854	9,430	101,284
2037	90,809	(4,383)	(884)	3,637	(416)	(25)	88,739	4,111	92,849	9,494	102,343
CAGR	**0.8%**	**14.5%**	**18.1%**	**33.7%**	**18.9%**	**28.2%**	**0.7%**	**0.7%**	**0.7%**	**0.9%**	**0.8%**

Within the DEC service territory, the following programs will have a significant impact on net retail load over the initial 15-year time horizon:

- **Utility Energy Efficiency**: UEE is forecasted to achieve a robust compound annual growth rate ("CAGR") of 14.5% over the first 15 years, peaking at approximately 5% of gross retail sales by the year 2037. UEE savings reflect an incremental annual reduction of 1% of each year's eligible retail sales. It is important to note that this 1% annual target is based on an aspirational goal emerging from the Company's ongoing engagement with the Carolinas EE/DSM Collaborative, which consists of both Duke Energy experts and a broad range of external stakeholders.

  The cumulative UEE savings shown in Table 2-1 are net of the roll-off, or decay, of historical savings associated with the measure lives of previously achieved program savings. To be clear, this does not mean the savings associated with those earlier measures have ended. Once roll-off occurs, the Companies account for these historical savings as a part of the load forecast rather than showing those savings in the UEE forecast. This forecast only represents the incremental savings directly attributed to utility-sponsored programs above and beyond any naturally occurring or policy-driven savings. Within the load forecast modeling framework, naturally occurring efficiency trends replace the rolled off UEE savings, continuing to reduce forecasted load on an enduring basis.

  Achievement of annual savings of this magnitude over the full timeline of this plan will require substantial customer participation and regulatory support as further discussed in Appendix G (Grid Edge and Customer Programs). Duke Energy will continue extensive engagement with the EE/DSM Collaborative and other stakeholders in pursuit of these aggressive goals.

- **Rooftop Solar with Net-Energy Metering ("NEM")**: Under Net Energy Metering rates approved in the Carolinas as of January 1, 2022, behind-the-meter solar is assumed to achieve an 18.1% CAGR. The Companies continue to work with stakeholders to develop new rate designs and complementary programs that are discussed further in Appendix G (Grid Edge and Customer Programs).

- **Electric Vehicles ("EV")**: Within DEC, electric vehicles are projected to grow from roughly 0.6% of the total vehicle fleet today to 5.5% in 2035, achieving the highest CAGR of any of the components listed above at 33.7%. Appendix F (Electric Load Forecast) provides further detail regarding the net impact of electric vehicles in DEC.

- **Integrated Volt-Var Control ("IVVC")**: IVVC is a newly approved program within DEC that will begin operations in 2023 and has been modeled to achieve a rollout across 96% of eligible circuits in DEC's service territory over a multi-year timeframe. IVVC has two modes of operation, Peak-Shaving mode, which is counted as a firm capacity resource, and Conservation Voltage Reduction ("CVR") mode, which reduces gross retail load. The Peak-Shaving and CVR modes of operation will be managed by a centralized Distribution Management System ("DMS"). CVR mode will eventually support voltage reduction and energy conservation on a year-round basis across 90% of the hours in the year, as opposed to Peak-Shaving mode which will reduce demand during the remaining peak 10% of hours as a firm capacity resource (similar to demand response programs). IVVC CVR mode is projected to achieve a CAGR of 18.9% through 2037.

- **Critical Peak Pricing ("CPP") / Peak Time Rebate ("PTR")**: Described in further detail in Appendix F (Electric Load Forecast) and Appendix G (Grid Edge and Customer Programs), the approved CPP rate rider is a dynamic overlay option for DEC's electric service, including both its existing flat volumetric rates as well as its existing and newly proposed time-of-use rates. This time variant pricing option allows DEC to call critical events up to 20 times per year (20 CP) based on system conditions such as when there is expected to be extreme temperatures, high energy usage, high market energy costs or major generation or transmission outages. Peak Time Rebate is another structure that is added to a base rate plan that rewards customers who consume lower than usual energy during peak hours. The rebate structure for PTR has not yet been approved but is modeled within the DEC Load Forecast. CPP/PTR achieve a 28.2% CAGR in DEC although the greatest measurable impact will be upon peak capacity described in further detail below.

Table 2-2: Forecasted Energy Sales – System Obligation at Generator – DEP [GWh]

YEAR	GROSS RETAIL SALES	ENERGY EFFICIENCY	NEM ROOFTOP SOLAR	ELECTRIC VEHICLES	VOLTAGE CONTROL (IVVC)	CRITICAL PEAK PRICING / PEAK TIME REBATE	NET RETAIL SALES AT METER	LINE LOSS + CO USE	GROSS RETAIL AT GEN	WHOLESALE	SYSTEM OBLIGATION AT GEN
2023	45,223	(377)	(64)	44	(39)	(1)	44,786	2,049	46,835	17,424	64,259
2024	45,676	(627)	(93)	81	(78)	(1)	44,957	2,056	47,013	17,623	64,636
2025	45,929	(877)	(116)	132	(395)	(2)	44,672	2,044	46,716	17,809	64,525
2026	45,840	(1,125)	(139)	205	(398)	(3)	44,379	2,031	46,411	17,997	64,408
2027	45,908	(1,369)	(166)	305	(402)	(5)	44,272	2,027	46,298	18,187	64,486
2028	46,060	(1,598)	(194)	436	(406)	(6)	44,292	2,027	46,320	18,432	64,752
2029	46,256	(1,800)	(222)	587	(409)	(9)	44,403	2,032	46,435	18,616	65,051
2030	46,420	(1,976)	(251)	755	(413)	(10)	44,525	2,038	46,563	18,812	65,375
2031	46,655	(2,122)	(280)	937	(417)	(12)	44,761	2,048	46,810	18,985	65,795
2032	46,897	(2,222)	(310)	1,135	(420)	(14)	45,066	2,062	47,127	19,264	66,391
2033	47,121	(2,282)	(339)	1,341	(424)	(15)	45,401	2,076	47,477	19,460	66,937
2034	47,365	(2,315)	(369)	1,562	(428)	(15)	45,799	2,094	47,893	19,677	67,570
2035	47,629	(2,333)	(400)	1,794	(432)	(18)	46,240	2,113	48,354	19,901	68,254
2036	47,916	(2,325)	(433)	2,043	(436)	(19)	46,746	2,135	48,881	20,144	69,026
2037	48,187	(2,256)	(463)	2,290	(442)	(20)	47,295	2,159	49,455	20,362	69,817
CAGR	**0.5%**	**13.6%**	**15.2%**	**32.7%**	**19.0%**	**29.2%**	**0.4%**	**0.4%**	**0.4%**	**1.1%**	**0.6%**

Within the DEP service territory, the following programs will have a significant impact on net retail load over the initial 15-year time horizon:

- **Utility Energy Efficiency**: UEE is forecasted to achieve a robust CAGR of 13.6% over the first 15 years, peaking at approximately 5% of gross retail sales by the year 2037. UEE savings reflect an incremental annual reduction of 1% of each year's eligible retail sales. As noted previously for DEC, achievement of annual savings of this magnitude over the full timeline of this Plan will require substantial customer participation and regulatory support as further discussed in Appendix G (Grid Edge and Customer Programs).

- **Rooftop Solar with Net-Energy Metering**: Under NEM rates approved in the Carolinas as of January 1, 2022, behind-the-meter solar is assumed to achieve a 15.2% CAGR. The Companies continue to work with stakeholders to develop new rate designs and complementary programs that are discussed further in Appendix G (Grid Edge and Customer Programs).

- **Electric Vehicles**: Within DEP, electric vehicles are projected to grow from roughly 0.7% of the total vehicle fleet today to 6.28% in 2035, achieving the highest CAGR of any of the components listed above at 32.7%. Appendix F (Electric Load Forecast) provides further detail regarding the net impact of electric vehicles in DEP.

- **Integrated Volt-Var Control**: In contrast to DEC, DEP has completed the circuit-level upgrades required to fully implement IVVC through the legacy Distribution System Demand Response ("DSDR") peak-shaving program, which accomplished the program goal of upgrading 97% of eligible circuits by July 2014. Therefore, the only IVVC program upgrade required in DEP is to implement CVR mode through a centralized Distribution Management System to control voltage by circuit. CVR mode will be fully operational by 2025 and will support voltage reduction and energy conservation on a year-round basis across 90% of the hours in the year while the already functioning DSDR Peak-Shaving mode will continue to clip demand during the 10% of hours classified as peak.

- **Critical Peak Pricing / Peak Time Rebate**: Similar to DEC, the approved CPP rate rider is a dynamic overlay option for DEP's electric service, including both its existing flat volumetric rates as well as its existing and newly proposed time-of-use rates. This time variant pricing option allows DEP to call critical events up to 20 times per year (20 CP) based on system conditions such as when there is expected to be extreme temperatures, high energy usage, high market energy costs or major generation or transmission outages. The rebate structure for PTR has not yet been approved but is modeled within the DEP Load Forecast. CPP/PTR achieve a 29.2% CAGR in DEP although the greatest measurable impact will be upon peak capacity described in further detail below.

Table 2-3: DEC Winter Peaks – Impacts of Programs [MW]

YEAR	GROSS RETAIL PEAK	UEE/NEM/ CPP/PTR	ELECTRIC VEHICLES	NET RETAIL PEAK	LINE LOSS + CO USE	RETAIL PEAK AT GEN	WHOLESALE	SYSTEM PEAK AT GEN
2023	14,840	(94)	2	14,748	621	15,369	1,863	17,231
2024	14,956	(183)	4	14,777	646	15,423	1,910	17,333
2025	15,059	(278)	7	14,788	654	15,442	1,941	17,383
2026	15,194	(375)	11	14,830	659	15,489	1,953	17,442
2027	15,316	(505)	16	14,827	651	15,478	1,983	17,461
2028	15,517	(605)	24	14,936	629	15,565	1,996	17,562
2029	15,720	(707)	33	15,046	653	15,699	2,025	17,724
2030	15,848	(806)	44	15,086	659	15,746	2,034	17,779
2031	16,137	(899)	56	15,295	669	15,964	2,061	18,024
2032	16,400	(979)	70	15,492	678	16,170	2,075	18,244
2033	16,644	(1,051)	86	15,679	650	16,329	2,107	18,436
2034	16,825	(1,110)	103	15,819	650	16,469	2,084	18,553
2035	17,046	(1,070)	146	16,122	677	16,799	2,094	18,893
2036	17,199	(1,193)	144	16,151	690	16,840	2,168	19,008
2037	17,422	(1,203)	168	16,387	700	17,087	2,200	19,286
CAGR	1.2%	19.9%	36.6%	0.8%	0.9%	0.8%	1.2%	0.8%

Note: UEE/NEM/CPP/PTR/EV are at meter and system peak is at generator.

Note: The system peak at generator grows over time at a compound annual rate of 0.8% over the initial 15 years but this rate would have been higher if not for the significant growth rates of UEE/NEM/CPP/PTR (19.9%). These programs achieve impacts that grow from a modest 0.6% of gross retail peak in 2023 to 6.9% by 2037.

Note: IVVC CVR mode will be turned off during the 10% of hours considered peak in any given year and IVVC Peak-Shaving mode will be turned on as a firm capacity resource. Therefore, the latter is not a reduction of the system peak within the load forecast but rather Peak-Shaving is treated as a dispatchable supply-side capacity resource in the modeling framework.

Table 2-4: DEP Winter Peaks – Impacts of Programs [MW]

YEAR	GROSS RETAIL PEAK	UEE/NEM/ CPP/PTR	ELECTRIC VEHICLES	NET RETAIL PEAK	LINE LOSS + CO USE	RETAIL PEAK AT GEN	WHOLESALE	SYSTEM PEAK AT GEN
2023	9,954	(56)	1	9,900	365	10,264	3,941	14,206
2024	10,093	(108)	2	9,987	388	10,375	4,012	14,387
2025	10,144	(162)	3	9,984	392	10,376	4,011	14,387
2026	10,070	(218)	4	9,856	387	10,244	4,091	14,335
2027	10,214	(293)	6	9,927	383	10,309	4,122	14,432
2028	10,195	(351)	8	9,852	367	10,219	4,146	14,365
2029	10,383	(409)	11	9,985	381	10,366	4,166	14,532
2030	10,340	(463)	14	9,891	382	10,273	4,215	14,487
2031	10,463	(513)	18	9,968	385	10,353	4,291	14,644
2032	10,563	(553)	22	10,032	388	10,419	4,295	14,714
2033	10,667	(587)	27	10,107	372	10,478	4,342	14,821
2034	10,742	(614)	34	10,162	366	10,528	4,380	14,909
2035	10,976	(636)	40	10,381	390	10,771	4,440	15,212
2036	10,967	(649)	48	10,366	395	10,761	4,494	15,255
2037	11,109	(652)	57	10,514	401	10,915	4,546	15,461
CAGR	0.8%	19.2%	33.5%	0.4%	0.7%	0.4%	1.0%	0.6%

Note: UEE/NEM/CPP/PTR/EV are at meter and system peak is at generator.

Note: The system peak at generator grows over time at a compound annual rate of 0.6% over the initial 15 years but this rate would have been higher if not for the significant growth rates of UEE/NEM/CPP/PTR (19.2%). These programs achieve impacts that grow from a modest 0.6% of gross retail peak in 2023 to 5.9% by 2037.

Note: IVVC CVR mode will be turned off during the 10% of hours considered peak in any given year and IVVC Peak-Shaving mode, currently operating as DSDR in DEP, will be turned on as a firm capacity resource. Therefore, the latter is not a reduction of the system peak within the load forecast but rather Peak-Shaving is treated as a dispatchable supply-side capacity resource in the modeling framework.

Inputs – Demand-Side Management (DR, CPP/PTR and IVVC)

Demand-Side Management ("DSM") contains three components: customer-sited demand response, circuits-focused peak shaving (IVVC Peak Shaving mode), and peak shifting via CPP and PTR rate programs. All share similarities in that DEC/DEP system operators initiate DSM events to reduce system load during winter and summer peaks. DR and IVVC peak shaving are similar in that they are counted as capacity while CPP/PTR sends price signals to participating customers to avoid usage during peak times, therefore reducing aggregate peak demand on the system. DSM programs are explained in further detail below and in Appendix G (Grid Edge and Customer Programs).

Demand Response

In addition to the programs shown in the previous tables that reduce the load forecast, controllable DR customer programs also serve a very important role in meeting system peak demand requirements. When winter and summer peaks occur, system operators can initiate DR events to lower customer energy consumption and quickly reduce the stresses on the system that can occur during high demand periods. Mechanical DR programs send signals directly to customer equipment such as thermostats and water heaters to immediately lower energy usage. Alternatively, large commercial and industrial customers can participate in customized manual DR programs where Duke Energy will communicate the request to reduce load during high system demand periods. Employees of those firms comply by flexibly choosing what load to reduce to meet their previously agreed upon demand reduction commitments. Mechanical and manual DR customers are compensated monthly for opting-in to these programs in return for their commitment to reducing consumption during peak periods.

DR capacity is modeled as a controllable peaking resource similar to traditional generation and contributes equally to capacity planning reserve margins. Effective utilization of DR programs can decrease the runtime of older, more expensive generation and avoid or defer the need for new supply-side peaking resources. The DR forecast incorporates new measures or program concepts identified in the Winter Peak Study[10] in addition to existing programs currently offered by the Companies.

Table 2-5 below summarizes the peak winter capacities of mechanical and manual demand response programs in the Carbon Plan throughout time.

Table 2-5: Mechanical and Manual Demand Response, Winter [MW]

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

[10] The 2020 Winter Peak Demand Reduction Potential Assessment (also referred to as the Winter Peak Study) was prepared for Duke Energy by Dunsky Energy Consulting in partnership with Tierra Resource Consultants. The objective of the study was to identify the potential for new demand response programs and measures to reduce the winter peak demand in each of the DEC and DEP systems. The Winter Peak Study reports were filed with the NCUC in Docket No. E-100, Sub 165.

Critical Peak Pricing and Peak Time Rebate

The Carbon Plan also includes the projected impacts of peak reduction pricing programs, including CPP and PTR programs. These programs were also identified in the Companies' 2020 Winter Peak Study as a means to reduce peak winter demand using new voluntary customer rates structures. CPP and PTR programs are designed to send price signals to customers who opt-in to the program to encourage them to reduce load during peak 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 2-6 below.

Table 2-6: Critical Peak Pricing Demand Response, Winter [MW]

	DEC	DEP
2030 Projection	229	131
2040 Projection	514	298

Integrated Volt-VAR Control – Peak Shaving Mode

As previously described, IVVC is a voltage reduction and peak-shaving program that operates at the circuit level using a centralized Distribution Management System. System operators utilize the CVR mode of IVVC for 90% of the hours of the year that are non-peak by adjusting voltage across eligible circuits utilizing the DMS. During winter and summer peak hours, which account for 10% of the year, CVR is turned off and Peak Shaving mode is turned on. This mode operates the same way as DR but instead of reducing load by individual customer, it reduces voltage at the circuit level at carefully calibrated levels. This mode has existed in DEP as the DSDR program since 2014 and has been installed on 97% of eligible circuits. DEC is upgrading circuits in phases with the goal of eventually implementing IVVC across 96% of eligible circuits.

Below in Table 2-7 are the peak load reduction projections of the program in 2030:

Table 2-7: IVVC Peak Shaving Capacity, Winter [MW]

	DEC	DEP
2023 Projection	17	160
2030 Projection	203	168

Inputs – Supply-Side Resources

Significant additions of renewables, storage and other technologies will be required to achieve HB 951 CO_2 emissions reductions targets while also maintaining strong system reliability. The Companies considered a diverse range of baseload, peaking/intermediate, variable energy and energy storage technologies in developing the Carbon Plan. Appendix H (Screening of Generation Alternatives) describes the technical and economic screening of resources that was conducted prior to performing the detailed Carbon Plan modeling and analysis. This section provides an overview of the input assumptions associated with the selectable supply-side resources made available in the EnCompass capacity expansion modeling phase.

Figure 2-4 below summarizes the key assumptions for selectable resources included in the capacity expansion modeling. Further details regarding model input assumptions for selectable resources are provided in this section with additional information also provided in the relevant appendices. It is important to note that input assumptions such as project capital costs and transmission interconnection costs for each resource type are proxy values as site-specific costs for any given resource will only be known as projects are sited during execution of the Plan.

Figure 2-4: Key Base Assumptions for Selectable Supply-Side Resources

Solar

- Solar interconnection potential increases to 1,350 MW/year in the 70% by 2034 Pathway while increasing to 1,800 MW/year in the 70% by 2030 Pathway
- Bifacial panels, single-axis tracking
- Two configurations of solar paired with storage
- Modeled capital cost slightly lower than moderate NREL 2021 ATB moderate scenario costs[11]

Storage

- Up to 3,000 MW stand-alone batteries per year available for selection in all portfolios
- Modeled capital cost within 1% of moderate NREL 2021 ATB moderate scenario costs
- Bad Creek II – long-duration storage modeled in all portfolios

New Nuclear

- SMR – 570 MW (two units) available beginning 2033 and 2034 for 70% carbon reduction by 2034
- Additional SMR available beginning 2036
- Advanced reactors available beginning 2038

Wind

- Onshore wind at approximately 30% capacity factor – 300 MW/year starting 2029 up to 1,800 MW/total available for selection in all Portfolios
- Offshore wind ("OSW") at approximately 42% capacity factor
- First 800 MW block OSW available for selection for the beginning of 2030
- Second 800 MW block available for selection for the beginning of 2032
- Additional OSW available for selection after 2040

Gas

- For planning purposes all new resource emissions are modeled as if located in North Carolina
- Transition from market-based to fundamentals-based natural gas commodity prices in years five-eight with use of full fundamentals prices beginning in year nine
- Limited Appalachian gas supply (limit of two new CCs up to 2,400 MW)

[11] National Renewable Energy Laboratory, 2021 Annual Technology Baseline, https://atb.nrel.gov/ (last visited May 10, 2022).

Hydrogen

- Hydrogen (H_2) blending at existing CC and CT units in 2035+
- Hydrogen market assumed available by 2040
- All new CTs 2040+ are assumed to be operated on 100% H_2
- Existing CT and CC units on the system in 2050 as well as all CTs and CCs added to the portfolios operate on hydrogen in 2050

Modeling Inputs and Assumptions for Selectable Supply-Side Resources

Solar and Solar Plus Storage

Technology Description

Based on stakeholder feedback, the Companies assumed that all future solar would reflect projects with bifacial panels, single-axis tracking capability and operating at an annual capacity factor of approximately 28%. Pairing storage with solar can further increase the energy output of solar. Based on stakeholder feedback, the Companies included two options for solar paired with battery storage as shown in Table 2-8 below.

Table 2-8: Solar Paired with Battery Storage, Plan Modeling Options

	Option 1	Option 2
Solar Capacity	75 MW	75 MW
Storage Capacity	20 MW	40 MW
Duration	4-hour	2-hour
Approximate Capacity Factor %	32%	32%

Technology Cost Source

The Companies based solar and solar paired with storage costs on proprietary third-party engineering estimates specific to the Carolinas, which are slightly lower than the NREL 2021 Annual Technology Baseline ("ATB") moderate scenario cost assumptions.[12]

Transmission Cost

Table 2-9 below provides the transmission costs for solar and solar plus storage resources used in the capacity expansion model. Appendix E (Quantitative Analysis) explains the Companies' approach to incorporating transmission costs for solar and other resources into the model in further detail.

[12] *Id.*, https://atb.nrel.gov/electricity/2021/utility-scale_pv (last visited May 10, 2022).

Table 2-9: Transmission Cost of Solar and Solar Plus Storage

	Transmission Cost [2022 $/W]	
	DEC	DEP
Solar 2026	$ 0.17	$ 0.17
Solar 2027-2030	$ 0.19	$ 0.19
Solar 2031-2037	$ 0.21	$ 0.21
Solar 2038+	$ 0.24	$ 0.24

Constraints

As previously described, the Companies' Carbon Plan presents two pathways to meeting the 70% interim CO_2 emissions reductions targets on the path to achieving carbon neutrality by 2050. The 70% by 2030 Pathway and the 70% by 2034 Pathway including wind and nuclear have different interconnection limits as shown in Table 2-10 below, which illustrates the more aggressive requirement for annual interconnections required to achieve the 70% by 2030 pathway.

Table 2-10: Maximum Solar [MW] Allowed to Connect Annually (by January 1 of year shown)

	2027	2028	2029	2030+
70% by 2034	750	1,050	1,350	1,350
70% by 2030	750	1,050	1,800	1,800

The general convention used in the Companies' Carbon Plan is that resources are available or retired on a beginning-of-year basis. Thus, the years in the table above refer to solar available at the start of the year to serve energy and capacity needs for the entire year. As an example, the 750 MW of solar available for selection for the start of 2027 are added by the end of the calendar year 2026. Appendix I (Solar) explains the Companies' modeling approach for assumed future solar interconnections in further detail.

Energy Storage

Technology Description

Energy storage will play a critical role in the low-carbon future of the power system. Energy storage does not create CO_2 emissions when discharging and can be charged from zero-carbon resources including nuclear, solar, wind and hydro power. Energy storage also provides the system benefit of allowing excess zero-carbon power to be stored for later use instead of curtailed. The dispatchable nature of energy storage allows this energy to be injected back into the grid when it is needed most, offsetting higher cost, carbon intensive generation.

Various configurations of stand-alone battery energy storage were modeled in EnCompass. Those configurations are:

- 50 MW/200 MWh
- 50 MW/300 MWh
- 50 MW/400 MWh

Additionally, the Companies modeled an expansion of the Bad Creek Pumped Storage Hydro Station ("Bad Creek II"), which essentially provides an additional 1,680 MW long-duration storage resource in the Carbon Plan. The final type of energy storage modeled in the Carbon Plan is the integrated storage of Advanced Reactors ("ARs"). This integrated storage option allows for thermal energy to be stored from the reactor and released to supplement generation in times of peak demand. This storage configuration allows for the consistent operation of the nuclear plant, while changing the output of the overall facility. Furthermore, integrated thermal storage has a very high round trip efficiency compared to the other storage options.

Technology Cost Source

Battery storage costs were based on proprietary third-party engineering estimates specific to the Carolinas and are within 1% of the NREL 2021 ATB moderate scenario cost assumptions.[13] Bad Creek II Pumped Storage Hydro cost was based on proprietary third-party engineering estimates. As noted in the New Nuclear section below, advanced nuclear with integrated storage technology costs were based on third-party engineering estimates.

Transmission Cost

Table 2-11 below provides the transmission costs for energy storage resources used in the capacity expansion model. Appendix E (Quantitative Analysis) explains the Companies' approach to incorporating transmission costs for energy storage and other resources into the model in further detail. Transmission costs associated with advanced nuclear with integrated storage are provided in the New Nuclear section below.

Table 2-11: Transmission Cost of Energy Storage

	Transmission Cost [2022 $/W]	
	DEC	DEP
Battery Storage	$ 0.19	$ 0.22
Bad Creek II Pumped Storage	$ 0.22	

[13] *Id.*, https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage (last visited May 10, 2022).

Constraints

The Companies assumed interconnection potential for battery energy storage to be 3,000 MW per year.[14]

New Nuclear

Technology Description

New nuclear has the potential to be a significant technology in enabling the achievement of the targets set out in HB 951, particularly in meeting the 2050 carbon neutrality target. In addition to the zero-carbon energy already provided by the current nuclear fleet, new nuclear can provide significant operational flexibility that will be needed to support increased deployment of renewable energy resources to replace natural gas generation and achieve carbon neutrality by 2050.

As shown in Table 2-12 below, the Companies considered two types of advanced nuclear reactors in development of the Carbon Plan which included small modular reactors ("SMRs") and advanced reactors ("ARs"). SMRs are water-cooled reactors and ARs are non-water-cooled (e.g., molten salt, liquid metal, or high-temperature gas).

Table 2-12: Advanced Nuclear Reactors Modeled in the Carbon Plan

Definitions	
Small Modular Reactors	• Light water-cooled, much like today's current commercial fleet • Proven technology and furthest along from a licensing standpoint • Typically, 300 megawatts electric (MWe) or less • Leverage design, size, and modular application to lower cost
Advanced Reactors	• Non-water-cooled – molten salt, helium gas, liquid sodium • Higher efficiency, cycling ability and integrated storage • Integrates well with variable renewable power • Can be 50 MWe up to 1,200 MWe

Technology Cost Source

Advanced nuclear reactor costs were based on EPRI's cost and performance estimate[15] and proprietary third-party engineering estimates.

[14] *See* Appendix K (Energy Storage) for further information.
[15] Reference EPRI 2021 TAGWeb Generation and Storage Summary Report available to funding members at https://www.epri.com/research/products/000000003002022367.

Transmission Cost

Table 2-13 below provides the transmission costs for advanced nuclear reactors used in the capacity expansion model. Appendix E (Quantitative Analysis) provides additional detail on the Companies' approach to incorporating transmission costs for advanced nuclear reactors and other resources into the model.

Table 2-13: Transmission Cost of Advanced Nuclear Reactors

	Transmission Cost [2022 $/W]	
	DEC	**DEP**
Advanced Nuclear	$ 0.19	$ 0.22

Constraints

Carbon Plan modeling assumed two 285 MW blocks of SMRs available in the 2033-2034 time period to meet CO_2 emissions reductions targets and additional SMRs available beginning 2036. Advanced reactors are available beginning in 2038.[16]

Wind

Technology Description

Onshore and offshore wind technologies are mature, scalable, and increasingly cost-effective zero-carbon resources. Both onshore and offshore wind turbines generally operate by harnessing wind with large turbine blades that spin and turn a generator that converts the rotational energy into electrical energy. Multiple wind turbines installed in an array form a wind farm, which can add up to hundreds of megawatts to the system. Similar to solar, onshore and offshore wind resources are variable energy resources. Onshore wind is assumed to have an annual capacity factor of approximately 30%[17] and offshore wind is assumed to have an annual capacity factor of approximately 42%.[18]

Technology Cost Source

Wind technology costs are based on proprietary third-party engineering estimates specific to the Carolinas.

[16] *See* Appendix L (Nuclear) for further information.
[17] Onshore wind is assumed to have a 30% capacity factor, as determined in coordination with stakeholders during the February 18, 2022, Solar and Wind Technology and Cost Assumptions technical subgroup meeting.
[18] Offshore wind capacity factor based on a composite of potential sites along the North Carolina coast. These sites are discussed in greater detail in Appendix J (Wind).

Transmission Cost

Table 2-14 below provides the transmission costs for wind resources used in the capacity expansion model. Appendix E (Quantitative Analysis) explains the Companies' approach to incorporating transmission costs for wind and other resources into the model in further detail.

Table 2-14: Transmission Cost of Wind

	Transmission Cost [2022 $/W]	
	DEC	**DEP**
Onshore Wind	Note 1	$ 0.24
Offshore Wind First 800		$ 0.45
Offshore Wind Second 800		$ 0.79
Offshore Wind 1600+		$ 0.22

Note 1: DEC onshore wind is assumed to be imported. As a proxy transmission cost, DEC used the PJM border charge. The current PJM rate for 2022 is $67,625/MW-year. Based on historic trends, the annual cost is assumed to increase 5% per year. Additional costs for network system upgrades may also be required as further addressed in Appendix P (Transmission System Planning and Grid Transformation).

Constraints

Appendix J (Wind) provides a detailed discussion of the development timeline and process to site onshore and offshore wind energy projects. For onshore wind, the Carbon Plan modeling assumed that the annual amount of onshore wind that could be selected between DEC and DEP was 300 MW/year up to a total volume of 1,800 MW through 2050 with the following assumptions:

- **DEC:** Up to 300 MW/year of additional wind energy could be imported into the DEC service territory starting in 2029 and up to a total volume of 600 MW through the planning period.
- **DEP:** Up to 300 MW/year of additional wind energy could be developed in the DEP service territory starting in 2029 and up to a total volume of 1,200 MW through the planning period.

For offshore wind, the modeling allowed selection of two 800 MW offshore wind blocks (January 1, 2030, and January 1, 2032) and additional offshore wind is assumed to be available after 2040.

Simple Cycle Combustion Turbines and Combined Cycle Power Blocks

Technology Description

New simple cycle combustion turbines ("CT" or "peakers") and combined cycle power blocks ("CC") with the future capability to use hydrogen fuel will play a critically important role into the future, given the system's growing need for reliability resources that are both dispatchable and capable of operating for extended periods of time as required to support and back stand the integration of variable energy renewables resources, and to enable the retirements of older less-efficient coal units. Future gas generation will not operate as often as fossil-fueled plants do today but will serve an important role in providing firm dispatchable capacity in the transition to renewable resources. Based on modeled fuel supply constraints, the Companies limit the amount of new CC capacity able to be selected in the Carbon Plan modeling. The exact model of CT chosen during Plan execution, whether in simple-cycle or combined cycle configuration, will depend on the specific needs of the system at the time of development. For modeling purposes, the Companies' Carbon Plan considers J-Class peakers and F-Class and J-Class CCs depending on fuel supply assumptions. New CC and CT assets will be designed with hydrogen (or other carbon-neutral fuel) capability. Hydrogen blending with natural gas and eventually 100% hydrogen use will lower the carbon footprint of any future CTs and CCs as further described in Appendix O (Low-Carbon Fuels and Hydrogen).

Technology Cost Source

CT and CC costs are based on proprietary third-party engineering estimates specific to the Carolinas.

Transmission Cost

Table 2-15 below provides the transmission costs for CT and CC resources used in the capacity expansion model. Appendix E (Quantitative Analysis) explains the Companies' approach to incorporating transmission costs for CTs, CCs, and other resources into the model in further detail.

Table 2-15: Transmission Cost of CTs and CCs

	Transmission Cost [2022 $/W]	
	DEC	DEP
Natural Gas CCs and CTs	$ 0.19	$ 0.22

Constraints

- All four portfolios assumed a limited amount of firm transportation capacity to transport Appalachian gas supply to the Carolinas but were constrained to allow the model to select up to two new CC facilities or ~2,400 MW of new CC capacity.
- Alternate fuel case portfolios assumed no pipeline capacity was available to provide access to Appalachian gas supply and as such were constrained to allow the model to select only a single new CC, which was modeled as a smaller ~800 MW CC.
- Hydrogen capable simple-cycle CT capacity additions were modeled with sufficient ultra-low sulfur fuel oil back-up eliminating the need for interstate firm gas delivery.

Appendix M (Natural Gas) and Appendix N (Fuel Supply) provide additional details on the CC and CT combustion technology and assumptions used in the modeling.

Hydrogen

Technology Description

The Companies' existing CT and CC generation fleet was designed to operate by utilizing natural gas or fuel oil. Hydrogen and hydrogen-based fuels are emerging zero-carbon or low-carbon emissions fuels that offer an alternative to fossil fuels. When utilized in an appropriate generating asset, hydrogen can be a zero-emitting load-following resource, enabling the support of more grid-connected renewable resources. With some modifications to the combustion turbines and the development of a robust supply chain, hydrogen could replace existing fossil fuels in power generation.

Technology Cost Source

Hydrogen-fueled turbines are a developing technology, and cost estimates for retrofits and new hydrogen capable units are not available from original equipment manufacturers ("OEMs") at this time. Duke Energy developed cost estimates for use in the Carbon Plan modeling based on discussions with third-party OEMs.

Constraints

Hydrogen blending is represented in the modeling with a starting point of 3% in 2035 and ramping up in several steps to 15% by 2041 and holding steady thereafter (both numbers representing hydrogen/natural gas volume ratio). This blend is applied to all gas assets existing or added before 2040. Any new peakers built in the 2040s are treated as 100% hydrogen fueled, and existing CT and CC units on the system in 2050 as well as all CTs and CCs added to the portfolios operate on hydrogen in 2050 to achieve zero carbon emissions by the end of the planning horizon. Appendix O (Low-Carbon Fuels and Hydrogen) provides additional details on future hydrogen use considerations.

Portfolio Development

EnCompass Capacity Expansion Modeling

The capacity expansion model optimizes portfolio resources to meet customer energy and peak demand needs as well as carbon reductions targets over the planning horizon. The model seeks to develop a portfolio of resources that will minimize overall system costs inclusive of capital costs for new resources as well as ongoing operation, maintenance and fuel costs. Capacity expansion examines numerous permutations of possible resource options that meet system reliability and CO_2 emissions reductions targets. Given the vast number of resource options examined in this phase of the analysis, the capacity expansion model uses a simplified, average representation of hourly system demand to screen for the optimal resource portfolio. Due to these necessary computational simplifications, additional modeling in the detailed production cost model is necessary to validate and adjust the resource selections with respect to cost, reliability and emissions reductions targets as further discussed in Appendix E (Quantitative Analysis).

The Carbon Plan is based on specific CO_2 emissions reductions targets by differing dates depending on the portfolio. The capacity expansion model is designed to develop a portfolio that meets a specific emissions target, sometimes referred to as meeting a mass cap. To incentivize a plan that shows continual CO_2 emissions reductions, an emissions target was set in 2025 and was reduced an equivalent amount each year until the 70% target was met. After the 70% CO_2 target was met, annual emissions reductions targets were set until zero CO_2 emissions were achieved in 2050.

Each portfolio is based on a least-cost resource mix using the EnCompass capacity expansion model that satisfies CO_2 emissions reductions targets required by HB 951 subject to model objectives and constraints. The operational reserve requirements are then developed consistent with each portfolio evaluated. Each portfolio is then reoptimized within the capacity expansion model using these new requirements.

The next step in the portfolio development process is to perform coal unit retirement analysis endogenously within capacity expansion. The endogenous evaluation was in part based on stakeholder feedback as well as the enhanced modeling capability offered by EnCompass. The projected on-going capital, and operating and maintenance coal unit expenses, were estimated using the capacity factors from the initial expansion plan analysis. After inputting these expenses into the model, capacity expansion selected the coal unit retirements as a part of the resource mix while minimizing cost and meeting the CO_2 emissions reductions targets. Final retirement dates are then established based on the ability to execute replacement resources and transmission upgrades necessary to ensure or improve reliability. The retirement selection process is explained in more detail in Appendix E (Quantitative Analysis).

Expansion plans are optimized again incorporating the portfolio specific operational reserve requirements and fixed coal retirements for further evaluation within the production cost model.

Production Cost

EnCompass Detailed Production Cost Modeling

The portfolio of resources developed using the capacity expansion model is then evaluated in the production cost model. This model uses detailed, chronological, hourly granularity to simulate the commitment and dispatch of resources to meet the load requirements of the system consistent with least-cost system operations. This level of detailed analysis allows for modeling resources with specified generation profiles or other detailed operating characteristics. The detailed production cost step in EnCompass also allows for verification of, and adjustments to, initial storage and CT levels from the capacity expansion model to ensure least-cost optimization while maintaining system reliability and meeting carbon reduction targets. The detailed hourly production cost model is also utilized for sensitivity analyses of selected portfolios. Completion of this step produces preliminary carbon plan portfolios that satisfy carbon reduction targets subject to a final step required to ensure that the portfolios maintain power system reliability. The results from the production cost runs are the basis for the economic and rate impact analysis, and verification that CO_2 targets, reserve margins and Joint Dispatch Agreement transfer limits are met. Finally, a check on system operation and reliability is performed using results from the production cost analysis.

The Bad Creek II second pumped storage hydro powerhouse was included in all portfolios in 2033. On the path to the 2050 carbon neutrality target, longer-duration storage will be needed to balance system needs. The Companies have a long operating history with pumped storage and a second powerhouse at Bad Creek would be an addition of a demonstrated technology that can provide over 10 hours of storage. To assure competitiveness, an alternative using longer-term lithium-Ion batteries was evaluated. In this evaluation, the second powerhouse at Bad Creek was replaced with an equivalent amount of long-term lithium-ion storage and evaluated over a 60-year operating life.The present value of revenue requirements incorporating the operating and capital cost of each option were compared and validated the benefits of Bad Creek II versus adding longer-term lithium-ion batteries. Detailed results of the analysis are discussed in Appendix E (Quantitative Analysis).

Reliability Validation

Initial reserve margin and ELCC values are dependent on many factors including system peak demand and load shape to be served, the existing resource mix, as well as the expected adoption level of different renewable and energy storage resource technologies. The capacity expansion model introduces changes in the resource mix, which can impact ELCC values, LOLE and operational reserve requirements. Since it is not practical to determine these values for infinite combinations of resources, nor are such inputs easily integrated into the resource planning models, the Companies conducted SERVM model simulations of the portfolios for study years 2030 and 2035 in this validation step to ensure that reliability is maintained at higher levels of renewable resources. Additional dispatchable resources are added in this step if needed to maintain system reliability. Results of this reliability validation step produce the final portfolios evaluated in the Performance Analysis step discussed in the next section. Appendix E (Quantitative Analysis) addresses the LOLE validation process in greater detail.

Performance Analysis

The final portfolios from the production cost analysis with any additional resources required for reliability are then evaluated for CO_2 reductions over the planning horizon and for cost, both in terms of present value of revenue requirements and estimated customer bill impacts. These customer bill impacts incorporate system fuel, operating and maintenance and capital expenditures of new resources for each portfolio projected through 2035. Chapter 3 (Portfolios) includes analysis of portfolio performance against the core Carbon Plan objectives (CO_2 reduction, affordability, reliability and executability) with additional detail provided in Appendix E (Quantitative Analysis).

Sensitivity Analysis

To examine the impacts of input variables and test the robustness of the four portfolios, sensitivity analysis around natural gas supply and price, potential federal carbon tax, load forecast, new supply-side resource capital costs, and hydrogen fuel supply were performed. These sensitivities provide insight into any changes in resource selection, overall cost of the portfolio, and the ability to meet carbon reduction targets resulting from inputs that deviate from the base planning assumptions. Chapter 3 (Portfolios) introduces this sensitivity analysis, which is described in more detail in Appendix E (Quantitative Analysis).

Conclusion

The Carbon Plan modeling process utilized the EnCompass modeling tool to analyze future system operations and needs through a multi-step capacity expansion and production cost modeling process that also analyzed coal unit retirements. The Companies also performed additional more granular reliability modeling to ensure day-to-day and long-term system reliability as the system transitions to larger levels of carbon-free variable energy resources. Key inputs and assumptions relied upon in the development of the portfolios were informed by multiple stakeholder input sessions and provide reasonable technology cost and planning assumptions based on this current snapshot in time. As highlighted in this Chapter, these costs and assumptions are subject to change in future Carbon Plan updates given the extremely dynamic nature of the energy industry and supply chain both domestically and globally.

A diverse set of portfolios was evaluated from an hourly perspective through 2050 with increased granularity from a reliability perspective through 2035. Increased attention was given to the cost, executability and reliability through 2035 by which time all portfolios will achieve the interim 70% CO_2 reduction target. The Carbon Plan modeling process also provides insight into how each portfolio performs against the core Carbon Plan objectives of CO_2 reduction, affordability, reliability, and executability. Chapter 3 (Portfolios) discusses how the final portfolios developed through the modeling process meet these objectives.