PUBLIC

INFORMATION SHEET

PRESIDING: Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Monday, May 22, 2023
TIME: 1:00 p.m. – 2:42 p.m.
DOCKET NOS.: E-2, Sub 1311
COMPANY: Duke Energy Progress, LLC
DESCRIPTION: In the Matter of Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a 9.5 MW Solar Photovoltaic Generating Facility in Buncombe County, North Carolina

VOLUME NUMBER:

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

REPORTED BY: Tonja Vines		TRANSCRIPT PAGES:	95
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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, May 22, 2023

TIME: 1:00 p.m. - 2:42 p.m.

DOCKET NO: E-2, Sub 1311

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a 9.5 MW Solar Photovoltaic Generating Facility in Buncombe County, North Carolina

A P P E A R A N C E S:

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

	IDENTIFIED/ADMITTED
Duke Energy Progress, LLC Application, Exhibits 1 - 4, and Supplemental Exhibits 3 - 4	/10

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: May 22, 2023 DOCKET NO.: E-2, Sub 1311

ATTORNEY NAME and TITLE: Jason Higginbotham, Associate General Counsel

FIRM NAME: Duke Energy

ADDRESS: 410 Fayetteville St

CITY: Raleigh STATE: NC ZIP CODE: ____

APPEARANCE ON BEHALF OF: Duke Energy Progress

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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☑ **Yes, I have signed the Confidentiality Agreement.**

Email: jason.higginbotham@duke-energy.com

SIGNATURE: ____

(Required for distribution of CONFIDENTIAL transcript)

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: May 22, 2023 DOCKET NO.: E-2, Sub 1311

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APPEARANCE ON BEHALF OF:

Duke Progress Energy, LLC

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION
PUBLIC STAFF - APPEARANCE SLIP

DATE May 22, 2023 DOCKET #: E-2, Sub 1311

PUBLIC STAFF ATTORNEY Anne Keyworth

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1311

In the Matter of	)	
Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a Solar Generating Facility in Buncombe County, North Carolina	)	APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT THE ASHEVILLE PLANT SOLAR GENERATING FACILITY

Duke Energy Progress, LLC ("DEP" or "the Company") hereby applies to the North Carolina Utilities Commission ("Commission") pursuant to North Carolina General Statutes ("N.C. Gen. Stat.") § 62-110.1 and Commission Rule R8-61 for a Certificate of Public Convenience and Necessity ("CPCN") authorizing the construction and completion of a solar photovoltaic electric generator on DEP-owned land in Buncombe County, North Carolina ("Asheville Plant Solar Facility" or "Project"). The Asheville Plant Solar Facility is consistent with the Company's commitment to construct at least 15 MW of solar in the Asheville region and the Commission's March 28, 2016, *Order Granting Application, in Part, with Conditions, and Denying Application in Part* in Docket No. E-2, Sub 1089 ("the WCMP CPCN Order") directing DEP to follow through on that commitment. The Application is supported by the pre-filed direct testimony of Justin LaRoche, Director of Renewable Development, and the Exhibits required by Commission Rule R8-61. In accordance with Commission Rule R8-61(b)(1), Exhibit 1A contains portions of the 2020 DEP Integrated Resource Plan ("IRP") and the Commission's December 30, 2022 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning ("Carbon Plan

Order”), the as-filed 2022 joint DEP and Duke Energy Carolinas, LLC’s (“DEC” and together with DEP, “Duke Energy”) Carbon Plan (“Duke Energy Carbon Plan”) as well as Appendix E (Solar) to the 2022 Carbon Plan. Exhibit 1B contains the additional resource planning information required by Rule R8-6(b)(1). Exhibit 2 (Siting and Permitting Information), Confidential Exhibit 3 (Equipment and Cost Information), and Exhibit 4 (Construction Schedule and Other Facility Information) contain the additional information required by Commission Rules R8-61(b)(2) – (4). All exhibits are incorporated as part of the Application. The Asheville Plant Solar Facility is also included in DEP’s Application to Adjust Retail Base Rates and for Performance-Based Regulation, and Request for an Accounting Order (“PBR Application”) filed in Docket No. E-2, Sub 1300. In further support of the Application, the Company respectfully submits the following:

GENERAL INFORMATION

1. The Applicant’s general offices are located at 410 S. Wilmington Street, Raleigh, North Carolina, and its mailing address is:

Duke Energy Progress, LLC
410 S. Wilmington Street, NCRH 20
Raleigh, North Carolina 27601

2. DEP is a public utility operating in North Carolina and South Carolina where it is engaged in the generation, transmission, distribution, and sale of electricity for compensation and is regulated by this Commission.

3. The names and addresses of Applicant’s attorneys are:

Jason A. Higginbotham
Associate General Counsel
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Copies of all pleadings, testimony, orders, and correspondence in this proceeding should be served upon the attorneys listed above.

THE WESTERN CAROLINAS MODERNIZATION PROJECT

4. As discussed in the WCMP CPCN Order, the Western Carolinas Modernization Project ("WCMP") is an energy innovation project for the Asheville area in the western region of DEP. Through this project, DEP has partnered with the local community and elected leaders to help transition Western North Carolina to a cleaner, smarter and more reliable energy future. DEP is committed to this partnership to promote the efficient use of energy in the region. The WCMP has allowed DEP to retire the previously operational Asheville coal units and replace that capacity with new natural gas combined cycle units.

5. The WCMP calls for the deliberate investment in distributed energy resources, including solar and storage, and increased promotion and access to new and existing demand-side management and energy efficiency ("DSM/EE") programs. In the WCMP CPCN Order, the Commission accepted DEP's commitment to solar and storage projects and directed DEP, "to file as soon as practicable the CPCN to construct at least 15

MW of solar at the Asheville Plant or in the Asheville region" and "to move forward in a timely manner with the 5 MW storage project in the Asheville region." WCMP CPCN Order at p. 38.

6. The Commission previously approved CPCN applications for DEP's Hot Springs Microgrid ("Hot Springs")[1] and Woodfin Solar Facility projects ("Woodfin")[2]. Hot Springs included 2 MWac of solar and 4 MW of battery storage and was placed in service in July 2022. Woodfin provides another 5 MW of solar and is expected to be placed in service in Summer 2023. Combined, these two projects provide 7 MW of solar generation. The addition of the Asheville Plant Solar Facility will allow DEP to meet its commitment to construct at least 15 MW of solar at the Asheville Plant or in the Asheville region.

PROJECT OVERVIEW

7. The Asheville Plant Solar Facility consists of an approximately 9.5 megawatt ("MW") alternating current ("AC") / ~12.8 MW direct current ("DC") solar photovoltaic ("PV") electric generator that will be located at the Asheville Plant site. It is part of the WCMP and complies with the Commission's directive in the WCMP CPCN Order that DEP move forward in a timely manner on DEP's commitment to site solar and energy storage in the Asheville region. Construction of the Asheville Plant Solar Facility will further transform the Asheville Plant site while promoting the continued transition to clean energy.

8. In addition, finding available sites within the Asheville region that can support a solar facility of this scale while limiting environmental impacts (such as tree

[1] Docket No E-2, Sub 1185 CPCN Order, May 10, 2019.
[2] Docket No. E-2 Sub 1257 CPCN Order, April 20, 2021.

clearing and wetland disturbance) is challenging, given the topography and high land cost in the Asheville region. The Asheville Plant site is an optimal location for the Asheville Plant Solar Facility because it: (1) is a brownfield development on a former coal generation site and suitable for solar, (2) has the acreage sufficient for siting multiple MW of solar generation and is primarily clear of trees and debris; (3) has the point of interconnection onsite, does not require additional land rights or permitting to access the interconnection facilities, and takes advantage of the existing transmission switching station onsite; (4) is not adjacent to residential customers; (5) does not require tree clearing to support the solar facility; and (6) is Company-owned.

TECHNOLOGY

9. The Asheville Plant Solar Facility consists of PV modules affixed to a fixed-tilt racking system, 20 degree fixed-tilt racking, solar inverters, electrical protection and switching equipment, and step-up transformers. Additional equipment to support the facility will include circuit breakers, combiners, surge arrestors, conductors, disconnect switches, and connection cabling. The Project will install solar PV modules on (i) the former coal ash basin that is being fully removed and decommissioned, (ii) the former coal plant itself that is being fully removed and decommissioned and (iii) on top of the lined landfill being constructed on site.

10. Exhibit 2 contains additional details concerning the Asheville Plant Solar Facility site and permitting details and includes Appendices 1 and 2 that provide site layout and other information. Exhibit 3 contains additional details related to cost and other financial aspects of the project. Exhibit 4 identifies details related to the anticipated construction schedule and other aspects of the facility. The Asheville Plant Solar Facility

will be interconnected to the existing Asheville Steam Electric Plant West 115kV Bus using the vacant old Unit #1 bay position[3].

NEED FOR THE PROJECT

11. The Asheville Plant Solar Facility is a key component of the WCMP. In addition to allowing DEP to meet its commitments, construction of the facility is consistent with, and will promote, the public policies of North Carolina, specifically those enumerated in Senate Bill 3 (Session Law 2007-397) and will contribute to achieving the carbon dioxide ("CO_2") reduction targets established by HB 951 (Session Law 2021-165).

12. Among other requirements, Commission Rule R8-61 requires a description of "[t]he extent to which the proposed facility would conform to the utility's most recent biennial report and the most recent annual report that was filed pursuant to Rule R8-60." The Commission has recently acknowledged the substantial overlap between the IRP process pursuant to N.C. Gen. Stat. § 62-110.1(c) and the analyses required to meet the CO_2 emissions reduction targets of N.C. Gen. Stat. § 62-110.9. Therefore, the Commission in its November 19, 2021 Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines in Docket No. E-100, Sub 179 delayed the next comprehensive IRP filings under Commission Rule R8-60(h)(1) to September 2023, and in its Carbon Plan Order, directed Duke Energy to file a full Carbon Plan and IRP by no later than September 1, 2023 and to propose rules to govern such new combined process.

13. In light of the fact that this Application is being filed in the midst of the transition period in the IRP structure and rules, out of an abundance of caution, DEP confirms that Asheville Plant Solar Facility is consistent with the Company's 2020

[3] The Project has completed all interconnection studies and has executed a Large Generator Interconnection Agreement.

Integrated Resource Plan ("IRP") and the 2020 IRP Update. The 2020 IRP was filed on September 1, 2020, in Docket No. E-100, Sub 165, and includes an update on the Company's progress on the Western Carolinas Modernization Plan in Appendix N. The 2020 IRP demonstrates that a combination of renewable resources, DSM/EE programs, and additional base load, intermediate, and peaking generation will be required over the next fifteen years to reliably meet customer demand. From a total system perspective, the DEP 2020 IRP identifies the need for approximately 8,800 MW of new resources to meet customers' energy needs by 2035. Additionally, the 2020 IRP calls for 100 MW of energy storage and approximately 930 MW of incremental solar installations from 2021 through 2025.

14. Furthermore, the Asheville Plant Solar Facility is consistent with the Carbon Plan adopted by the Commission in its Carbon Plan Order. The Company's proposed Carbon Plan, filed with the Commission on May 16, 2022, in Docket No. E-100, Sub 179, assumed as a baseline solar generation amounts that included the Asheville Plant Solar Facility. Accordingly, the Asheville Plant Solar Facility is consistent with the 2020 IRP as well as the Carbon Plan.

ENVIRONMENTAL

15. Operation of the Asheville Plant Solar Facility will have no emissions or pollutants, and the generation source of the solar facility's power will be 100% renewable. In addition, the Asheville Plant Solar Facility shall be designed in accordance with State of North Carolina environmental requirements with regard to materials.

COST ESTIMATES

16. The cost estimate for the Asheville Plant Solar Facility is approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The estimate includes Engineering Procurement & Construction ("EPC"), major equipment, labor, and associated permitting and development costs. The average annual operating cost is approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** The costs reflect the requirement that DEP must site the facility in the Asheville region. Any tax credits and accelerated depreciation benefits will offset project costs for the benefit of customers.

17. The Project anticipates qualifying for tax credits available through the Inflation Reduction Act ("IRA"), including a production tax credit ("PTC") or investment tax credit ("ITC"). The Company will use the applicable tax credit in calculating amounts associated with recovery of the Project in retail rates. The Company will carefully examine the appropriateness of utilizing the PTC or ITC based on the facts and circumstances of the Project and will focus on maximizing the value for customers over the life of the Project. As DEP and the entire industry await guidance and official rules from the IRS, it will continue evaluating relevant provisions and applicability for: (1) siting in an energy community; (2) meeting domestic content standards; and (3) meeting prevailing wage standards, although DEP anticipates that the Project will qualify for the energy community adder.

CONTRACTORS

18. The Company will contract with reputable component manufacturers. The Company will also seek to purchase components and services from North Carolina

providers – to the extent that they provide the required functionality and are cost competitive in relation to other options – so as to promote economic development in the State. The Company plans to issue competitive request for proposals ("RFP") to competitively source the EPC and major equipment to execute the project as cost-effectively as possible for customers. DEP has not yet signed any binding agreements, other than a Large Generator Interconnection Agreement, related to the Asheville Plant Solar Facility.

PROCEDURAL ISSUES

The Commission has previously received comments concerning the intersection of the PBR process and the CPCN process. In its comments, Duke Energy emphasized the need for a flexible approach that ensures the required level of review while also optimizing administrative efficiency. Duke Energy also noted that a one-size-fits-all approach was not appropriate given the wide variety of both foreseeable and unforeseeable circumstances that might arise. In its September 8, 2022 Order Approving Template Notice and Providing Initial Guidance on Issues Related to CPCN Process and Cost Recovery Under PBR in Docket No. E-100, Sub 178, the Commission agreed that flexibility on this issue was appropriate and declined to adopt the rigid and formulaic approach urged by certain intervenors.

This set of facts illustrates the wisdom of a flexible approach. In this case, DEP had sufficient information to support inclusion of the Asheville Plant Solar Facility in the DEP PBR Application. As part of the PBR Application, DEP provided substantial detailed information regarding the cost and schedule of the project, along with site plans and other details as summarized in the testimony of witness Justin LaRoche (who is also filing testimony in this proceeding). In addition Public Staff has already issued substantial discovery concerning the Asheville Plan Solar Facility and DEP has provided responses to all questions. In essence, Public Staff and all parties have effectively already had a head start on assessing the Asheville Plan Solar Facility.

As Duke Energy pointed out in comments in Docket No. E-100, Sub 178, both the PBR Application process and the CPCN process require essentially the same determination from the Commission—whether the capital project is needed and whether the projected cost is reasonable. Because there is no fundamental difference between the need and cost determination required under the PBR Application process and that required under the CPCN process, the Commission appropriately retained flexibility to approve cost recovery within a MYRP for a capital project that has not yet obtained a CPCN

In this particular circumstance, DEP is now in a position to submit the CPCN application in parallel with the PBR application process. While this will not be possible in all future scenarios,[4] in this case the submission of the CPCN application allows DEP to seek to fulfill the requirement under N.C. Gen. Stat. § 62-110.1 to obtain a CPCN for the project in parallel with the PBR process.

WHEREFORE, Duke Energy Progress, LLC respectfully requests that the Commission issue a Certificate pursuant to N.C. Gen. Stat. § 62-110.1 that the public convenience and necessity require construction of the Asheville Plant Solar Facility and requests such further relief as the Commission deems just and proper.

[4] For instance, as will be described in more detail in supplemental testimony in the DEP PBR proceeding, the other solar generating facility in the MYRP already has a CPCN that will need to be transferred to DEP.

Respectfully submitted, this the 20th day of January 2023.

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Exhibit 1B

STATEMENT OF NEED

1.1 BIENNIAL AND ANNUAL IRP REPORTS

DEP's 2020 Integrated Resource Plan Biennial Report ("IRP") and the filed 2022 Carbon Plan and Appendices E (Quantitative Analysis) and I (Solar) to the 2022 Carbon Plan are included as Exhibit 1A. The Company's 2020 IRP discusses the Asheville Plant Solar Facility in the Western Carolinas Modernization Plan ("WCMP") update located in Appendix N. The IRP includes 15 MW of solar that represents the solar required to meet the Company's commitment to the WCMP referenced on page 383 of the Company's 2020 IRP. The Company subsequently included the proposed Asheville Plant Solar Facility in the 2022 Carbon Plan as part of the "Incremental Forecasted Solar" described on pages 25 and 26 in Appendix E to the Carbon Plan. The Asheville Plant Solar Facility will enable the Company to provide safe, cost-effective, and reliable service for DEP's customers. Additionally, by constructing and operating the solar facility, the Company will satisfy the solar requirements laid out in the WCMP.

1.2 RESOURCE AND FUEL DIVERSITY

The comprehensive planning process for the 2020 IRP demonstrates that a combination of renewable resources, DSM/EE programs, and additional base load, intermediate, and peaking generation are required over the next fifteen years to reliably meet customer demand. The solar PV generation of the Asheville Plant Solar Facility will contribute to the diverse resource mix identified in the IRP. The solar facility does not require any additional fuel to operate, and no fuel will be stored at the site.

1.3 STATEMENT OF NEED

While PV solar installations provide little to no capacity value at the time of the Company's winter peak, solar does provide valuable energy with zero fuel cost. As such, the Asheville Plant Solar Facility will contribute to meeting the energy needs of the DEP system.

Additionally, as part of the WCMP that was approved in Docket No. E-2, Sub 1089, the Commission accepted DEP's commitment to solar and storage projects and directed DEP "to file as soon as practicable the CPCN to construct at least 15 MW of solar at the Asheville Plant or in the Asheville region. The Commission further urges DEP to move forward in a timely manner with the 5 MW storage project in the Asheville region." (WCMP CPCN Order at p. 38) Along with furthering its commitment to site solar and storage technologies in the western region, the Asheville Plant Solar Facility and future

Company facilities will support the goals and objectives of the WCMP and complies with the WCMP CPCN Order.

The Asheville Plant Solar Facility is projected to produce approximately 19,761 MWh per year. This corresponds to a 23.7% net capacity factor. The service life of the asset is 35 years.

Exhibit 2

SITING AND PERMITTING INFORMATION

2.1. General Site Information

The proposed solar generating facility will be located at the Duke Energy Progress (DEP) Asheville Plant (the plant) site in Buncombe County, North Carolina.

Located in a developing residential and commercial area approximately one mile from the Asheville, NC, corporate limits, this generating facility has been used by Duke Energy Progress since 1964 to provide energy to the region. Bordered by Interstate Highway 26 (I-26) and the French Broad River to the west and US Highway 25 (US-25) to the east, the Asheville Combined Cycle Plant is located on Duke Energy Drive, approximately ¾ mile north of Airport Road.

A color map showing the proposed site boundary and layout, with all major equipment, the E911 street address and GPS coordinates is included as Appendix 1. The Asheville Facility is located in Buncombe County and Appendix 2 shows its geographic location.

2.2. Site Owner, Site Justification and Additional Site Details

The Site Owner is Duke Energy Progress. The plant property occupies about 806 acres of land, a portion of which is occupied by an operating two-unit combined cycle station, two combustion turbines, electrical substations, former ash basins, and an ash landfill. The proposed generating facilities will be located in the footprint of a closed ash basin (64 Ash Basin) just west of the existing combined cycle station. The site is just east of I-26.

To identify sites suitable for solar in the Greater Asheville Region, DEP conducted a GIS solar suitability survey. Many alternative sites were evaluated, including Company-owned land. Due to limitations in terms of parcel size, topography (e.g., slope), availability of land and distribution circuit limitations that would be suitable to support a 15 MW solar installation, DEP has been exploring the possibility of multiple, distributed solar installations in lieu of a single, larger installation. In addition, finding available sites within the Asheville region that can support a solar facility of this scale while limiting environmental impacts (such as tree clearing and wetland disturbance) is challenging given topography and high land cost in the Asheville region.

The Asheville Plant Site was determined to have the following beneficial characteristics: (1) the site is a brownfield development on former coal generation site and suitable for solar, (2) the acreage is sufficient for siting multiple MW of solar generation and the site is primarily clear of trees and debris; (3) the point of interconnection is located onsite, does not require additional land rights or permitting to access the interconnection facilities and takes advantage of the existing transmission switching station onsite; (4) the site is not adjacent to residential customers; (5) the site does not require tree clearing to support the solar; and (6) the property is Company-owned.

The following is further background concerning the site selected.

Geological

The site of the proposed facilities is in the Blue Ridge Physiographic Province (Blue Ridge) of western North Carolina. Asheville is located on an intermountain plateau (a basin in a ridge) between the Great Smoky Mountains and the Blue Ridge Mountains. Rolling topography is typical throughout the area, although the project area has been significantly altered by the development of the prior coal plant. This section describes the regional and local geology of the Blue Ridge for the proposed project site.

The Blue Ridge extends from the Great Smoky fault in the west to the Brevard fault zone in the east and primarily consists of Mesoproterozoic to late Neoproterozoic allochthonous (rock that originated a distance from its present position), crystalline rocks covered by surface soils. The Great Smoky reverse fault is the barrier between the Valley and Ridge physiographic province (Valley and Ridge) and the Blue Ridge, where the igneous rocks of the Blue Ridge were thrust over the 500-million-year-old Paleozoic, sedimentary rocks of the Valley and Ridge. The Brevard fault zone comprises the boundary between the Blue Ridge and the Piedmont physiographic provinces. Studies suggest the Brevard fault last moved almost 200 million years ago, leaving behind a zone of sheared rocks that define the "zone" of the fault. Erosion and weathering of the rocks in the fault zone have made determining the type of fault difficult, although the rocks present in the zone (Mylonites, schists, and gneisses) suggest a lateral movement.

The rocks forming the core of the Blue Ridge Mountains are over a billion years old and are remnants of ancient mountain-building events during a time when the continents merged to form a supercontinent. As the continents began to drift apart, basins were created. One basin in particular, the Ocoee, was filled with sea water. Rivers flowing into this shallow sea carried clay, sand, and gravel and deposited these sediments within the basin. Over millions of years, the waters in the basin subsided; and the accumulated sediments formed the bedrock of the Great Smoky Mountains, the local branch of the Blue Ridge Mountains. The rocks that make up the top of the Blue Ridge Mountains formed as underwater volcanoes erupted and the lava crystallized. As the continents moved back together, these igneous rocks were metamorphosed along with ocean floor sediments and thrusted onto the basin layer during the Grenville Orogeny, forming the Great Smoky Mountains of the Blue Ridge.

The general project area is located on the Great Smoky unit and is composed of many different formations. The project site is directly located on the Ashe metamorphic suite and Tallulah Falls formation. The late Proterozoic, 500 million-year-old Ashe and Tallulah Falls formation is composed of metamorphic rocks, which have gone through metamorphism from high heat and pressure. In some areas, the rocks have gone through lower grade metamorphism than others with only metasedimentary rocks, or rocks that have gone through partial metamorphism. The formation, composed of locally sulfidic muscovite-biotite gneiss, has interlayers and gradational contacts with mica schists, minor amphibolite, and hornblende gneiss. The geometry of these layers is relatively variable, and combined they are approximately 14,000 to 40,000 feet thick, shallowing in an easterly direction. The project site is located in an area where the

Great Smoky unit is roughly 20,000 feet thick. The late Precambrian unit overlies older early Precambrian mafic and calc-alkaline migmatite gneiss, named the Carolina Gneiss. The metamorphic gneiss comprises the bedrock of the area. This rock is agreed to be one of the oldest in the Carolinas, having been created during the Grenville Orogeny about 1.1 billion years ago when the igneous rocks formed from the underwater volcanoes were subjected to metamorphism and uplifted. The Great Smoky unit is firm, and the slight metamorphism that occurred aided in cementing the unit. Both the bedrock and the Great Smoky unit are somewhat resistant to weathering and erosion; however, the sedimentary features of the units are more easily weathered and eroded than igneous formations due to their compositions.

Soil cover of the Blue Ridge consists of residuum of underlying units, alluvium (loose soil and sediments), colluvium (sediments that accumulate at the bottom of slopes), and marine sediments. Site soils mapped by the Natural Resources Conservation Service (NRCS) are shown as Figure 2.6.5-2. The NRCS shows soils at the location of the combined-cycle site and the South and East Construction Facility Areas as water, since these areas are within the 1982 Ash Basin. A majority of this area has since been drained as part of the coal ash removal. The Fuel Oil Storage and portions of the Natural Gas Metering & Regulation (M&R) Station areas are mapped as Udorthents—Urban land complex, 2 to 50 percent slopes. These areas represent developed and highly disturbed soils. The remaining portion of the Natural Gas M&R Station, portions of the East Construction Facility Area, and the entire Rail Unloading Area are located within areas mapped as Clifton-Urban land complex. These clay loam soils have also been altered through development. Areas of udorthents, highly disturbed soils, are also present within the portions of the North Construction Facility Area. Other portions of the North Construction Facility Area represent the least disturbed soils of the project area and consist of Clifton clay loam, moderately eroded soils with slopes ranging from 2 to 30 percent. Clifton clay loam is a deep, well drained, moderately permeable soil on the side slopes and ridges of the Blue Ridge Mountains. The Clifton soils formed in residuum weathering from intermediate and mafic igneous rocks and high-grade metamorphic rocks. According to the geotechnical borings performed within the ash basin, in general, the soil grades upward with deeper soils having larger fragments of residuum. Auger refusal caused by rocks was recorded at approximately 20 to 30 feet deep, while water tables were recorded at greater than 10 feet to deeper than auger refusal.

Aesthetic

The Site is in Buncombe County at the existing DEP Asheville Plant, and it is zoned as Employment District (EMP). The Site is buffered by Lake Julian to the north and east, by forested vegetation to the northwest by Interstate 26 to the west and the Asheville Combined Cycle Station to the south. Due to surrounding land uses, the facility will have minimum viewshed by the public. Site access is limited to the north via Duke Energy Ln off New Rockwood Rd.

Environmental Justice

To ensure the Asheville Solar project and activities undertaken by Duke Energy provide meaningful involvement and fair treatment to all our community members, an initial Environmental Justice Technical Assessment was performed utilizing the EPA EJSCREEN tool to identify EJ risks and aid the project team with developing mitigation strategies to enhance engagement and minimize impacts.

The initial EJ Technical Assessment for the Asheville Solar project found that the Low-income population is at the state average (33% vs. 33%) and the Limited English-speaking population is above the state average (9% vs 2%). Based on this Assessment and historic site knowledge, Duke Energy will engage these communities to solicit input and use its feedback to inform our business decisions and collaborate on solutions that maintain the health and safety of the community.

The Asheville Plant Solar project plans to utilize brownfield areas to deliver local access to clean, renewable, and reliable electrical generation resources. This project will provide short-term economic benefits during construction including purchase of materials, equipment, and services from local and regional businesses and increase in employment and income for construction workforce. Long-term benefits include increased tax revenue to support local services and local access to renewable energy generation.

<u>Ecological</u>

Threatened and Endangered Species

Based on desktop database and literature review, the site consists of an excavated ash basins, historic landfills, former coal fired steam station plant and former lay down areas that have all been graded and regularly maintained. The site consists of grasses and herbaceous vegetation typical of the active land and industrial use. The Migratory Bird Treaty Act ("MBTA") protects more than 1,000 bird species that occur in the U.S., including 13 species of conservation with ranges encompassing the Site. Under the MBTA, it is unlawful to take any migratory bird, or any part, nest, or egg of any such bird. Although tree clearing is not anticipated for construction activities, Duke Energy's Natural Resource Group has developed specific tree-clearing protocols that are incorporated into project planning and disseminated to all sub-contractors. Potential migratory birds habitat outside of the proposed project boundaries include Back-billed Cuckoo, Bobolink, Canada Warbler, Cerulean Warbler, Chimney Swift, Eastern Whip-poor-will, Kentucky Warbler, Northern Saw-whet Owl, Prairie Warbler, Prothonotary Warbler, Red headed Woodpecker and Rusty Blackbird.

Adjacent forested habitat outside the study area may provide suitable summer roosting sites for the northern long-eared bat ("NLEB") and gray bat. Bat surveys are recommended (acoustic or mist net) to confirm presence or absence of the NLEB and gray bat and may be required by the USFWS. No bald eagle nests are known to be within or in one mile proximity of the overall proposed work areas. The Carolina northern flying squirrel, Blueridge goldenrod, mountain sweet pitcher plant, spreading avens, and rock gnome lichen are all species that occur in high elevation habitats. The site's elevation is approximately 2,100 – 2,220 feet in elevation. Due to existing construction activities and land use, these species are not considered for consideration in this characterization due to lack of suitable habitat and existing conditions.

Cultural Resources

No structures or Districts were listed on the NRHP within the project area or within a half mile radius. According to the North Carolina Office of State Archeology records, the study area has not been surveyed for archeological resources.

Habitat

The Site consists primarily of excavated and capped ash basins, historical landfills and industrial areas associated with the existing combined cycle plant. Available aerial imagery (Google Earth 2017) depicts the project area as cleared and graded with no existing trees but Astro turf and grass vegetation are present. According to the USGS topographic map, the Site ranges in elevation from approximately 2,100 to approximately 2,220 feet above mean sea level (AMSL).

A review of the Protected Areas Database of the U.S. (PAD-US 2018) reveals no protected areas within the Site; however, several protected areas are located within five (5) miles of the Site, including the Buncombe County Park, a Conservation Trust of North Carolina Easement, the Sandy Mush Game Land, a Southern Appalachian Highlands Conservancy Easement, the Southern Appalachian Highlands Conservancy Preserve, the Thomas Wolfe Memorial State Historic Site, and the Western Governors Residence.

Meteorological

2.6.7.1 Climatology

The Asheville Plant is located in Skyland, in southwestern North Carolina between the French Broad River and Lake Julian in Buncombe County, south of Asheville.

It is in the southern portion of the Appalachian Mountain Range. The plant's height above sea level is approximately 2,140 feet, and it is surrounded by mountains with peaks up to 6,000 feet high. It is located about 270 miles from the Atlantic Ocean and about 400 miles from the Gulf of Mexico. The mountainous terrain and inland location allow for cool winters and moderate summer temperatures.

Due to the high elevation, temperatures do not normally get above 90 degrees Fahrenheit (F), with only about nine days on average annually getting above this mark. Temperatures often fall below freezing, mostly in the winter seasons, with an average of 98 days per year reaching 32 degrees F or below. Because of the mountainous terrain, fog and low clouds occur frequently, typically in the mornings before they are burned off with diurnal heating. On average, Asheville experiences 68.3 days of fog with less than a quarter mile visibility, 3 - 5 inches of precipitation each month, and about 48 inches of precipitation annually. Strong thunderstorms are typical across the region, mostly during the spring and fall.

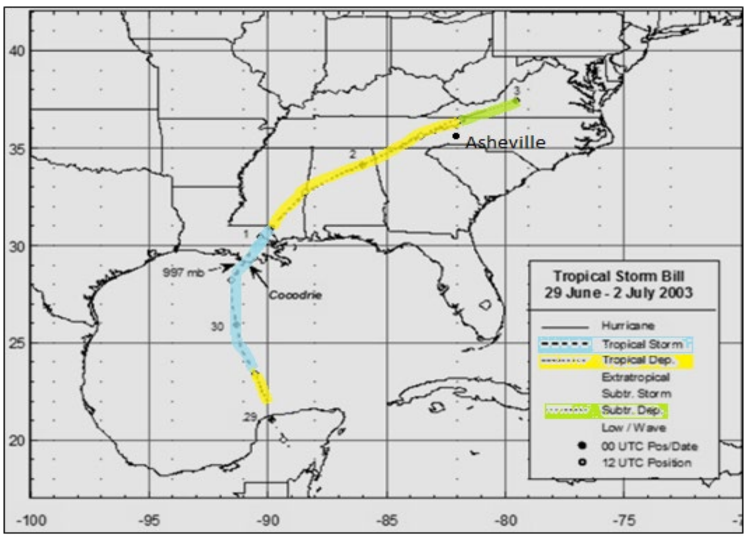
Flooding is a primary natural hazard for the Asheville area. The French Broad River floods about every 12 years, often caused by storms that move up from the Gulf of Mexico. During the drier parts of the year or during drought-like conditions, isolated wildfires are a threat. Most of these are caused by people, lightning, or controlled burns.

Tornadoes occur rarely. Sixteen tornadoes have been reported in Buncombe County since 1950. All tornados reported were weak; the largest reported was a 2 on the Enhanced Fujita (EF) Scale, which rates the strength of tornadoes from 1 to 5, based on the damage caused.

Because of Asheville's distance from a coastline, hurricanes are not considered a threat; however, impacts from tropical systems can bring gusty winds and heavy rainfall. A recent example, Tropical Storm Bill, made landfall along the Gulf coast in July of 2003 (Figure 2.6.7.1-1) and tracked northeast towards the southern Appalachians. Bill dumped 2.23 inches of rain in a 24-hour period at the Asheville

Regional Airport (KAVL) and more rain just to the southeast. Between July 10 and 16, 1916, two hurricanes made landfall, one from the Gulf and one from the Atlantic Ocean, and made their way to Asheville as tropical storms. These two tropical systems were responsible for the "Great Flood of Asheville," during which the French Broad River rose to 23.1 feet above normal.

Figure 2.6.7.1-1. Tropical Storm Bill in 2003.
Downgraded to a tropical depression as it passed near Asheville.



Winter precipitation comes mostly from migratory low pressure systems, as well as arctic and sub-arctic fronts. From December to February, the average high temperature is 48.6 degrees F. The average low for the same period is 26.6 degrees F. The all-time recorded low temperature for Asheville was -16 degrees F on January 21, 1985.

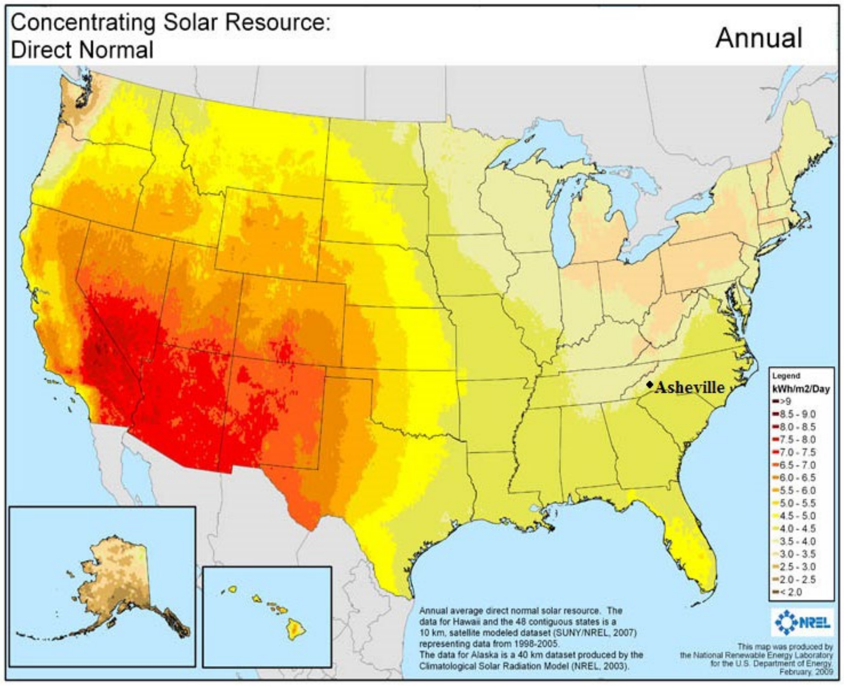
The two main types of winter weather systems are cold fronts that approach from the northwest and low pressure systems coming up from the Gulf of Mexico. Gulf systems tend to bring more moisture to the area and often combine with cold air from the north to produce frozen precipitation. The two main winter precipitation types for Asheville are rain and snow. Sleet and freezing rain are possible but less common, with an average of 0.2 - 0.3 inches of freezing rain annually. On average,

Asheville receives around 15.4 inches of snow a year. The largest snowfall event on record occurred March 12 – 14, 1993, with a total of 18.2 inches of accumulation. Winter is the "drier" season in Asheville with a monthly average of 3.57 inches, coming just under the fall average of 3.7 inches per month.
Summers in this region are pleasant, with monthly highs around 81-82 degrees F. The average low is around 60 degrees F. Summer precipitation averages 4.47 inches of rain each month. This can originate from a variety of weather systems. Typically, general air mass showers and storms (also known as "pop-up" storms) are likely in the evenings due to differential heating. Fronts that push in from the north occasionally produce showers and storms in the area during the summer months as well.

Spring and fall are transitional seasons. Spring weather patterns shift as the jet stream migrates back up to a northern position, having less of an impact on the Carolina mountains. The weather changes from arctic and sub-arctic fronts to more pop-up showers and low pressure systems. Annually Asheville experiences around 39.8 thunderstorm-days per year, with most storms happening in late spring (April and May), and early fall (September and October). Fall is just the opposite, as the jet stream falls down into the Deep South and fronts become the dominant weather feature.

Solar radiation is rates slightly above average for the eastern United States. Asheville averages around 4 kWh/m^2/day (kilowatt-hours per square meter per day), as shown in Figure 2.6.7.1-2. On average, KAVL experiences 99 clear days, 113 partly cloudy days, and 153 cloudy days annually.

Figure 2.6.7.1-2 United States Average Solar Availability: Average kWh per Square Meter per Day



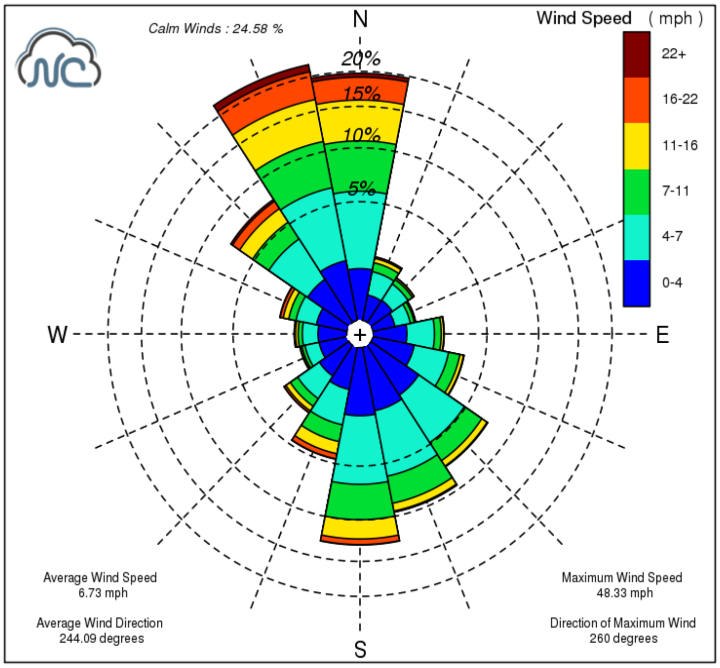
The seasonal mixing height is affected by both diurnal and seasonal patterns. The annual minimum daily mixing height occurs typically in the morning and is around 312 meters. The average maximum daily mixing height, typically occurring in the afternoon, is 982 meters. The seasonal mixing heights for Asheville, NC, are given in Table 2.6.7.1. Winds at KAVL come mostly from the north-northwest and south-southeast because of the Asheville plateau's orientation with mountains on both the east and west sides. The Wind Rose in Figure 2.6.7.1-3 gives wind information from 1948 to June 19, 2015.

Table 2.6.7.1. Seasonal Mixing Heights for Asheville, NC (1986-2006). This table shows the seasonal mixing heights in the morning and afternoon in meters. The data represented in the table is from 1986 to 2006 at KAVL. The data was collected twice a day each month over the specified time period.

Winter	356 m	769 m
Spring	366 m	1236 m
Summer	261 m	1037 m
Fall	263 m	887 m

Figure 2.6.7.1-3

Wind Rose for Asheville Regional Airport (KAVL)
Jan. 1, 1948 to Jun. 19, 2015



2.6.8 Seismic

The project site is located in an area of relatively low to moderate seismic activity. The facilities will have adequate protection in the event of an earthquake. This section presents a description of the seismic conditions of the project area as well as a brief history of earthquakes affecting the project vicinity. The estimated Peak Ground Acceleration (PGA) of the area is also provided. A more comprehensive review of the historical seismic activity affecting this area of North Carolina can be found in Appendix D.

The central and eastern sections of the United States have a low recurrence of high magnitude (4.5 and higher on the Richter scale) earthquakes. Most earthquakes in the eastern United States are classified as minor (less than a magnitude of 4 on the Richter scale) or micro (less than a magnitude of 3); however, the strong and rigid basement rock enables the earthquakes to travel farther than in other parts of the Unites States. Therefore, structures built in this area will be designed for ground motion from distant locations.

North Carolina is on top of a continental passive margin. A passive margin is where oceanic crust meets continental crust but does not submerge. Instead, the oceanic and continental crust is one plate. The eastern United States is on a plate, rather than at a plate boundary, where earthquakes commonly occur (e.g., California). The faults in North Carolina are inactive, and local earthquakes can be attributed to small, random, scattered movements of the earth's crust. Consequently, historical earthquakes have been generally recorded as less than three in magnitude on the Richter Scale. The Richter Scale is a logarithmic scale used to compare the size of earthquakes through the measurement of the amplitude of waves, where each whole number increase on the scale represents an increase of approximately 31 times more energy. Western North Carolina has recorded a group of earthquakes that span to east Tennessee. This particular grouping is part of the Eastern Tennessee Seismic Zone (ETSZ). Earthquakes are frequently recorded in this zone, and they can occasionally be felt as far away as Asheville.

On October 29, 1915, an earthquake near Marshall, North Carolina, also affected the Asheville area, measuring Intensity V on the Mercalli Scale. The Mercalli Scale was developed prior to the Richter Scale and measures earthquakes based on the perceived shaking and damage done by the earthquake. The largest earthquake recorded in North Carolina occurred outside of Asheville on February 21, 1916. This event was estimated as a 5.5 on the Richter scale and recorded as Intensity VII on the Mercalli Scale. The damage from the 1916 earthquake consisted of cracked plaster, fallen crockery and fallen bricks. In November 1928, an earthquake in Newport, Tennessee, resulted in an Intensity VI movement near Asheville. In 1957 Asheville was affected by two aftershocks of an Intensity VI earthquake whose source was several miles away in western North Carolina.

The USGS assesses seismic hazard by calculating the probability that an earthquake will generate an amount of ground motion exceeding a specified reference level in a certain time period, typically 50 years. Hazards are based on the magnitude and distance of potential earthquakes, the frequency at which these events are likely to occur, and the amount of movement that is expected to occur from the earthquakes. To estimate hazards, the National Seismic Hazard Mapping program developed by the USGS uses peak ground acceleration (PGA), which is the largest increase in velocity recorded by a particular station during an earthquake. PGA is expressed as a fraction of standard gravity (g) (the acceleration due to earth's gravity, i.e., the g-force). For the Asheville area the PGA is 0.05 g, with a 10 percent probability of exceedance in 50 years and a 476-year return period (recurrence interval). For a two percent probability of exceedance in 50 years, a return period of 2,475 years, the USGS estimates a PGA value of 0.15 g for the site. An estimated PGA of 0.08 to 0.16 roughly translates into an intensity of VI, which results in strong shaking, and light potential damage. Figure 2.6.8 (Seismic Hazard and Earthquake Location Map) shows the two percent probability of exceedance in 50 years, PGA contours, regional earthquake source information, and a 50-mile radius for the proposed project site.

After ash removal has been completed, fill material will be used to elevate the grade of the locations for the power blocks of the proposed generating facilities. The potential for low to moderate shaking will be considered when selecting the fill material and determining compaction requirements for construction. The regional PGA values will be used in facility design; therefore all structures should perform satisfactorily during a seismic event.

Water Supply

2.6.9 Water Supply

The Asheville Plant Solar project site is in the Upper French Broad River basin, Hydrologic Unit Code (HUC) 06010105. This river system is part of the Tennessee River basin, which ultimately empties into the Mississippi River system and the Gulf of Mexico. The Upper French Broad basin drains the western slope of the Eastern Continental Divide and encompasses 1,658 square miles from its headwaters in Transylvania County to the Tennessee-North Carolina state line. According to NC DEQ, approximately 70% of the Upper French Broad basin is forested, 14% is agriculture, and 12% is developed.

The project site generally slopes west towards the French Broad River, with northern portions of the project area sloping north and east toward Lake Julian. The French Broad is designated as Class B (waters used for primary recreation and other uses suitable for Class C, such as fishing, wildlife, fish consumption, aquatic life, and agriculture). The water quality of the French Broad River basin is generally good, although the segment of river at the project site is listed as impaired for fecal coliform.

Lake Julian, to the north of the site, was created by impounding Powell's Creek to serve as part of the cooling system for the Asheville Plant. This 321-acre lake consists of a 106-acre farm where the steam station discharged cooling water and a 215-acre main body. The lake's 4.8-square-mile watershed is comprised of primarily residential and urban land uses. The existing intake structure for the combined cycle station is located along the southwest shore of the main body of the lake, near the dam. During periods of low rainfall and high evaporative loss, makeup water is pumped from the French Broad River to ensure an adequate supply of cooling water for steam station operations.

The lake is designated as Class C (waters supporting aquatic life and secondary recreation uses such as wading, boating, and other uses involving human body contact with water). The lake has relatively clear water, low nutrient concentrations, and low biological productivity. Lake Julian was determined to be consistently oligotrophic since it was first monitored in 1990.

The existing Asheville Combined Cycle Plant operates under NPDES NC0000396 (effective January 1, 2006), which authorizes the following:

- Discharge from the ash pond treatment system, which receives ash transport water, storm water runoff, various low volume wastes (such as HRSG blowdown, backwash from the water treatment processes, cooling tower blowdown, plant drains), and air preheater cleaning water. Chemical metal cleaning wastewater discharged from Internal Outfall

004 may also be discharged from Outfall 001 after DWQ approval (Outfall 001).

- Evaporator system discharge. This outfall is located directly on Lake Julian (Outfall 002).
- With prior approval from DWQ, the discharge of the chemical metal cleaning treatment system may be permitted to the ash pond treatment system (Internal Outfall 004).

Duke Energy Progress currently is pursuing an NPDES permit modification to authorize dewatering activities associated with ash removal.

Potential impacts to water quality due to the construction of the proposed facilities include possible introduction of sediment into Lake Julian or the French Broad River. The implementation of erosion and sediment control best management practices during construction will minimize the potential for such impacts. These controls will be implemented under erosion-control plans, as required by Buncombe County Stormwater and State Stormwater Permits.

The existing intake on the French Broad River will continue to be used to provide make-up water to Lake Julian for the station cooling and make-up water needs.

Population

This facility is in Arden, NC which has a population of 20,606 people as of the 2020 census. It is part of the Asheville Metropolitan Statistical Area (AMSA). The AMSA between 2010 and 2020 has experienced an increase in population of 10%, going from 424,858 to 469,454 people.

2.3. Transmission Line

The Asheville Plant Solar Facility will interconnect at the existing Asheville Steam Electric Plant (SEP) West 115kV Bus using the vacant old Unit #1 bay position (as shown on both Appendix 1 and 2).

2.4. Nameplate Generating Capacity

The nameplate generating capacity is 9.5 MW AC / ~12.8 MW DC.

2.5. Permitting Information

No federal, state, or local air quality programs are associated with this facility.

Below is a list of Agencies from which approvals may be sought, if necessary.

Federal

- US Army Corps of Engineers (USACE):
    - Jurisdictional Determination.

- Environmental Protection Agency (EPA):
    - Spill Prevention and Control Plan (SPCC)
        - Prepare and update as required. No submittal or filing required.

- Federal Aviation Administration
    - File a Notice of Proposed Construction.

North Carolina

- NC Division of Energy, Mineral, and Land Resources (NC DEMLR):
    - Stormwater Construction General Permit NCG010000 (Erosion and Sedimentation Control Plan).

- NC Division of Water Resources (NC DWR):
  - 404, Riparian Buffer, Stream and Wetland Mitigation Program.

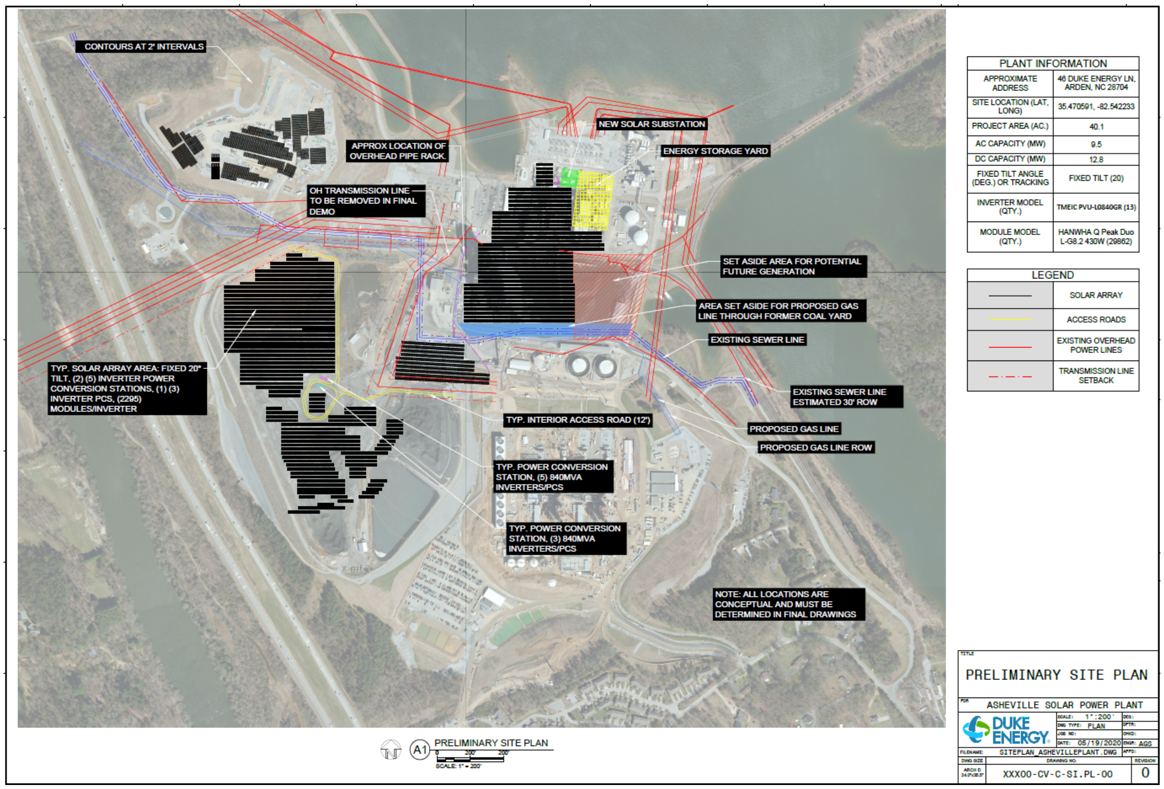
- NC Public Utilities Commission:
  - Certificate of Public Convenience and Necessity (CPCN).

NC Department of Transportation:
  - Oversize/Overweight Permit (if necessary).

- Buncombe County:
  - Conditional Use Permit, Post Construction Stormwater, Floodplain Permitting.

Appendix 1 to Exhibit 2

PRELIMINARY SITE LAYOUT



Appendix 2 to Exhibit 2

VICINITY LOCATION MAP

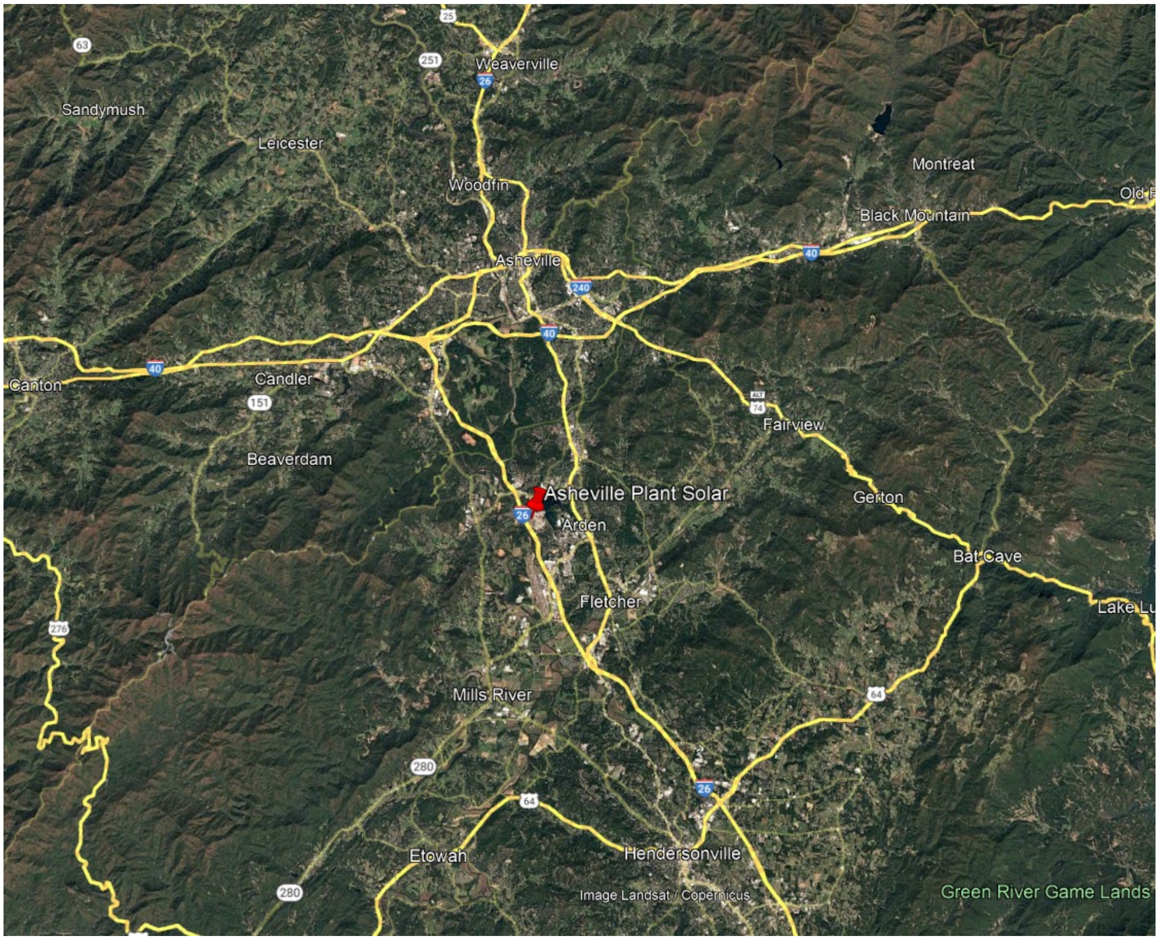


Exhibit 3

EQUIPMENT AND COST INFORMATION

3.1 Estimated Construction Costs

The estimated cost of the Asheville Solar Facility is approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3.2 Estimated Construction Costs Expressed as $/MW

Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3.3 Estimated Annual Operating Expenses by Category

Average annual operating expense is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3.4 Estimated Annual Operating Expenses Expressed as $/MWH

Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** averaged over 35 years.

3.5 Projected Cost of Major Components and Schedule for Incurring Costs

[BEGIN CONFIDENTIAL]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
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[END CONFIDENTIAL]

3.6 Utility Revenue Requirement During Construction

The Construction Work in Progress for this project will not be included in rate base, but instead will accrue AFUDC of $854,000. Therefore, there should be no impact on revenue requirements during the construction period.

3.7 Anticipated In-Service Expenses During the First Year

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**.

3.8 Anticipated Impact on Customers Rates. Estimated Construction Costs

The annual North Carolina retail revenue requirement for Year 1 of operation is estimated to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which would result in an approximate average retail rate increase of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Exhibit 4

CONSTRUCTION SCHEDULE AND OTHER FACILITY INFORMATION

4.1. Anticipated Construction Schedule

Should the Commission approve the CPCN request, the Ashville Plant Solar Facility, construction would be targeted to allow for commission of the project by September of 2025, assuming timely authorization to procure major equipment and obtain necessary permits and approvals. A more detailed preliminary schedule can be seen below.

Activity Name	Milestone Date
Notice to Proceed	Q4 2024
Engineering/Procure Equipment	Q3 2023 – Q4 2024
Site Mobilization	Q4 2024 / Q1 2025
Placed in Service	September 2025
Final Commission	Q1 2026

4.2. Additional Generating Facility Information

The specific equipment suppliers have not been selected at this time for every component. However, the following is a preliminary description of the major components of the Asheville Plant Solar Facility.

Solar Array

The solar array is expected to consist of 1,106 strings of 430W modules for a total capacity of 12.8 MWdc.

Racking System

A fixed tilt racking system will be used to mount the modules. The racking will be set at a fixed tilt of 20°.

Solar Power Conversion Devices

Duke Energy plans to use a total of 13 TMEIC PVU-L0840GR inverters. Each sting inverter has a capacity of 840 kW to meet the net export capacity of 9.5 MW.

4.3. Qualifications and Selection Process for Principal Contractors

The Company plans to issue a competitive request for proposals ("RFP") to competitively source the EPC and major equipment to execute the project as cost-effectively as possible for customers. These activities are planned for the second half of 2023.

4.4. Risk Factors Related to the Construction and Operation of the Generating Facility.

There would be no additional risk for the construction or operation of this solar facility compared to other facilities owned or operated by Duke Energy.

Exhibits 1-4
/A

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

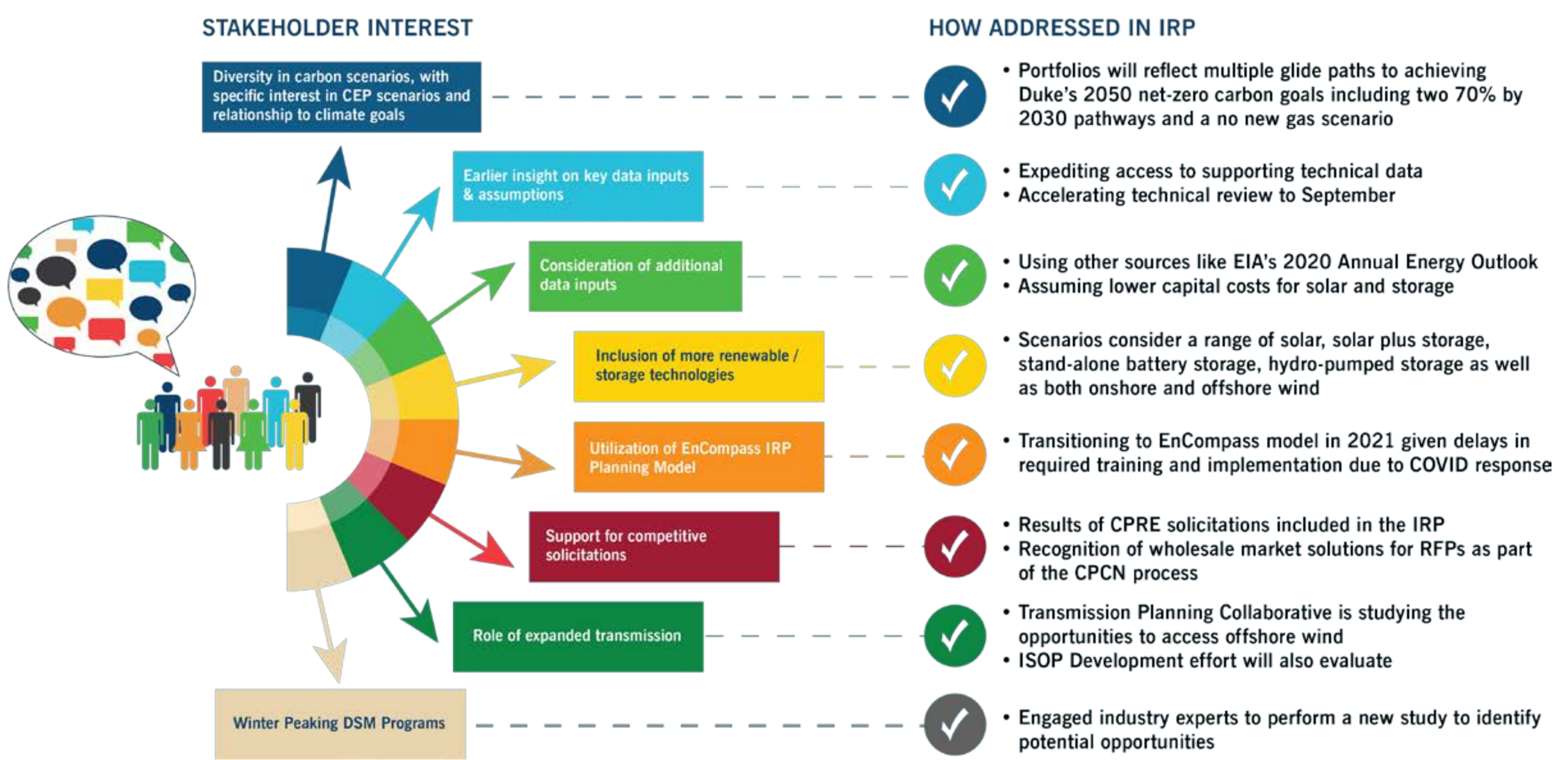
Docket No. E-100, Sub 165

DUKE ENERGY PROGRESS 2020 INTEGRATED RESOURCE PLAN CONTENTS

Corrected 11.06.2020

ATTACHMENTS FILED AS SEPARATE DOCUMENTS:

the planning process. The Company initiated this engagement with local listening sessions followed by a series of virtual events which were facilitated by ICF,[6] and consisted of an IRP 101 education session and three stakeholder virtual forums, with over 200 participants from stakeholder groups involved across all activities. The forums included presentations and discussions from Duke Energy subject matter experts, and enabled discussion around the areas of greatest interest to stakeholders as identified through listening sessions, and pre- and post-engagement surveys. The sessions drew unique external stakeholder participants from across the Carolinas and provided recommendations in the areas of resource planning, carbon reduction, energy efficiency and demand response. Input from stakeholders helped shape the IRP development, and influenced the evaluation of different pathways in the 2020 IRP. A summary report of these activities was developed by ICF and can be found on [Duke Energy's web site](www.duke-energy.com/irp)[7].



2020 IRP INFORMED BY NEW STUDIES, ILLUSTRATES MULTIPLE PATHWAYS

The 2020 IRP is informed by several new studies and analysis as well as collaboration and input

[6] www.icf.com, ICF, an advisory and professional services company with a specialty in utility sector planning.
[7] www.duke-energy.com/irp.

weather, regional economic and demographic trends, electricity prices and appliance efficiencies. The average annual growth rate of Residential energy sales in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021-2035 is 1.4%.

The three largest sectors in the Commercial class are offices, education and retail. The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. Commercial energy sales are expected to grow 0.1% per year over the forecast horizon.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

The Company continues to look at ways to improve the load forecasting methodology in order to develop the most accurate and reasonable demand forecasts for DEP. The 2020 load forecast update is lower compared to the 2019 IRP. The decrease in the 2020 update is primarily driven by refinements to peak history, the addition of 2019 peak history and declines in Commercial and Industrial energy sales. The 2020 update also includes revised projections for rooftop solar and electric vehicle programs and the impacts of voltage control programs. The key economic drivers and forecast changes are shown below in Tables 3-A and 3-B. A more detailed discussion of the load forecast can be found in Appendix C.

TABLE 3-A
KEY DRIVERS

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

Table 3-B reflects a comparison between the 2020 and 2019 growth rates of the load forecast with and without impacts of EE.

TABLE 5-A

DEP BASE WITH CARBON POLICY TOTAL RENEWABLES

DEP BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	8	131	0	1,305	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	8	131	0	1,329	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	7	120	0	1,345	41	3	120	0	165
2027	4,184	88	120	0	4,392	1,223	48	120	0	1,391	42	22	120	0	184
2028	4,239	163	116	0	4,518	1,229	88	116	0	1,433	42	41	116	0	199
2029	4,294	237	60	0	4,591	1,234	128	60	0	1,422	43	59	60	0	162
2030	4,323	436	43	0	4,802	1,237	234	43	0	1,515	43	109	43	0	195
2031	4,352	634	43	0	5,029	1,240	340	43	0	1,623	44	158	43	0	245
2032	4,331	856	42	0	5,228	1,238	460	42	0	1,740	43	214	42	0	299
2033	4,311	1,076	42	150	5,579	1,236	581	42	12	1,870	43	269	42	53	406
2034	4,290	1,296	41	300	5,928	1,234	701	41	24	2,000	43	324	41	105	513
2035	4,270	1,514	41	450	6,276	1,232	822	41	36	2,131	43	379	41	158	620

Data presented on a year beginning basis.

Solar includes 0.5% per year degradation.

Capacity listed excludes REC Only Contracts.

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.

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storage costs evolve. Currently the Company forecasts an approximate 50% decline in battery storage costs by 2030 understanding that the actual pace of technological advancements, or even future potential policy mandates that influence storage costs, may change this forecast in future IRPs.

Additionally, the projected steep cost declines of battery storage add some risk to early adoption of this technology. The pace at which storage is integrated on the system is important as the benefits gained from storage may be captured a few years later at a lower cost to customers. As a result, striking the proper pace of adoption will require balancing the operational benefits of earlier adoption with the cost savings from a more measured pace.

However, as is the case with all energy-limited resources, as the penetration of short-term duration storage increases, the incremental benefit of that resource diminishes. To investigate how quickly this loss of value could occur, the Company commissioned Astrapé Consulting, a nationally recognized expert in the field, to conduct a detailed Capacity Value of Battery Storage study that is included as an attachment to the DEP IRP and is discussed in greater detail in Appendix H. This study assessed the contribution to winter peak capacity of varying levels and durations of both standalone battery storage and battery storage paired with solar resources under increasing levels of solar integration. As shown in Figure 6-A, longer duration batteries maintain capacity value as market penetration increases. For instances, 6-hour batteries maintain over 80% contribution to winter peak demand for up to nearly 3,000 MW on the system, and 4-hour batteries maintain 80% capacity value for nearly 2,200 MW. Conversely, 2-hour batteries fall below 80% at just 1,100 MW on the system. This drop is even more dramatic when considering the incremental value of battery storage shown in Figure 6-B. While the first 800 MW of two-hour batteries on the system provide almost 90% to meeting winter peak capacity needs, the next 800 MW provide about half of that value.

Two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish, and for these reasons, DEP only considered four and six-hour battery storage in the IRP.

ELECTRIC VEHICLES

Another important form of energy storage is electric vehicles. Electrification is expected to play an important role in the reduction of carbon dioxide emissions across all sectors of the economy. Electric vehicles (EVs) in particular are poised to transform and decarbonize the transportation industry which accounts for 28% of US carbon dioxide emissions, more than any other economic sector[2].

EVs also offer financial benefits for consumers and for the electric grid. EV drivers save money on fuel and maintenance costs, and the purchase of a new EV can be offset by up to $7,500 with the Qualified Plug-In Electric Drive Motor Vehicle Tax Credit. Increasing EV growth can create benefits for all utility customers by increasing utilization of the electric grid and putting downward pressure on rates.

Duke Energy receives monthly updates on light-duty vehicle registrations from the Electric Power Research Institute (EPRI). Registrations are tracked by county and attributed to DEP based on the size of its customer count in each county. Reporting and analysis focus on plug-in electric vehicles (PEVs) which are charged from the electric grid. Conventional vehicles and hybrid EVs are also tracked to provide context for PEV growth within the total vehicle market.

According to EPRI, 2,200 new PEVs were registered in 2019, and 8,200 PEVs were in operation by the end of the year. Most of those vehicles were adopted in NC which had 8,000 PEVs in operation compared to 200 in SC. Annual registrations increased from 2018 to 2019 by a small margin. The modest growth was partly due to an outsized increase in 2018 (+130%) driven by the popular Tesla Model 3 sedan.

On October 29, 2018, NC Governor Cooper issued Executive Order 80, in which he directed the State of NC to "strive to accomplish" increasing the number of registered, zero-emission vehicles to at least 80,000 by 2025. In order to adequately respond to state policies like Executive Order 80 and considering the significant pace of EV adoption in its service territories, Duke Energy recognizes that it must prepare for and better understand the electrical needs and impacts of EVs on its systems. As

[2] U.S. EPA's Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2018.

TABLE 12-F

BASE CASE WITH CARBON POLICY LOAD, CAPACITY AND RESERVES TABLE - SUMMER

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Forecast															
1 DEP System Summer Peak	12,885	12,909	12,913	13,063	13,207	13,381	13,461	13,589	13,833	13,918	14,093	14,241	14,377	14,499	14,757
2 Firm Sale	150	150	150	150	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(67)	(101)	(133)	(162)	(191)	(220)	(245)	(265)	(281)	(287)	(286)	(282)	(277)	(247)	(237)
4 Adjusted Duke System Peak	**12,968**	**12,957**	**12,930**	**13,051**	**13,016**	**13,161**	**13,216**	**13,324**	**13,552**	**13,631**	**13,807**	**13,959**	**14,100**	**14,252**	**14,520**
Existing and Designated Resources															
5 Generating Capacity	12,477	12,477	12,477	12,477	12,479	12,479	12,303	12,307	10,915	9,147	9,147	9,147	9,147	9,147	9,147
6 Designated Additions / Uprates	0	0	0	2	0	0	4	0	6	0	0	0	0	0	0
7 Retirements / Derates	0	0	0	0	0	(176)	0	(1,392)	(1,774)	0	0	0	0	0	0
8 Cumulative Generating Capacity	**12,477**	**12,477**	**12,477**	**12,479**	**12,479**	**12,303**	**12,307**	**10,915**	**9,147**	**9,147**	**9,147**	**9,147**	**9,147**	**9,147**	**9,147**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,837**	**2,904**	**2,932**	**2,935**	**2,955**	**2,934**	**2,923**	**2,902**	**2,839**	**2,830**	**2,822**	**2,818**	**2,677**	**2,676**	**2,674**
Non-Compliance Renewable Purchases	352	558	603	625	657	696	682	667	604	595	587	585	583	582	581
Non-Renewables Purchases	2,485	2,346	2,330	2,311	2,298	2,237	2,240	2,235	2,235	2,235	2,235	2,234	2,094	2,094	2,094
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle								1,152	1,152						
12 Combustion Turbine						419	419		837						
13 Solar										38	38	56	56	56	56
14 Wind													53	53	53
15 Battery											457				479
Renewables															
16 Cumulative Renewables Capacity	**484**	**369**	**357**	**371**	**361**	**339**	**400**	**457**	**510**	**569**	**643**	**707**	**833**	**949**	**1,075**
Renewables w/o Storage	484	369	357	365	355	333	360	384	404	403	419	418	417	416	415
Solar w/ Storage (Solar Component)	0	0	0	3	3	3	19	35	50	59	69	69	68	68	68
Solar w/ Storage (Storage Component)	0	0	0	3	3	3	21	39	57	69	80	89	107	116	134
17 Combined Heat & Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Grid-connected Energy Storage	29	14	17	17	19	19	19	0	0	0	0	0	0	0	0
19 Cumulative Production Capacity	**15,826**	**15,793**	**15,826**	**15,862**	**15,891**	**16,109**	**16,600**	**16,397**	**16,608**	**16,658**	**16,724**	**16,785**	**16,769**	**16,884**	**17,008**
Demand Side Management (DSM)															
20 Cumulative DSM Capacity	**966**	**976**	**980**	**979**	**786**	**788**	**789**	**791**	**794**	**796**	**800**	**803**	**806**	**809**	**812**
IVVC Peak Shaving	**-**	**-**	**9**	**19**	**96**	**97**	**98**	**99**	**100**	**100**	**101**	**102**	**103**	**104**	**105**
21 Cumulative Capacity w/ DSM	**16,792**	**16,769**	**16,816**	**16,861**	**16,773**	**16,994**	**17,488**	**17,287**	**17,501**	**17,555**	**17,625**	**17,690**	**17,679**	**17,798**	**17,925**
Reserves w/ DSM															
22 Generating Reserves	3,824	3,812	3,886	3,809	3,757	3,833	4,272	3,963	3,949	3,923	3,818	3,731	3,579	3,546	3,405
23 % Reserve Margin	**29.5%**	**29.4%**	**30.1%**	**29.2%**	**28.9%**	**29.1%**	**32.3%**	**29.7%**	**29.1%**	**28.8%**	**27.7%**	**26.7%**	**25.4%**	**24.9%**	**23.4%**

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TABLE 12-G

DEP ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLES

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a percent.

LINE ITEM	LINE INCLUSION[2]
1.	Peak demand for the Duke Energy Carolinas System as defined in Chapter 3 and Appendix C.
2.	Firm sale of 150 MW through 2024.
3.	Cumulative new energy efficiency and conservation programs (does not include demand response programs).
4.	Peak load adjusted for firm sales and cumulative energy efficiency.
5.	Existing generating capacity reflecting the impacts of designated additions, planned uprates, retirements and derates as of January 1, 2020.
6.	Designated Capacity Additions
	Nuclear uprates: Brunswick 1; 4 MW available for the winter of 2025. Brunswick 2; 6 MW available for the winter of 2028; 10 MW available for the winter of 2030.
7.	Estimated retirement dates for planning that represent most economical retirement date for coal units as determined in Coal Retirement Analysis discussed in Chapter 11. Other units represent estimated retirement dates based on the depreciation study approved in the most recent DEP rate case: Darlington 1-4, 6-8 and 10 (514 MW): March 2020 Blewett 1-4 (68 MW): December 2025 Weatherspoon 1-4 (164 MW): December 2025 Roxboro 3 and 4 (1,409 MW): December 2027 Roxboro 1 and 2 (1,053 MW): December 2028 Mayo 1 (746 MW): December 2028
	All nuclear units are assumed to have subsequent license renewal at the end of the current license.
	All hydro facilities are assumed to operate through the planning horizon.
	All retirement dates are subject to review on an ongoing basis. Dates used in the 2020 IRP are for planning purposes only, unless the unit is already planned for retirement.
8.	Sum of lines 5 through 7.

[2] Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the following year.

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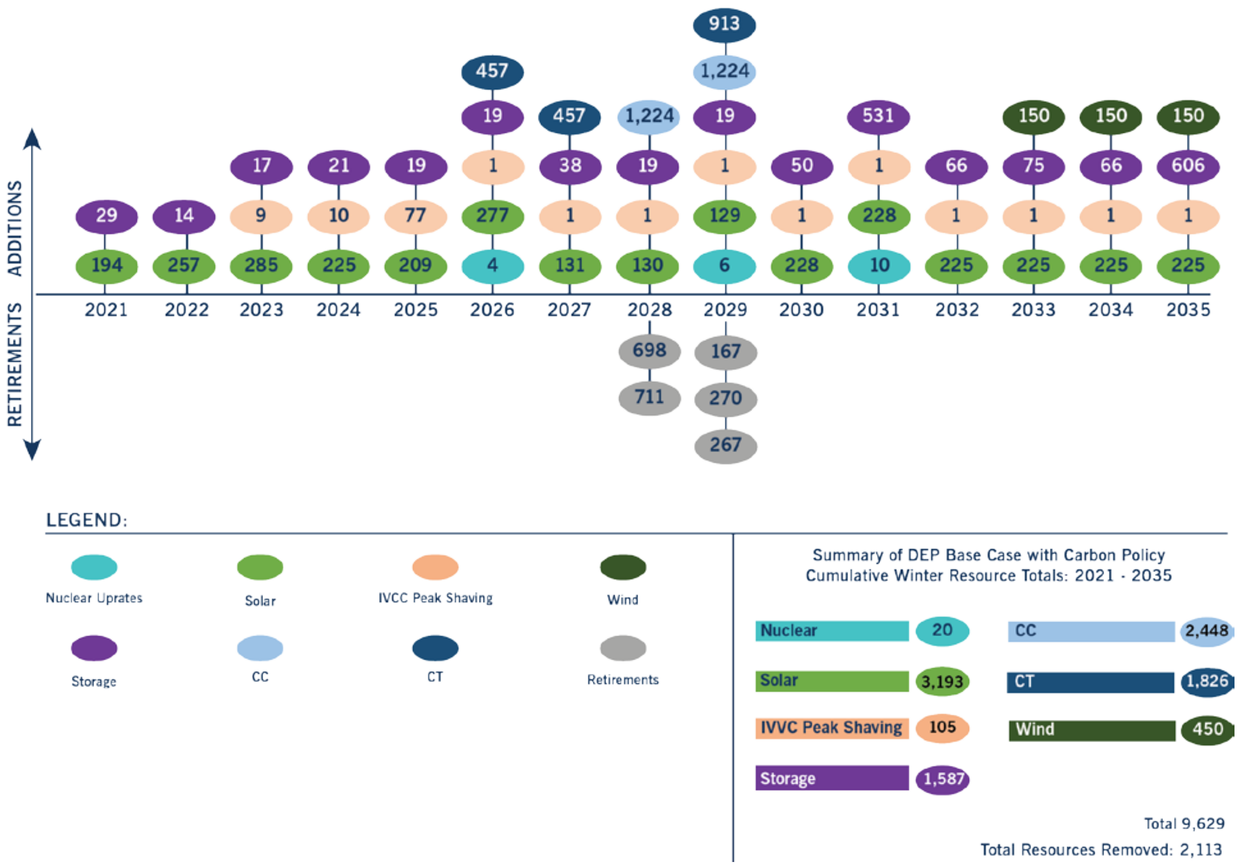
FIGURE 12-F

DEP WINTER BASE CASE WITH CARBON POLICY ANNUAL ADDITIONS BY TECHNOLOGY



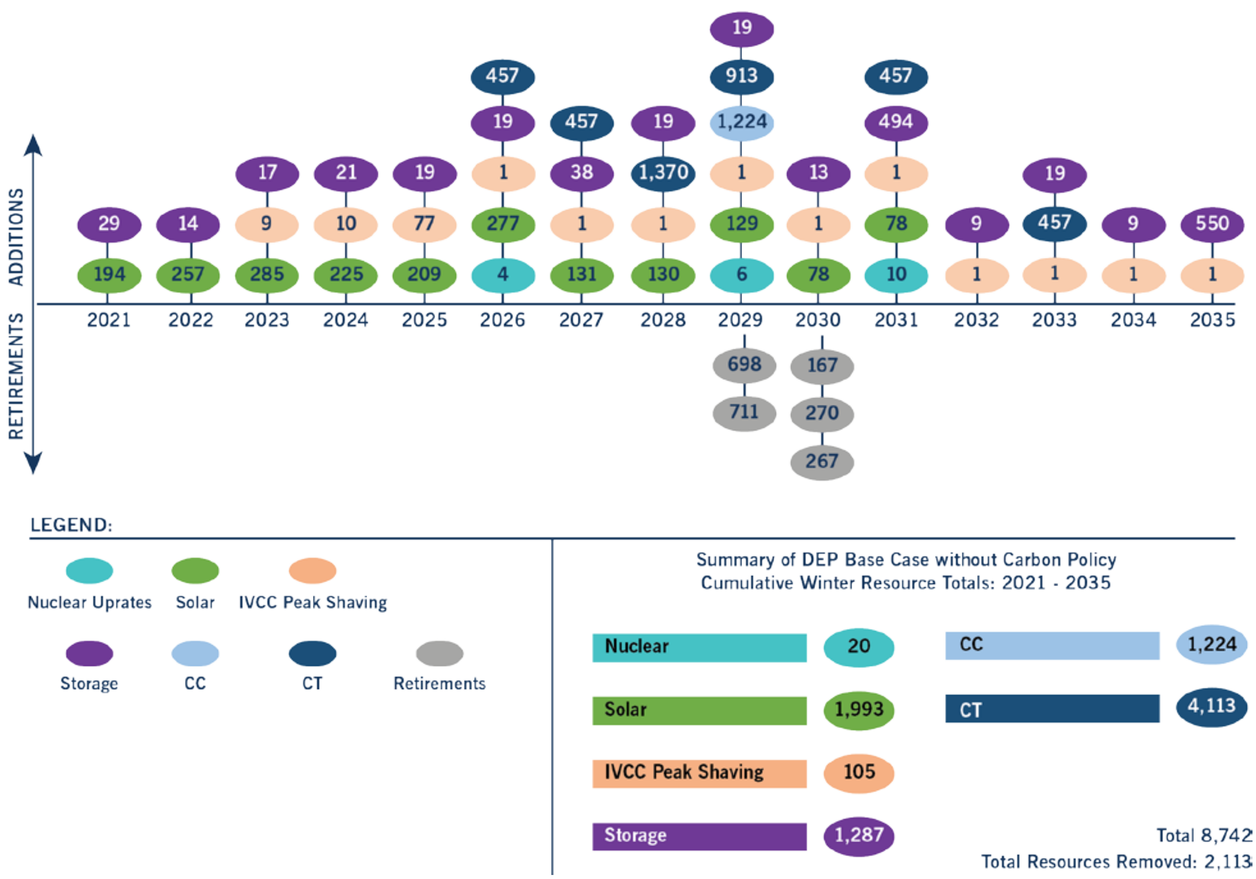
he following figures illustrate both the current and forecasted capacity for the DEP system, as projected by the Base Case with Carbon Policy. Figure 12-G depicts how the capacity mix for the DEP system changes with the passage of time. In 2035, the Base Case with Carbon Policy projects that DEP will have no reliance on coal and a significantly higher reliance on renewable resources and energy storage as compared to the current state. It is of particular note that nearly 50% of the new resources added over the study period are solar, wind and energy storage resources. Natural gas-fired resources continue to be an important part of maintaining the reliability of the DEP system, as well.

As mentioned above, the Company's Base Case with Carbon Policy resources depicted in Figure 12-G below reflects a significant amount of growth in solar capacity with nameplate solar growing from 2,888 MW in 2021 to 4,270 MW by 2035. However, given that solar resources only contribute approximately 1% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter compared to the Base Case with Carbon Policy. Additionally, no incremental renewable resources were economically selected in this case.

A graphical presentation of the Winter Base Case without Carbon Policy resource plan is shown below in Figure 12-I. This figure provides annual incremental capacity additions to the DEP system by technology type for this case. Additionally, a summary of the total resources by technology is provided below the figure. Further details of the development of the Base Case without Carbon Policy may be found in Appendix A.

FIGURE 12-I

DEP WINTER BASE CASE WITHOUT CARBON POLICY ANNUAL ADDITIONS BY TECHNOLOGY



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CONTINUE TO FIND OPPORTUNITIES TO ENHANCE EXISTING CLEAN RESOURCES

DEP is committed to continually looking for opportunities to improve and enhance its existing resources. DEP is expecting capacity uprates to its existing nuclear units, Brunswick and Harris, due to upcoming projects at those sites. The uprates total 20 MW and are projected to occur from 2025 to 2030.

ADDITION OF CLEAN NATURAL GAS RESOURCES [1]

- The Company continues to consider advanced technology combined cycle and combustion turbine units as excellent options for a diversified, reliable portfolio required to meet future customer demand. The improving efficiency and reliability of CCs coupled with the lower carbon content and continued trend of lower prices for natural gas make these resources economically attractive as well as very effective at enabling significant carbon reductions through accelerated economic coal retirements. As older units on the DEP system are retired, CC and CT units continue to play an important role in the Company's future diverse resource portfolio.

  - Two 1x1 combined cycle units (each with one CT and one steam turbine, for a total capacity of 560 MW winter / 474 MW summer began full operation at the Asheville site [2] by April 2020. These efficient units will assist in providing reliable energy to DEP's customers.

A summarization of the capacity resource changes for the Base Plans in the 2020 IRP is shown in Table 14-B below. Capacity retirements and resource additions are presented in the table as incremental values in the year in which the change impacts the winter peak. The values shown for renewable resources, EE, DSM and IVVC represent cumulative totals.

[1] Capacities represent winter ratings.
[2] Asheville CC individual components began commercial operation at various dates between 12/27/19 and 4/5/20.

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COMBUSTION TURBINES									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Asheville	3	185	160	Arden, NC	Natural Gas/Oil	Peaking	20	20	N/A
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking	19	20	N/A
Blewett	1	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	2	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	3	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	4	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Darlington	1	63	50	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	2	64	48	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	3	63	50	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	4	66	48	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	6	62	43	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	7	65	47	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	8	66	44	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	10	65	49	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking	22	18	N/A
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking	22	18	N/A
Smith [4]	1	197	157	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith [4]	2	197	156	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith [4]	3	197	155	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A

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NUCLEAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Brunswick [2]	1	975	938	Southport, NC	Uranium	Base	42	37	2036
Brunswick[2]	2	953	932	Southport, NC	Uranium	Base	44	35	2034
Harris [2]	1	1009	964	New Hill, NC	Uranium	Base	32	47	2046
Robinson	2	793	759	Hartsville, SC	Uranium	Base	48	31	2030
Total NC		2,937	2,834						
Total SC		793	759						
Total Nuclear		3,730	3,593						

SOLAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
NC Solar		141	141	NC	Solar	Intermittent	Various	N/A	N/A
Total Solar		141	141						

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PLANNING ASSUMPTIONS – UNIT RETIREMENTS [a, b, c]					
UNIT & PLANT NAME	LOCATION	WINTER CAPACITY (MW)	SUMMER CAPACITY (MW)	FUEL TYPE	EXPECTED RETIREMENT
Darlington 1	Hartsville, S.C.	63	50	Natural Gas/Oil	3/2020
Darlington 2	Hartsville, S.C.	64	48	Oil	3/2020
Darlington 3	Hartsville, S.C.	63	50	Natural Gas/Oil	3/2020
Darlington 4	Hartsville, S.C.	66	48	Oil	3/2020
Darlington 6	Hartsville, S.C.	62	43	Oil	3/2020
Darlington 7	Hartsville, S.C.	65	47	Natural Gas/Oil	3/2020
Darlington 8	Hartsville, S.C.	66	44	Oil	3/2020
Darlington 10	Hartsville, S.C.	65	49	Oil	3/2020
Mayo 1	Roxboro, N.C.	746	727	Coal	12/2028
Roxboro 1	Semora, N.C.	380	379	Coal	12/2028
Roxboro 2	Semora, N.C.	673	665	Coal	12/2028
Roxboro 3	Semora, N.C.	698	691	Coal	12/2027
Roxboro 4	Semora, N.C.	711	698	Coal	12/2027
Blewett 1	Lilesville, N.C.	17	13	Oil	12/2025
Blewett 2	Lilesville, N.C.	17	13	Oil	12/2025
Blewett 3	Lilesville, N.C.	65	13	Oil	12/2025
Blewett 4	Lilesville, N.C.	66	13	Oil	12/2025
Weatherspoon 1	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2025
Weatherspoon 2	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2025
Weatherspoon 3	Lumberton, N.C.	41	33	Natural Gas/Oil	12/2025
Weatherspoon 4	Lumberton, N.C.	41	31	Natural Gas/Oil	12/2025
Total		4,051	3,719		

NOTE a: Retirement assumptions are for planning purposes only; Coal retirement dates represent the economic retirement dates determined in the Coal Retirement Analysis (as discussed in Chapter 11). Other technology units represent retirement dates based on the depreciation study approved as part of the most recent DEP rate case.

NOTE b: For planning purposes, all portfolios in the 2020 IRP assume subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses.

NOTE c: Asheville coal units and Darlington CT units have been officially retired as of January 2020 and March 2020, respectively. Darlington CT units are included in this table as their retirement shows up in the Winter of 2021 in the LCR tables.

Following are the EE and DSM programs currently available through DEP as of December 31, 2019:

RESIDENTIAL EE PROGRAMS	NON-RESIDENTIAL EE PROGRAMS	COMBINED RESIDENTIAL / NON-RESIDENTIAL EE PROGRAMS	RESIDENTIAL DSM PROGRAMS	NON-RESIDENTIAL DSM PROGRAMS
Energy Efficient Appliances and Devices	Non-Residential Smart $aver® Energy Efficient Products and Assessment	Energy Efficient Lighting	EnergyWise[SM] Home	CIG Demand Response Automation
Energy Efficiency Education	Non-Residential Smart $aver® Performance Incentive	Distribution System Demand Response (DSDR)		Large Load Curtailable Rates & Riders
Multi-Family Energy Efficiency	Small Business Energy Saver			EnergyWise® Business
My Home Energy Report				
Neighborhood Energy Saver (Low-Income)				
Residential Energy Assessments				
Residential New Construction				
Residential Smart $aver® Energy Efficiency				

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ENERGY EFFICIENCY PROGRAMS

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[1]) since the inception of these existing programs through the end of 2019 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for the specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEP's existing EE programs.

RESIDENTIAL EE PROGRAMS

Energy Efficient Appliances and Devices Program

The Energy Efficient Appliances and Devices Program is a new program that combines DEP's previous "Save Energy and Water Kit" with a variety of high efficiency products available through the Company's Online Savings Store, including but not limited to Air Purifiers, Dehumidifiers and LED Fixtures. The Save Energy and Water kit offers low flow water fixtures and insulating pipe tape to residential single-family homeowners with electric water heaters. Program participants are eligible for one kit shipped free of charge to their home. Kits are available in two sizes for homes with one or more full bathrooms and contain varying quantities of shower heads, bathroom aerators, kitchen aerator and insulating pipe tape.

APPLIANCES AND DEVICES				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	1,311,635	78,693	25,278	21,285

[1] "Gross of Free Riders" means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. "At the Plant" means that the impacts associated with the EE programs have been increased to include line losses.

CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	46,842	25,717	3,626	1,356

RESIDENTIAL ENERGY ASSESSMENTS PROGRAM

The Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment, performed by a Building Performance Institute (BPI) certified energy specialist and designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90-minute walk through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficient lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet. Additional energy efficient bulbs are available to be installed by the auditor if needed.

RESIDENTIAL ENERGY ASSESSMENTS				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	144,853	31,026	3,787	2,939

RESIDENTIAL NEW CONSTRUCTION PROGRAM

The Residential New Construction Program provides incentives for new single family and multi-family residential dwellings (projects of three stories and less) that fall within the 2018 North Carolina Residential Building Code to meet or exceed the 2018 North Carolina Energy Conservation Code High Efficiency Residential Option (HERO). If a builder or developer constructing to the HERO standard elects to participate, the Program offers the homebuyer an incentive guaranteeing the heating and cooling consumption of the dwelling's total annual energy costs. Additionally, the Program incents the

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installation of high-efficiency heating ventilating and air conditioning (HVAC) and heat pump water heating (HPWH) equipment in new single family, manufactured, and multi-family residential housing units.

New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or costlier to install at a later time.

RESIDENTIAL NEW CONSTRUCTION				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	39,880,246	60,788	23,231	21,201

NOTE: The participants and impacts are from both the Residential New Construction program and the previous Home Advantage program.

RESIDENTIAL SMART $AVER® EE PROGRAM (FORMERLY KNOWN AS THE HOME ENERGY IMPROVEMENT PROGRAM)

The Residential Smart $aver® EE Program offers DEP customers a variety of energy conservation measures designed to increase energy efficiency in existing residential dwellings. The Program utilizes a network of participating contractors to encourage the installation of: (1) high efficiency central air conditioning (AC) and heat pump systems with optional add on measures such as Quality Installation and Smart Thermostats, (2) attic insulation and sealing, (3) heat pump water heaters, and (4) high efficiency variable speed pool pumps.

The prescriptive menu of energy efficiency measures provided by the program allows customers the opportunity to participate based on the needs and characteristics of their individual homes. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs.

This program previously offered HVAC Audits and Room AC's, however, those measures were removed due to no longer being cost-effective.

The tables below show actual program performance for all current and past program measures.

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RESIDENTIAL SERVICE – SMART $AVER				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	201,592	81,238	43,398	2,898

NON-RESIDENTIAL EE PROGRAMS

Non-Residential Smart $aver Energy Efficient Products and Assessment Program (formerly known as the Energy Efficiency for Business Program)

The Non-Residential Smart $aver Energy Efficient Products and Assessment Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

Commercial and industrial customers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the Program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products.

The program provides incentives through prescriptive measures, custom measures and technical assistance.

- ***Prescriptive Measures***: Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment. The program will no longer offer A-Line bulb incentives after 2020.
- ***Custom Measures***: Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Prescriptive measure list. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without

the Company's technical or financial assistance. Unlike the Prescriptive portion of the program, all Custom measure incentives require pre-approval prior to the project implementation. The program will no longer offer A-Line bulb incentives after 2020.

- *Energy Assessments and Design Assistance*: Incentives are available to assist customers with energy studies such as energy audits, retro commissioning, and system-specific energy audits for existing buildings and with design assistance such as energy modeling for new construction. Customers may use a contracted Duke Energy vendor to perform the work or they may select their own vendor. Additionally, the Program assists customers who identify measures that may qualify for Smart $aver Incentives with their applications. Pre-approval is required. In 2019, the program modified its approach to a Virtual Energy Assessment utilizing an energy modeling software to complete the assessment in 2-3 weeks at a lower cost.

NON-RESIDENTIAL SMART SAVER ENERGY EFFICIENCY PRODUCTS AND ASSESSMENT				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	76,167,085	759,203	137,149	49,442

* NOTE: Participants have different units of measure.

NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE PROGRAM

The Non-Residential Smart $aver® Performance Incentive Program offers financial assistance to qualifying commercial, industrial and institutional customers to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program encourages the installation of new high efficiency equipment in new and existing nonresidential establishments as well as efficiency-related repair activities designed to maintain or enhance efficiency levels in currently installed equipment. Incentive payments are provided to offset a portion of the higher cost of energy efficient installations that are not eligible under the Smart $aver® EE Products and Assessment program. The Program requires pre-approval prior to project initiation.

The types of projects covered by the Program include projects with some combination of unknown building conditions or system constraints, or uncertain operating, occupancy, or production schedules. The intent of the Program is to broaden participation in non-residential efficiency programs by being able

NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	100	3,871	325	347

SMALL BUSINESS ENERGY SAVER PROGRAM

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM Rider and have an average annual demand of 180 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Progress. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The Company-authorized vendor schedules the installation of the energy efficiency measures at a convenient time for the customer, and electrical subcontractors perform the work.

SMALL BUSINESS ENERGY SAVER				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	198,207,936	266,094	49,099	17,322

NOTE: Participants have different units of measure.

Corrected 11.06.2020

COMBINED RESIDENTIAL/NON-RESIDENTIAL CUSTOMER

ENERGY EFFICIENT LIGHTING PROGRAM

The Energy Efficient Lighting Program partners with lighting manufacturers and retailers across North and South Carolina to provide marked-down prices at the register to DEP customers purchasing energy efficient lighting products. Starting in 2017, the Program removed CFLs and only offers LEDs and energy-efficient fixtures.

As the program enters its eighth year, the DEP Energy Efficient Lighting Program will continue to encourage customers to adopt energy efficient lighting through incentives on a wide range of energy efficient lighting products. Customer education is imperative to ensure customers are purchasing the right bulb for the application in order to obtain high satisfaction with lighting products and subsequent purchases.

ENERGY EFFICIENT LIGHTING				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	34,575,395	1,798,852	285,602	18,845

DISTRIBUTION SYSTEM DEMAND RESPONSE PROGRAM (DSDR)

Duke Energy Progress' Distribution System Demand Response (DSDR) program manages the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Progress distribution system. In general, the program tends to optimize the operation of these devices, resulting in a "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation and capacitors, line capacitors and line voltage regulators while integrating them into a single control system. This control system continuously monitors and operates the voltage regulators and capacitors to maintain the desired "flat" voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage at the substation, results in an immediate reduction of system loading during peak conditions.

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VOLTAGE CONTROL ACTIVATIONS			
DATE	START TIME	END TIME	DURATION (H:MM)
7/16/2020	18:05	21:00	2:55
7/30/2020	18:00	21:00	3:00

DEMAND-SIDE MANAGEMENT PROGRAMS

RESIDENTIAL:

ENERGYWISE℠ HOME PROGRAM

The EnergyWise℠ Home Program allows DEP to install load control switches at the customer's premise to remotely control the following residential appliances:

- Central air conditioning or electric heat pumps
- Auxiliary strip heat on central electric heat pumps (Western Region only)
- Electric water heaters (Western Region only).

For each of the appliance options above, an initial one-time bill credit of $25 following the successful installation and testing of load control device(s) and an annual bill credit of $25 is provided to program participants in exchange for allowing the Company to control the listed appliances.

ENERGYWISE℠ HOME			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS*	2019 CAPABILITY (MW@GEN)	
		SUMMER	WINTER
December 31, 2019	196,192	405	14.1

* Number of participants represents the number of measures under control.

The following table shows Residential EnergyWise℠ Home Program activations that were for the general population from July 1, 2018 through December 31, 2019.

Corrected 11.06.2020

TABLE E-2

DEP BASE WITH CARBON POLICY TOTAL RENEWABLES

DEP BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	8	131	0	1,305	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	8	131	0	1,329	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	7	120	0	1,345	41	3	120	0	165
2027	4,184	88	120	0	4,392	1,223	48	120	0	1,391	42	22	120	0	184
2028	4,239	163	116	0	4,518	1,229	88	116	0	1,433	42	41	116	0	199
2029	4,294	237	60	0	4,591	1,234	128	60	0	1,422	43	59	60	0	162
2030	4,323	436	43	0	4,802	1,237	234	43	0	1,515	43	109	43	0	195
2031	4,352	634	43	0	5,029	1,240	340	43	0	1,623	44	158	43	0	245
2032	4,331	856	42	0	5,228	1,238	460	42	0	1,740	43	214	42	0	299
2033	4,311	1,076	42	150	5,579	1,236	581	42	12	1,870	43	269	42	53	406
2034	4,290	1,296	41	300	5,928	1,234	701	41	24	2,000	43	324	41	105	513
2035	4,270	1,514	41	450	6,276	1,232	822	41	36	2,131	43	379	41	158	620

Data presented on a year beginning basis.

Solar includes 0.5% per year degradation.

Capacity listed excludes REC Only Contracts.

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.

Corrected 11.06.2020

TABLE E-3

DEP HIGH RENEWABLES SENSITIVITY

DEP HIGH RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	8	131	0	1,305	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	8	131	0	1,329	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	7	120	0	1,345	41	3	120	0	165
2027	4,109	229	120	0	4,458	1,216	125	120	0	1,461	41	57	120	0	218
2028	4,089	446	116	0	4,652	1,214	244	116	0	1,574	41	112	116	0	269
2029	4,070	677	60	0	4,807	1,212	372	60	0	1,644	41	169	60	0	270
2030	4,051	904	43	0	4,997	1,210	498	43	0	1,750	41	226	43	0	309
2031	4,031	1,138	43	60	5,272	1,208	629	43	14	1,894	40	285	43	37	405
2032	4,011	1,383	42	120	5,556	1,206	766	42	29	2,043	40	346	42	74	501
2033	3,992	1,647	42	180	5,861	1,204	914	42	43	2,203	40	412	42	111	604
2034	3,974	2,084	41	390	6,489	1,202	1,160	41	70	2,473	40	521	41	200	802
2035	3,955	2,533	41	615	7,144	1,201	1,413	41	100	2,754	40	633	41	299	1,013

Data presented on a year beginning basis.

Solar includes 0.5% per year degradation.

Capacity listed excludes REC Only Contracts.

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.

Corrected 11.06.2020

TABLE E-4
DEP LOW RENEWABLES SENSITIVITY

DEP LOW RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	8	131	0	1,305	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	8	131	0	1,329	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	7	120	0	1,345	41	3	120	0	165
2027	4,109	13	120	0	4,242	1,216	7	120	0	1,343	41	3	120	0	164
2028	4,089	13	116	0	4,219	1,214	7	116	0	1,337	41	3	116	0	160
2029	4,070	163	60	0	4,293	1,212	90	60	0	1,361	41	41	60	0	141
2030	4,051	312	43	0	4,406	1,210	172	43	0	1,425	41	78	43	0	161
2031	4,031	461	43	0	4,534	1,208	254	43	0	1,505	40	115	43	0	198
2032	4,011	609	42	150	4,811	1,206	336	42	12	1,596	40	152	42	53	286
2033	3,992	756	42	300	5,090	1,204	419	42	24	1,689	40	189	42	105	375
2034	3,974	902	41	450	5,367	1,202	501	41	36	1,781	40	225	41	158	464
2035	3,955	1,047	41	600	5,644	1,201	584	41	48	1,874	40	262	41	210	553

Data presented on a year beginning basis.

Solar includes 0.5% per year degradation.

Capacity listed excludes REC Only Contracts.

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.

Corrected 11.06.2020

customers is maximized when the utility maintains dispatch rights for the battery asset. For these reasons, the Company relied on the ELCC results modeled under Economic Arbitrage conditions.

- Only 4-hour and 6-hour storage considered for standalone storage – Under all dispatch options, the value of 2-hour storage quickly diminishes as their penetration increases on the system. As shown in Appendix B of the Resource Adequacy report (Attachment III to the IRP), even though most of the LOLH occurs in the hour beginning 7AM, DEP has LOLH over a range of hours in the morning and evening which limits the value that 2-hour storage can provide to the system. Additionally, two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish.

While the above results show the average capacity value attributed to varying levels of storage on the DEP system, the incremental value of adding 800 MW blocks of storage can be calculated from the results. The incremental values are useful when determining the capacity value of the next block of energy storage, particularly when evaluating replacing a CT with a 4-hour battery as discussed in Appendix A and the economic coal retirement discussion Chapter 11. The incremental capacity value of storage assumed in the IRP is shown in the following table.

DEP QF
INTERCONNECTION QUEUE

Corrected 11.06.2020

APPENDIX K: DEP QF INTERCONNECTION QUEUE

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition; however, the current queue clearly supports solar generation's central role in DEP's NC REPS compliance plan and HB 589.

Below is a summary of the interconnection queue as of July 31, 2020:

TABLE K-1
DEP QF INTERCONNECTION QUEUE

UTILITY	FACILITY STATE	ENERGY SOURCE TYPE	NUMBER OF PENDING PROJECTS	PENDING CAPACITY (MW AC)
DEP	NC	Battery	5	153
		Solar	188	4,612
	NC Total		193	4,765
	SC	Solar	140	2,332
	SC Total		140	2,332
	DEP Total		333	7,097

NOTE: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.
(2) Table does not include net metering interconnection requests.

WESTERN CAROLINAS MODERNIZATION PLAN (WCMP)

Corrected 11.06.2020

GLOSSARY OF TERMS

10 CFR	Title 10 of the Code of Federal Regulations
AC or A/C	Alternating Current
ACE	Affordable Clean Energy
ACP	Atlantic Coast Pipeline
ACT 62	South Carolina Act 62
ADP	Advanced Distribution Planning
AEO	Annual Energy Outlook
AGC	Automatic Generator Control
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Electric
ARP	Acid Rain Program
ARPA-E	Advanced Resource Projects Agency-Energy
ASOS	National Weather Service Automated Surface Observing System
BHPCC	Blue Horizons Project Community Council (DEP)
BCFD	Billion Cubic Feet Per Day
BFB	Bubbling Fluidized Bed
BOEM	Bureau of Ocean Energy Management
BYOT	Bring Your Own Thermostat
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMA	North Carolina Coal Ash Management Act of 2014
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals Rule
CCS	Carbon Capture and Sequestration (Carbon Capture and Storage)
CCUS	Carbon Capture, Utilization and Storage
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
CEP	Comprehensive Energy Planning
CES	Clean Electricity Standard
CFL	Compact Fluorescent Light bulbs
CHP	Combined Heat and Power

Corrected 11.06.2020

GLOSSARY OF TERMS (CONT.)

CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COVID-19	Coronavirus 2019
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity (NC)
CPP	Clean Power Plan
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DER	Duke Energy Renewables
DESC	Dominion Energy South Carolina, Inc. (formerly SCE&G)
DIY	Do It Yourself
DMS	Distribution Management System
DoD	Depth of Discharge
DOE	Department of Energy
DOJ	Department of Justice
DOM	Dominion Zone within PJM RTO
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSDR	Distribution System Demand Response Program
DSM	Demand-Side Management

GLOSSARY OF TERMS (CONT.)

EC or Rider EC	Receiving Credits under Economic Development Rates and/or Self-Generation deferral rate
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
EITF	Energy Innovation Task Force
ELCC	Effective Load Carrying Capability
ELG Rule	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction Contractors
EPRI	Electric Power Research Institute
ER or Rider ER	Receiving Credits under Economic Re-Development Rates
ESG	Environmental, Social and Corporate Governance
ET	Electric Transportation
EVs	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLG	Federal Loan Guarantee
FPS	Feet Per Second
FRCC	Florida Reliability Coordinating Council, Inc.
FSO	Fuels and System Optimization
FT Solar	Fixed-tilt Solar
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GA-AL-SC	Georgia-Alabama-South Carolina
GHG	Greenhouse Gas
GIP	Grid Improvement Plan
GTI	Gas Technology Institute
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HB 589	North Carolina House Bill 589
HRSG	Heat Recovery Steam Generator

Corrected 11.06.2020

GLOSSARY OF TERMS (CONT.)

HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
IESO	Independent Electricity System Operator
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ILR	Inverter Load Ratios
IPI	Industrial Production Index
IRP	Integrated Resource Plan
IS	Interruptible Service
ISO-NE	ISO New England, Inc.
ISOP	Integrated Systems and Operations Planning
IT	Information Technologies
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LCR Table	Load, Capacity, and Reserves Table
LED	Light Emitting Diodes
LEED	Leadership in Energy and Environmental Design
LEO	Legally Enforceable Obligation
LFE	Load Forecast Error
Li-ION	Lithium Ion
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
M&V	Measurement and Verification
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MGD	Million Gallons Per Day
MISO	Midcontinent Independent Operator

GLOSSARY OF TERMS (CONT.)

MPS	Market Potential Study
MMBtu	Million British Thermal Units
MW	Megawatt
MW AC	Megawatt-Alternating Current
MW DC	Megawatt-Direct Current
MWh	Megawatt-hour
MWh AC	Megawatt-hour-Alternating Current
MWh DC	Megawatt-hour-Direct Current
MyHER	My Home Energy Report
NAAQS	National Ambient Air Quality Standards
NAPP	Northern Appalachian Coal
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC REPS or REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCDEQ	North Carolina Division of Environmental Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NEM	Net Energy Metering
NEMS	National Energy Modeling Systems
NERC	North American Electric Reliability Corporation
NERC RAPA	Reliability and Performance Analysis
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NET CONE	Net Cost of New Entry
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System

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GLOSSARY OF TERMS (CONT.)

NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
NUG	Non-Utility Generator
NUREG	Nuclear Regulatory Commission Regulation
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
OATT	Open Access Transmission Tariff
PC	Participant Cost Test
PD	Power Delivery
PERFORM	Performance-based Energy Resource Feedback, Optimization and Risk Management
PEV	Plug-In Electric Vehicles
PHS	Pumped Hydro Storage
PJM	PJM Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PRB	Powder River Basin
PROSYM	Production Cost Model
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PSH	Pumped Storage Hydro
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificate
REPS or NC REPS	Renewable Energy and Energy Efficiency Portfolio Standard

GLOSSARY OF TERMS (CONT.)

RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engines
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
RRP	Refrigerator Replacement Program
RTO	Regional Transmission Organization
RTR	Residential Risk and Technology Review
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar
SB 3 or NC SB 3	North Carolina Senate Bill 3
SC	South Carolina
SC Act 62	South Carolina Energy Freedom Act of 2018
SC DER or SC ACT 236	South Carolina Distributed Energy Resource Program
SC DER	South Carolina Distributed Energy Resources
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SEIA	Solar Energy Industries Association
SEPA (Ch. 15)	Smart Electric Power Alliance
SEPA (Ch. 2)	Southeastern Power Administration
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SG	Standby Generation or Standby Generator Control
SIP	State Implementation Plan
SISC	Solar Integration Services Charge
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SO	System Optimizer
SO_2	Sulfur Dioxide
SOC	State of Charge
SOG	Self-Optimizing Grid
SPM	Sequential Peaker Method

GLOSSARY OF TERMS (CONT.)

SRP – SLR	Standard Review Plan for the Review of Subsequent License Renewal
STAP	Short-Term Action Plan
STEO	Short-Term Energy Outlook
SVC	Static Var Compressors
T&D	Transmission & Distribution
TAG	Technology Assessment Guide
TCFD	Trillion Cubic Feet per Day
Transco	Transcontinental Pipeline
The Company	Duke Energy Progress
The Plan	Duke Energy Progress Annual Plan
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
UNC	University of North Carolina
USCPC	Ultra-Supercritical Pulverized Coal
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive
VCEA	Virginia Clean Economy Act
VVO	Volt-Var Optimization
WCMP	Western Carolinas Modernization Project (DEP)
WERP	Weatherization and Equipment Replacement Program
WIIN	Water Infrastructure Improvement for the Nation Act
ZELFR	Zero – Emitting Load Following Resource

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

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DUKE ENERGY®

September 1, 2020

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

**RE: Duke Energy Progress, LLC 2020 Integrated Resource Plan, 2020 REPS Compliance Plan, and 2020 CPRE Compliance Plan
Docket No. E-100, Sub 165**

Dear Ms. Campbell:

Pursuant to N.C. Gen. Stat. § 62-133.8, Commission Rules R8-60, R8-62(p) and R8-67, I enclose Duke Energy Progress, LLC's ("DEP" or the "Company") 2020 Integrated Resource Plan ("IRP"), 2020 Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Plan, and 2020 Competitive Procurement of Renewable Energy Compliance Plan (collectively, the "2020 IRP"), for filing in connection with the referenced matter. The 2020 IRP includes the Company's most recent resource adequacy studies together with supporting exhibits, attachments and appendices.

Portions of the DEP 2020 IRP contain confidential information that should be protected from public disclosure. The Confidential Appendix to the 2020 Resource Adequacy Plan includes, but is not limited to, such data as fuel costs, outage rate, transmission assumptions, and other confidential data. Disclosure of this commercially sensitive and proprietary information would put DEP at a competitive disadvantage, which would harm customers. Table 2 of the REPS Compliance Plan (Attachment 1) on page 15 contains the Company's projected avoided energy costs and combustion turbine capacity costs. If this commercially-sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to customers. Moreover, the projected avoided energy costs reflect the Companies' costs to procure additional energy and/or capacity. The wholesale electricity market is extremely competitive, and in order for the Company to obtain the most cost-effective energy and capacity to meet the needs of its customers, it must protect from public disclosure its projected and actual cost to procure such energy, capacity or both. In addition, if this information were publicly available, potential suppliers would know the price against which they must bid, and rather than bidding the lowest price possible, they would simply bid a price low enough to beat the Company's projections. Exhibit A of the REPS Compliance Plan, pages 18 through 26, contains names of counterparties with whom DEP has contracted for Renewable Energy Certificates ("RECs"), contract duration and estimated RECs. Public disclosure of this information would harm DEP's ability to negotiate and procure cost-effective purchases and discourage potential bidders from participating in requests for proposals. In addition, the filing includes DEP's most recent FERC Form 715, which contains critical energy infrastructure information that should be kept confidential and non-public.

Accordingly, I am filing portions of the 2020 IRP under seal and request that they be treated confidentially pursuant to N.C. Gen. Stat. § 132-1.2 and protected from public disclosure. The Company will provide a copy of the confidential information to parties to this proceeding upon execution of an appropriate confidentiality agreement with DEP.

The Company is also making available approximately 250 MB of supporting technical data for the Resource Adequacy Study included in the 2020 IRP, as well as other supporting information. Portions of this supporting technical data are confidential. Access to the confidential data will be provided to intervenors who have executed confidentiality agreements. For information on how to access the supporting technical data, please send an email to Dawn Sutton (dawn.sutton@duke-energy.com).

DEP will schedule the Rule R8-60(m) stakeholder meeting by November 30 and will contact parties of record once a date has been selected.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

Enclosure

cc: Parties of record

CERTIFICATE OF SERVICE

I certify that Duke Energy Progress, LLC's 2020 Integrated Resource Plan, in Docket No. E-100, Sub 165, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties of record.

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This is the 1st day of September, 2020.

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

DOCKET NO. E-100, SUB 165

DUKE ENERGY PROGRESS INTEGRATED RESOURCE PLAN

2020

DUKE ENERGY PROGRESS 2020 INTEGRATED RESOURCE PLAN CONTENTS

ATTACHMENTS FILED AS SEPARATE DOCUMENTS:

1 EXECUTIVE SUMMARY

As one of the largest investor-owned utilities in the country, Duke Energy has a strong history of delivering affordable, reliable and increasingly cleaner energy to our customers. In planning for the future, the Company is transforming the way it does business by investing in increasingly cleaner resources, modernizing the grid and transforming the customer experience. Duke Energy Progress (DEP), a public utility subsidiary of Duke Energy, owns nuclear, coal, natural gas, renewables and hydroelectric generation. That diverse fuel mix provides about 13,700 megawatts (MW) of owned electricity capacity to 1.6 million customers in a 29,000 square-mile service area of North Carolina and South Carolina.

As required by North Carolina Utilities Commission (NCUC) Rule R8-60 and subsequent orders, the Public Service Commission of South Carolina (PSCSC) and The Energy Freedom Act (Act 62) in South Carolina, Duke Energy Progress is submitting its 2020 Integrated Resource Plan (IRP). The IRP balances resource adequacy and capacity to serve anticipated peak electrical load, consumer affordability and least cost, as well as compliance with applicable state and federal environmental regulations. The IRP details potential resource portfolios to match forecasted electricity requirements, including an appropriate reserve margin, to maintain system reliability for customers over the next 15 years. In addition to meeting regulatory and statutory obligations, the IRP is intended to provide insight into the Company's planning processes.

DEP operates as a single utility system across both states and is filing a single system IRP in both North Carolina and South Carolina. As such, the quantitative analysis contained in both the North Carolina and South Carolina filings is identical, although certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be unique to individual state requirements. The IRP to be filed in each state is identical in form and content. It is important to note that DEP cannot fulfill two different IRPs for one system. Accordingly, it is in customers' and the Company's interest that the resulting IRPs accepted or approved in each state are consistent with one another.

In alignment with the Company's climate strategy, input from a diverse range of stakeholders, and other policy initiatives, the 2020 IRP projects potential pathways for how the Company's resource portfolio may evolve over the 15-year period (2021 through 2035) based on current data and assumptions across a variety of scenarios. As a regulated utility, the Company is obligated to develop an IRP based on the policies in effect at that time. As such, the IRP includes a base plan without carbon policy that represents existing policies under least-cost planning principles. To show the impact potential new policies may have on future resource additions and in response to stakeholder feedback, the 2020 IRP also introduces a variety of portfolios that evaluate more aggressive carbon emission reduction targets. As described throughout the IRP, these portfolios have trade-offs between the pace of carbon reductions weighted against the associated cost and operational considerations. These portfolios will ultimately be shaped by the pace of carbon reduction targeted by future policies and the rate of maturation of new, clean technologies.

Inputs to the IRP modeling process, such as load forecasts, fuel and technology price curves and other factors are derived from multiple sources including third party providers such as Guidehouse, IHS, Burns and McDonnell, and other independent sources such as the Energy Information Administration (EIA) and National Renewable Energy Laboratory (NREL). These inputs reflect a "snapshot in time," and modeling results and resource portfolios will evolve over time as technology costs and load forecasts change. The plan includes different resource portfolios with different assumptions around coal retirement and carbon policy but recognizes that the modeling process is limited in its ability to consider all potential policy changes and lacks perfect foresight of other variables such as technology advancements and economic factors. To the extent these factors change over time, future resource plans will reflect those changes.

To further inform the Company's planning efforts, in 2019, Duke Energy contracted with NREL[1] to conduct a Carbon-Free Resource Integration Study[2] to evaluate the planning and operational considerations of integrating increasing levels of carbon-free resources onto the Duke Energy Carolinas and Duke Energy Progress systems. Phase 1 of the study[3] has helped inform some of the renewable resource assumptions and reinforced the benefits that a diverse portfolio can provide when integrating carbon-free generation on the system. Phase 2 of the NREL study is underway now. This study is being informed by stakeholder input and will provide a more granular analysis to understand the integration, reliability and operational challenges and opportunities for integrating carbon-free resources and will inform future IRPs and planning efforts.

In accordance with North Carolina and South Carolina regulatory requirements, the 2020 IRP includes a most economic or "least-cost" portfolio, as well as multiple scenarios reflecting a range of potential future resource portfolios. These portfolios compare the carbon reduction trajectory, cost, operability and execution implications of each portfolio to support the regulatory process and inform public policy dialogue. In North Carolina, Duke Energy is an active participant in the state's Clean Energy Plan stakeholder process, which is evaluating policy pathways to achieve a 70% reduction in greenhouse gas emissions from 2005 levels by 2030 and carbon neutrality for the electric power sector by 2050. Accordingly, this year's IRP includes two resource portfolios that illustrate potential pathways to achieve 70% CO_2 reduction by 2030, though both scenarios would require supportive state policies in North Carolina and South Carolina. All portfolios keep Duke Energy on a trajectory to meet its near-term enterprise carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050. These portfolios would also enable the Company to retire all units that rely exclusively on coal by 2030. Looking beyond the planning horizon, the 2020 IRP includes a section that provides a qualitative overview of how technologies, analytical tools and processes, and the grid will need to evolve to achieve the Company's net-zero 2050 CO_2 goal. Duke Energy welcomes the opportunity to work constructively with policymakers and stakeholders to address technical and practical issues associated with these scenarios.

Act 62, which was signed into law in South Carolina on May 16, 2019, sets out minimum requirements for each utility's IRP. The 2020 IRP contains the necessary information required by

[1] "An industry-respected, leading research institution that advances the science and engineering of energy efficiency, sustainable transportation and renewable power technologies", www.nrel.gov.
[2] https://www.nrel.gov/grid/carbon-free-integration-study.html.

[3] https://www.nrel.gov/grid/carbon-free-integration-study.html.

Act 62, including, the utility's long-term forecast of sales and peak demand under various scenarios, projected energy purchased or produced by the utility from renewable energy resources, and a summary of the electrical transmission investments planned by the utility. The IRP also includes resource portfolios developed with the purpose of fairly evaluating the range of demand side, supply side, storage, and other technologies and services available to meet the utility's service obligations. Consistent with Act 62 and NC requirements, the IRP balances the following factors: resource adequacy and capacity to serve anticipated peak electrical load with applicable planning reserve margins; consumer affordability and least cost; compliance with applicable state and federal environmental regulations; power supply reliability; commodity price risks; and diversity of generation supply.

EXECUTIVE SUMMARY

Duke Energy's history of delivering reliable, affordable and increasingly cleaner energy to its customers in the Carolinas stems back to the early 1900's, when visionaries harnessed the natural resource of the Catawba River to develop an integrated system of hydropower plants that provided the electricity to attract new industries to the region. As the population in the Carolinas has grown and energy demand increased, the Company has worked collaboratively with customers and other stakeholders to invest in a diverse portfolio of generation resources, enabled by an increasingly resilient grid, to respond to the region's growing energy needs and economic growth.

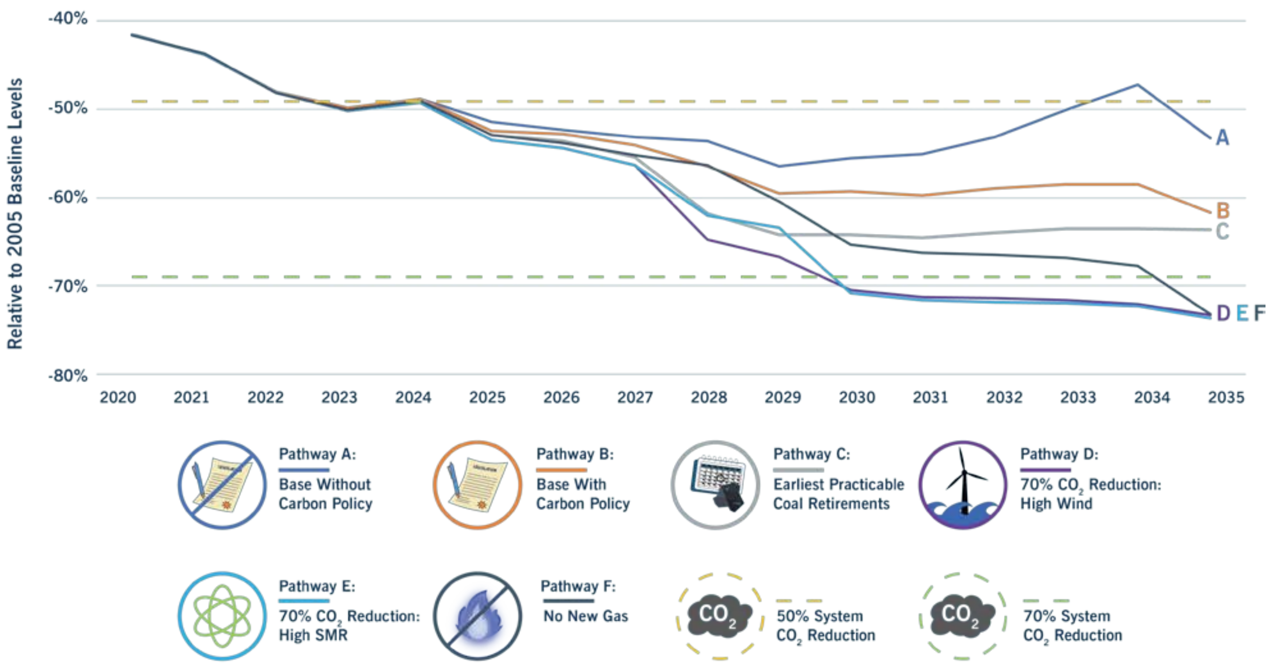
Today, Duke Energy Progress (DEP) serves approximately 1.6 million customers. Over the 15-year planning horizon, the Company projects the addition of 264,000 new customers in DEP contributing to 1,850 MW of additional winter peak demand on the system. Even with the expansion of energy efficiency and demand reduction programs contributing to declining per capita energy usage, cumulative annual energy consumption is expected to grow by approximately 7,050 GWh between 2021 and 2035 due to the projected population and household growth that exceeds the national average. This represents an annual winter peak demand growth rate of 0.9% and an annual energy growth rate of 0.8%. In addition to growing demand, DEP is planning for the potential retirement of some of its older, less efficient generation resources, creating an additional need of at least 3,950 MW over the 15-year planning horizon. After accounting for the required reserve margin, approximately 6,200 MW of new resources are projected to be needed over the 15-year planning horizon.

While growing, DEP is projecting slightly lower load growth compared to the 2019 IRP due to a somewhat weaker economic outlook, the addition of 2019 peak history showing declines in commercial and Industrial energy sales, and other refinements to the forecasting inputs. Additionally, due to the timing of the spring 2020 load forecast, which was developed using Moody's economic inputs as of January 2020, and the lack of relevant historical data upon which to base forecast adjustments, the potential impacts of COVID-19 are not incorporated in this forecast. Based on summer 2020 demand observations to date, however, it appears that the COVID-19 impact to peak demand is relatively insignificant. The Company will continue to monitor the impacts from the pandemic, including the higher residential demand and changing usage patterns, as well as the projected macroeconomic implications and incorporate changes to the long-term planning assumptions in future IRPs.

REDUCING GHG EMISSIONS

In 2019, Duke Energy announced a corporate commitment to reduce CO_2 emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050. This is a shared goal important to the Company's customers and communities, many of whom have also developed their own clean energy initiatives. As one of the largest investor-owned utilities in the U.S., the goal to attain a net-zero carbon future represents one of the most significant reductions in CO_2 emissions in the U.S. power sector. The development of the Company's IRP and climate goals are complementary efforts, with the IRP serving as a road map that provides the analysis and stakeholder input that will be required to achieve carbon reductions over time. All pathways included in the 2020 IRP keep Duke Energy on a trajectory to meet its carbon goals over the 15-year planning horizon.

COMBINED CARBON REDUCTION BY SCENARIO

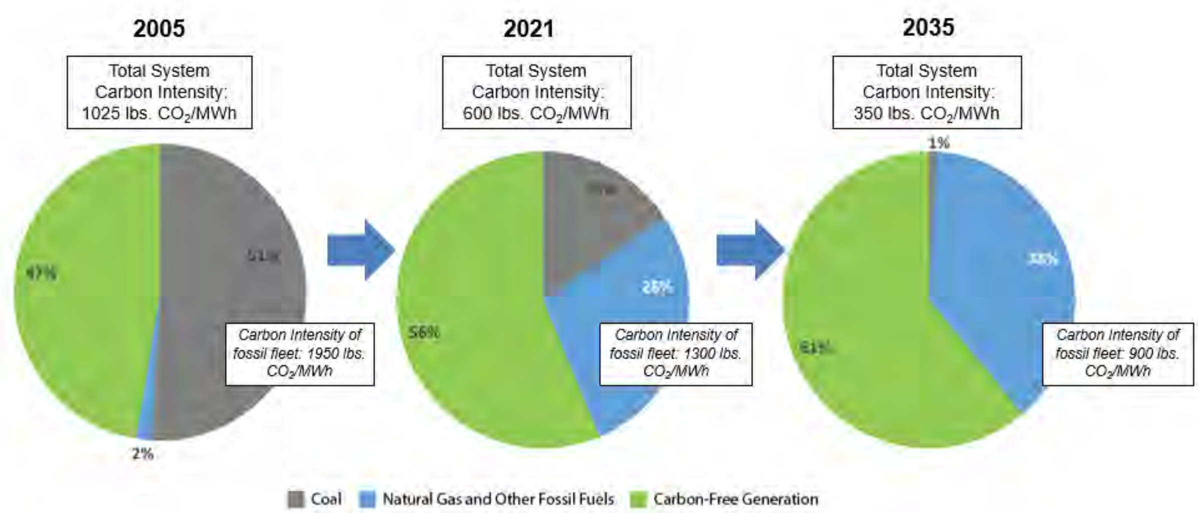


DEP has a strong historic commitment to carbon-free resources such as nuclear, hydro-electric and solar resources. In addition, as described in Appendix D, DEP provides customers with an expansive portfolio of energy efficiency and demand-side management program offerings. In total, DEP and Duke Energy Carolinas (DEC), through their Joint Dispatch Agreement (JDA), serve more than half of the energy needs of their customers with carbon free resources, making the region a national leader in carbon-free generation.

Combined, DEP and DEC operate six nuclear plants and 26 hydro-electric facilities in the Carolinas with winter capacities of over 11,000 MW and 3,400 MW respectively. In 2018, Duke Energy's nuclear fleet provided half of our customers' electricity in the Carolinas, avoiding the release of about 54 million tons of carbon dioxide, or equivalent to keeping more than 10 million passenger cars off the road. As the Company meets its customers' future energy needs and reduces its carbon footprint, it is seeking to renew the licenses of 11 nuclear units it operates at six plant sites in the Carolinas. This provides the option to operate these plants for an additional 20 years. In addition, DEP and DEC purchase or own approximately 4,000 MW of solar generation coming from approximately 1,000 solar facilities throughout the Carolinas. In DEP, where a large portion of energy has historically been sourced from carbon-free resources, the Company has reduced CO_2 emissions by 41% since 2005. In addition to a leadership position in absolute emission reductions, energy produced from the combined DEP/DEC fleet has one of the lowest carbon-intensities in the country. With a current CO_2 emissions rate of just over 600 pounds /megawatt-hour, the combined Carolinas' fleet ranks among the nation's top utilities for the provision of low carbon-intensive energy.[4] The following figure illustrates how the Company is building on its leadership position through the addition of carbon free resources such as solar and wind while also reducing the emissions profile and carbon intensity of remaining fossil generation by reducing dependence on coal and increasing utilization of more efficient, less carbon intense, natural gas resources.

COMBINED SYSTEM CARBON REDUCTION TRAJECTORY (BASE CO_2)

THE COMBINED DEC / DEP FLEET IS A NATIONAL LEADER IN LOW CARBON INTENSITY ENERGY, WITH A CURRENT RATE 37% LOWER THAN THE INDUSTRY AVERAGE OF 957 LBS. CO_2/MWH[5]



STAKEHOLDER ENGAGEMENT

As part of the development of the 2020 IRP, Duke Energy actively engaged stakeholders in North Carolina and South Carolina with the objectives of listening, educating and soliciting input to inform

[4] Source: MJ Bradley, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" – July 2020, p. 30.

[5] Source: MJ Bradley, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" – July 2020, p. 30.

from stakeholders. The analysis and studies in this IRP explore the opportunities and challenges over a range of options for achieving varying trajectories of carbon emission reduction. Specifically, the 2020 IRP highlights six possible portfolios, or plans, within the 15-year planning horizon. These portfolios explore the most economic and earliest practicable paths for coal retirement; acceleration of renewable technologies including solar, onshore and offshore wind; greater integration of battery and pumped-hydro energy storage; expanded energy efficiency and demand response and deployment of new zero-emitting load following resources (ZELFRs) such as small modular reactors (SMRs).

Consistent with regulatory requirements, the base case portfolios evaluate the need for the new resources associated with customer growth and the economic retirement of existing generation under a “no-carbon policy” view and a “with carbon policy” view respectively. These base case portfolios employ traditional least cost planning principles as prescribed in both North Carolina and South Carolina. The remaining plans build upon the carbon base case and were constructed with the assumption of future carbon policy. As described below, and in more detail in Appendix A, these six portfolios show different trajectories for carbon reduction with varying inputs such as coal retirement dates, types of resources and the level and pace of technology adoption rates, as well as contributions from energy efficiency and demand-side management initiatives. All six portfolios were evaluated under combinations of differing carbon and gas prices to test the impact these future scenarios would have on each plan. The results of that scenario analysis, including a table with retirement dates for each portfolio, are presented in Appendix A.

The portfolios also incorporate varying levels of demand-side management programs as an offset to future demand and energy growth. Stakeholders have voiced strong support for these initiatives and the Company has responded by including new conservation programs like Integrated Volt-Var Control (IVVC) which will further support the integration of renewables while also delivering peak and energy demand savings and enhanced reliability for our customers over time, and is further described in Appendix D. With input and support from stakeholders, the Company also undertook a new Winter Peak Shaving study with top consultants in this field. While more work is needed to develop and gain approval for new programs and complementary rate designs, this study provides an increased level of confidence that the high energy efficiency and demand response assumptions used in the portfolios with higher carbon reductions (D - F) could be realized with supportive regulatory policies in place.

The following table outlines the supportive studies used in development of this IRP. These studies cover an array of topical areas with perspective and analysis from some of the industry's leading experts in their respective fields.

STUDY REQUIREMENTS

STUDY	STUDY REQUIREMENTS
Economic Coal Retirements	• Analysis established the most economic coal unit retirement dates for the Base CO_2 and Base No CO_2 scenarios.
Earliest Practicable Coal Retirements	• Analysis established the earliest feasible coal unit retirement dates. Analysis set aside normal economic considerations and focused on procurement and construction timelines for replacement capacity in order to retire the coal units at the earliest attainable dates.
Resource Adequacy Study/ Reserve Margin Study	• Astrapé Consulting study evaluated reliability based on meeting the one day in ten years loss of load expectation (LOLE) metric.
Storage Effective Load Carrying Capability (ELCC) Study	• Astrapé Consulting study evaluated capacity value of storage under multiple conditions, including its contribution to winter peak and considerations with increasing levels of renewable penetration.
Energy Efficiency and Market Potential Study	• Nexant study evaluated market potential for energy efficiency and demand response initiatives.
Winter Specific DR and Rate Design Benchmarking Study	• Being conducted by Tierra Resource Consultants, Proctor Engineering Group, and Dunsky. Studies the integration of new rate designs and DSM technology with innovative program structures to drive winter peak focused reductions.

GRID INVESTMENTS

Significant investment in the transmission and distribution system will be required to retire existing coal resources that support the grid and to integrate the incremental resources forecasted in this IRP. While grid investments are critical, ascribing precise cost estimates for individual technologies in the context of an IRP is challenging as grid investments depend on the type and location of the resources that are being added to the system. As described in Appendix A, if replacement generation with similar capabilities is not located at the site of the retiring coal facility, transmission investments will generally first be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation coming onto the grid. To that end, since the level of retirements and replacement resources vary by portfolio, separate estimates of potential required transmission investments are shown and are included in the present value revenue requirements (PVRR) for each of the portfolios. On a combined basis, the transmission investments described further in Chapter 7 have an approximate range of $1 billion in the Base Case portfolios to $9 billion in the No New Gas portfolio. The incremental transmission cost estimates are high level projections 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 Company's control. These also do not include the costs of infrastructure upgrades that would be needed on affected third party transmission systems, e.g., other utilities and regional transmission organizations.

With respect to the distribution grid, the Company is working to develop and implement necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased penetration of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs and rate designs. Distribution grid control enhancement investments are foundational across the scenarios in this IRP, improving flexibility to accommodate increasing levels of distribution connected renewable resources while developing a more sustainable and efficient grid. In recognition of the critical role of the transmission and distribution system in an evolving energy landscape, the Company believes it will be critical to modernize the grid as outlined in Chapter 16 and to further develop its Integrated System & Operations Planning (ISOP) framework described in Chapter 15. The Company will use ISOP tools to identify and prioritize future grid investment opportunities that can combine benefits of advanced controls with innovative rate designs and customer programs to minimize total costs across distribution, transmission, and generation.

TECHNOLOGY, POLICY AND OPERATIONAL CONSIDERATIONS

As depicted further below, portfolios that seek quicker paces of carbon reductions have greater dependency on technology development, such as battery storage, small modular reactors and offshore wind generation, which are at varying levels of maturity and commercial availability[8]. As a result, these portfolios will have a greater dependence on technology advancements and projected future cost reductions, thus requiring near-term supportive energy policies at the state or Federal levels. For example, future policy may serve to lower the cost of these emerging technologies to consumers through research and development funding or by providing direct tax incentives to these technologies.

As noted above, all portfolios will require additional grid investments in the transmission and distribution systems to integrate the new resources outlined in each of the portfolios. The portfolio analysis includes estimates of system costs, associated average residential monthly bill impact and operational and executional challenges for each portfolio. When considering these portfolios across both utilities, a combined look is presented below, followed by a DEP only view.

The "Dependency on Technology & Policy Advancement" row in the portfolio results table below reflects a qualitative assessment for each respective portfolio. More shading within a circle indicates a higher degree of dependence on future development of the respective technologies, supporting policy and operational protocols. The Base without Carbon Policy case reflects the current state, with little to no dependence on further technology advancements, policy development, and minimal operational risks. Working from left to right across the table, all other portfolios, including the Base with Carbon Policy case requires policy changes relative to the current state. The 70% CO_2 Reduction High Wind case would require supportive policies for expeditious onshore and offshore wind development and associated, necessary transmission build by 2030. The 70% CO_2 Reduction High SMR case was included to illustrate the importance of support for advancing these technologies as part of a balanced plan to achieve net-zero carbon. The No New Gas case includes dependence on all factors listed, as well as a much greater dependence on siting, permitting, interconnection and supply chain for battery storage. For the 70% reduction and No New Gas cases, the unprecedented levels of storage that are required to support significantly higher levels of variable energy resources present increased system risks, given that there is no utility experience for winter peaking utilities in the U.S. or abroad with operational protocols to manage this scale of dependence on short-term energy storage.

[8] Source: Browning, Morgan S., Lenox, Carol S. "Contribution of offshore wind to the power grid: U.S. air quality. implications." *ScienceDirect,* 2020, https://www.sciencedirect.com/science/article/abs/pii/S0306261920309867.

DEP / DEC COMBINED SYSTEM PORTFOLIO RESULTS TABLE

PORTFOLIO	A: Base without Carbon Policy	B: Base with Carbon Policy	C: Earliest Practicable Coal Retirements	D: 70% CO_2 Reduction: High Wind	E: 70% CO_2 Reduction: High SMR	F: No New Gas Generation
System CO_2 Reduction (2030 | 2035)[1]	56% 53%	59% 62%	64% 64%	70% 73%	71% 74%	65% 73%
Present Value Revenue Requirement (PVRR) [$B][2]	$79.8	$82.5	$84.1	$100.5	$95.5	$108.1
Estimated Transmission Investment Required [$B][3]	$0.9	$1.8	$1.3	$7.5	$3.1	$8.9
Total Solar [MW][4, 5] by 2035	8,650	12,300	12,400	16,250	16,250	16,400
Incremental Onshore Wind [MW][4] by 2035	0	750	1,350	2,850	2,850	3,150
Incremental Offshore Wind [MW][4] by 2035	0	0	0	2,650	250	2,650
Incremental SMR Capacity [MW][4] by 2035	0	0	0	0	1,350	700
Incremental Storage [MW][4, 6] by 2035	1,050	2,200	2,200	4,400	4,400	7,400
Incremental Gas [MW][4] by 2035	9,600	7,350	9,600	6,400	6,100	0
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035	2,050	2,050	2,050	3,350	3,350	3,350
Remaining Dual Fuel Coal Capacity [MW][4, 8] by 2035	3,050	3,050	0	0	0	2,200
Coal Retirements	Most Economic	Most Economic	Earliest Practicable	Earliest Practicable[9]	Earliest Practicable[9]	Most Economic[10]
Dependency on Technology & Policy Advancement	○	◔	◑	◕	●	●

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline
[2]PVRRs exclude the cost of CO_2 as tax. Including CO_2 costs as tax would increase PVRRs by ~$11-$16B. The PVRRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives
[3]Represents an estimated nominal transmission investment; cost is included in PVRR calculation
[4]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon
[5]Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected)
[6]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro
[7]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour
[8]Remaining coal units are capable of co-firing on natural gas, **all coal units that rely exclusively on coal are retired before 2030**
[9]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit and Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030
[10]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

LEGEND:
- ● Completely dependent
- ◕ Mostly dependent
- ◑ Moderately dependent
- ◔ Slightly dependent
- ○ Not dependent

DEP PORTFOLIO RESULTS TABLE

DUKE ENERGY. PROGRESS

	Base without Carbon Policy		Base with Carbon Policy		Earliest Practicable Coal Retirements		70% CO_2 Reduction: High Wind		70% CO_2 Reduction: High SMR		No New Gas Generation	
PORTFOLIO	A		B		C		D		E		F	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	59%	62%	64%	64%	70%	73%	71%	74%	65%	73%
Average Monthly Residential Bill Impact for a Household Using 1000kWh (by 2030 | by 2035)[2]	$13	$21	$15	$27	$16	$24	$31	$39	$27	$36	$49	$58
Average Annual Percentage Change in Residential Bills (through 2030 | through 2035)[2]	1.2%	1.2%	1.3%	1.5%	1.4%	1.4%	2.7%	2.1%	2.4%	1.9%	4.0%	2.9%
Present Value Revenue Requirement (PVRR) [$B][3]	$35.4		$35.7		$37.3		$44.5		$41.9		$52.1	
Estimated Transmission Investment Required [$B][4]	$0.4		$0.8		$0.7		$3.2		$1.0		$6.2	
Total Solar [MW][5, 6] by 2035	4,950		6,350		6,450		7,800		7,800		7,950	
Incremental Onshore Wind [MW][5] by 2035	0		600		1,350		1,750		1,750		1,750	
Incremental Offshore Wind [MW][5] by 2035	0		0		0		1,300		100		2,500	
Incremental SMR Capacity [MW][5] by 2035	0		0		0		0		700		0	
Incremental Storage [MW][5, 7] by 2035	700		1,600		1,600		2,000		2,000		5,000	
Incremental Gas [MW][5] by 2035	5,350		4,300		3,950		2,150		2,150		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][8] by 2035	825		825		825		1,500		1,500		1,500	
Remaining Coal Capacity [MW][5] by 2035	0		0		0		0		0		0	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable[9]		Earliest Practicable[9]		Most Economic[10]	
Dependency on Technology & Policy Advancement	○		◔		◑		◕		●		●	

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline

[2]Represents specific IRP portfolio's incremental costs included in IRP analysis; does not include complete costs for other initiatives that are constant throughout the IRP or that may be pending before state commissions

[3]PVRRs exclude the cost of CO_2 as tax. Including CO_2 costs as tax would increase PVRRs by ~$5-$8B. The PVRRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives

[4]Represents an estimated nominal transmission investment; cost is included in PVRR calculation

[5]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[6]Total solar nameplate capacity includes 2,950 MW connected in DEP as of year-end 2020 (projected)

[7]Includes 4-hr and 6-hr grid-tied storage and storage at solar plus storage sites

[8]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[9]Earliest Practicable retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030

[10]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

LEGEND:

- ● Completely dependent
- ◕ Mostly dependent
- ◑ Moderately dependent
- ◔ Slightly dependent
- ○ Not dependent

CUSTOMER FINANCIAL IMPACTS

The Company is committed to the provision of affordable electricity for the residents, businesses, industries and communities served by DEP across its Carolinas' footprint. For each of the six portfolios analyzed, the IRP shows a high level projected present value of long-term revenue requirements and an average residential monthly bill impact across the Company's combined North and South Carolina service territory. Portfolios that have earlier and more aggressive adoption of technologies that are at earlier stages of development in the U.S., such as offshore wind or SMR generators, demonstrate or produce incrementally larger costs (revenue requirements) and bill impacts, but achieve carbon reductions at a more aggressive pace. While the IRP forecasts potential incremental system revenue requirement and system residential bill impact differences associated with each of the various scenarios analyzed in the IRP, it is recognized that these forecasts will change over time with evolving market conditions and policy mandates. Seeking the appropriate pace of technology adoption to achieve carbon reduction objectives requires balancing affordability while maintaining a reliable energy supply. The Company is actively engaged in soliciting stakeholder input into the planning process and is participating in the policy conversation to strike the proper balance in achieving progressive carbon reduction goals that align with customer expectations while also maintaining affordable and reliable service. Finally, cost and bill impacts presented are associated with incremental resource retirements, additions, and demand-side activities identified in the IRP and as such do not include potential efficiencies or costs in other parts of the business. Factors such as changing cost of capital, and changes in other costs will also influence future energy costs and will be incorporated in future IRP forecasts as market conditions evolve. Finally, future cost of service allocators and rate design will impact how these costs are spread among the customer classes and, therefore, customer bill impacts.

BASE CASES

The IRP reflects two base cases, each developed with a different assumption on carbon policy. The first case assumes no carbon policy, which is the current state today. Alternatively, the second base case assumes a policy that effectively puts a price on carbon emissions from power generation, with pricing generally in line with various past or current legislative initiatives, to incentivize lower carbon resource selection and dispatch decisions needed to support a trajectory to net-zero CO_2 emissions by 2050. Given the uncertainties associated with how a carbon policy may be designed, the 2020 IRP carbon policy includes a cost adder on carbon emissions in resource selection as well as daily operations, effectively a "shadow price" on CO_2 emissions. This "shadow price" is a generic proxy that could represent the effects of a carbon tax, price of emissions allowances, or a price signal needed to meet a given clean energy standard. Given the uncertainty of the ultimate form of policy, the cost and rate impacts shown only reflect the cost of the resources that would be required to achieve carbon reduction and not the "shadow price" itself. Customers could bear an additional cost if carbon policy takes the form of a carbon tax.

In accordance with regulatory requirements of both North Carolina and South Carolina, the base cases apply least cost planning principles when determining the optimal mix of resources to meet customer demand. It should be noted that even the Base Case without Carbon Policy includes results that more than double the amount of solar connected to the DEP and DEC system today. In addition, the Base Case without Carbon Policy includes approximately 1,000 MW of battery storage across the two utilities, which is slightly above the total amount in operation in the U.S. today (source: EIA[9]). The inclusion of a price on carbon emissions drives outcomes that include higher integration of solar, wind, and storage resources when compared to the case that excludes a carbon price. Both pathways utilize the most economic coal retirement date assumption, rather than relying on the depreciable lives of the coal assets as was the case in previous IRPs.

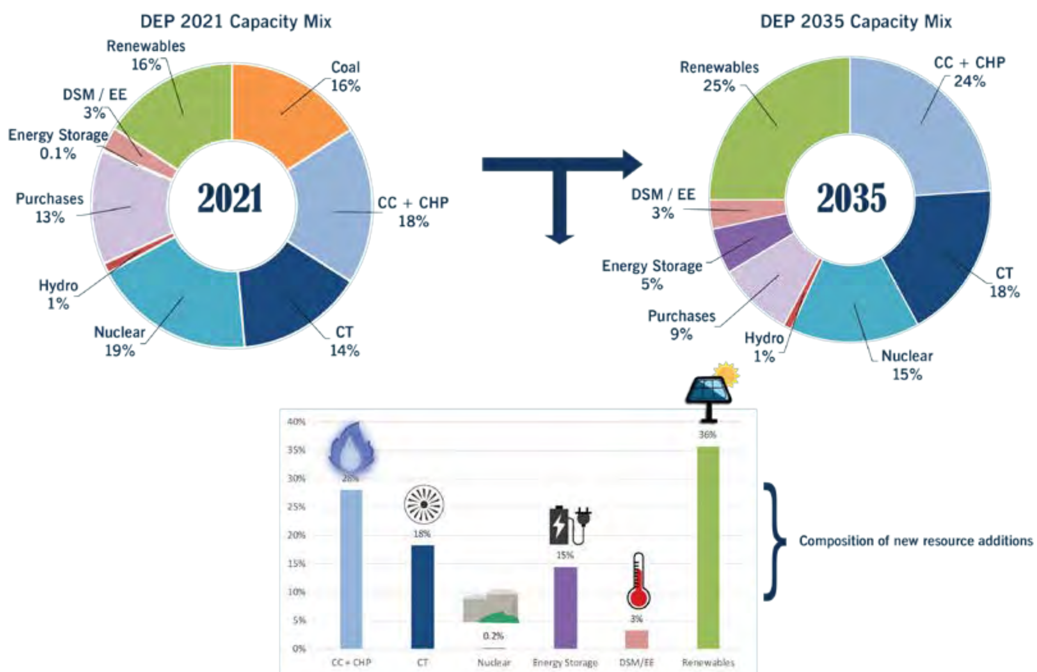
In the Company's base cases, across DEP and DEC combined, all units that operate exclusively on coal would be retired by 2030. The only remaining units that would continue to operate would be dual-fuel units with operation primarily on lower carbon natural gas. By 2035, 7,000 MW of coal-units representing 17% of nameplate capacity across the DEP and DEC system would retire, with the only remaining dual-fuel units of Cliffside 6 and Belews Creek 1 &2 operating through the remainder of their economic lives primarily on lower carbon natural gas. Under these base cases, DEP retires all 3,200 MW of coal capacity by 2030 and DEC retires approximately 3,800 MW of coal capacity by 2035. The remaining units can continue to provide valuable generation capacity to meet peak demand, with generation making up approximately less than 5% of the energy served by DEC and DEP combined by 2035.

The Company's investment to allow for use of lower carbon natural gas at certain coal sites provides a benefit to customers by optimizing existing infrastructure. This dual-fuel capability also improves operational flexibility to accommodate renewables by lowering minimum loads and improving ramp rates while also reducing carbon emissions over the remaining life of the assets. These base case

[9] https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

portfolios serve as the benchmark for comparing the incremental costs and benefits of alternative more aggressive carbon reduction scenarios. The figure below illustrates how DEP's capacity mix changes over the 2021 through the 2035 period in the Base Case with Carbon Policy. The bar chart at the bottom illustrates the makeup of the incremental resources added over that timeframe. For example, renewables make up 36% of the incremental resources added between 2021 and 2035, raising the proportion of renewables in the overall fleet to 25% by 2035.

CHANGE IN INSTALLED CAPACITY[10]



EARLIEST PRACTICABLE COAL RETIREMENTS

For comparison purposes, the Earliest Practicable Retirement case suspends traditional "least cost" economic planning considerations and evaluates the physical feasibility of retiring all the Company's 10,000 MW of coal generation sites within DEP and DEC as early as practicable when taking into consideration the timing required to put replacement resources and supporting infrastructure into service. Aggressive levels of new solar, wind and battery storage were also utilized in this portfolio to accelerate the retirement of a portion of existing coal generation while also reducing the need for

[10] Change in capacity from the Base Case with Carbon Policy portfolio.

incremental gas infrastructure. In determining the "earliest practicable" coal retirement dates, this case considers the siting, permitting, regulatory approval and construction timeline for replacement resources as well as supporting infrastructure such as new transmission and new gas transportation infrastructure. This case assumes the majority of dispatchable resources are replaced at the coal retiring facilities to minimize the resources needed and time associated with additional land acquisition as well as transmission and gas infrastructure that would be required. This approach enables a more rapid transition from coal to lower carbon technologies while maintaining appropriate planning reserves for reliability.

Under this portfolio, all coal units in DEP and DEC would be retired by 2030 with the exception of DEC's Cliffside 6 unit, which would take advantage of its current dual fuel capability and switch to 100% natural gas by 2030. In the aggregate across DEP and DEC, this portfolio includes a diverse mix of over 20,000 MW of new resources being placed in service. This diverse mix results in a combined system carbon reduction of 64% by 2030 while mitigating overall costs and bill impacts by leveraging existing infrastructure associated with the current coal fleet. Finally, while "practicable" from a technical perspective, the sheer magnitude, pace and array of technologies included in this portfolio with approximately half coming from renewable wind and solar resources and half from dispatchable gas, make it evident that new supportive energy policy and regulations would be required to effectuate such a rapid transition.

70% GHG REDUCTION CASES

This IRP also details two cases to achieve a more aggressive carbon reduction goal, such as the goal to achieve 70% greenhouse gas emission reductions from the electric sector by 2030, which is under evaluation in the development of the North Carolina Clean Energy Plan. Achieving these targets will require the addition of diverse, new types of carbon-free resources as well as additional energy storage to replace the significant level of energy and capacity currently supplied by coal units. To support this pace of carbon reduction, this case assumes the same coal unit retirement dates as the "earliest practicable" case, with the exception of shifting the retirement date of one of the Belews Creek units and Roxboro 1&2 units to the end of 2029 to allow for the integration of new carbon free resources by 2030. The resource portfolios in the 70% CO_2 reduction scenarios reflect an accelerated utilization of technologies that are yet to be commercially demonstrated at scale in the United States and may be challenging to bring into service by the 2030 timeframe.

For the purposes of this IRP, the Company evaluated the emerging carbon free technologies that are furthest along the development and deployment curves – Carolinas offshore wind and small modular nuclear reactors. Adding this level of new carbon free resources prior to 2030 will require the adoption of supportive state policies in both North Carolina and South Carolina. It will also require extensive additional analysis around the siting, permitting, interconnection, system upgrades, supply chain and operational considerations of more significant amounts of intermittent resources and much greater dependence on energy storage on the system. The High SMR case also assumes that SMRs are in service by 2030. However, the challenges with integrating a first of a kind technology in a relatively compressed timeframe are significant. Therefore, these cases are intended to illustrate the importance of advancing such technologies as part of a blended approach that considers a range of carbon-free technologies to allow deeper carbon reductions. When comparing and contrasting the two portfolios, differences in resource characteristics, projected future views on technology costs, associated transmission infrastructure requirements and dependencies on federal regulations and legislation all influence the pace and resource mix that is ultimately adopted in the Carolinas. An examination of two alternate portfolios that achieve 70% carbon reduction by 2030 highlight some of these key considerations for stakeholders. As discussed in Chapter 16, the Company is actively promoting the further development of future carbon free technologies which are a prerequisite to a net-zero future.

NO NEW GAS GENERATION

In response to stakeholder interest in a No New Gas case, the Company evaluated the characteristics of an energy system that excludes the addition of new gas generating units from the future portfolio. Recognizing the challenges of replacing coal energy and capacity with only carbon-free resources, this scenario does not accelerate coal retirements but rather assumes the most economic coal retirement dates reflected in the base case with the exception of Roxboro 1&2 which are delayed to the end of 2029 to allow for integration of offshore wind by 2030. Similar to the 70% CO_2 reduction cases, this resource portfolio is highly dependent upon the development of diverse, new carbon-free sources and even larger additions of energy storage and offshore wind as well as the adoption of supportive policies at the state and federal level. Also similar to the 70% case, the No New Gas case would require additional analysis around the siting, permitting, interconnection, system upgrades, supply chain integration and operational considerations of bringing on significant amounts of intermittent resources onto the system. Notably, the heavier reliance on large-scale battery energy storage in this scenario would require significant additional analysis and study since this technology is emergent with very limited history and limited scale of deployment on power grids worldwide. To provide a sense of scale, at the combined system level it would require approximately 1,100 acres of land, or more than 830 football fields to support the amount of batteries in this portfolio and would represent over six times the amount of large-scale battery storage currently in service in the United States. The lack of meaningful industry experience with battery storage resources at this scale presents significant operational considerations that would need to be resolved prior to deployment at such a large scale, which is addressed further in Chapter 16.

Finally, in the combined DEP and DEC view, the No New Gas case is estimated to have the highest customer cost impacts primarily due to the magnitude of early adoption of emerging carbon free technologies and the significant energy storage and transmission investments required to support those technologies. As is the case with almost all technologies, improvements in performance and reductions in cost are projected to occur over time. Without the deployment of new efficient natural gas resources as one component of a long-term decarbonization strategy, the system must run existing coal units longer to allow emerging technologies to evolve from both a technological and an economic perspective. In the alternative, the acceleration of coal retirements without some consideration of new efficient natural gas as a transition resource forces the large-scale adoption of such technologies before they have a chance to mature and decline in price, resulting in higher costs and operational risks for consumers. The summary table highlights the fact that this scenario is dependent on significant technological advances and new policy initiatives that would seek to recognize and address these considerations prior to implementation.

KEY ASSUMPTIONS

The following table provides an overview of the key assumptions applied to our modeling and analysis with comparisons to 2019 IRP. In addition, the company runs a number of sensitivities, such as high and low load growth, energy efficiency and renewable integration levels that demonstrate the impact of changes in various assumptions.

KEY ASSUMPTIONS TABLE

TOPIC AREA	2019 IRP	2020 IRP	NOTES
Load Forecast	**DEP:** 0.9% Winter Peak Demand CAGR **DEC:** 0.8% Winter Peak Demand CAGR	**DEP:** 0.9% Winter Peak Demand CAGR **DEC:** 0.6% Winter Peak Demand CAGR	Lower load growth due to economic factors and refinements of historical load data.
Reserve Margin	17%	17%	New LOLE Study reaffirms 17% strikes the appropriate balance between cost and reliability
Solar (Single Axis Tracking)	37% cost decline through 2030	42% cost decline through 2030	7% lower year one cost compared to 2019 IRP
4-hour Battery Storage	54% cost decline through 2030	49% cost decline through 2030	32% lower year one cost compared to 2019 IRP
Onshore Wind	12% cost decline through 2030	11% cost decline through 2030	7% lower year one cost compared to 2019 IRP; For the first time, wind allowed to be economically selected in planning process
Offshore Wind	N/A	40% cost decline through 2030	For the first time, offshore wind is considered in the planning horizon
Natural Gas	17% cost decline through 2030	17% cost decline through 2030	No Material Change
Coal	Retired based on depreciable lives at the time of the IRP	Retired based on analysis for most economic and earliest practicable retirement dates	Scenarios consider earliest practicable and most economic
New Nuclear	SMRs discussed but not screened for selection	SMRs included for selection	For the first time, SMRs available to be economically selected as a resource

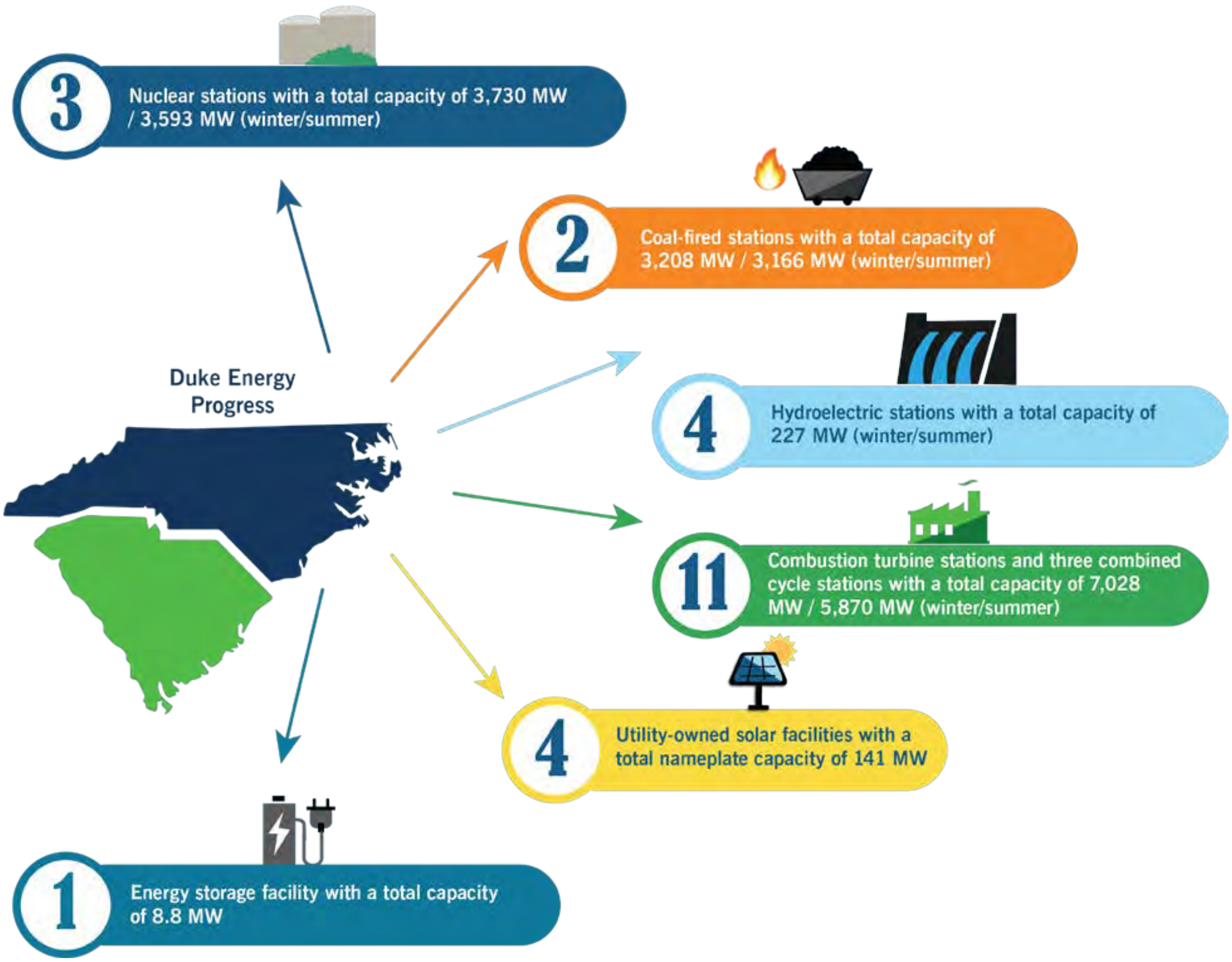
EXECUTIVE SUMMARY CONCLUSION

DEP remains focused on transitioning to a cleaner energy future, advancing climate goals that are important to its customers and stakeholders, while continuing to deliver affordable and reliable service. The 2020 IRP reflects multiple potential future pathways towards these goals. An analysis of each case reflects the associated benefits and costs with each portfolio as well as challenges that would need to be addressed with more aggressive carbon reduction scenarios. This range of portfolios helps illustrate the benefits of a diverse resource mix to assure the reliability of the system and efficiently support the transition toward a carbon-free resource mix. Public policies and the advancement of new, innovative technologies will ultimately shape the pace of the ongoing energy transformation. Duke Energy looks forward to continued engagement and collaboration with stakeholders to chart a path forward that balances affordability, reliability and sustainability.

2 SYSTEM OVERVIEW

DEP's service area covers approximately 29,108 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. In addition to retail sales to approximately 1.61 million residential, commercial and industrial customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities.

DEP currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

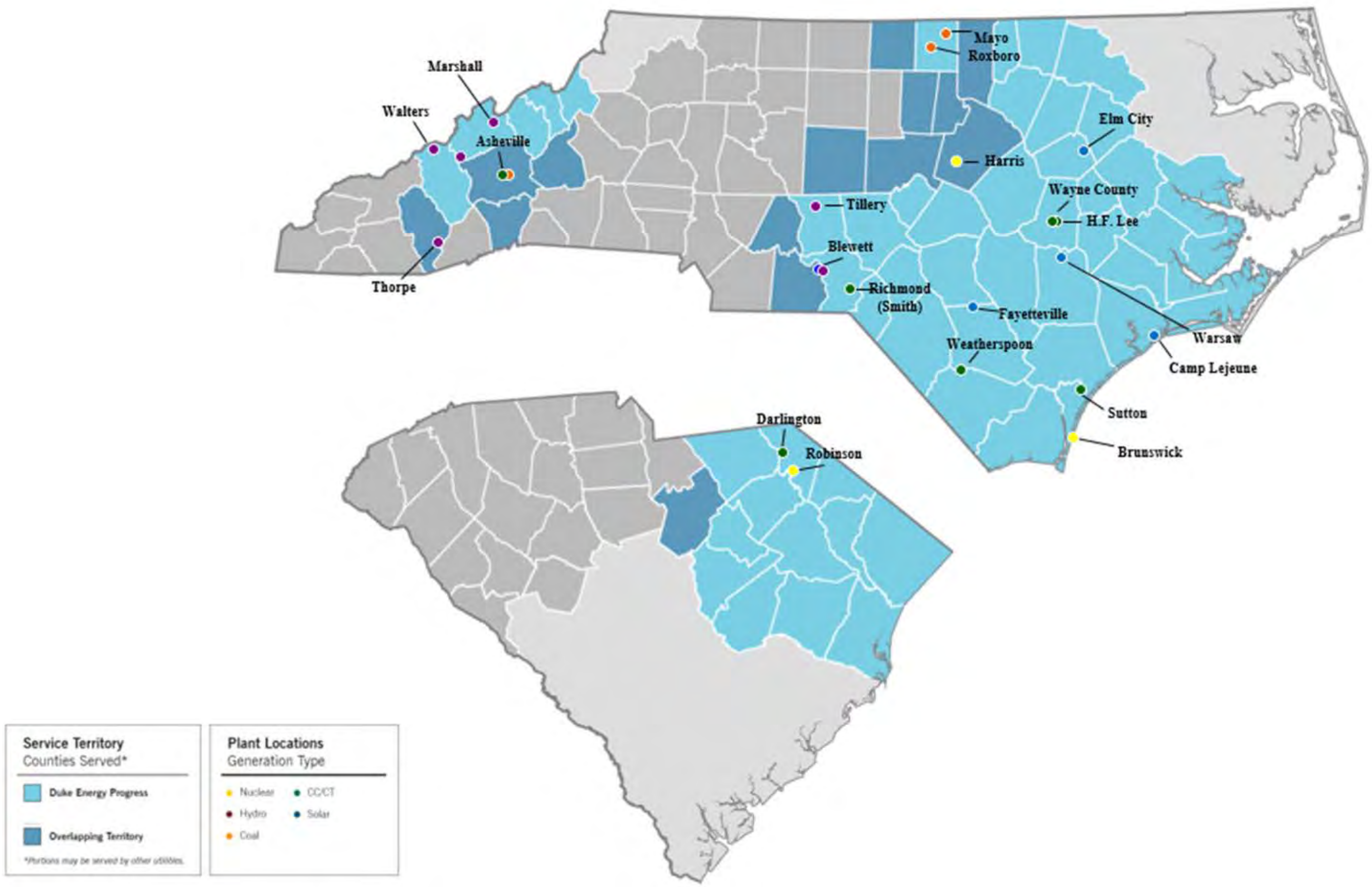


DEP's power delivery system consists of approximately 77,203 miles of distribution lines and 6,266 miles of transmission lines. The transmission system is directly connected to all the Transmission Operators that surround the DEP service area. There are 43 tie-line circuits connecting with six different Transmission Operators: DEC, PJM, Tennessee Valley Authority (TVA), Cube Hydro, Dominion Energy South Carolina (DESC), and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC), and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the DEP service area.

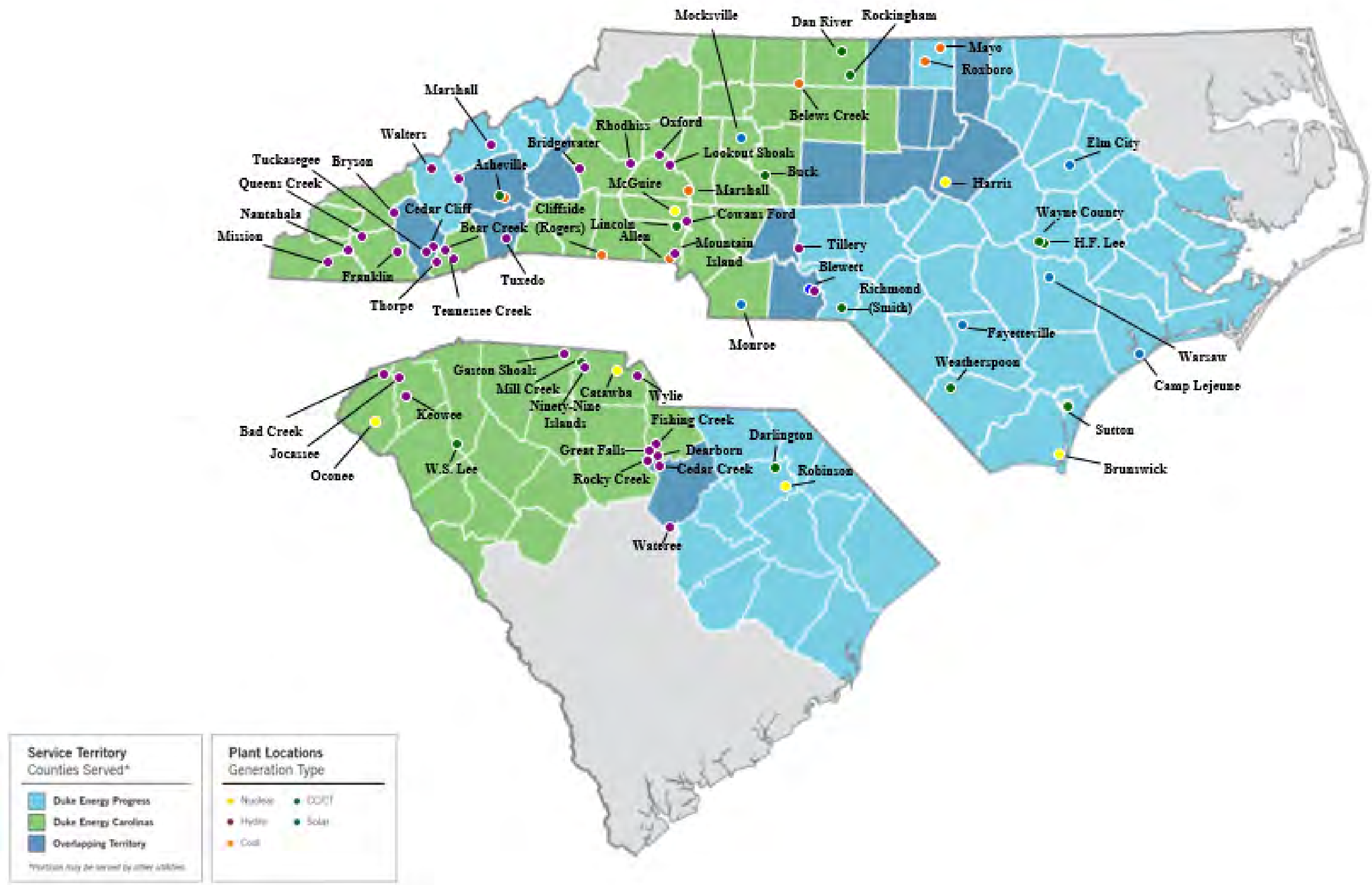
FIGURE 2-A

DUKE ENERGY PROGRESS SERVICE AREA



The service territories for both DEC and DEP lend to future opportunities for collaboration and potential sharing of capacity to create additional savings for North Carolina and South Carolina customers of both utilities. An illustration of the service territories of the Companies are shown in the map below.

FIGURE 2-B
DEP AND DEC SERVICE AREA



3 ELECTRIC LOAD FORECAST

The Duke Energy Progress Spring 2020 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2021-2035 and represents the needs of the following customer classes:

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies. The average annual growth rate of Residential energy sales in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021-2035 is 1.4%.

The three largest sectors in the Commercial class are offices, education and retail. The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. Commercial energy sales are expected to grow 0.1% per year over the forecast horizon.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

The Company continues to look at ways to improve the load forecasting methodology in order to develop the most accurate and reasonable demand forecasts for DEP. The 2020 load forecast update is lower compared to the 2019 IRP. The decrease in the 2020 update is primarily driven by refinements to peak history, the addition of 2019 peak history and declines in Commercial and Industrial energy sales. The 2020 update also includes revised projections for rooftop solar and electric vehicle programs and the impacts of voltage control programs. The key economic drivers and forecast changes are shown below in Tables 3-A and 3-B. A more detailed discussion of the load forecast can be found in Appendix C.

TABLE 3-A

KEY DRIVERS

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

Table 4-B reflects a comparison between the 2020 and 2019 growth rates of the load forecast with and without impacts of EE.

TABLE 3-B

2020 DEP LOAD FORECAST GROWTH RATES VS. 2019 LOAD FORECAST GROWTH RATES (INCLUSIVE OF RETAIL AND WHOLESALE LOAD)

	2020 FORECAST (2021-2035)			2019 FORECAST (2020-2034)		
	SUMMER PEAK DEMAND	WINTER PEAK DEMAND	ENERGY	SUMMER PEAK DEMAND	WINTER PEAK DEMAND	ENERGY
Excludes impact of new EE programs	1.0%	1.0%	0.9%	1.2%	1.1%	1.2%
Includes impact of new EE programs	0.9%	0.9%	0.8%	1.0%	0.9%	1.0%

4 ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT, AND VOLTAGE OPTIMIZATION

DEP is committed to ensuring electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEP advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to energy efficiency (EE) and demand-side management (DSM).

Since 2008, DEP has been actively developing and implementing new EE and DSM programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. DEP's EE and DSM plan is designed to be flexible, with programs being evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost-effectiveness. Initiatives are aimed at helping all customer classes and market segments use energy more wisely. The potential for new technologies and new delivery options is also reviewed on an ongoing basis in order to provide customers with access to a comprehensive and current portfolio of programs.

DEP's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEP evaluates the cost-effectiveness of EE/DSM programs from the perspective of program participants, non-participants, all customers and total utility spending using the four California Standard Practice tests (i.e., Participant Test, Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test and Utility Cost Test (UCT), respectively) to ensure the programs can be provided at a lower cost than building supply-side alternatives. The use of multiple tests can ensure the development of a reasonable set of programs and indicate the likelihood that customers will participate. DEP will continue to seek approval from State utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEP's forecasted resource needs over the planning horizon. DEP currently has approval from the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC) to offer a large variety of EE and DSM programs and measures to help reduce electricity consumption across all types of customers and end-uses.

For IRP purposes, these EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities. DEP also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as resource options that can be dispatched to meet system capacity needs during periods of peak demand.

In 2019, DEP commissioned an EE market potential study to obtain estimates of the technical, economic and achievable potential for EE savings within the DEP service area. The analysis to develop the market potential study included three distinct scenarios: a Base scenario using the baseline input assumptions, an Enhanced scenario which considered the impact of increased program spending to attract new customers, and an Avoided Energy Cost Sensitivity where higher future energy prices result in increased economic and achievable EE savings potential.

The final report was prepared by Nexant, Inc. and was completed in June 2020. The results of the market potential study are suitable for integrated resource planning purposes and use in long-range system planning models. However, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the EE/DSM savings contained in this IRP were projected by blending DEP's five-year program planning forecast into the long-term achievable potential projections from the market potential study.

DEP prepared a Base EE Portfolio savings projection that was based on DEP's five-year program plan for 2020-2024. For periods beyond 2029, the Base Portfolio assumed that the Company could achieve the annual savings projected in the Base Achievable Portfolio presented in Nexant's Market Potential Study. For the period of 2025 through 2029, the Company employed an interpolation methodology to blend together the projection from DEP's program plan and the Market Potential Study Achievable Potential.

DEP also prepared a High EE Portfolio savings projection based on the Enhanced and Avoided Energy Cost Sensitivity Scenarios contained in Nexant's Market Potential Study. The High EE savings forecast was developed using a similar process to the Base case, however; for the Nexant MPS portion of the forecast, the difference between the Avoided Energy Cost Sensitivity and Base Scenarios for all years was added to the Enhanced Case forecast. This method captures the higher EE savings potential resulting from both the higher avoided energy cost assumptions as well as from increased incentives in the Enhanced case.

Finally, a Low EE Portfolio savings projection was developed by applying a reduction factor to the Base EE Portfolio forecast. Additionally, for the Base, High and Low Portfolios described above, DEP included an assumption that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C.

In addition to the updated MPS and consistent with feedback from stakeholders, the Company undertook a detailed study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that were outside of the MPS scope. To develop this targeted demand response study the Company engaged Tierra Resource Consultants who collaborated with Dunsky Energy Consulting and Proctor Engineering. These firms represent three of the industry's leading practitioners in the development and deployment of innovative energy efficiency and demand response programs across North America. The Company envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort. At the time of this writing preliminary results from this study show promise for additional winter peak demand savings that could move the Company closer to the high energy efficiency and demand response sensitivity identified in the IRP. While it is premature to include such findings in the Base Case forecast, the results do show a potential pathway for moving closer to the High Case identified in the IRP. Over time as new programs/rate designs are approved and become established, the Company will gain additional insights into customer participation rates and peak savings potential and will reflect such findings in future forecasts.

Lastly, Integrated Voltage/VAR Control (IVVC) is part of the proposed Duke Energy Progress Grid Improvement Plan (GIP) and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. If the GIP is approved for DEP, the current Distribution System Demand Response (DSDR) program will be rolled into the IVVC program by the year 2025 and will contain both its current peak-shaving capability

(MW) and a Conservation Voltage Reduction (CVR) operational mode that will support energy conservation across the majority of hours of the year versus only peak shaving and emergency conditions of the current program. First implemented in 2014, the North Carolina Utility Commission classified DSDR as an Energy Efficiency program with rider recovery. The rollout of IVVC is anticipated to take approximately four years and will be deployed on 100% of the total circuits and substations across the DEP service territory.

See Appendix D for further detail on DEP's EE, DSM and consumer education programs, which also includes a discussion of the methodology for determining the cost effectiveness of EE and DSM programs. A complete writeup and detailed implementation schedule on the IVVC program is included, as well.

5 RENEWABLE ENERGY STRATEGY / FORECAST

The growth of renewable generation in the United States continued in 2019. According to EIA, in 2019, 9.1 GW of wind and 5.3 GW of utility-scale solar capacity were installed nationwide. The EIA also estimates 3.7 GW of small scale solar was added as well.[1] Notably, U.S. annual energy consumption from renewable sources exceeded coal consumption for the first time since before 1885.[2]

North Carolina ranked sixth in the country in solar capacity added, and first in additions of solar plants greater than 2 MW, in 2019 and remains second behind only California in total solar capacity online, while South Carolina ranked seventh in solar capacity added in 2019.[3] [4] Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high investment in solar.

RENEWABLE ENERGY OUTLOOK FOR DUKE ENERGY IN THE CAROLINAS

The future is bright for opportunities for continued renewable energy development in the Carolinas as both states have supportive policy frameworks and above average renewable resource availability, particularly for solar. The Carolinas also benefits from substantial local expertise in developing and interconnecting large scale solar projects and the region will benefit from such a concentration of skilled workers. Both states are supporting future renewable energy development via two landmark pieces of

[1] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.
[2] https://www.eia.gov/todayinenergy/detail.php?id=43895
[3] https://www.seia.org/states-map
[4] https://www.eia.gov/electricity/data/eia860M/; February month end data

legislation, HB 589 in North Carolina (2017) and Act 62 in South Carolina (2019). These provide opportunities for increased renewable energy, particularly for utility customer programs for both large and small customers who want renewable energy. These programs have the potential to add significant renewable capacity that will be additive to the historic reliance on administratively-established standard offer procurement under PURPA in the Carolinas. Furthermore, the Companies' pending request to implement Queue Reform—a transition from a serial study interconnection process to a cluster study process—will create a more efficient and predictable path to interconnection for viable projects, including those that are identified through any current or future procurement structures. It is also worth noting that that there are solar projects that appear to be moving forward with 5-year administratively-established fixed price PURPA contracts and additional solar projects that will likely be completed as part of the transition under Queue Reform.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

DRIVERS FOR INCREASING RENEWABLES IN DEP

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the Federal ITC, and declining installed solar costs continue to make solar capacity the Company's primary renewable energy resource in the 2020 IRP. However, achieving the Company's goal of net-zero carbon emissions by 2050 will require a diverse mix of renewable, and other zero-emitting, load following resources. Wind generation, whether onshore wind generated in the Carolinas or wheeled in from other regions of the country, or offshore wind generated off the coast of the Carolinas, may become a viable contributor to the Company's resource mix over the planning horizon.

The following key input assumptions regarding renewable energy were included in the 2020 IRP:

- Through existing legislation such as NC HB589 and opportunities under SC Act 62, along with materialization of existing projects in the distribution and transmissions interconnection queues, installed solar capacity increases in DEP from 2,888 MW in 2021 to 4,598 MW in 2035 with approximately 85 MW of usable AC storage coupled with solar included prior to incremental solar added economically during the planning process.
- Additional solar coupled with storage was available to be selected by the capacity

expansion model to provide economic energy and capacity. Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 200 MW per year over the planning horizon in DEP.

- Up to 150 MW of onshore Carolinas wind generation, assumed to be located in the central Carolinas, could be selected by the capacity expansion model annually to provide a diverse source of economic energy and capacity.

- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases.

- Achievement of the SC Act 236 goal of 39 MW of solar capacity located in DEP.

- Implementation of NC HB 589 and SC Act 62 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements.

For more details regarding these assumptions, along with more information about NC HB 589 and SC Act 62, see Appendix E.

BASE WITH CARBON POLICY

The 2020 IRP Base with Carbon Policy case incorporates the projected and economically selected renewable capacities shown below. This case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base with Carbon Policy case also includes additional projected solar growth beyond NC HB 589, including potential growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. This case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

However, it is the Company's belief that continued declines in the installation cost of solar and storage will enable coupled "solar plus storage" systems, to contribute to energy and capacity needs. Additionally, the inclusion of a CO_2 emissions tax, or some other carbon emissions reduction policy, would further incentivize expansion of solar resources in the Carolinas. In the Base with Carbon Policy case, the capacity expansion model selected additional solar coupled with storage averaging 200 MW annually beginning in 2029 if a CO_2 tax were implemented in the 2025 timeframe.

In addition to solar generation, wind energy is expected to play an important role in providing a diverse source of generation in the Carolinas. While previous IRPs have contemplated wind generation as a potential resource, for the first time, the 2020 IRP includes wind generation located in the central Carolinas as a technically viable source of carbon free energy and capacity. Though capacity factors of wind generation located in this region are much lower than other onshore or offshore regions, central Carolinas wind benefits from significantly lower transmission costs while still providing a diverse source of carbon free generation. The materialization of wind in the Carolinas is dependent on resolving historic barriers to siting and permitting; but, because the Company views wind as a potentially viable resource and an important step in meeting its carbon reduction goals, central Carolinas wind was included as a resource in the capacity expansion modeling process. With the inclusion of a CO_2 tax beginning in 2025, 150 MW of wind generation was selected annually beginning in the 2032 timeframe.

In addition to onshore wind, the Company is also evaluating offshore wind as a potential energy resource in the short and long term to support increased renewable portfolio diversity, an important resource for achieving the Company's 2050 net-zero carbon emission goal, as well as long-term general compliance need. The 70% CO_2 Reduction: High Wind and No New Gas Generation portfolios both include over 2,400 MW of offshore wind imported into the Carolinas. The challenges with accessing this potential resource are described further in Appendix E.

The Company anticipates a diverse renewable portfolio including solar, biomass, hydro, storage fed by solar, wind, and other resources. Actual results could vary substantially for the reasons discussed in Appendix E. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table 5-A below.

TABLE 5-A

DEP BASE WITH CARBON POLICY TOTAL RENEWABLES

DEP BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	3	131	0	1,301	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	3	131	0	1,324	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	3	120	0	1,341	41	3	120	0	165
2027	4,184	88	120	0	4,392	1,223	22	120	0	1,365	42	22	120	0	184
2028	4,239	163	116	0	4,518	1,229	41	116	0	1,386	42	41	116	0	199
2029	4,294	237	60	0	4,591	1,234	59	60	0	1,354	43	59	60	0	162
2030	4,323	436	43	0	4,802	1,237	109	43	0	1,389	43	109	43	0	195
2031	4,352	634	43	0	5,029	1,240	158	43	0	1,441	44	158	43	0	245
2032	4,331	856	42	0	5,228	1,238	214	42	0	1,494	43	214	42	0	299
2033	4,311	1,076	42	150	5,579	1,236	269	42	12	1,559	43	269	42	53	406
2034	4,290	1,296	41	300	5,928	1,234	324	41	24	1,623	43	324	41	105	513
2035	4,270	1,514	41	450	6,276	1,232	379	41	36	1,688	43	379	41	158	620

Data presented on a year beginning basis

Solar includes 0.5% per year degradation

Capacity listed excludes REC Only Contracts

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study

As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

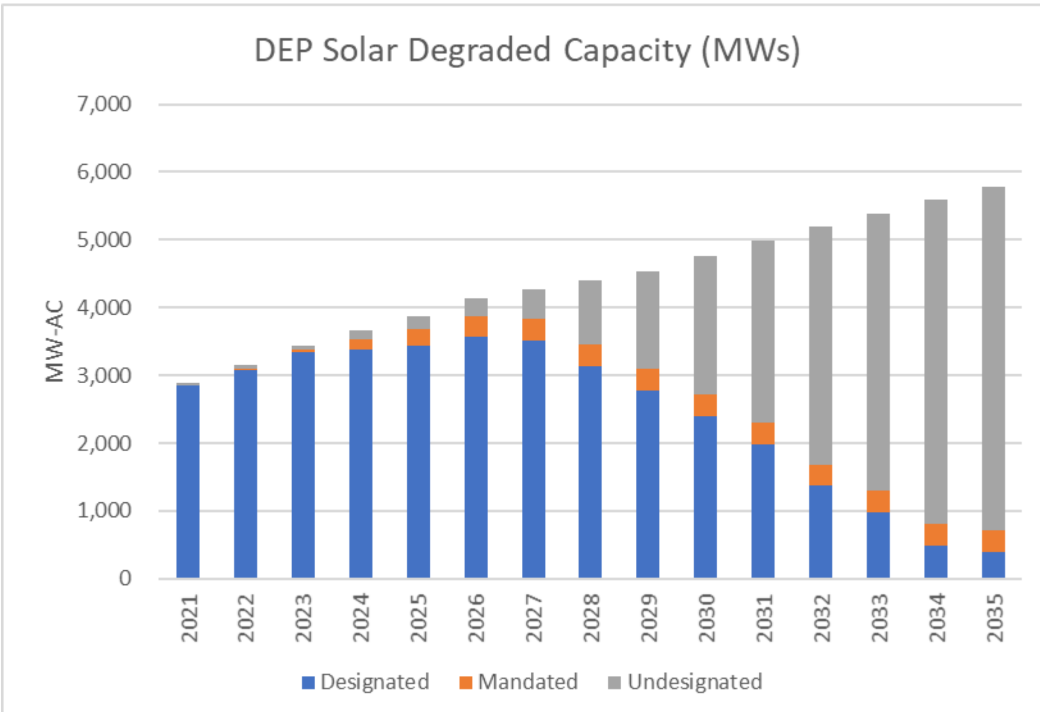
- **Designated:** Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.

- **Mandated:** Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589, as well as SC Act 236).

- **Undesignated:** Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed.

The figure below shows DEP's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case.

FIGURE 5-A
DEP SOLAR DEGRADED CAPACITY (MW)



In addition to these base case additions, the Company also developed high and low renewable investment sensitivities that are discussed in Appendix E.

6 ENERGY STORAGE AND ELECTRIC VEHICLES

As part of DEP's broader efforts to modernize the grid, the Company is strategically developing and deploying battery storage projects at locations where it can deliver maximum value for customers and surrounding communities. Battery storage is capable of both storing and dispatching energy at strategic times to provide a variety of benefits for customers as well as the grid. Utility dispatch and operation of battery systems is typically accomplished in fractions of a second, which is critical to manage the continued growth of intermittent resources (e.g. solar and wind) connected to the grid. The versatility of battery storage enables these facilities to be a natural extension of the grid and the Company will continue to apply its engineering and operational expertise to integrate this important technology into its regular planning and grid management functions.

Battery storage costs are declining rapidly which allows the Company to consider the technology as a viable option for grid services, as described in the 2018 IRP, including ancillary services (e.g. frequency regulation, voltage, and ramping support), energy and capacity, renewable smoothing, T&D deferral, and backup power. Operational benefits are gained from improved efficiencies, flexibility, and reliability – in some cases enabling the Company to defer future grid investments that would otherwise be required. The Company is also working with its customers who require enhanced resiliency and energy security as they provide critical services to the community (e.g. hospitals, first responders, emergency shelters and the military).

While there are various types of storage technologies, in the near term, the Company plans to deploy megawatt-scale electrochemical batteries and continues to partner with diverse suppliers who can provide the latest battery technology expertise and resources. The Company is ensuring compliance with evolving regulations and standards related to safety, reliability, and cybersecurity. Furthermore, the Company consults with leading fire protection engineers to guide the design process, includes multiple layers and levels of safety systems in each of its batteries, and actively engages and trains first responders and 911 reporting centers.

In DEP's 2018 IRP, the Company included 140 MW of nameplate battery storage, representing grid connected projects that have the potential to provide benefits to the generation, transmission, and distribution systems. These 140 MW of nameplate battery storage are also included in this 2020 IRP. As part of the Western Carolinas Modernization Plan, two battery projects totaling approximately 9 MW are currently operational and one approximately 4 MW battery project is under construction. The remaining 127 MW of battery storage will be installed at different locations across both the western and eastern regions of DEP's service territory. Additionally, as discussed in greater detail in Appendix A, the Company sees a growing need for energy storage later in the planning horizon. Meanwhile, DEP continues to analyze other opportunities to utilize battery storage systems, including customer-sited projects and combining battery storage with new or existing PV facilities.

For over a decade, Duke Energy has been piloting emerging battery storage technologies at several sites in the Carolinas. For example, the McAlpine Substation Energy Storage and Microgrid Project in Charlotte, N.C. was commissioned in late 2012. An existing 200-kW BYD lithium iron phosphate battery and a newly installed 30-kW Eos battery is interconnected with a 50-kW solar facility. The batteries provide energy shifting and solar smoothing applications when grid connected and maintain power to a fire station during a grid outage event. At Duke Energy's state-of-the-art research center in Mount Holly, N.C., the Company continues to collaborate with vendors, utilities, research labs and government agencies to develop and commercialize an interoperability framework that enables the integration of distributed resources and demonstrates alternative approaches for microgrid operations.

LONG-TERM OUTLOOK

As solar and other intermittent generation increases on DEP's system, and the cost of battery storage technologies fall, the need for, and value of, additional storage will continue to grow. As shown in Phase 1 of NREL's Integration of Carbon Free Resources Study, storage can play an important role in reducing curtailment of solar resources on DEP's system as the penetration of solar energy expands. Additionally, as shown in the Company's portfolio analysis, energy storage is expected to become competitive with peaking generation in the 2030 timeframe under certain conditions. Importantly, this outcome will be revisited periodically as future projections for battery storage costs evolve. Currently the Company forecasts an approximate 50% decline in battery storage costs by 2030 understanding that the actual pace of technological advancements, or even future potential policy mandates that influence storage costs, may change this forecast in future IRPs.

Additionally, the projected steep cost declines of battery storage add some risk to early adoption of this technology. The pace at which storage is integrated on the system is important as the benefits gained from storage may be captured a few years later at a lower cost to customers. As a result, striking the proper pace of adoption will require balancing the operational benefits of earlier adoption with the cost savings from a more measured pace.

However, as is the case with all energy-limited resources, as the penetration of short-term duration storage increases, the incremental benefit of that resource diminishes. To investigate how quickly this loss of value could occur, the Company commissioned Astrapé Consulting, a nationally recognized expert in the field, to conduct a detailed Capacity Value of Battery Storage study that is included as an attachment to the DEP IRP and is discussed in greater detail in Appendix H. This study assessed the contribution to winter peak capacity of varying levels and durations of both standalone battery storage and battery storage paired with solar resources under increasing levels of solar integration. As shown in Figure 6-A, longer duration batteries maintain capacity value as market penetration increases. For instances, 6-hour batteries maintain over 80% contribution to winter peak demand for up to nearly 3,000 MW on the system, and 4-hour batteries maintain 80% capacity value for nearly 2,200 MW. Conversely, 2-hour batteries fall below 80% at just 1,100 MW on the system. This drop is even more dramatic when considering the incremental value of battery storage shown in Figure 6-B. While the first 800 MW of two-hour batteries on the system provide almost 90% to meeting winter peak capacity needs, the next 800 MW provide about half of that value.

Two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish, and for these reasons, DEPC only considered four and six-hour battery storage in the IRP.

FIGURE 6-A

AVERAGE CAPACITY VALUE OF TWO, FOUR, AND SIX HOUR STORAGE

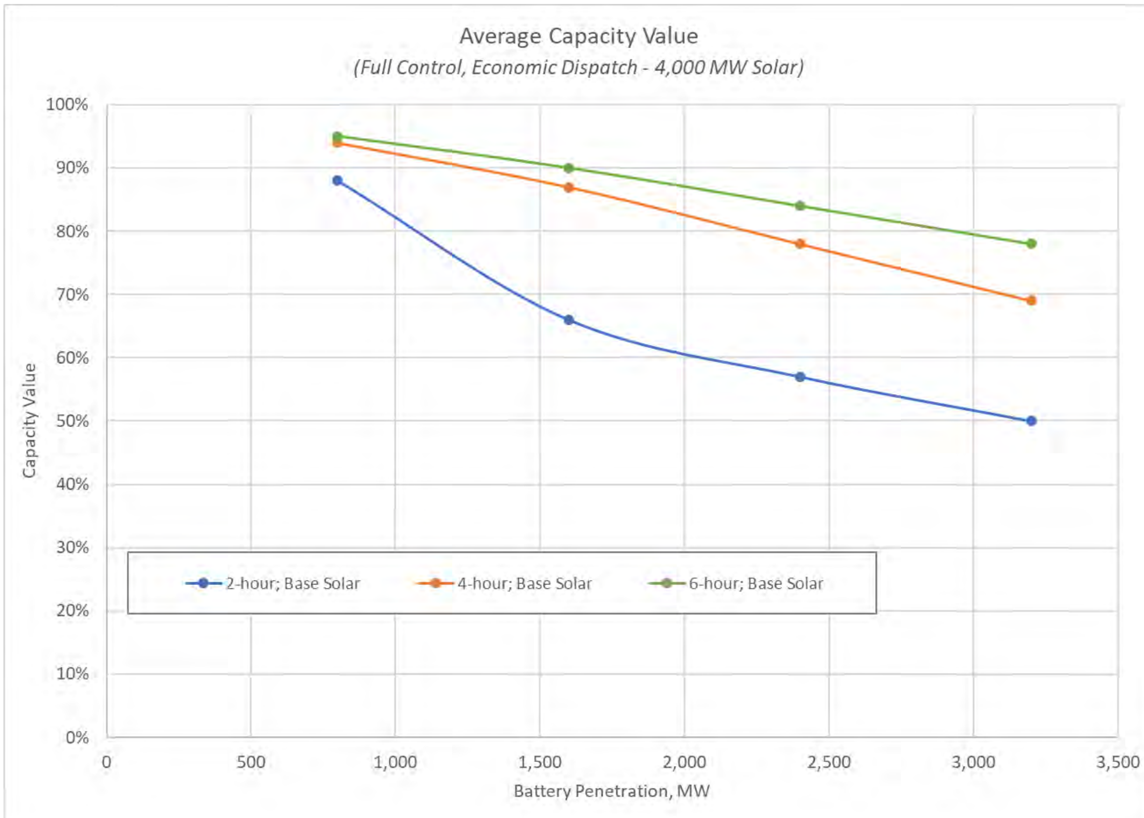
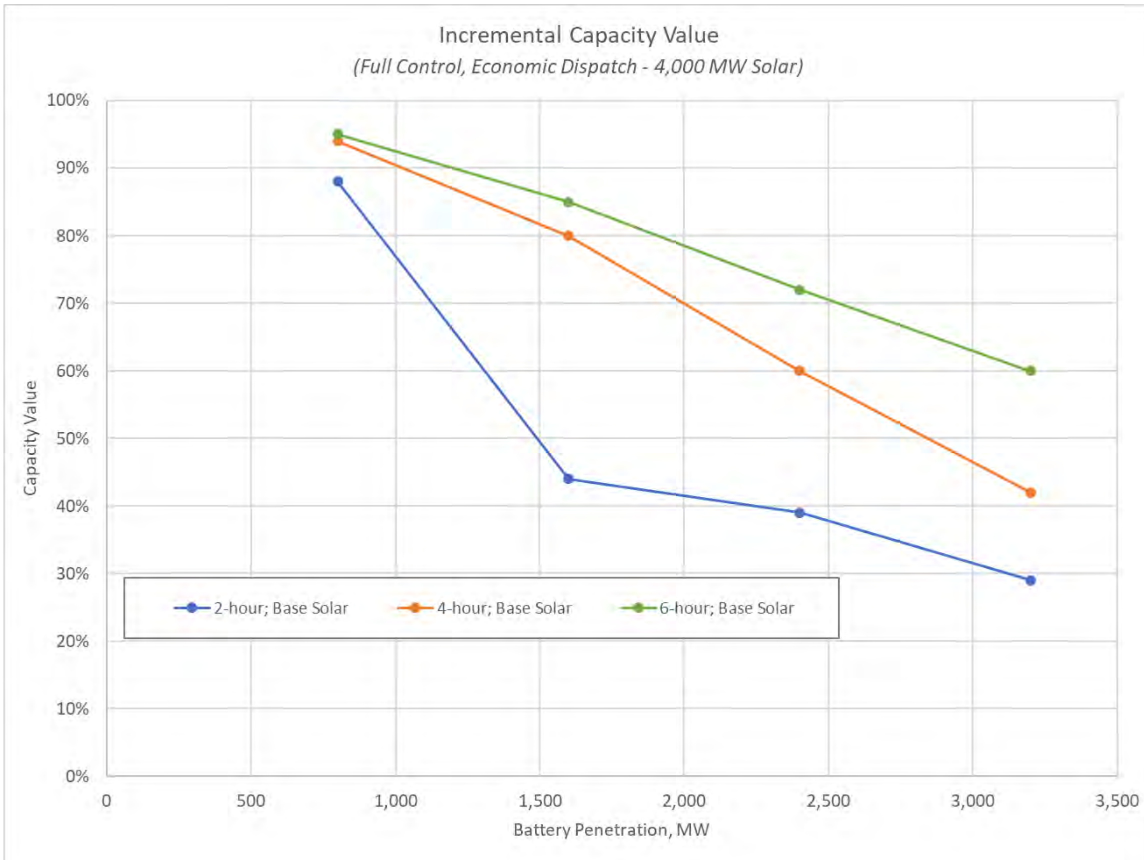


FIGURE 6-B

INCREMENTAL CAPACITY VALUE OF TWO, FOUR, AND SIX HOUR STORAGE[1]

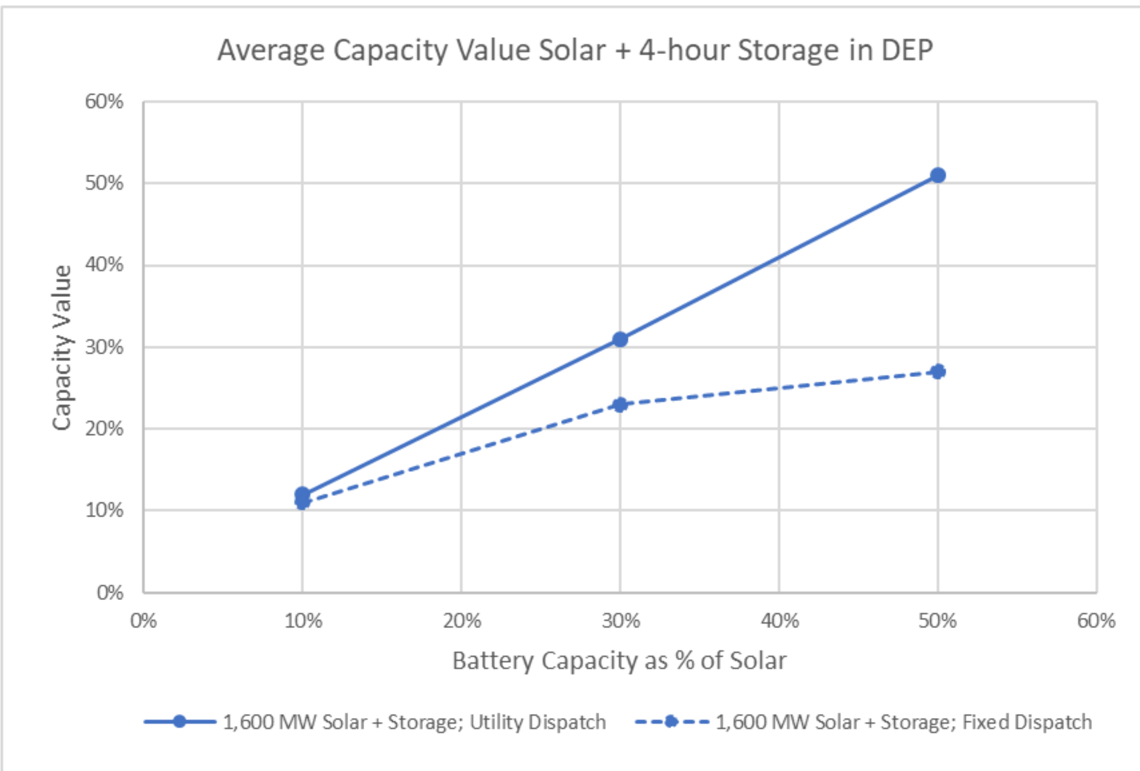


The Capacity Value of Storage study also evaluated the capacity value of solar coupled with storage under multiple solar penetrations and with increasing ratios of storage to solar capacity. In this analysis, the battery storage could only be charged from the solar asset it was coupled with, and the solar plus storage maximum output was limited to the capacity of the solar asset. The capacity value of a solar plus storage facility is represented as the percent of solar nameplate capacity, so if a 100 MW solar facility coupled with a 25 MW / 100 MWh battery has a capacity value of 25% the MW contribution to winter peak is 25 MW.

[1] Incremental values are calculated based on the average capacity value for 800 MW increments of battery storage. Due to rounding, calculated incremental values may appear higher or lower than the actual incremental value.

One factor that can impact the capacity value of storage is the level of control the Utility maintains over dispatching the battery. A solar plus storage PURPA QF, may charge and discharge the battery to a fixed, long-term contract with static price signals. Conversely, if the Utility has control over dispatch of the battery, the likelihood that the battery will be available to provide capacity when it is needed is increased. Figure 6-C shows capacity value of the solar plus storage facility can be decreased by nearly 50% if the storage is dispatched on a fixed price schedule rather than under Utility control.

FIGURE 6-C
AVERAGE CAPACITY VALUE OF SOLAR PLUS STORAGE FACILITY UNDER UTILITY CONTROL VS FIXED DISPATCH SCHEDULE



In addition to the discussion of the Battery ELCC study, Appendix H also includes a discussion of the terminology and operating characteristics of battery storage technologies. There is frequently confusion when discussing the duration, capacity, energy losses, modeling assumptions and costs of battery storage. The "Battery Storage Assumptions" section of Appendix H was developed in order to increase transparency related to Duke's assumptions associated with battery storage in the

2020 IRP.

ELECTRIC VEHICLES

Another important form of energy storage is electric vehicles. Electrification is expected to play an important role in the reduction of carbon dioxide emissions across all sectors of the economy. Electric vehicles (EVs) in particular are poised to transform and decarbonize the transportation industry which accounts for 28% of US carbon dioxide emissions, more than any other economic sector[2].

EVs also offer financial benefits for consumers and for the electric grid. EV drivers save money on fuel and maintenance costs, and the purchase of a new EV can be offset by up to $7,500 with the Qualified Plug-In Electric Drive Motor Vehicle Tax Credit. Increasing EV growth can create benefits for all utility customers by increasing utilization of the electric grid and putting downward pressure on rates.

Duke Energy receives monthly updates on light-duty vehicle registrations from the Electric Power Research Institute (EPRI). Registrations are tracked by county and attributed to DEP based on the size of its customer count in each county. Reporting and analysis focus on plug-in electric vehicles (PEVs) which are charged from the electric grid. Conventional vehicles and hybrid EVs are also tracked to provide context for PEV growth within the total vehicle market.

According to EPRI 2,700 new PEVs were registered in 2019, and 10,600 PEVs were in operation by the end of the year. Most of those vehicles were adopted in NC which had 9,100 PEVs in operation compared to 1,600 in SC. Annual registrations increased from 2018 to 2019 by a small margin. The modest growth was partly due to an outsized increase in 2018 (+130%) driven by the popular Tesla Model 3 sedan.

On October 29, 2018, NC Governor Cooper issued Executive Order 80, in which he directed the State of NC to "strive to accomplish" increasing the number of registered, zero-emission vehicles to at least 80,000 by 2025. In order to adequately respond to state policies like Executive Order 80 and considering the significant pace of EV adoption in its service territories, Duke Energy recognizes that it must prepare for and better understand the electrical needs and impacts of EVs on its systems. As

[2] U.S. EPA's Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2018

insufficient charging infrastructure is commonly cited as a barrier to EV adoption[3], Duke Energy believes that more investment in EV charging infrastructure will accelerate EV adoption, consistent with the intent of state policies and the fast-developing EV market. To that end, Duke Energy conducted an analysis to demonstrate the potential electric system/customer benefits of increased EV adoption, and the potential for utility-managed charging to enhance those benefits.

Duke Energy designed and proposed electric transportation (ET) pilots in NC and SC to determine best practices for realizing the significant potential benefits of increased ET adoption, including the long-term potential for downward rate pressure, retaining fuel cost savings in the states, reducing vehicle emissions and improving air quality. The ET pilots would span three years and comprise a series of programs that address three areas of concern: EV charging management on the grid, transit electrification and public charging expansion. For EV charging management, Duke Energy proposed a residential EV charging infrastructure rebate and a fleet EV charging infrastructure rebate. For transit electrification, Duke Energy proposed an EV school bus charging program and an EV transit bus charging program for both North and South Carolina, including a Vehicle-to-Grid research component for the EV school bus program. For public charging expansion, Duke Energy proposed a multi-family dwelling charging station program, a public level 2 charging station program and a direct current fast charging station program to establish a baseline network of charging infrastructure across the states.

TABLE 6-A
PROPOSED CAROLINAS ELECTRIC TRANSPORTATION PILOT PROGRAMS

PROGRAM COMPONENT	UNITS (NORTH CAROLINA)	UNITS (SOUTH CAROLINA)
Residential Charging	800	400
Fleet Charging	900	N/A
Transit Bus Charging	105	30
School Bus Charging	85	15
Public Level 2/Multi-Family	480	N/A
Public DC Fast Charging	120	60

[3] Edison Electric Institute: Accelerating EV Adoption Report (February 2018).
https://www.eei.org/issuesandpolicy/electrictransportation/Documents/Accelerating_EV_Adoption_final_Feb201 8.pdf

Duke Energy is also partnering with EPRI to study the market potential for non-road EVs and to develop strategies to promote electrification in the commercial and industrial sectors. Commercial and non-road EVs are expected to have a significant impact on the electric grid due to their high utilization rates and high energy demand. Deployment of these technologies, and their impact on the grid, may scale up quickly when companies with large commercial and non-road vehicle fleets transition to EVs. One early example is Amazon's order of 100,000 electric delivery vans from Rivian, expected to be deployed over 2021-2030.

7 GRID REQUIREMENTS

The purpose of this chapter is to describe the development of initial estimates for costs associated with the retirement of coal generating units and siting of replacement generation for the six key portfolios outlined in the Executive Summary and Appendix A.

Retiring existing coal facilities that support the grid and integrating incremental resources forecasted in this IRP will require significant investment in the transmission and distribution systems. As described in Chapter 11 and Appendix A, if replacement generation that can provide similar ancillary service as well as real power needs is not located at the site of the retiring coal facility, transmission investments will generally be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation coming onto the grid. To avoid overstating these Grid upgrade costs, the Company took the approach of assuming resources would be interconnected at the transmission level. In general, connecting generators at the transmission level does not require distribution upgrades, whereas connecting generators at the distribution level can require upgrades to transmission.

With respect to the distribution grid, the Company is working with policy makers and stakeholders to develop and implement necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased penetration of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs. D istribution investments that enable increased levels of distributed energy resources are foundational across the scenarios in this IRP and provide flexibility to accommodate the dynamic power flows resulting from a changing customer service needs and distributed energy resource landscape. In recognition of the critical role of the transmission and distribution system in an evolving energy landscape, the Company sees significant value in modernizing the distribution portion of the grid as outlined in Chapter 16 and to further develop its Integrated System Optimization and Planning (ISOP) framework described in Chapter 15.

DEP FUTURE TRANSMISSION PROJECTS TO FACILITATE CARBON REDUCTION TARGETS

The six portfolios presented in this IRP included different assumptions for coal plant retirement dates along with a varying array of demand and supply-side resource requirements to reliably serve load over the planning horizon. The Company conducted high-level assessments to estimate the associated necessary transmission network upgrades for retiring the existing coal facilities and integrating each scenario's requisite incremental resources, including combinations of some or all of the following resources: solar, solar-plus-storage hybrid facilities, stand-alone battery storage, pumped-hydro generation/storage, onshore wind, offshore wind, increased off-system purchases, and dispatchable natural gas facilities. These assessments were conducted at a high level utilizing several reasonable, simplifying assumptions. To the extent possible, the Company used recent interconnection studies as a basis for future costs. Extensive additional study and analysis of the complex interactions regarding future resource planning decisions will be needed over time to better quantify the cost of transmission system upgrades associated with any portfolio.

As noted in Appendix L, location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to approve the interconnection request for a new resource and the associated costs. Also, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor, materials, environmental, siting and permitting costs in future years could be significant. In addition to risks associated with costs, to facilitate meeting necessary deadlines for placing new transmission lines and substations in service, policies and approvals for siting and permitting will need to allow for expediting and streamlining associated processes. The timing and nature of these future projects will also be dependent on any neighboring system upgrades needed.

With the significant volume of interconnection requests in the future indicated by the six portfolios described in this IRP, the proposed clustering process associated with queue reform, if approved, will help from a planning studies perspective. The increase in volume of interconnection requests however, unlike the small volume of interconnection requests for traditional larger size generators, will make studying such requests and assigning necessary upgrades quite complex. The complexity and uncertainty of planning for high volumes of DERs, compared to planning for conventional generation that has known capacity and locations with a planning and construction timeline similar to that of the associated transmission upgrades, is much greater for the following reasons:

- The number of permutations of resource types, locations, timing, capacity within resource scenarios and between scenarios can be significant.
- A large volume of both distribution and transmission connected generation and battery storage resources that are in un-sited locations, are of unknown capacity, and have unspecified and variable production profiles, make modeling these resource scenarios very complex.

Given the long lead times for planning, siting, permitting and construction of new transmission, there is some risk that some of the projects represented in the estimates below could not be completed in time to support the in-service dates contemplated by the more aggressive scenarios (C-F).

The resources required to reliably serve load under each portfolio impacts the Company's existing transmission system. Every portfolio requires upgrades to the Duke Energy transmission system, some substantial, and some would require substantial transmission upgrades to other third parties' transmission systems interconnected to Duke Energy's transmission grid. This section outlines high level assessments of the transmission infrastructure required for each portfolio and the estimated costs of that transmission infrastructure[1]. This section does not attempt to estimate the projects that would be required on third party transmission systems, nor does the Company estimate these third-party costs.

Importantly, the transmission costs for each portfolio and sensitivity presented in this IRP were not calculated directly in each individual case. For instance, transmission costs associated with retiring coal assets were estimated by evaluating the impact of retiring each plant individually without replacement

[1] The cost estimates provided are high-level and not yet at a Class 5 level. As such, the cost estimates could vary greatly depending upon, among other factors, ultimate corridor or resource location, MW interconnection requested, resource/load characteristics, interconnection queue changes, escalation in construction labor and materials costs, siting and permitting, interest rates, cost of capital, and schedule delays beyond the Company's control. In addition, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

on site. These estimates were calculated based on information as was known at the time the analysis was conducted and without regard for any particular portfolio. In this manner, in any portfolio where the coal asset was not replaced on site, the transmission cost associated with that plant retirement was assumed to be the same. Furthermore, any new generation added to, or generation removed from, the DEP system in the analysis may significantly impact these cost estimates and therefore, these costs will need to be re-evaluated at the time the decision to retire these assets is made.

Additionally, the cost of integrating increasing levels of distributed and other resources was based on three portfolios:

- Base with Carbon Policy
- 70% CO_2 Reduction: High Wind
- No New Gas Generation

The transmission cost estimates from these portfolios were used as the basis for calculating the transmission costs in all other portfolios and sensitivities discussed in this document. As an example, if the cost to integrate the first 2,000 MW of solar on the DEP system was $100M based on the Base with Carbon Policy, that same cost was assumed to be the cost for integrating the first 2,000 MW of solar in all portfolios and sensitivities. These three specific portfolios were chosen because they represent a broad range of the types of technologies found in all portfolios.

The following are the transmission cost estimates, in overnight 2020 dollars, that were used as a reference in the development of the PVRR values shown later in Appendix A.

DEP FUTURE TRANSMISSION PROJECTS TO FACILITATE RETIREMENT OF EXISTING DEP COAL FACILITIES

The high-level assessment conducted to determine the transmission network upgrades needed to enable the retirement of the DEP coal facilities without replacing generation on site was estimated to be:

- Mayo & Roxboro 1-4: $80 M

DEP FUTURE TRANSMISSION PROJECTS TO FACILITATE THE BASE WITH CARBON POLICY PORTFOLIO

The high-level assessment conducted to determine the transmission network upgrades needed to enable the interconnection of new resources for the Base with Carbon Policy portfolio resulted in an estimate of approximately $460M for DEP transmission network upgrades.

DEP FUTURE TRANSMISSION PROJECTS TO FACILITATE THE 70% CO_2 REDUCTION: HIGH WIND PORTFOLIO

The high-level assessment conducted to determine the transmission network upgrades needed to enable the interconnection of new resources for the 70% CO_2 Reduction: High Wind portfolio resulted in an estimate of approximately $4.6B for DEP transmission network upgrades. Estimates for transmission network upgrades to import offshore wind energy were based on prior North Carolina Transportation Planning Collaborative (NCTPC) assessments. An update of these NCTPC assessments are in progress and may result in materially different network upgrade costs.

DEP FUTURE TRANSMISSION PROJECTS TO FACILITATE THE NO NEW GAS GENERATION PORTFOLIO

The high-level assessment conducted to determine transmission network upgrades needed to enable the interconnection of new resources for the No New Gas Generation portfolio resulted in an estimate of approximately $4.8B for DEP transmission network upgrades. It is likely that to integrate offshore wind energy into the Carolinas; statewide policies would be required, and the transmission infrastructure costs to move the energy from the coast to load centers could be spread across all customers regardless of their legacy transmission provider.

DEP/DEC AREA FUTURE TRANSMISSION PROJECTS TO FACILITATE INCREASED IMPORT CAPABILITY

In addition to the estimates shown above, the Company conducted a high-level evaluation of increasing import capability into the DEP and DEC area transmission systems. Based on prior experience and similar transmission interface projects, it is expected that such third-party transmission costs would be substantial; particularly under scenarios where 5 to 10 GWs of power is imported into the DEP/DEC area transmission systems. Additional analysis would be needed to further refine the transmission projects and costs however these preliminary assessments indicate that extensive incremental Transmission investment would be required if existing generation were retired and replaced with generation outside of the Company's area transmission systems.

The Company conducted a high-level assessment to identify the number of transmission projects and estimated costs associated with increasing import capability into the DEP/DEC area transmission systems from all neighboring transmission regions as well as from offshore wind. The assessments considered the necessary new construction and upgrades needed to increase import capability by 5GW and 10GW respectively.

The 5GW import scenario would require on the DEP/DEC transmission systems alone:

- four (4) new 500kV lines,
- three (3) new 230kV lines,
- two (2) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower-class voltage upgrades.

The estimated costs for the associated transmission projects is between $4B and $5B. The 10GW import scenario would require on the DEP/DEC transmission systems alone:

- seven (7) new 500kV lines,
- four (4) new 230kV lines,
- three (3) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower-class voltage upgrades.

The estimated costs for the associated transmission projects is between $8B and $10B.

Importantly, actual upgrade costs may vary significantly when the specific projects to enable the requested incremental import capability need are identified through detailed Transmission Planning studies. Equally significant, these estimates exclude the cost of neighboring third-parties' transmission system upgrades, which would be dependent on items, including, but not limited to, the location of the capacity resource being purchased, the MW level of the capacity being purchased, the position in the queue of competing transmission service requests, and the performance of third parties to complete such projects on schedule and on budget.

The system risks with relying on significant incremental import capability for future resource plan needs include, but are not limited to:

a. Delay in resource availability – if required transmission network upgrades on the DEP/DEC transmission systems or neighboring transmission systems are delayed due to sitting, permitting, or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource.
b. Loss of local ancillary benefits that are inherent with an on-system resource (e.g. Voltage/Reactive Support, Inertia/Frequency Response, AGC/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding SVCs for voltage support.
c. Curtailment due to transmission constraints in neighboring areas
d. Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

8 SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE programs that have been pre-screened for cost-effectiveness. The growth in this adjusted load forecast and associated reserve requirements, along with existing unit retirements or purchased power contract expirations, creates a need for future generation. This need is partially met with DSM resources and the renewable resources required for compliance with NC REPS, HB 589, and SC Act 236. The remainder of the future generation needs can be met with a variety of potential supply side technologies.

For purposes of the 2020 IRP the Company considered a diverse range of technology choices utilizing a variety of different fuels, including Combustion Turbines (CTs), Reciprocating Engines, Combined Cycles (CCs) with and without duct firing, Ultra-Supercritical Pulverized Coal (USCPC) with Carbon Capture and Sequestration (CCS), Integrated Gasification Combined Cycle (IGCC) with CCS, Nuclear, and Combined Heat and Power (CHP). In addition, Duke Energy considered renewable technologies such as Onshore and Offshore Wind, Fixed and Single Axis Tracking (SAT) Solar PV, Landfill Gas, and Wood Bubbling Fluidized Bed (BFB). Duke also considered a variety of storage options such as Pumped Storage Hydro (PSH), Lithium-Ion (Li-Ion) Batteries, Flow Batteries, and Advanced Compressed Air Energy Storage (CAES) in the screening analysis. Lastly, a hybrid of the above technologies was considered: SAT Solar PV with Li-Ion Storage.

For the 2020 IRP screening analysis the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, renewable, and storage with the goal of screening to pass the best alternatives from each of these four categories to the integration process. As in past years the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation on the DEP system. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process as discussed in Appendix A.

The results of these screening processes determine a smaller, more manageable subset of technologies for detailed analysis in the expansion planning model. Table 8-A details the technologies that were evaluated in the screening analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix G.

TABLE 8-A

TECHNOLOGIES SELECTED FOR ECONOMIC SCREENING

DISPATCHABLE (WINTER RATINGS)			
BASELOAD	**PEAKING / INTERMEDIATE**	**STORAGE**	**RENEWABLE**
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	**NON-DISPATCHABLE (NAMEPLATE)**
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		**1,400 MW Pumped Storage Hydro (PSH)**	**75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery**

9 RESOURCE ADEQUACY

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

2020 RESOURCE ADEQUACY STUDY

DEC and DEP retained Astrapé Consulting to conduct new resource adequacy studies to support the Companies' 2020 IRPs.[3] The Companies utilized a stakeholder engagement process which included participation from the NC Public Staff, SC Office of Regulatory Staff and the NC Attorney General's Office. The Companies hosted an in-person meeting on February 21, 2020 to provide an overview of the study methodology and model, and to review input data. The Companies worked with stakeholders to define Base Case assumptions and develop a list of planned sensitivities. The Companies and Astrapé presented preliminary results to stakeholders on May 8, 2020 and presented

[1] NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf, at 9.
[2] Total resources reflect contribution to peak values for intermittent resources such as solar and energy limited resources such as batteries.
[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé also conducted resource adequacy studies for DEC and DEP in 2012 and 2016.

recommended reserve margin targets on May 27, 2020.

Astrapé analyzed the optimal planning reserve margin based on (i) providing an acceptable level of physical reliability and (ii) analyzing economic costs to customers at various reserve levels. The most common physical reliability metric used in the industry is to target a reserve margin that satisfies the one day in 10 years Loss of Load Expectation (0.1 LOLE) standard.[4] This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. The Company and Astrapé believe that physical reliability metrics should be used for determining the planning reserve margin since customers expect a reliable power supply during extreme hot summer conditions and extreme cold winter weather conditions.

Customer costs provide additional information in resource adequacy studies. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the probability of reliability events increases along with an increase in the cost of energy. Thus, there is an economic optimum point where the total system costs (total energy costs plus the cost of unserved energy plus the capacity cost of incremental reserves) are minimized.

All inputs were updated in the new study. Current solar projections increased compared to the 2016 study which concentrated LOLE even more in the winter. As in the 2016 study, winter load volatility remains a significant driver of the reserve margin requirement. In response to stakeholder feedback, the 4-year ahead economic load forecast error (LFE) was diminished by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. As discussed more fully below, this assumption essentially removed any economic load forecast uncertainty from the modeling and put downward pressure on the reserve margin target. Please reference the 2020 Resource Adequacy Study report included as Attachment III for further details regarding inputs and assumptions. Results of the study are presented below.

ISLAND CASE

Astrapé ran an Island Case to determine the level of reserves that would be needed assuming no

[4] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; Reference Table 14 in Appendix A, at A-1. PJM, MISO, NYISO, ISO-NE, Quebec, IESO, FRCC, APS, and NV Energy all use the 1 day in 10-year LOLE standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 0.1 LOLE standard.

market assistance is available from neighbor utilities. Results showed that the Company would need to carry a 25.5% reserve margin in the Island Case to satisfy a 0.1 LOLE without neighbor assistance.

BASE CASE

Base Case results reflect the reliability benefits of the interconnected system including the diversity in load and generator outages across the region. Base case results for DEP showed that a 19.25% reserve margin is needed to maintain a 0.1 LOLE. Comparing Base Case results (19.25% reserve margin) to the Island Case (25.5% reserve margin) highlights the significant benefit of being interconnected to neighboring electric systems in the southeast. However, as discussed in more detail in the study report, there are limits and risks associated with too much dependence on neighboring systems during peak demand periods. Careful consideration of the appropriate reliance on neighboring systems is a key consideration in the determination of an appropriate planning reserve margin.

From an economic perspective, Astrapé analyzed total system costs across a range of reserve margins which resulted in a weighted average economic risk neutral reserve margin of 10.25%.[5] The risk neutral level of reserves represents the weighted average results of all iterations at each reserve margin level. However, there are high risk scenarios within the risk neutral result that could cause customer rates to be volatile from year to year. This volatility can be diminished by carrying a higher level of reserves. The study showed that the 90th percentile cost curve resulted in a reserve margin of 17.5%. Please reference the economic reliability results presented in the Executive Summary of the study report for further details regarding the potential capital costs and energy savings at different reserve margin levels.

Base Case results for DEC showed that a 16.0% reserve margin is needed to meet a 0.1 LOLE. The higher physical reserve margin required for DEP compared to DEC is driven primarily by greater winter load volatility, and to a lesser extent less import capability. The weighted average risk neutral economic results for DEC yielded a reserve margin of 15.0% and the 90th percentile cost curve

[5] Given the significant level of solar on the DEP system, summer reserve margins are approximately 12% greater than winter reserve margins. Thus, the risk neutral reserve margin of 10.25% for DEP is significantly lower than the 19.25% reserve margin required to meet 0.1 LOLE since there is little economic benefit of additional reserves in the summer and the majority of the savings seen in adding additional capacity is only being realized in the winter.

resulted in a reserve margin of 16.75%.

COMBINED CASE RESULTS

Astrapé also simulated a Combined Case to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority. This scenario allowed preferential reliability support between DEC and DEP to share capacity, operating reserves and demand response capability. The Combined Case results showed that a 16.75% reserve margin is needed to meet the 0.1 LOLE. The weighted average risk neutral economic results for the Combined Case yielded a reserve margin of 17.0% and the 90th percentile confidence level scenario resulted in a reserve margin of 17.75%.

SENSITIVITIES

A range of sensitivities was simulated in the study to understand which assumptions and inputs impact study results and to address questions and requests from stakeholders. Sensitivities included both physical and economic drivers of reserve margin. Please reference the study report for a detailed explanation of each sensitivity and the reliability and economic results.

TARGET RESERVE MARGIN

Based on the physical and economic reliability results of the Island Case, Base Case, Combined Case, and all sensitivities for both DEC and DEP, Astrapé recommends that DEC and DEP continue to maintain a minimum 17% reserve margin for IRP planning purposes. Maintaining a 17% reserve margin results in an LOLE of 0.12 events per year (or, one event every 8.3 years) for DEP which slightly exceeds the 0.1 LOLE standard. However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 16% required by DEC to meet the 0.1 LOLE standard, Astrapé believes the 17% reserve margin is still reasonable for planning purposes. The Company supports this recommendation and further notes that the results of the Combined Case physical LOLE reserve margin (16.75%), weighted average risk neutral economic reserve margin (17.0%) and 90th percentile economic reserve margin (17.75%) converge on a reserve margin of approximately 17.0%.[6]

[6] In 2019, DEC and DEP entered into an as-available capacity sales agreement which allows the companies to sell excess capacity to the sister utility. This agreement allows the Companies to take advantage of excess capacity available from the

As discussed more fully below, the sensitivity results that remove all economic load forecast uncertainty actually increase the reserve margin required to meet 0.1 LOLE. Thus, Astrapé and the Company recommend that this minimum target be used in the short- and long-term planning process. A 17% reserve margin provides adequate reliability to customers but also provides rate stabilization by removing the volatility seen in the coldest years, and thus strikes a reasonable balance between reliability and cost. Similar to the 2016 resource adequacy study, Astrapé also recommends maintaining a minimum 15% reserve margin across the summer. Given the resource portfolio in the Base Case, the 15% summer reserve margin will always be met if a 17% winter target is met.

SUPPLEMENTAL INFORMATION

Short-Term versus Long-Term Resource Planning

The NCUC notes on page 12 of its 2019 IRP order:

> The Commission notes with interest that the Companies appear to acknowledge that it is possible that short-term reserve capacity could fall below the long-term target of 17% without posing a significantly increased risk of resource inadequacy.

This statement is in reference to Duke's response to an NCUC question regarding prior reserve margin targets. Duke stated in its response:[7]

> DEP determined that an 11% capacity margin (12.4% reserve margin) may be acceptable in the near term when there is greater certainty in forecasts; however, a 12%-13% capacity margin (13.6%-14.9% reserve margin) is appropriate in the longer term to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts, or delays in bringing new capacity additions online.

Astrapé included economic load forecast error in the study to capture the uncertainty in Duke's 4-year ahead load forecast. Four years is the approximate amount of time it takes to permit and

sister utility and thus provides some of the enhanced reliability benefits assumed in the Combined Case.

[7] Duke's Responses, Docket No. E-100, Sub 157, at p.19.

construct a new resource. In the 2016 study, the LFE was fit to a normal distribution reflecting equal probably of over-forecasting or under-forecasting load, which resulted in an increase in reserve margin of approximately 1.0-1.5% to account for forecast uncertainty. However, based on stakeholder feedback, the 4-year ahead economic LFE in the 2020 study was diminished by using an asymmetric distribution with higher probability weightings on over-forecasting scenarios relative to under-forecasting scenarios. The Company and Astrapé accepted this modeling change in the study; however, it is noted that tailwinds of economic growth such as the adoption rate of electric vehicles and the rate of electrification of end-uses may result in additional load growth uncertainty not captured in the study.

Since there is greater certainty in load in the near term versus longer term, it was anticipated that removal of the LFE uncertainty may support a lower reserve margin in the near term. Interestingly, however, Astrapé ran a sensitivity that removed the LFE uncertainty and results showed a slightly higher reserve margin (0.75%) was required compared to the Base Case. Astrapé ran a second sensitivity that removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for 0.1 LOLE increased by 1.0% in the Base Case to 20.25%. Since removing the LFE actually increases the reserve margin required to meet the 0.1 LOLE standard (since over-forecasting load is more heavily weighted than under-forecasting load), Astrapé and the Company believe that a 17% minimum reserve margin is appropriate to use for each year of the planning period.

The NCUC also states on page 11 of its 2019 IRP order:

> In terms of risk or volatility, the Commission does not view the differences in Total System Costs are enough to warrant a "hard and fast" minimum reserve margin for planning. This is not to say that the minimum reserve margins supported by the 2016 Astrapé Study are not valid for planning. Rather, the Commission's guidance is that the Companies should not be constrained in their planning to produce resource plans that meet the indicated minimum target reserve margin in each and every one of the plan years.

While the Company supports the general application of a 17% reserve margin target for each year of the planning period, per the NCUC's guidance, the Company will not employ this target as a "hard and fast" constraint in every plan year. Rather, the Company will consider letting reserves decline below 17% in certain circumstances as long as the risk of a loss of load event is not unreasonably compromised. As an example, the 2020 DEP IRP allows reserves to drop below 17% in 2024 (16.8%) and 2025 (16.6%). At this time, DEP does not plan to make short-term market purchases to satisfy a 17% minimum target; however, DEP will continue to monitor changes in the load forecast and the resource mix and will adjust accordingly.

APPROPRIATENESS OF USING THE 0.1 LOLE STANDARD

Customers expect a high level of power reliability, especially during periods of extreme hot or cold weather events. While some power outages may be beyond the Company's control, such as events caused by hurricanes or other natural disasters, customers and regulators expect power to be available during extreme hot and cold periods to power their homes and businesses.[8] As previously noted, the 0.1 LOLE standard is widely used across the electric industry and the Company continues to apply the 0.1 LOLE target to determine the level of reserves needed to provide adequate generation reliability. Although this target does not eliminate reliability risk, the Company believes it does provide the level of reliability that customers expect without being overly excessive. The NCUC noted in its 2019 IRP order:[9]

> At this point the Commission is disinclined to direct that in their 2020 IRPs DEC and DEP use some alternative measure of resource inadequacy other than the LOLE .1 standard.

As further support for use of the 0.1 LOLE standard, the Company presents Table 9-A below which shows actual operating reserves during extreme winter weather events for the period 2014-2019. The table shows a total of 10 occurrences when operating reserves declined below 10%, with six occurrences below 5% and three occurrences below 2%. Operating reserves of -1.6% occurred on February 20, 2015, meaning the Company was relying on non-firm capacity to meet load and was still unable to maintain adequate operating reserves. The table also shows the planning reserve

[8] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "… a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."
[9] NCUC Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans, April 6, 2020, at 10.

margin as projected in the prior year's IRP. For example, on February 20, 2015, actual operating reserves dropped to -1.6% even though the Company's 2014 IRP projected a planning reserve margin of 31.7% based on normal weather for the winter of 2014/2015. The 31.7% projected reserve margin was approximately 15% above the Company's minimum planning target of 17%. It is almost certain DEP would have shed firm load in 2015 had the reserve margin going into the winter been 17%. For the 10 occurrences with operating reserves below 10%, planning reserves ranged from approximately 25% to 34%. Yet, without non-firm market assistance the Company would have shed firm load. This information is also shown graphically in Figure 9-A below. History has shown that adherence to the 0.1 LOLE standard has provided customers with adequate reliability without carrying an excessive level of planning reserves.

The 0.1 LOLE target is widely used in the industry for resource adequacy planning. The Combined Case economic reserve margin study results presented earlier give similar results to the 0.1 LOLE target of a 17% reserve margin. Further, actual operating reserves history has shown that planning to the 0.1 LOLE standard has provided adequate reliability without having excessive actual reserves at the time of winter peak demands. The Company and Astrapé continue to support use of the 0.1 LOLE for resource adequacy planning.

TABLE 9-A

DEP ACTUAL HISTORIC OPERATION RESERVES [10]

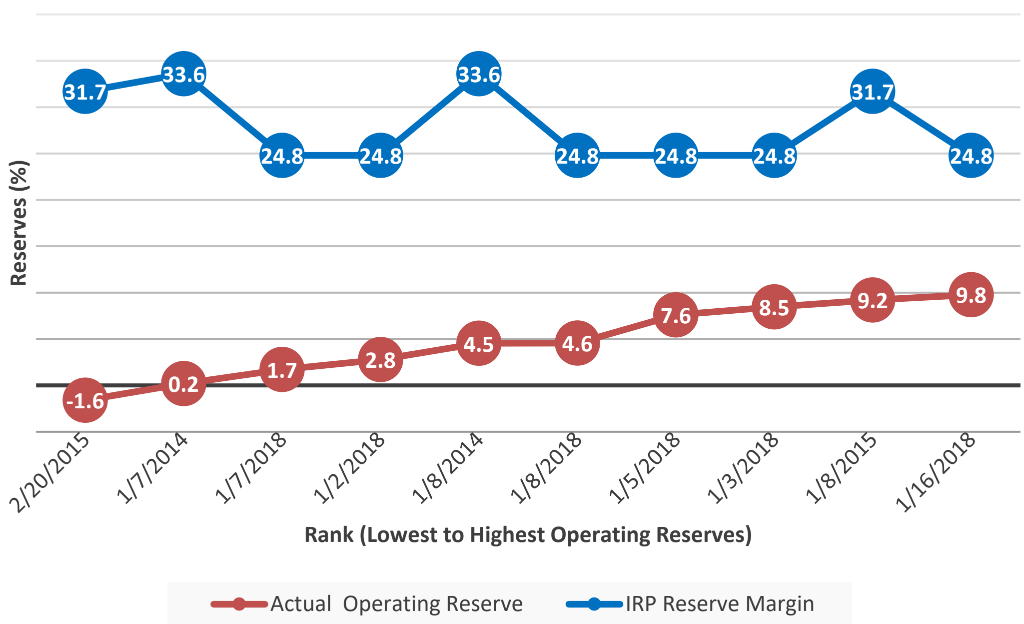
RANK (LOWEST TO HIGHEST OPERATING RESERVES)	DATE	PEAK DEMAND (MW)	OPERATING RESERVE* (%)	IRP RESERVE MARGIN ** (%)
1	02/20/15	15,515	-1.6	31.7
2	01/07/14	14,159	0.2	33.6
3	01/07/18	15,718	1.7	24.8
4	01/02/18	15,129	2.8	24.8
5	01/08/14	13,907	4.5	33.6
6	01/08/18	14,835	4.6	24.8
7	01/05/18	15,048	7.6	24.8
8	01/03/18	14,512	8.5	24.8
9	01/08/15	14,454	9.2	31.7
10	01/16/18	13,207	9.8	24.8

*Operating Reserves represent an estimate based on the last snapshot of projected reserves at the peak for each respective day and include the effects of DR programs that were activated at the time of the peak.

**IRP Reserve Margin reflects the projected reserve margin based on normal weather peak from the previous year's IRP.

[10] The operating reserves shown do not reflect non-firm energy purchases during the hour of the peak system demand in order to ensure a fair comparison with planning reserve margins which also do not include such non-firm purchases that may or may not be available during peak demand hours. The operating reserves data is based on Public Staff data request responses in past IRP dockets.

FIGURE 9-A
DEP ACTUAL HISTORIC OPERATING RESERVES



REGIONAL MODELING

It is important to note that Base Case results reflect the regional benefits of relying on non-firm market capacity resulting from the weather diversity and generator outage diversity across the interconnected system. However, there is risk in over reliance on non-firm market capacity. The Base Case reflects a 6.25% decrease in reserve margin compared to the Island Case (from 25.5% to 19.25%). Thus, approximately one quarter (6.25/25.5 = 25%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market. Astrapé and Duke believe that this market reliance is moderate to aggressive, especially when compared to surrounding entities such as PJM Interconnection L.L.C. (PJM) and the Midcontinent Independent System Operator (MISO). For example, PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin, compared to 6.25% assumed for DEP.[11] Similarly, MISO limits market assistance to 2,331 MW which represents approximately 1.8% of its reserve margin.[12]

[11] https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx - at 11
[12] https://www.misoenergy.org/api/documents/getbymediaid/80578 - at 24

As noted in the Executive Summary of the study report, the general trend across the country is a shift away from coal generation with greater reliance on renewable energy resources. As an example, the Dominion Energy (Virginia Electric and Power Company) 2020 IRP shows substantial additions of solar, wind and battery storage to comply with the recent passage of the Virginia Clean Economy Act (VCEA). The excerpt below is from page 6 of the 2020 Dominion IRP:[13]

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Dominion notes its anticipated "need to import a significant amount of energy during the winter" which means Dominion's greater reliance on PJM and other neighbors in the future. Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[14] The Company also notes California's recent experience with rolling blackouts under extreme weather conditions, as the state continues its shift away from fossil-fuel resources with greater reliance on intermittent renewable resources, storage and imported power.[15]

Duke and Astrapé believe the recommended 17% reserve margin is adequate for near term planning and appropriately captures the diversity in load and unit outage events with PJM and other neighbors. The Company used the 17% reserve margin target for the entire 15-year planning period in the IRP. However, changes in resource portfolios of neighboring utilities, as well as the experience in other states to meet extreme weather peak demands with high renewables portfolios, make

[13] Dominion Energy (Virginia Electric and Power Company) filed its 2020 IRP as the Astrapé study was underway. Dominion's 2020 IRP can be found at https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509
[14] Dominion Energy 2020 IRP, at 40.
[15] https://www.greentechmedia.com/articles/read/how-californias-shift-from-natural-gas-to-solar-is-playing-a-role-in-rolling-blackouts

reliability planning more challenging and place less confidence in future market assistance. For example, today neighboring systems with load diversity may be willing to turn fossil units on early or leave them running longer to assist an adjoining utility during a peak demand period. In the future, with the potential for battery storage to replace a portion of retiring fossil generation, neighboring systems may be reluctant to sell stored energy if they believe that limited stored energy may be required for their native load. Thus, future resource adequacy studies may show less regional benefit of the interconnected system, resulting in the need to carry greater reserves in the longer term. Duke will continue to monitor changes that may impact resource adequacy.

ADEQUACY OF PROJECTED RESERVES

The IRP provides general guidance in the type and timing of resource additions. Projected reserve margins will often be somewhat higher than the minimum target in years immediately following new generation additions since capacity is generally added in large blocks to take advantage of economies of scale. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need.

DEP's resource plan reflects winter reserve margins ranging from approximately 16.6% to 19.9%. As previously noted, reserves projected in DEP's IRP meet the minimum planning reserve margin target in all years except 2024 and 2025 when reserves are allowed to drop slightly below 17%. DEP will continue to monitor the load forecast and resource mix and will adjust accordingly. Projected reserve margins do not exceed the minimum 17% winter target by 3% or more during the planning period.

10 NUCLEAR AND SUBSEQUENT LICENSE RENEWAL (SLR)

NUCLEAR ASSUMPTIONS IN THE 2020 IRP

With respect to nuclear generation overall, the Company will continue to monitor and analyze key developments on factors impacting the potential need for, and viability of, future new baseload nuclear generation. Such factors include further developments on the Vogtle project and other new reactor projects worldwide, progress on existing unit relicensing efforts, nuclear technology developments, and changes in fuel prices and carbon policy.

SUBSEQUENT LICENSE RENEWAL (SLR) FOR NUCLEAR POWER PLANTS

DEP and DEC collectively provide approximately one half of all energy served in their NC and SC service territories from clean carbon-free nuclear generation. This highly reliable source of generation provides power around the clock every day of the year. While nuclear unit outages are needed for maintenance and refueling, outages are generally relatively short in duration and are spread across the nuclear fleet in months of lower power demand. In total, the fleet has a capacity factor, or utilization rate, of well over 90% with some units achieving 100% annual availability depending on refueling schedules. Nuclear generation is foundational to Duke's commitment to providing affordable, reliable electricity while also reducing the carbon footprint of its resource mix. Currently, all units within the fleet have operating licenses from the Nuclear Regulatory Commission (NRC) that allow the units to run up to 60 years from their original license date.

License Renewal is governed by Title 10 of the Code of Federal Regulations (10 CFR) Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.* The NRC has approved applications to extend licenses to up to 60 years for 94 nuclear units across the country.

SLR would cover a second license renewal period, for a total of as much as 80 years. The NRC has issued regulatory guidance documents, NUREG-2191 [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report] and NUREG-2192 [Standard Review Plan for the Review of Subsequent License Renewal (SRP-SLR) Applications for Nuclear Power Plants], establishing formal regulatory guidance for SLR.

NextEra submitted the industry's first SLR application to the NRC on January 31, 2018 for its Turkey Point station, which became the first nuclear units to receive a second renewed license in December 2019. The NRC review was completed in approximately 18 months from the completion of the sufficiency review.

On July 10, 2018, Exelon Corporation submitted an SLR application for its Peach Bottom plant. The Peach Bottom second renewed license was issued in March 2020, also in approximately 18 months from the completion of the sufficiency review.

Dominion Energy submitted an SLR application for its Surry station on October 15, 2018 and is currently in the final stages of the process of receiving its second renewed license. Dominion Energy plans to submit an SLR application for its North Anna plants in 2020.

Based on the technologically safe and reliable operation of the Duke Energy nuclear fleet, the economic benefits of continued operation of the current nuclear fleet and the environmental role played by the nuclear fleet to continue to reduce carbon emissions, Duke Energy announced in September 2019 its intent to pursue SLR for all eleven nuclear units in the operating fleet. The Oconee SLR application will be submitted first, in 2021. An SLR application takes approximately three years to prepare and approximately two years to be reviewed and approved.

11 COAL RETIREMENT ANALYSIS

For more than 50 years, coal assets in the DEP fleet have provided reliable capacity and energy to DEP's customers. These assets continue to provide year-round energy that is especially critical during winter and summer peaks. However, as the industry landscape changes and market forces drive down costs of other resources, it is important to continue to evaluate the economic benefit the coal fleet provides to customers.

In order to assess the on-going value of these assets, DEP conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. This analysis identified the retirement dates used in the Base Cases developed with and without Carbon Policy for each of DEP's coal plants. In addition to the economic retirement analysis, the Company also determined the earliest practicable retirement dates for each coal asset. The "earliest practicable" retirement date portfolio is discussed in Appendix A.

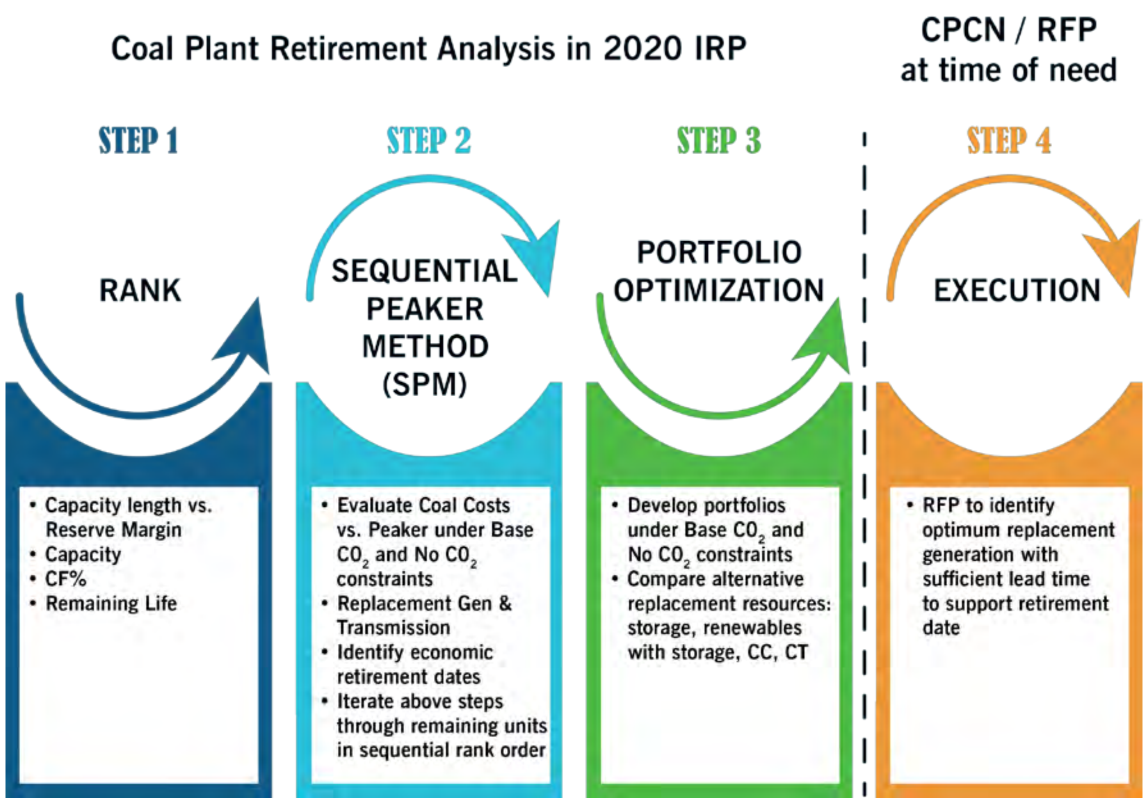
The retirement dates discussed in this chapter do not represent commitments to retire. The IRP is a planning document, but the execution of the plan can vary for multiple reasons including changes to the load forecast, market conditions, and generator performance just to name a few. Similar to new undesignated resources identified in this document that do not have an approval to build or a commitment to build, the coal retirement dates presented herein only represent the current economic retirement dates and are not a commitment to retire.

FOUR-STEP PROCESS

The economic retirement dates, along with the optimum replacement generation, of the coal plants were determined through the process depicted in the diagram below.

FIGURE 11-A

PROCESS FOR DETERMING ECONOMIC RETIREMENT DATES AND REPLACEMENT GENERATION OF COAL PLANTS



The first three steps of the process include both identifying the most economic date and the most economic replacement resources for the retiring coal plants. These steps are included in the 2020 IRP and are detailed in the discussion below. Steps 2 & 3 were evaluated under Base Cases with and without Carbon Policy.

The fourth step in the process, or the execution step, occurs outside of the IRP when the retirement date for the plant is finalized and replacement resource needs are determined. Importantly, the Company includes assumptions for future costs and the commercial availability of replacement resources in the first 3 steps of the retirement analysis, as well as throughout the entirety of the IRP. Only at the time of execution, when the Company issues an RFP for replacement resources, will the *actual* costs, availability, and need for those resources be known.

STEP 1: RANKING PLANTS FOR RETIREMENT ANALYSIS

Due to the retirement of one asset impacting the operation and value of other assets on the system, it was important to identify the order in which to conduct the retirement analysis. Additionally, the Joint Dispatch Agreement (JDA) between DEP and DEC allows for non-firm energy purchases and sales between the two utilities. Because of this interaction, the ranking of assets for retirement was evaluated across the utilities, and both DEP and DEC assets are presented below.

To rank the assets for retirement, the Company first ran preliminary capacity expansion plan and production cost models to determine the capacity factors (CF%) for each facility using the 2019 IRP coal plant retirement dates as a starting point for the analysis. This exercise was necessary for estimating future capital and fixed operating and maintenance (FOM) costs at the sites, including incremental coal ash management costs, as well as, for identifying the capacity length versus reserve margin to determine if replacement generation was needed when the individual plants were retired. The results of Step 1 are shown in Table 11-A below:

TABLE 11-A
RANKING OF COAL PLANTS FOR RETIREMENT ANALYSIS

COAL FACILITY	CAPACITY (MW WINTER)	CF% RANGE THROUGH 2035	YEARS IN SERVICE (AS OF 1/2020)	RANK
Allen 1 – 3	604	3% – 11%	60 – 62	1
Allen 4&5	526	2% - 9%	58 – 59	2
Cliffside 5	546	2% - 23%	47	3
Mayo	746	1% - 12%	36	4
Roxboro 1&2	1,053	5% - 34%	51 – 53	5
Roxboro 3&4	1,409	1% - 32%	39 – 46	6
Marshall 1-4	2,078	1% - 49%	49 – 54	7
Belews Creek 1&2	2,220	16% - 57%	44 – 45	8

Because the cost of replacement generation for coal plants is a critical factor when determining the value of retirement, the Company considered the capacity of the plant to be one of the most important factors for determining the order in which to conduct the retirement analysis. For instance, while Cliffside 5 has a higher capacity factor than Mayo, which would indicate Cliffside 5 has higher production cost value, the lower capacity of Cliffside 5 requires less replacement generation at the time of retirement. For this reason, Cliffside 5 was ranked above Mayo in the order for conducting the retirement analysis.

STEP 2: SEQUENTIAL PEAKER METHOD (SPM)

Once the order to conduct the retirement analysis was determined, the next step was to determine the most economic date for each coal plant. As discussed above, as coal plants are retired, the value of the remaining coal plants in the fleet changes. For this reason, the Company evaluated the economic value of each plant in a sequential manner. Additionally, for determining the optimum retirement date, the Company used a Net Cost of New Entry (Net CONE) methodology when evaluating each plant. The Net CONE method is similar to the Peaker Method used in calculating avoided costs as it considers both the capital and fixed costs of a generic peaker, as well as, the net production cost value of the peaker versus the asset the peaker is replacing. Importantly, this step is used solely to determine the optimal date for retirement. In Step 3, or the Portfolio Optimization step, the optimum replacement generation is determined, considering alternative technology options such as solar, wind, battery storage, solar + storage, and natural gas generation to determine the lowest total cost resource mix to support the aggregate defined economic retirement dates.

In addition to accelerating the cost of the replacement peaker and the impacts to the system variable production costs, the second step also considered the on-going capital and fixed operating costs avoided by accelerating the retirement date of the coal plant. For example, the avoided costs included any incremental coal ash management costs, including estimates for new landfill cells that would have been required to store incremental coal ash generated through continued operation of these plants.

Finally, the Sequential Peaker Method included the cost to accelerate transmission upgrades associated with the retirement of some of the coal plants. In several instances, the retiring coal plant or units provided support to the transmission system, and in those cases, the Company included the cost of Static Var Compensators (SVCs) and/or line upgrades to address the loss of generation on the system.

The figure below presents a high-level view of how the SPM analysis was conducted, and the results of the analysis are presented in Table 11-B. While not shown in the graphic below, Allen Units 1-5 were evaluated in an initial step once it was determined replacement generation would not be needed since there was sufficient capacity above reserve margin requirements prior to 2025. For all other units, the Company assumed replacement generation or the necessary transmission upgrades needed to retire the facilities would not be available until 2025, and therefore the earliest date any plant after Allen Units 1-5 could be retired was considered to be 2025.

FIGURE 11-B

SEQUENTIAL PEAKER METHOD PROCESS FOR DETERMING ECONOMIC RETIREMENT DATES OF COAL PLANTS

The table below shows the economic retirement dates for each coal plant as determined via the Sequential Peaker Method.

TABLE 11-B

ECONOMIC RETIREMENT DATES OF COAL PLANTS FROM SPM

COAL PLANT	BASE CASE W/ CO_2 POLICY MOST ECONOMIC RETIREMENT YEAR (JAN 1)[1]
Allen 2 – 4[2]	2022
Allen 1 & 5	2024
Cliffside 5	2026
Roxboro 3 & 4	2028
Roxboro 1 & 2	2029
Mayo 1	2029
Marshall 1 – 4	2035
Belews Creek 1	2039
Belews Creek 2	2039
Cliffside 6	2049

[1] There was no appreciable difference between the economic retirement dates in the Base Case with Carbon policy and Base Case without Carbon policy.

[2] For further information on the potential retirement of Allen Steam Station please see the Duke Energy Carolinas Integrated Resource Plan 2020 Biennial Report.

STEP 3: PORTFOLIO OPTIMIZATION

After the most economic retirement dates were determined, the Company relied on expansion plan and system production cost modeling to develop two optimized portfolios with the assumption that coal units were retired on the dates determined in Step 2. The resulting optimized portfolios represent the Base Plan with Carbon Policy and Base Plan without Carbon Policy discussed in greater detail in Chapter 12 and Appendix A, and replacement generation includes a mix of solar, solar plus storage, standalone storage, wind, EE/DSM, and natural gas generation.

The development of these optimized portfolios was based on the best available projections of fuel, technology, carbon, and other costs known at the time the inputs to the IRP were developed. As the economics of continued coal operations change relative to the costs of replacement resource alternatives, future IRPs will reflect such changes. However, it is only when units are ultimately planned for retirement in the future, with specific replacement resources identified at specific locations, that the actual costs for replacement resources can be known. Importantly, with the exception of the Allen units, all further coal unit retirements will require replacement resources to be in service prior to the physical retirement of the coal facility in order to maintain system reliability. It is at that time that the actual costs of replacement resources from Step 4, or the Execution step, will be determined as part of a future CPCN and associated RFP process.

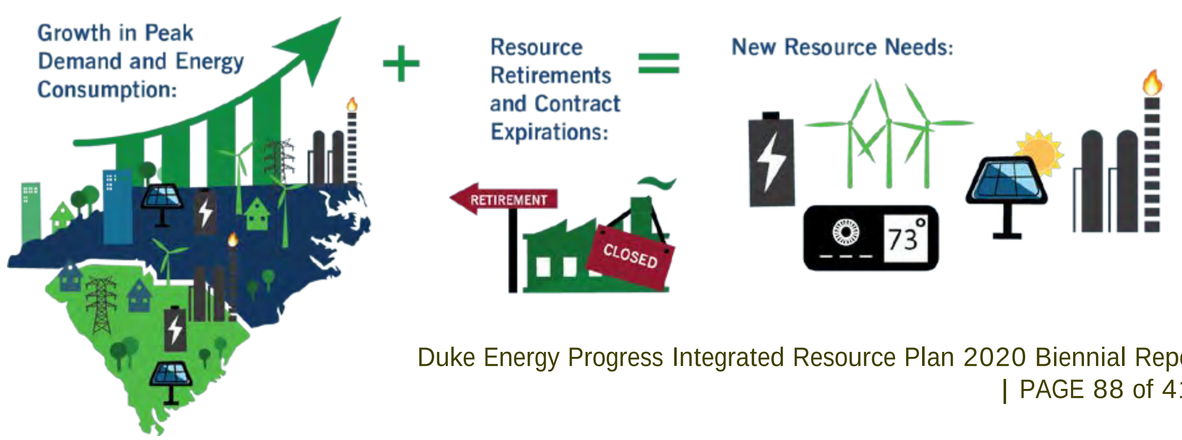
As previously noted, in addition to the most economic retirement dates for the coal plants, the Company also developed the earliest practicable retirement dates for each plant. The earliest practicable dates were determined without considerations of least cost planning, and they represent the earliest dates plants could be retired when considering transmission, fuel, replacement generation, and other logistical requirements. The methodology and results of the earliest practicable retirement date analysis is presented in Appendix A.

12 EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

As described in Chapter 9, DEP continues to plan to winter planning reserve margin criteria in the IRP process. To meet the future needs of DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEP develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning winter reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. A high-level representation of the IRP process is represented in Figure 12-A.

FIGURE 12-A
SIMPLIFIED IRP PROCESS

It should be noted that DEP considers the non-firm energy purchases and sales associated with the JDA with DEC in the development of its six portfolios as discussed later in this chapter and in Appendix A.



THREE PILLARS OF THE IRP

The IRP process has evolved as the energy industry has changed. While the intent of the IRP remains to develop a 15-year plan that is reliable and economical to meet future customer demand, other factors also must be considered when selecting a plan.

FIGURE 12-B
THREE PILLARS OF THE IRP

There are three pillars which determine the primary planning objectives in the IRP. These pillars are as follows:

- Environmental
- Financial (Affordability)
- Physical (Reliability)

The Environmental pillar of the IRP process takes into consideration various policies set by state and federal entities. Such entities include NCUC, PSCSC, FERC, NERC, SERC, NRC, and EPA, along with various other state and federal regulatory entities. Each of these entities develops policies that have a direct bearing on the inputs, analysis and results of the IRP process. While many regulatory and legislative policies impact the production of the IRP, the primary focus on both a state and national level is around environmental policies. Examples of such policies include NC HB 589, SC Act 236 and SC Act 62 programs that set targets for the addition of renewable resources. Environmental legislation at the state and federal level can impact the cost and operations of existing resources, as well as future assets. In addition, reliability and operational requirements imposed on the system influence the IRP process.

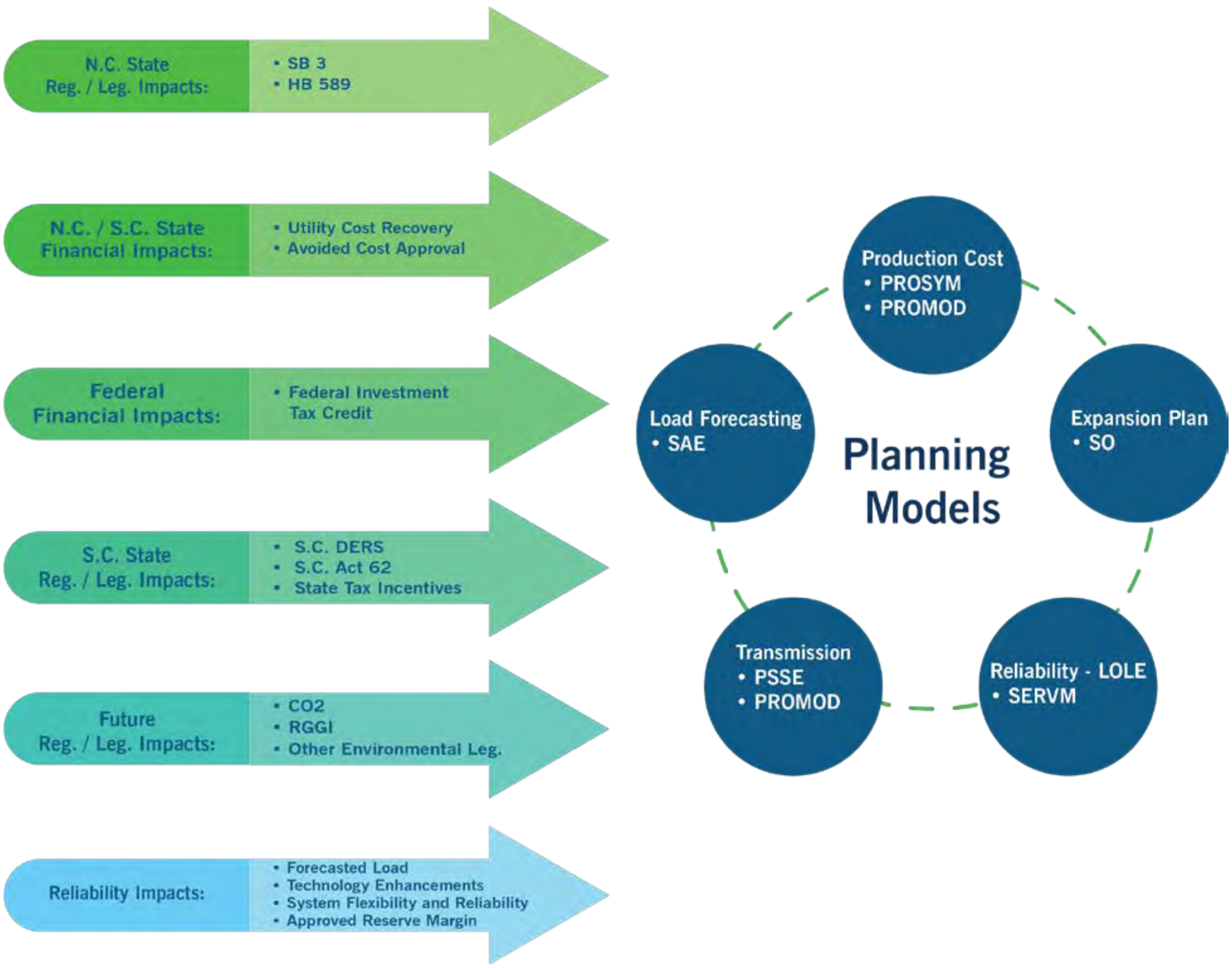
The Financial, or Affordability, pillar is another basic criterion for the IRP. The plan that is selected must be cost-effective for the customers of the Company. DEP's service territory, located in the southern United States, has climate conditions that require more combined electric heating and cooling per customer than any other region in the country. As such, DEP's customers require more electricity than customers from other regions, highlighting the need for affordable power. Changing customer preferences and usage patterns will continue to influence the load forecast incorporated in the Company's IRPs. Furthermore, as new technologies are developed and continue to evolve, the costs of these technologies are projected to decline. These downward impacts are contemplated in the planning process and changes to those projections will be closely monitored and captured in future IRPs. Technology costs are discussed in more detail in Appendices A and G.

Finally, Physical Reliability is the third pillar of the IRP process. Reliability of the system is vitally important to meeting the needs of today's customers as well as the future needs that come with substantial customer growth projected in the region. DEP's customers expect energy to be provided to them every hour of every day throughout the year without fail, today and into the future. To ensure the energy and capacity needs of our customers are met, the Company continues to plan to a reasonable 17% reserve margin, which helps to ensure that the reliability of the system is maintained. A more detailed discussion of the reliability requirements of the DEP system is discussed in Chapter 9.

Each of these pillars must be evaluated and balanced in the IRP in order to meet the intent of the process. The Company has adhered to the principles of these pillars in the development of this IRP and the portfolios and scenarios evaluated as part of the IRP process.

Figure 12-C below graphically represents examples of how issues from each of the pillars may impact the IRP modeling process and subsequent portfolio development.

FIGURE 12-C
IMPACTS OF THREE PILLARS ON THE IRP MODELING PROCESS



IRP ANALYSIS PROCESS

The following section summarizes the Data Input, Generation Alternative Screening, Portfolio Development and Detailed Analysis steps in the IRP process. A more detailed discussion of the IRP Process and development of the Base Cases and additional portfolios is provided in Appendix A.

DATA INPUTS

Refreshing input data is the initial step in the IRP development process. For the 2020 IRP, data inputs such as load forecast, EE and DSM projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data. These data inputs were developed and provided by Company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEP and DEC continue to benefit from the combined experience of both utilities' subject matter experts utilizing best practices from each utility in the development of their respective IRP inputs. Where appropriate, common data inputs were utilized.

As expected, certain data elements and issues have a larger impact on the IRP than others. Any changes in these elements may result in a noticeable impact to the plan, and as such, these elements are closely monitored. Some of the most consequential data elements are listed below. A detailed discussion of each of these data elements has been presented throughout this document and are examined in more detail in the appendices.

- Load Forecast for Customer Demand
- EE/DSM Forecast
- Environmental Legislation and Regulation
- Renewable Resources and Cost Projections
- Fuel Costs Forecasts
- Technology Costs and Operating Characteristics

GENERATION ALTERNATIVE SCREENING

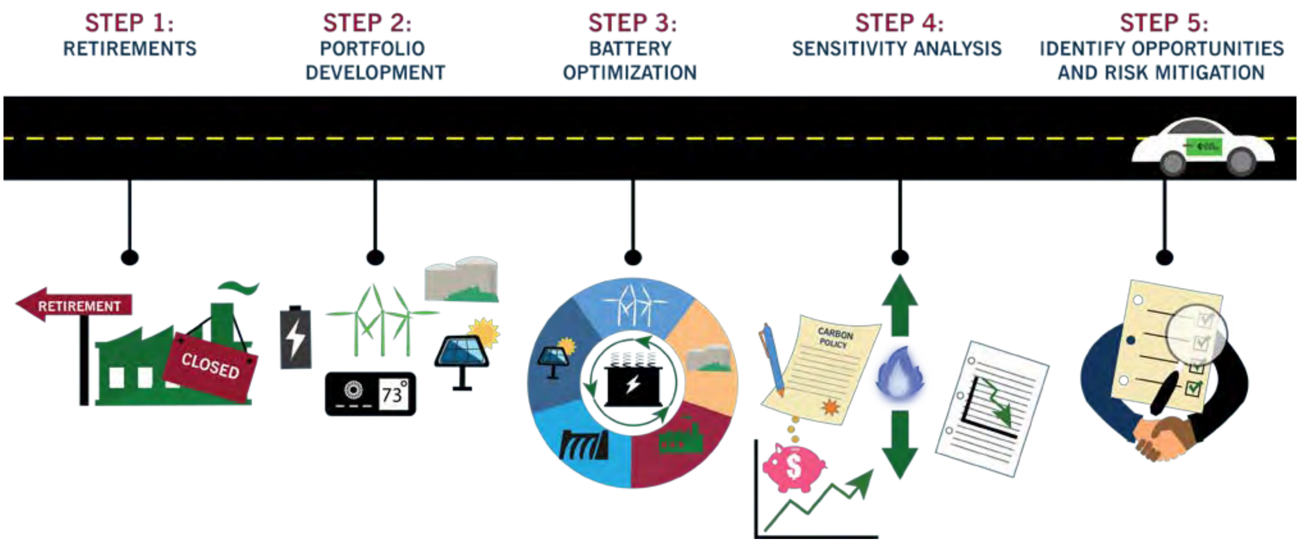
DEP reviews generation resource alternatives on a technical and economic basis. Resources must also be demonstrated to be commercially available for utility scale operations. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further evaluation. The process of screening these resources is discussed in more detail in Appendix G.

PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS

The following figure provides an overview of the process for the portfolio development and detailed analysis phase of the 2020 IRP.

FIGURE 12-D

OVERVIEW OF BASE CASE PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS PHASE



The Base Case Portfolio Development and Sensitivity Analysis phases rely upon the updated data inputs and results of the generation alternative screening process to derive resource portfolios or resource plans. The Base Case Portfolio Development and Sensitivity Analysis phases utilize an expansion planning model, System Optimizer (SO), to determine the best mix of capacity additions for the Company's short- and long-term resource needs with an objective of selecting a robust plan that meets reliability targets and minimizes the PVRR to customers and is environmentally sound by complying with or exceeding, all State and Federal regulations.

Sensitivity analysis of input variables such as load forecast, fuel costs, renewable energy, EE, and resource capital costs are considered as part of the quantitative analysis within the resource planning process. Utilizing the results of these sensitivities, possible expansion plan options for the DEP system are developed. These expansion plans are reviewed to determine if any overarching trends are present across the plans, and based on this analysis, portfolios are developed to represent these trends. Finally, the portfolios are analyzed using a capital cost model and an hourly production cost model (PROSYM) under various fuel price and carbon scenarios to evaluate the robustness and economic value of each portfolio under varying input assumptions. After this comprehensive analysis is completed, the portfolios are examined considering the trade-offs between costs, carbon reductions and dependency on technological and policy advancements.

In addition to evaluating these portfolios solely within the DEP system, the potential benefits of sharing capacity within DEP and DEC are examined in a common Joint Planning Case. A detailed discussion of these portfolios is provided in Appendix A.

SELECTED PORTFOLIOS

For the 2020 IRP, six portfolios were identified through the Base Case Portfolio Development and Sensitivity Analysis process that consider and attempt to address stakeholder interest in the transformation of the DEP generation fleet. As described below, the portfolios range from diverse intended outcomes ranging from least cost planning to high carbon reductions and resource restrictions. Additionally, some portfolios consider the increase in the amount and adoption rate of renewables, EE, and energy storage to achieve these outcomes.

PORTFOLIO A (BASE CASE WITHOUT CARBON POLICY)

This portfolio utilizes new natural gas generation to meet load growth and replace retiring existing capacity. This case incorporates the most economic retirement dates for the coal units, as discussed in Chapter 11, retiring 3,200 MW of coal capacity by 2029. As with all portfolios in DEP, existing expiring contracts are replaced with in-kind contracts to minimize need for newly constructed capacity. The base planning assumptions for expected renewable additions and interconnections, energy efficiency and demand response are also built into this plan, before a new resource is considered. Although no renewable resources were selected by the model, this case adds 2,000 MW of solar and solar plus storage throughout the IRP planning horizon. Portfolio A, with the considerable amount of intermittent renewable generation on the system, indicates that battery storage becomes economical in place of peaking CT capacity at the end of the study period. The Company already includes the addition of 140 MW of grid-tied battery storage placeholders in the early- to mid-2020s. These battery storage options have the potential to provide solutions for the transmission and distribution systems, while simultaneously providing benefits to the generation resource portfolio. Overall, this plan adds 5,300 MW of CT and CC gas capacity beginning the winter of 2026 to ensure the utility can meet customer load demand.

PORTFOLIO B (BASE CASE WITH CARBON POLICY)

This portfolio assumes the same base planning assumptions as the previous case but is developed with the IRP's base carbon tax policy as a proxy for future carbon legislation. This case adds 4,300 MW of natural gas capacity, replacing new peaking gas generation in favor of base and intermediate load gas resources. These changes are a result of the carbon tax, which increases prices on carbon-intense resources like coal. While less natural gas generation is built in the plan, renewable resources begin to be economically selected to meet demand. This plan selects 1,400 MW more of incremental solar plus storage than included in the base forecast and in the Base Case without Carbon Policy. This plan also begins to incorporate onshore central Carolinas wind, adding 600 MW throughout the planning horizon. This additional amount of fuel-free, but intermittent, resources spurs the economic selection of additional storage, including 500 MW of standalone, grid-tied storage as well as, 350 MW of storage coupled with solar. The inclusion of the carbon tax in the development of this case clearly changes the resource selection, favoring more carbon free resources to meet the Company's energy needs.

PORTFOLIO C (EARLIEST PRACTICABLE COAL RETIREMENTS)

This portfolio focuses on DEP's ability to retire its existing coal units as early as practicable. Several factors were considered in the establishment of these retirement dates and are discussed in detail in Appendix A. The earliest practicable retirement analysis resulted in the acceleration of Mayo Unit 1 from 2029 in the Base Cases to 2026 and Roxboro units 1 and 2 from 2029 to 2028, joining Roxboro 3 and 4 in that year. Part of the analysis for earliest practicable retirement dates requires construction and transmission upgrades and interconnection costs for replacement generation. Additionally, the retirement of the coal units was expedited by leveraging existing infrastructure and to eliminate the need for transmission upgrades at the retiring coal sites. Replacing 3,200 MW of coal capacity requires extensive firm capacity additions to the DEP system. As such, this plan results in the acceleration of the standalone, grid tied batteries as seen in the Base Case with Carbon Policy case from the early 2030s to the early and mid-2020s. Further, additional transmission upgrades are avoided by siting replacement gas generation at the Roxboro station. As with the Base Case with Carbon Policy scenario, this case also adds significant amounts of solar and wind resources to help replace this retiring coal generation in order to meet DEP's future energy and capacity needs.

PORTFOLIO D (70% CO_2 REDUCTIONS: HIGH WIND)

This portfolio outlines a pathway for the Carolinas combined system to achieve 70% CO_2 reductions, from a 2005 baseline, by tapping into wind resources off the coast of the Carolinas. This plan leverages high energy efficiency and demand response projections, as well as high penetration renewables forecasts with increased solar annual integration limits. This portfolio also utilizes the earliest practicable retirement dates as established in Portfolio C with the associated replacement capacity to enable those retirements. It is worth noting that even with assumptions of high EE, DR, and renewables, combined with the accelerated coal retirements do not get the combined system to 70% CO_2 reductions by 2030. In order to reach 70%, the Company adds 1,200 MW of offshore wind into the DEP system for the winter peak of 2030. For a long lead time infrastructure project such as this, the retirements of Roxboro 1 and 2 are delayed from 2028 to 2030 to maintain planning reserve capacity until the offshore wind can be operational.

PORTFOLIO E (70% CO_2 REDUCTIONS: HIGH SMR)

This portfolio outlines a pathway for the Carolinas combined system to achieve 70% CO_2 reductions, from a 2005 baseline, by deploying small modular nuclear reactor technology by the end of this decade. This plan also leverages high energy efficiency and demand response projections, as well as high penetration renewables forecasts with increased integration limits. As with Portfolio D, this portfolio utilizes the earliest practicable retirement dates as established in Portfolio C with the associated replacement capacity to enable those retirements. Again, it is worth noting that even with assumptions of high EE, DR, and renewables, combined with accelerated coal retirements do not get the combined system to 70% CO_2 reductions by 2030. In order to reach 70%, a 684 MW small modular nuclear reactor plant[1] is added to the DEP system at the beginning of 2030. For a long lead time infrastructure project such as this, the retirements of Roxboro 1 and 2 were delayed from 2028 to 2030 to maintain planning reserve capacity until the SMR can be operational.

PORTFOLIO F (NO NEW GAS GENERATION)

This portfolio addresses growing interest from stakeholders and Environmental, Social and Governance (ESG) investors to understand the impacts of transition the current portfolio to a net-zero carbon portfolio by 2050, without the deployment of new gas generation. Because the earliest practicable coal retirement dates are predicated on replacement with gas generation at some of the retiring coal sites, this plan uses to the most economic retirement dates as utilized in the Base Cases. In an effort

[1] As described in Appendix A, the first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEP.

to minimize cost to customers without the ability to build gas, high EE and DR projections, as well as high penetration renewables forecasts with increased solar annual integration limits are included in this plan. Despite the later coal retirement dates, there are still significant capacity needs in DEP by 2030. As no gas capacity is an option in this case, these energy and capacity needs are met by deploying 4,000 MW of batteries and 2,500 MW of offshore wind by 2030. This plan also adds significant amounts of other renewable resources including 5,000 MW of solar and solar plus storage and 1,700 MW of land-based wind, from both central Carolinas and midcontinental U.S.

PORTFOLIO ANALYSIS

The six portfolios developed from the Base Case Portfolio Development and Sensitivity Analysis phase and informed by the Base Case sensitivity analysis, were evaluated in more detail utilizing an hourly production cost model under a matrix of nine carbon and fuel cost scenarios. The results of these hourly production cost model runs were paired with the accompanying capital costs and analyzed focusing on the trade-offs between cost, carbon reductions, and dependency on technological and policy advancements. Table 12-A below shows the scenario matrix, in which each portfolio was tested.

TABLE 12-A
SCENARIO MATRIX FOR PORTFOLIO ANALYSIS

	NO CO_2	BASE CO_2	HIGH CO_2
Low Fuel			
Base Fuel			
High Fuel			

Table 12-B details the results of the PVRR analysis under the varying carbon and fuel scenarios with the cost of the carbon tax excluded, while Table 12-C provides the same results but includes the cost of a carbon tax.

TABLE 12-B
SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON (2020 DOLLARS IN BILLIONS)

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$38.8	$39.1	$40.8	$47.2	$44.3	$54.1
High CO_2-Base Fuel	$34.0	$35.1	$37.0	$44.3	$41.5	$51.6
High CO_2-Low Fuel	$31.0	$32.5	$34.5	$42.4	$39.6	$49.7
Base CO_2-High Fuel	$39.1	$39.7	$41.1	$47.3	$44.7	$54.7
Base CO_2-Base Fuel	$34.4	$35.7	$37.3	$44.5	$41.9	$52.1
Base CO_2-Low Fuel	$31.4	$33.1	$34.9	$42.5	$39.9	$50.3
No CO_2-High Fuel	$39.9	$41.0	$42.1	$47.9	$45.7	$56.0
No CO_2-Base Fuel	$35.4	$37.3	$38.4	$45.0	$42.9	$53.6
No CO_2-Low Fuel	$32.5	$34.8	$35.9	$43.1	$41.0	$51.8
Min	$31.0	$32.5	$34.5	$42.4	$39.6	$49.7
Median	$34.4	$35.7	$37.3	$44.5	$41.9	$52.1
Max	$39.9	$41.0	$42.1	$47.9	$45.7	$56.0

TABLE 12-C

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON (2020 DOLLARS IN BILLIONS)

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$50.6	$49.7	$50.7	$54.2	$51.9	$61.3
High CO_2-Base Fuel	$46.2	$46.0	$47.0	$51.4	$49.1	$59.1
High CO_2-Low Fuel	$43.3	$43.5	$44.6	$49.5	$47.2	$57.3
Base CO_2-High Fuel	$47.8	$47.4	$48.4	$52.5	$50.3	$59.9
Base CO_2-Base Fuel	$43.3	$43.7	$44.7	$49.7	$47.5	$57.6
Base CO_2-Low Fuel	$40.5	$41.2	$42.3	$47.8	$45.6	$55.9
No CO_2-High Fuel	$39.9	$41.0	$42.1	$47.9	$45.7	$56.0
No CO_2-Base Fuel	$35.4	$37.3	$38.4	$45.0	$42.9	$53.6
No CO_2-Low Fuel	$32.5	$34.8	$35.9	$43.1	$41.0	$51.8

Min	$32.5	$34.8	$35.9	$43.1	$41.0	$51.8
Median	$43.3	$43.5	$44.6	$49.5	$47.2	$57.3
Max	$50.6	$49.7	$50.7	$54.2	$51.9	$61.3

BASE CASE WITH CARBON POLICY

Each of the alternative portfolios provides insight on strategies and advancements necessary to further evaluate carbon reductions and cost trade-offs. However, for planning purposes, Duke Energy considers the lowest cost, reliable cases as the Base Case portfolios, as is the direction of NC and SC IRP rules and regulations currently in place. If a carbon constrained future is either delayed or is more restrictive than the base assumptions, or other variables such as fuel price and capital costs change significantly from the base assumptions, the selected carbon constrained portfolio remains adequately robust to provide value in those futures. Another factor that is considered when selecting the base portfolio is the likelihood that the selected portfolio can be executed as presented.

Portfolio B, Base Case with Carbon Policy, is presented below and includes the addition of a diverse compilation of resources including CCs, CTs, battery storage, EE, DSM and significant amounts of solar, solar plus storage, battery and wind. These resources are selected in conjunction with existing nuclear, natural gas, expected renewable projections and other assets already on the DEP system. This portfolio also enables the Company to lower carbon emissions under a range of future scenarios at a lower cost than most other scenarios.

Finally, the Base Case with Carbon Policy portfolio was developed utilizing consistent assumptions and analytic methods between DEP and DEC, where appropriate. This case does not consider the sharing of capacity between DEP and DEC. However, the Base Case incorporates the JDA between DEP and DEC, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that explores the potential for DEP and DEC to share firm capacity was also developed and discussed in Appendix A.

The Load and Resource Balance shown in Figure 12-E illustrates the resource needs required for DEP to meet its load obligation inclusive of a required 17% reserve margin. Existing generating resources, designated and expected resource additions and EE/DSM resources do not meet the required load and reserve margin beginning in 2026. As a result, the Base Case with Carbon Policy plan is presented to meet the resource gap.

FIGURE 12-E

DEP BASE CASE WITH CARBON POLICY LOAD RESOURCE BALANCE (WINTER)

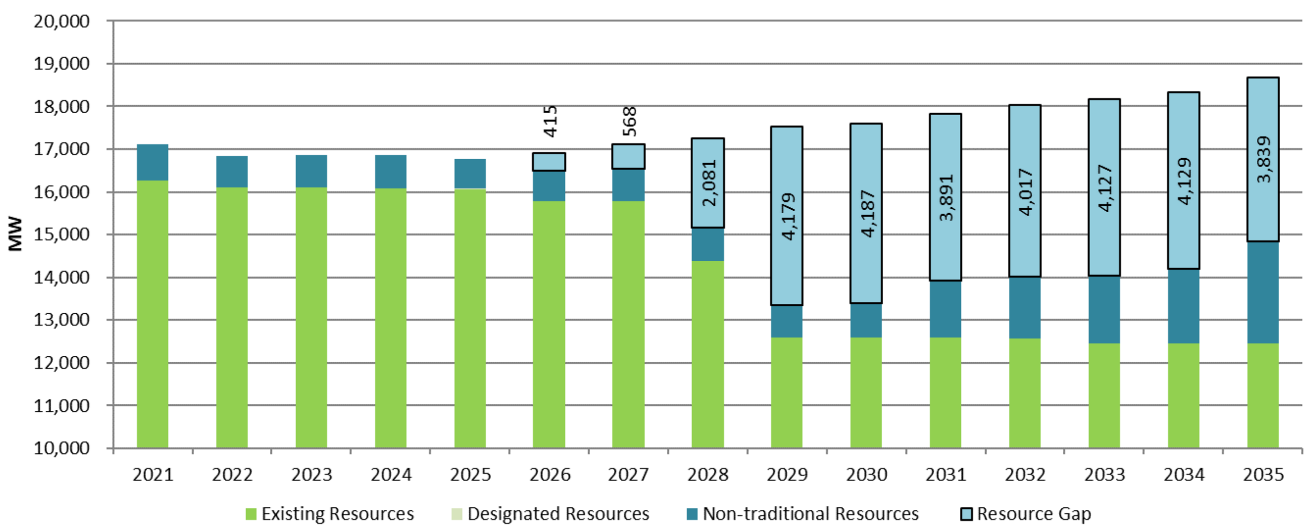


TABLE 12-D

CUMULATIVE RESOURCE ADDITIONS TO MEET WINTER LOAD OBLIGATION AND RESERVE MARGIN (MW)

YEAR	2021	2022	2023	2024	2025	2026	2027	2028
Resource Need	0	0	0	0	0	415	568	2,081

YEAR	2029	2030	2031	2032	2033	2034	2035
Resource Need	4,179	4,187	3,891	4,017	4,127	4,129	3,839

Tables 12-E and 12-F present the Load, Capacity and Reserves (LCR) tables for the Base Case with Carbon Policy analysis that was completed for DEP's 2020 IRP.

TABLE 12-E

BASE CASE WITH CARBON POLICY LOAD, CAPACITY AND RESERVES TABLE -WINTER

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Forecast															
1 DEP System Winter Peak	14,161	14,221	14,240	14,431	14,566	14,670	14,867	14,998	15,248	15,310	15,506	15,672	15,792	15,920	16,210
2 Firm Sale	150	150	150	150	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(43)	(78)	(111)	(141)	(185)	(214)	(238)	(258)	(272)	(276)	(273)	(268)	(262)	(254)	(243)
4 Adjusted Duke System Peak	**14,268**	**14,293**	**14,280**	**14,440**	**14,381**	**14,456**	**14,629**	**14,740**	**14,976**	**15,035**	**15,233**	**15,404**	**15,531**	**15,666**	**15,966**
Existing and Designated Resources															
5 Generating Capacity	14,193	13,679	13,679	13,679	13,679	13,683	13,451	13,451	12,048	10,249	10,259	10,259	10,259	10,259	10,259
6 Designated Additions / Uprates	0	0	0	0	4	0	0	6	0	10	0	0	0	0	0
7 Retirements / Derates	(514)	0	0	0	0	(232)	0	(1,409)	(1,799)	0	0	0	0	0	0
8 Cumulative Generating Capacity	**13,679**	**13,679**	**13,679**	**13,679**	**13,683**	**13,451**	**13,451**	**12,048**	**10,249**	**10,259**	**10,259**	**10,259**	**10,259**	**10,259**	**10,259**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,673**	**2,523**	**2,501**	**2,483**	**2,472**	**2,421**	**2,423**	**2,415**	**2,364**	**2,363**	**2,363**	**2,349**	**2,220**	**2,220**	**2,220**
Non-Compliance Renewable Purchases	83	89	82	83	85	86	86	83	32	31	31	30	30	29	29
Non-Renewables Purchases	2,591	2,434	2,419	2,400	2,388	2,334	2,337	2,332	2,332	2,332	2,332	2,320	2,191	2,191	2,191
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle								1,224	1,224						
12 Combustion Turbine						457	457		913						
13 Solar										38	38	56	56	56	56
14 Wind													71	71	71
15 Battery											457				479
Renewables															
16 Cumulative Renewables Capacity	**223**	**89**	**88**	**88**	**88**	**79**	**98**	**116**	**130**	**164**	**671**	**736**	**881**	**1,016**	**1,640**
Renewables w/o Storage	223	89	88	85	85	75	76	75	71	55	55	55	55	55	55
Solar w/ Storage (Solar Component)	0	0	0	0	0	0	1	2	2	3	3	3	3	3	3
Solar w/ Storage (Storage Component)	0	0	0	3	3	3	21	39	57	69	80	89	107	116	134
17 Combined Heat & Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Grid-connected Energy Storage	29	14	17	17	19	19	19	0	0	0	0	0	0	0	0
19 Cumulative Production Capacity	**16,604**	**16,334**	**16,327**	**16,327**	**16,340**	**16,522**	**17,019**	**16,850**	**17,151**	**17,194**	**17,701**	**17,753**	**17,768**	**17,903**	**18,527**
Demand Side Management (DSM)															
20 Cumulative DSM Capacity	**507**	**517**	**521**	**519**	**329**	**336**	**344**	**354**	**367**	**384**	**404**	**425**	**447**	**467**	**484**
21 IVVC Peak Shaving	**-**	**-**	**9**	**19**	**96**	**97**	**98**	**99**	**100**	**100**	**101**	**102**	**103**	**104**	**105**
22 Cumulative Capacity w/ DSM	**17,111**	**16,850**	**16,857**	**16,866**	**16,765**	**16,955**	**17,461**	**17,302**	**17,617**	**17,678**	**18,206**	**18,280**	**18,318**	**18,474**	**19,116**
Reserves w/ DSM															
23 Generating Reserves	2,843	2,557	2,577	2,425	2,383	2,499	2,832	2,562	2,642	2,643	2,973	2,876	2,788	2,809	3,149
24 % Reserve Margin	**19.9%**	**17.9%**	**18.0%**	**16.8%**	**16.6%**	**17.3%**	**19.4%**	**17.4%**	**17.6%**	**17.6%**	**19.5%**	**18.7%**	**18.0%**	**17.9%**	**19.7%**

DUKE ENERGY PROGRESS

TABLE 12-F

BASE CASE WITH CARBON POLICY LOAD, CAPACITY AND RESERVES TABLE - SUMMER

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
recast															
DEP System Summer Peak	12,885	12,909	12,913	13,063	13,207	13,381	13,461	13,589	13,833	13,918	14,093	14,241	14,377	14,499	14,757
Firm Sale	150	150	150	150	0	0	0	0	0	0	0	0	0	0	0
Cumulative New EE Programs	(67)	(101)	(133)	(162)	(191)	(220)	(245)	(265)	(281)	(287)	(286)	(282)	(277)	(247)	(237)
Adjusted Duke System Peak	**12,968**	**12,957**	**12,930**	**13,051**	**13,016**	**13,161**	**13,216**	**13,324**	**13,552**	**13,631**	**13,807**	**13,959**	**14,100**	**14,252**	**14,520**
and Designated Resources															
Generating Capacity	12,477	12,477	12,477	12,477	12,479	12,479	12,303	12,307	10,915	9,147	9,147	9,147	9,147	9,147	9,147
Designated Additions / Uprates	0	0	0	2	0	0	4	0	6	0	0	0	0	0	0
Retirements / Derates	0	0	0	0	0	(176)	0	(1,392)	(1,774)	0	0	0	0	0	0
Cumulative Generating Capacity	**12,477**	**12,477**	**12,477**	**12,479**	**12,479**	**12,303**	**12,307**	**10,915**	**9,147**	**9,147**	**9,147**	**9,147**	**9,147**	**9,147**	**9,147**
e Contracts															
Cumulative Purchase Contracts	**2,837**	**2,904**	**2,932**	**2,935**	**2,955**	**2,934**	**2,923**	**2,902**	**2,839**	**2,830**	**2,822**	**2,818**	**2,677**	**2,676**	**2,674**
Non-Compliance Renewable Purchases	352	558	603	625	657	696	682	667	604	595	587	585	583	582	581
Non-Renewables Purchases	2,485	2,346	2,330	2,311	2,298	2,237	2,240	2,235	2,235	2,235	2,235	2,234	2,094	2,094	2,094
nated Future Resources															
Nuclear															
Combined Cycle								1,152	1,152						
Combustion Turbine						419	419		837						
Solar										38	38	56	56	56	56
Wind													53	53	53
Battery											457				479
les															
Cumulative Renewables Capacity	**484**	**369**	**357**	**371**	**361**	**339**	**400**	**457**	**510**	**569**	**643**	**707**	**833**	**949**	**1,075**
Renewables w/o Storage	484	369	357	365	355	333	360	384	404	403	419	418	417	416	415
Solar w/ Storage (Solar Component)	0	0	0	3	3	3	19	35	50	59	69	69	68	68	68
Solar w/ Storage (Storage Component)	0	0	0	3	3	3	21	39	57	69	80	89	107	116	134
Combined Heat & Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grid-connected Energy Storage	29	14	17	17	19	19	19	0	0	0	0	0	0	0	0
Cumulative Production Capacity	**15,826**	**15,793**	**15,826**	**15,862**	**15,891**	**16,109**	**16,600**	**16,397**	**16,608**	**16,658**	**16,724**	**16,785**	**16,769**	**16,884**	**17,008**
Side Management (DSM)															
Cumulative DSM Capacity	**966**	**976**	**980**	**979**	**786**	**788**	**789**	**791**	**794**	**796**	**800**	**803**	**806**	**809**	**812**
IVVC Peak Shaving	**-**	**-**	**9**	**19**	**96**	**97**	**98**	**99**	**100**	**100**	**101**	**102**	**103**	**104**	**105**
Cumulative Capacity w/ DSM	**16,792**	**16,769**	**16,816**	**16,861**	**16,773**	**16,994**	**17,488**	**17,287**	**17,501**	**17,555**	**17,625**	**17,690**	**17,679**	**17,798**	**17,925**
s w/ DSM															
Generating Reserves	3,824	3,812	3,886	3,809	3,757	3,833	4,272	3,963	3,949	3,923	3,818	3,731	3,579	3,546	3,405
% Reserve Margin	**29.5%**	**29.4%**	**30.1%**	**29.2%**	**28.9%**	**29.1%**	**32.3%**	**29.7%**	**29.1%**	**28.8%**	**27.7%**	**26.7%**	**25.4%**	**24.9%**	**23.4%**

TABLE 12-G

DEP ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLES

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a percent.

LINE ITEM	LINE INCLUSION[2]
1.	Peak demand for the Duke Energy Carolinas System as defined in Chapter 3 and Appendix C.
2.	Firm sale of 150 MW through 2024.
3.	Cumulative new energy efficiency and conservation programs (does not include demand response programs).
4.	Peak load adjusted for firm sales and cumulative energy efficiency.
5.	Existing generating capacity reflecting the impacts of designated additions, planned uprates, retirements and derates as of January 1, 2020.
6.	Designated Capacity Additions
	Nuclear uprates: Brunswick 1; 4 MW available for the winter of 2025. Brunswick 2; 6 MW available for the winter of 2028; 10 MW available for the winter of 2030.
7.	Estimated retirement dates for planning that represent most economical retirement date for coal units as determined in Coal Retirement Analysis discussed in Chapter 11. Other units represent estimated retirement dates based on the depreciation study approved in the most recent DEP rate case: Roxboro 3 and 4 (1,409 MW): December 2027 Roxboro 1 and 2 (1,053 MW): December 2028 Mayo 1 (746 MW): December 2028
	All nuclear units are assumed to have subsequent license renewal at the end of the current license.
	All hydro facilities are assumed to operate through the planning horizon.
	All retirement dates are subject to review on an ongoing basis. Dates used in the 2020 IRP are for planning purposes only, unless the unit is already planned for retirement.
8.	Sum of lines 5 through 7.

[2] Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the following year.

LINE ITEM	LINE INCLUSION[3]
9.	Cumulative Purchase Contracts from traditional resources and renewable energy resources not used for NCREPS and NC HB589 compliance. This is the sum of the next two lines.
	Non-Compliance Renewable Purchases includes purchases from renewable energy resources for which DEP does not own the REC.
	Non-Renewables Purchases are those purchases made from traditional generating resources.
10.	New nuclear resources economically selected to meet load and minimum planning reserve margin. No nuclear resources were selected in the Base Case with Carbon Policy in this IRP.
11.	New combined cycle resources economically selected to meet load and minimum planning reserve margin. Addition of 1,224 MW of combined cycle capacity online in December 2027 and December 2028.
12.	New combustion turbine resources economically selected to meet load and minimum planning reserve margin. The case presented has the addition of the following CTs: 457 MW CT in December 2025 457 MW CT in December 2026 913 MW CTs in December 2028
13.	New solar resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected solar facilities. (1% for winter peak and between 25% for total solar < 3,099 MW reducing to 10% for total solar >3,700 MW for summer peak; Solar + Storage is approximately 25% in both summer and winter). The case presented has the addition of the following solar resources: Solar: No Solar Only was selected in DEP in the Base Case with Carbon Policy. Solar + Storage: 38 MW (150 MW nameplate) in years 2030 and 2031. 56 MW (225 MW nameplate) in years 2032 through 2035.
14.	New wind resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected wind facilities. (33% for winter peak 7% for summer peak). The case presented has the addition 71 MW (150 MW nameplate) of wind resources in December 2032 through December 2034.

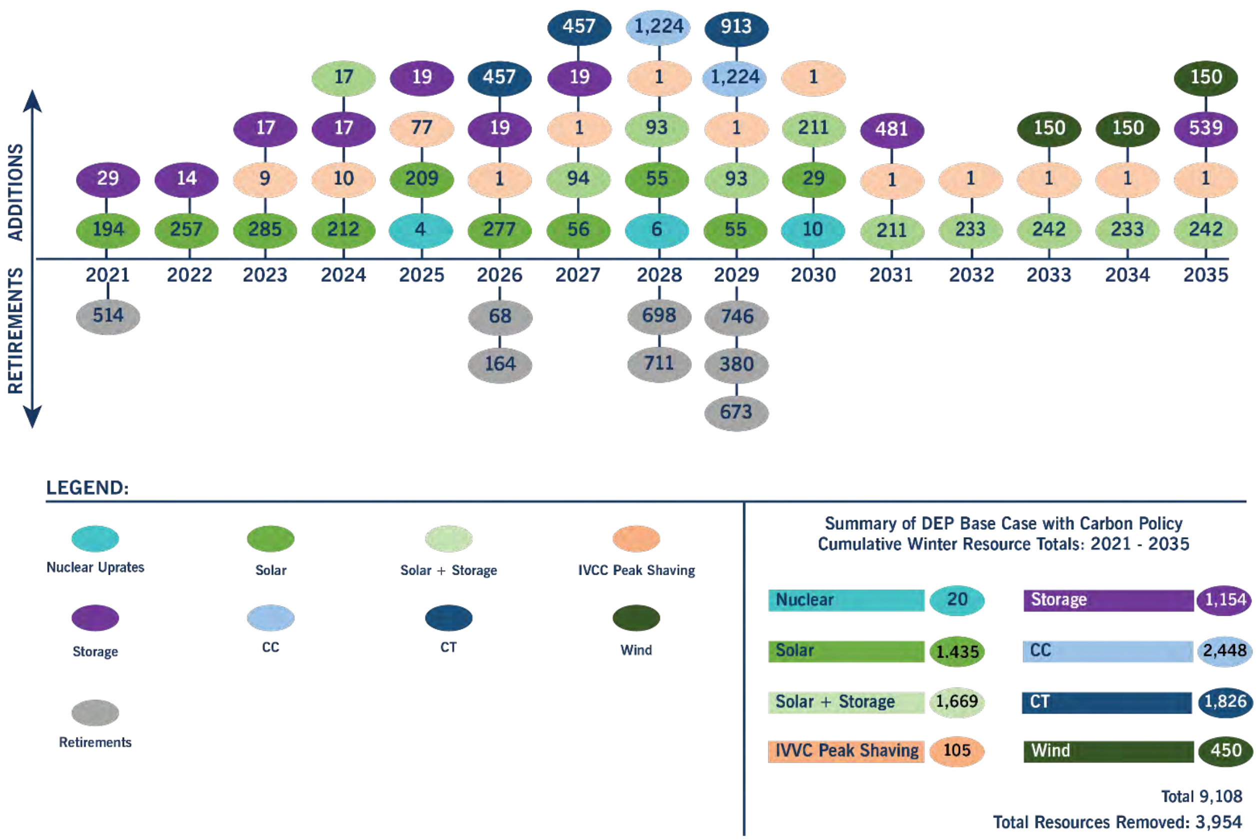
[3] Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the following year.

LINE ITEM	LINE INCLUSION[4]
15.	New battery storage resources economically selected to meet load and minimum planning reserve margin. 481 MW of energy storage in December 2030 and 539 MW of energy storage in December 2034.
16.	Cumulative Renewable Energy Contracts and renewable energy resources used for NCREPS and NC HB589 compliance. This is the sum of the next three lines and the selected cumulative renewable resources in lines 13-15.
	Renewables w/o Storage includes projected purchases from solar energy resources not paired with storage.
	Solar w/ Storage (Solar Component) includes the solar component of projected solar energy resources paired with storage.
	Solar w/ Storage (Storage Component) includes the storage component of projected solar energy resources paired with storage.
17.	Combined Heat and Power projects. There are no CHP projects included in the Base Case with Carbon Policy.
18.	Addition of 134 MW of grid-tied energy storage over years 2021 through 2027.
19.	Cumulative total of lines 8 through 18.
20.	Cumulative demand response programs including wholesale demand response.
21.	Cumulative capacity associated with peak shaving of IVVC program.
22.	Sum of lines 19 through 21.
23.	The difference between lines 22 and 4.
24.	Reserve Margin RM = (Cumulative Capacity-System Peak Demand)/System Peak Demand. Line 23 divided by Line 4. Minimum winter target planning reserve margin is 17%.

A graphical presentation of the Winter Base Case with Carbon Policy resource plan is shown below in Figure 12-F. This figure provides annual incremental capacity additions to the DEP system by technology type. Additionally, a summary of the total resources by technology type is provided below the figure.

[4] Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the following year.

FIGURE 12-F
DEP WINTER BASE CASE WITH CARBON POLICY
ANNUAL ADDITIONS BY TECHNOLOGY



he following figures illustrate both the current and forecasted capacity for the DEP system, as projected by the Base Case with Carbon Policy. Figure 12-G depicts how the capacity mix for the DEP system changes with the passage of time. In 2035, the Base Case with Carbon Policy projects that DEP will have no reliance on coal and a significantly higher reliance on renewable resources and energy storage as compared to the current state. It is of particular note that nearly 50% of the new resources added over the study period are solar, wind and energy storage resources. Natural gas-fired resources continue to be an important part of maintaining the reliability of the DEP system, as well.

As mentioned above, the Company's Base Case with Carbon Policy resources depicted in Figure 12-G below reflects a significant amount of growth in solar capacity with nameplate solar growing from 2,888 MW in 2021 to 4,270 MW by 2035. However, given that solar resources only contribute approximately 1% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 29 MW in 2021 to 43 MW by 2035. Additionally, the Base Case with Carbon Policy includes 450 MW of nameplate wind and nearly 1,200 MW of nameplate energy storage with higher contributions to DEP's winter peak of 47% and 95%, respectively.

FIGURE 12-G
DEP CAPACITY OVER 15-YEAR STUDY PERIOD BASE CASE WITH CARBON POLICY [5]

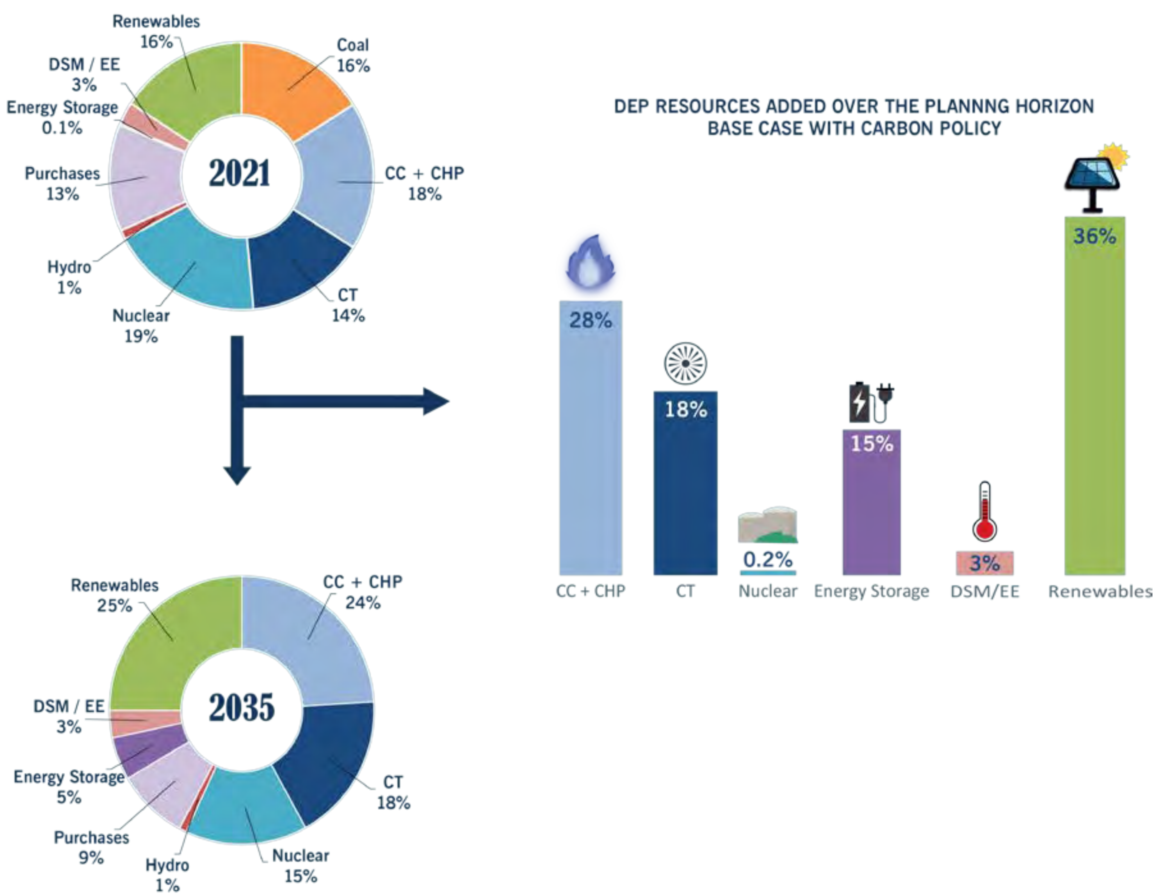
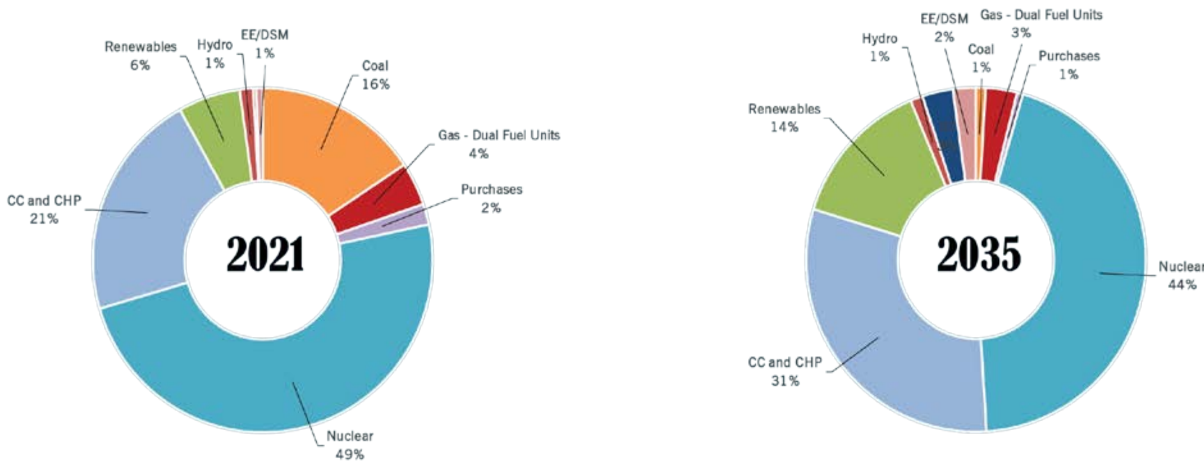


Figure 12-H represents the energy of both the DEP and DEC Base Cases with Carbon Policy over the IRP planning horizon. Due to the JDA, it is prudent to combine the energy of both utilities to develop a meaningful representation of energy for the Base Case with Carbon Policy. From 2021 to 2035, the

[5] All capacity based on winter ratings except Renewables and Energy Storage which are based on nameplate.

figure shows that nuclear resources will continue to serve almost half of DEC and DEP energy needs. Additionally, the figures display a substantial increase in the amount energy served by carbon-free resources (solar, energy storage, solar plus storage and wind). Natural gas continues to remain an economical and reliable source of energy for the Companies while the reliance on coal generation is reduced to only 1%.

FIGURE 12-H
DEP AND DEC ENERGY OVER 15-YEAR STUDY PERIOD – BASE CASE WITH CARBON POLICY [6]



A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Cases and other portfolios are contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2020 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

Base Case without Carbon Policy:

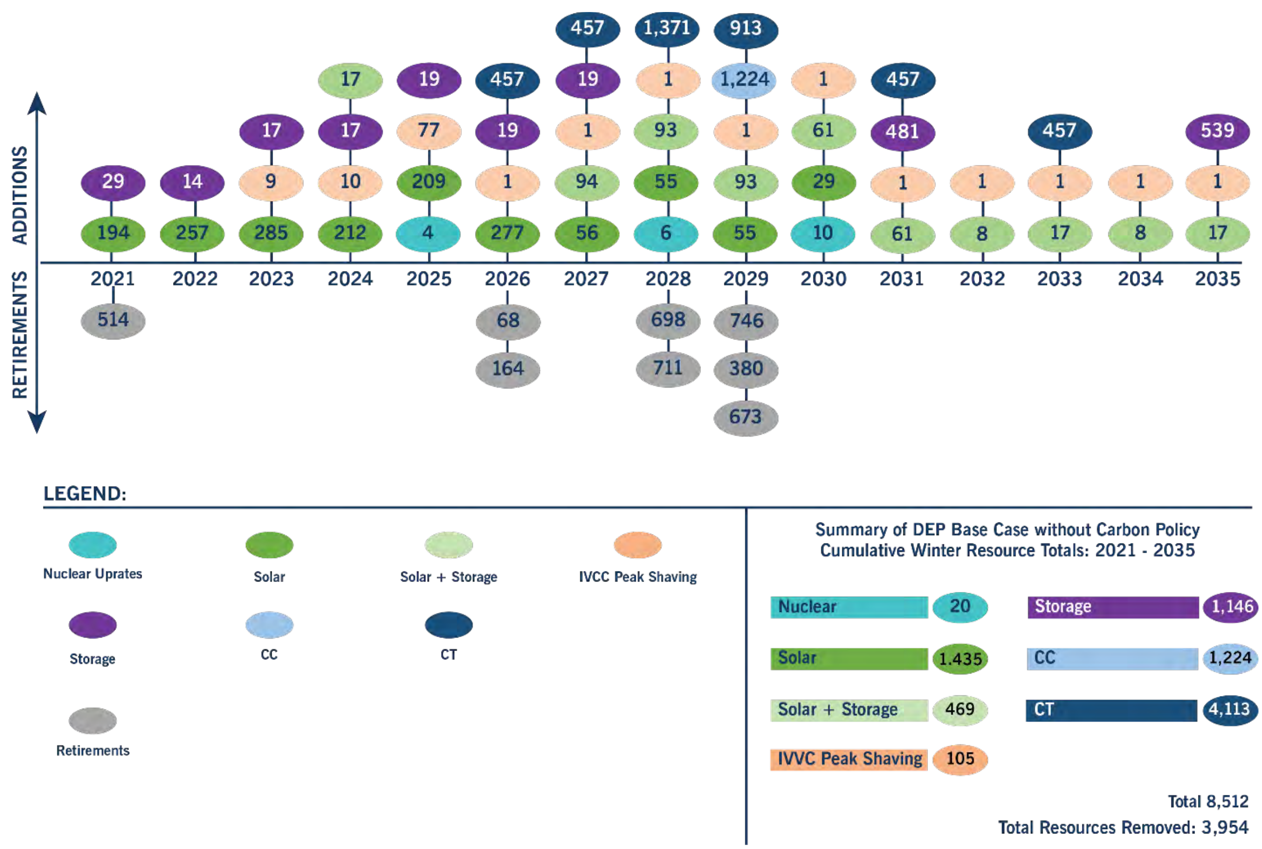
While Duke Energy presents a base resource plan developed under a carbon constrained future, the Company also provides a Base Case without Carbon Policy expansion plan that reflects a future without CO_2 constraints. In DEP, this expansion plan is represented by Portfolio A or the Base Case without Carbon Policy. During the 15-year planning horizon, there is a significant shift toward CT technology as

[6] All capacity based on winter ratings except renewables and energy storage which are based on nameplate.

compared to the Base Case with Carbon Policy. Additionally, no incremental renewable resources were economically selected in this case.

A graphical presentation of the Winter Base Case without Carbon Policy resource plan is shown below in Figure 12-I. This figure provides annual incremental capacity additions to the DEP system by technology type for this case. Additionally, a summary of the total resources by technology is provided below the figure. Further details of the development of the Base Case without Carbon Policy may be found in Appendix A.

FIGURE 12-I
DEP WINTER BASE CASE WITHOUT CARBON POLICY ANNUAL ADDITIONS BY TECHNOLOGY



JOINT PLANNING CASE

A Joint Planning Case that explores the potential for DEP and DEC to share firm capacity between the Companies was also developed. The focus of this case is to illustrate the potential for the Utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity. Rather, this case illustrates the benefits of joint planning between DEP and DEC with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

A discussion of the Joint Planning Case is provided in Appendix A.

13 DEP FIRST RESOURCE NEED

The IRP process provides a resource plan to most economically and reliably meet the projected load requirements and a reasonable reserve margin throughout the 15-year study period. In addition to load growth, planned unit retirements and expiring purchase power contracts contribute to the need for new generation resources.

The resources used to meet the load requirements fall into two categories: Designated and Undesignated. Designated resources are those resources that are in service, projects that have been granted a Certificate of Public Convenience and Necessity (CPCN) or Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN), smaller capacity additions that are a result of unit uprates that are in the Companies' planning budget, firm market purchases over the duration of the signed contract or DSM/EE programs.

Undesignated resources include purchase power contracts that have not yet been executed and projected resources in the IRP that do not have a CPCN or CECPCN granted,

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

Further, solar renewable contracts are broken down into three categories: Designated, Mandated and Undesignated. As discussed in Chapter 5, the definitions of each bucket are below:

FIGURE 13-A

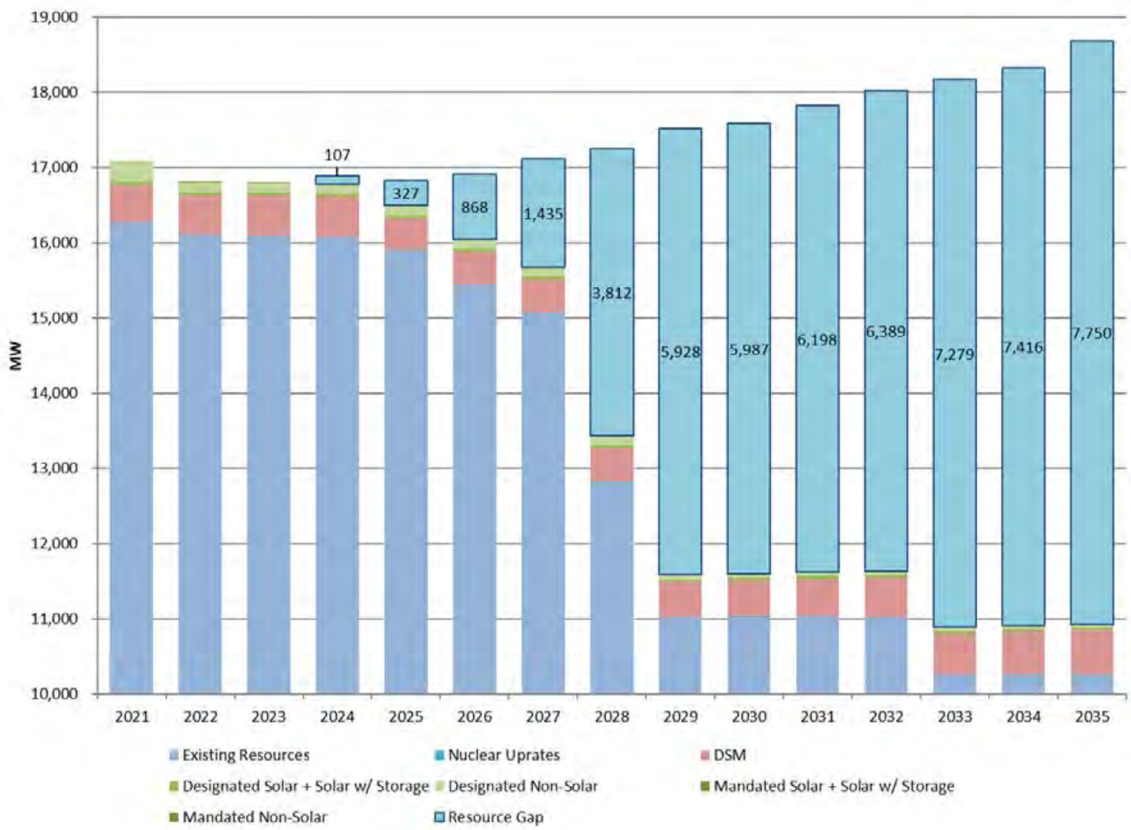
CONTRACT CATEGORIES

Only designated and mandated resources are considered when determining the first need for purposes of the development of standard offer avoided capacity rates. As such, a list of these resources for DEP is below:

- Designated and mandated renewable resources
- Nuclear uprates
- Designated wholesale contracts
- DSM/EE programs

Including only the designated and mandated resources, Figure 13-B demonstrates the first need for DEP is in 2024. To the extent current contracts become executed and move from an undesignated to a designated resource, the timing of the first need will change accordingly.

FIGURE 13-B
LOAD RESOURCE BALANCE FOR DEP FIRST NEED



In the 2019 IRP, the first resource need for DEP was determined to be in 2020. In the 2020 IRP, DEP's first resource need has shifted to 2024 as a result of a Request for Proposal (RFP) solicitation for peaking and intermediate generation resources in the fall of 2018. This RFP resulted in multiple successful contract executions required to meet the near-term DEP resource need.

14 SHORT-TERM ACTION PLAN

The Company's Short-Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

ACCOMPLISHMENTS IN THE PAST YEAR

The following items were completed by DEP and DEC in the last year to support the development of the 2020 IRP:

COMPLETED STUDIES

As previously discussed in the Executive Summary, multiple studies have been completed in the previous year. The results of each of these studies were utilized in the development of the 2020 IRP. Table 14-A is a reproduction of the table presented in the Executive Summary.

TABLE 14-A

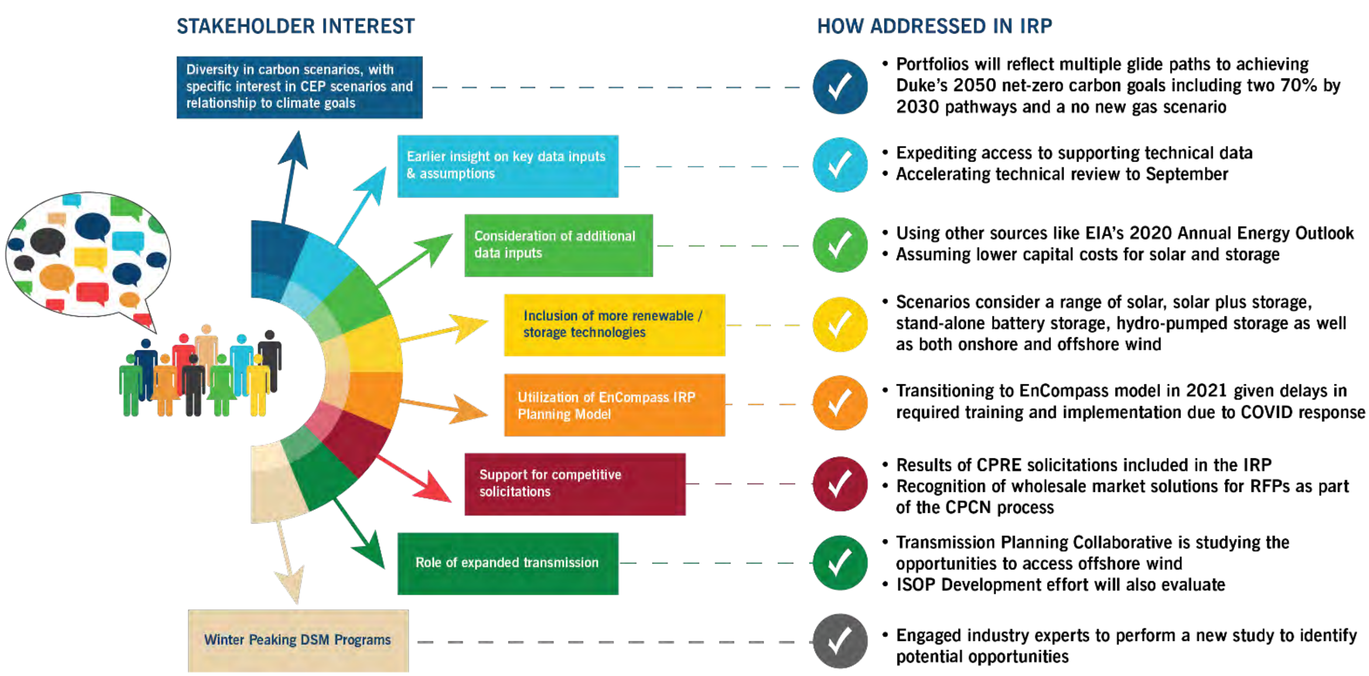
COMPLETED STUDIES INFORMING THE 2020 IRP

STUDY	STUDY REQUIREMENTS
Economic Coal Retirements	• Analysis established the most economic coal unit retirement dates for the Base CO_2 and Base No CO_2 scenarios.
Earliest Practicable Coal Retirements	• Analysis established the earliest feasible coal unit retirement dates. Analysis set aside normal economic considerations and focused on procurement and construction timelines for replacement capacity in order to retire the coal units at the earliest attainable dates.
Resource Adequacy Study/ Reserve Margin Study	• Astrapé Consulting study evaluated reliability based on meeting the one day in ten years loss of load expectation (LOLE) metric.
Storage Effective Load Carrying Capability (ELCC) Study	• Astrapé Consulting study evaluated capacity value of storage under multiple conditions, including its contribution to winter peak and considerations with increasing levels of renewable penetration.
Energy Efficiency and Market Potential Study	• Nexant study evaluated market potential for energy efficiency and demand response initiatives.
Winter Specific DR and Rate Design Benchmarking Study	• Being conducted by Tierra Resource Consultants, Proctor Engineering Group, and Dunsky. Studies the integration of new rate designs and DSM technology with innovative program structures to drive winter peak focused reductions.

IMPLEMENTED COLLABORATIVE STAKEHOLDER ENGAGEMENT PROCESS

Duke Energy implemented an intentional process to collaborate with stakeholders to help shape the development of the 2020 IRP. Stakeholders in North Carolina and South Carolina provided recommendations in the areas of resource planning, carbon reduction, energy efficiency and demand response. 188 unique external stakeholder participants from across the Carolinas participated in this process. Figure 14-A provides a graphical representation of the intention of the stakeholder engagement process, as presented in the Executive Summary.

FIGURE 14-A
STAKEHOLDER ENGAGEMENT



CONTINUED RELIANCE ON EE AND DSM RESOURCES

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEP will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial, and industrial classes.

- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services, such as: (1) adding new or expanding existing programs to include additional measures drawing on insights gained through the updated Market Potential Study, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research & development pilots.

- Continue to seek additional DSM programs employing both rate-enabled and traditional equipment-based measures that will specifically provide load reduction benefits during winter peak situations.

The Company undertook a detailed study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that were outside of the MPS scope. The Company envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort. Over time as new programs/rate designs are approved and become established, the Company will gain additional insights into customer participation rates and peak savings potential and will reflect such findings in future forecasts.

CONTINUED FOCUS ON RENEWABLE ENERGY RESOURCES

DEP is committed to the addition of significant renewable generation into its resource portfolio. Over the next five years, DEP is projecting to grow its renewable portfolio from 3,144 MW to 4,128 MW over the next five years. Supporting policy such as SC Act 236, SC Act 62, NC REPS and NC HB 589 have all contributed to DEP's aggressive plans to grow its renewable resources. DEP is committed to complying with NC REPS, meeting its targets for the SC DER Program, and under HB 589, DEP and DEC are responsible for procuring renewable energy and capacity through a competitive procurement program. DEP/DEC have completed two solicitations under CPRE, resulting in 162 MW of nameplate solar capacity expected in DEP. Planning for the next phase of CPRE activities is underway. These activities will be done in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. The Companies, under the competitive procurement program, are required to procure energy and capacity from renewable energy facilities in an aggregate amount of up to 2,660 MW through request for proposals. Note that the connection of other transition MW can act to replace the required CPRE capacity. DEP and DEC plan to jointly implement the CPRE Program across the NC and SC service territories.

For further details regarding DEP's plans regarding renewable energy, refer to Chapter 5, Appendix E, and Attachments I and II.

INTEGRATION OF BATTERY STORAGE

The Company has begun investing in grid-connected storage systems, with plans for additional multiple grid connected storage systems. These systems will be dispersed throughout its North and South Carolina service territories that will be located on property owned by the Company or leased from its customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale. Also, as directed by the NCUC, the Company has been working with stakeholders to assess challenges and develop recommendations to address challenges related to retrofit of existing solar facilities with energy storage. A report on this matter is expected to be filed in September 2020. Finally, as noted in the table of studies above, the Company engaged Astrapé Consulting to perform a study to assess the incremental change in Effective Load Carrying Capability of battery storage as more batteries are added to the system. This report is further described in Chapter 6, Appendix H and Attachment IV.

Additionally, DEP plans to deploy the 9 MW Asheville-Rock Hill energy storage facility in Asheville, NC in 2020. See Appendix N for further information.

IVVC IMPLEMENTATION AS PART OF THE GRID IMPROVEMENT PLAN

IVVC is part of the proposed Duke Energy Progress Grid Improvement Plan (GIP) and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid.

If the GIP is approved for DEP in 2022, the current Distribution System Demand Response (DSDR) program will be rolled into the IVVC program by the year 2025 and will contain both its current peak-shaving capability (MW) and a Conservation Voltage Reduction (CVR) operational mode that will support energy conservation across the majority of hours of the year versus only peak shaving and emergency conditions of the current program. A detailed discussion of IVVC may be found in Appendix D.

CONTINUE TO FIND OPPORTUNITIES TO ENHANCE EXISTING CLEAN RESOURCES

DEP is committed to continually looking for opportunities to improve and enhance its existing resources. DEP is expecting capacity uprates to its existing nuclear units, Brunswick and Harris, due to upcoming projects at those sites. The uprates total 20 MW and are projected to occur from 2025 to 2030.

ADDITION OF CLEAN NATURAL GAS RESOURCES [1]

- The Company continues to consider advanced technology combined cycle and combustion turbine units as excellent options for a diversified, reliable portfolio required to meet future customer demand. The improving efficiency and reliability of CCs coupled with the lower carbon content and continued trend of lower prices for natural gas make these resources economically attractive as well as very effective at enabling significant carbon reductions through accelerated economic coal retirements. As older units on the DEP system are retired, CC and CT units continue to play an important role in the Company's future diverse resource portfolio.

    - Two 1x1combined cycle units (each with one CT and one steam turbine, for a total capacity of 560 MW winter / 474 MW summer) began full operation [2] by April 2020. These efficient units will assist in providing reliable energy to DEP's customers.

A summarization of the capacity resource changes for the Base Plans in the 2020 IRP is shown in Table 14-B below. Capacity retirements and resource additions are presented in the table as incremental values in the year in which the change impacts the winter peak. The values shown for renewable resources, EE, DSM and IVVC represent cumulative totals.

[1] Capacities represent winter ratings.
[2] Asheville CC individual components began commercial operation at various dates between 12/27/19 and 4/5/20.

TABLE 14-B

2020 DUKE ENERGY PROGRESS SHORT-TERM ACTION PLAN (1) (2)

BASE CASE WITH CARBON POLICY

				RENEWABLE RESOURCES (CUMULATIVE NAMEPLATE MW)				
YEAR	RETIREMENTS (6)	ADDITIONS (3)	SOLAR (4)	SOLAR WITH STORAGE (5)	BIOMASS / HYDRO	CUMULATIVE EE	DSM	IVVC (6) (7)
2021	514 MW Darlington CT 1-4, 6-8, 10	30 MW Energy Storage 560 MW Asheville CC	2,888	0	284	43	507	0
2022		15 MW Energy Storage	3,144	0	146	78	517	0
2023		18 MW Energy Storage	3,430	0	135	111	521	9
2024		18 MW Energy Storage	3,641	14 w/ 3 Storage	131	141	519	19
2025		20 MW Energy Storage 4 MW Nuclear Uprate	3,850	14 w/ 3 Storage	131	185	329	96

(1) Capacities shown in winter ratings unless otherwise noted.
(2) Dates represent when the project impacts the winter peak.
(3) Energy storage is grid-tied storage and represents total usable MW.
(4) Capacity is shown in nameplate ratings and does not include solar coupled with energy storage.
(5) Solar coupled with storage; storage only charged from solar.
(6) Integrated Volt Var Control represents cumulative impacts.
(7) DSM declines as IVVC ramps up. IVVC replaces existing DSDR program.

CONTINUE WITH PLAN FOR SUBSEQUENT LICENSE RENEWAL OF EXISTING NUCLEAR UNITS

In September 2019, Duke Energy announced its intent to pursue SLR for all eleven nuclear units in the operating fleet. The Oconee SLR application will be submitted first, in 2021. An SLR application takes approximately three years to prepare and approximately two years to be reviewed and approved. The first DEP nuclear unit to require an SLR application is Robinson 2, where the current license is set to expire in 2030.

CONTINUED TRANSITION TOWARD INTEGRATED SYSTEMS AND OPERATIONS PLANNING

As explained further in Chapter 15, the concept of ISOP remains on the path as described in the 2019 IRP filed in NC and SC. The Company continues to view this effort as an important and necessary evolution in electric utility planning processes. The Company remains committed to the goal of implementing the basic elements of ISOP in the 2022 IRPs for the Carolinas. This timeline is based on the Company's perspective that declining costs of distributed resources, including energy storage and advanced demand response options will increasingly create opportunities late in this decade and beyond to defer or potentially even avoid traditional "wires" upgrades and, in some cases, help to offset needs for building generation resources.

CONTINUED COMMITMENT TO MEETING THE COMPANY'S CARBON PLAN

As discussed throughout this IRP document, DEP is committed to meeting Duke Energy Corporation's Carbon Plan. All six of the key portfolios outlined in the Executive Summary keep Duke Energy on a trajectory to meet its near-term enterprise carbon reduction goal of at least 50% by 2030, and long-term goal of net-zero by 2050. See Chapter 16 for additional discussion on the net-zero carbon goal. As part of Duke Energy's long-standing commitment to carbon reductions, older coal and CT units have been retired and replaced with cleaner renewable energy resources and advanced CC and CT units. The overall effort includes the following elements:

- Retire older coal generation.
  - As of December 2013, all of DEP's older, un-scrubbed coal units have been retired.

- To date, DEP has retired approximately 2,300 MW of older coal units in total since 2011.

- Two Asheville coal units (350 MW winter / 344 MW summer) were retired at the end of January of this year. Asheville units 1 and 2 operated reliably for 55 and 48 years, respectively.

- Retire older CT generation.
  - As of April 2020, DEP has retired approximately 1,000 MW of older CT generation since 2011. The most recent retirements include:

    - Darlington Units 1-4, 6-8 and 10 (514 MW) retired in March of 2020. At the time of retirement, the Darlington units provided reliable generation to DEP's customers for approximately 46 years.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals (CCR) rule, the Cross-State Air Pollution Rule (CSAPR), and any future federal or state carbon reduction policies.

WHOLESALE

- Over the next five years, DEP has approximately 425 MW of purchased power contracts that expire under the current contract terms. The Company plans to engage the marketplace to determine the feasibility of extending existing contracts or replacing them with other purchased power arrangements to economically meet customer demand.

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

REGULATORY

- Continue to monitor energy-related statutory and regulatory activities.
- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

DEP REQUEST FOR PROPOSAL (RFP) ACTIVITY

This section provides a status of any traditional and renewable energy RFP activity since the last biennial IRP.

DUKE ENERGY PROGRESS CAPACITY AND ENERGY MARKET SOLICITATION

DEP identified a near-term need for approximately 2,000 MW of firm dispatchable peaking/intermediate capacity and energy resources resulting from existing traditional purchase power contract expirations. A capacity and energy market solicitation was released on August 27, 2018 and closed on September 24, 2018.

DEP received a strong response to this RFP. As a result, multiple contracts have been successfully executed to meet DEP's near-term capacity needs.

COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE)

Pursuant to N.C. Gen. Stat. § 62-110.8, DEP has completed the first RFP solicitation under the Competitive Procurement of Renewable Energy Program and is currently in the contracting phase for the second RFP. In summary, the final results from Tranche 1 and the initial results from Tranche 2 have been successful, procuring approximately 162 MW of resources at prices below administratively-established avoided costs. Details concerning the CPRE program can be found in the annual CPRE Program Plan filing, which is Attachment II to this document.

15 INTEGRATED SYSTEM & OPERATIONS PLANNING (ISOP)

The concept of ISOP remains on the path as described in the 2019 IRP filed in NC and SC. The Company continues to view this effort as an important and necessary evolution in electric utility planning processes to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles (EVs). The anticipated growth of Distributed Energy Resources (DERs) necessitates moving beyond the traditional distribution and transmission planning assumption of one-way power flows on the distribution system and analysis based on limited snapshots of peak or minimum system conditions. As the grid becomes more dynamic, analysis of the distribution and transmission systems will need to account for increasing variability of generation and two-way power flows on the distribution system, which requires significant changes to modeling inputs and tools. The Company remains committed to the goal of implementing the basic elements of ISOP in the 2022 IRPs for the Carolinas. This timeline is based on the Company's perspective that declining costs of distributed resources, including energy storage and advanced demand response options will increasingly create opportunities late in this decade and beyond to defer or potentially even avoid some traditional "wires" upgrades and, in some cases, help to offset needs for building generation resources.

The advancements in planning tools through the ISOP initiative also open new possibilities for analysis to help identify transmission and distribution infrastructure opportunities from a more holistic perspective. In the current regulatory paradigm, utilities provide first come, first serve access to resource developers and utility participants that request system interconnections where their projects seem best suited. This paradigm tends to result in the utility systems evolving incrementally based on the requests they receive, in the order received, in contrast with a system plan that could be developed reflecting the desired energy resource mix over the longer term. Over time, there may be the opportunity to evolve to a longer-term grid planning approach as contemplated here, but it is important to recognize that this type of transition would affect many stakeholders and would require constructive regulatory support to consider these changes. These ideas reflect some of the longer-term strategic concepts that are being considered in the development of the new ISOP advanced planning tools and processes.

DISTRIBUTION CIRCUIT LEVEL FORECASTING

Historically, distribution planners have used historical peak snapshots along with an expected growth factor to assess circuit capacity needs. To assess the potential for non-traditional solutions such as energy storage or other DERs, hourly time-series forecasts are needed at the circuit level to analyze the expected load profile, including how it could change over time as a function of residential, commercial or industrial growth, or adoption of net load modifiers such as energy efficiency, rooftop solar, and electric vehicles. This effort involves a significant time and resource commitment to gather the necessary input data and build the forecasting models required to support this extensive level of granular forecasting. Over the past year, the Company has developed models to enable derivation of hourly forecasts for the distribution circuits in the Carolinas covering a ten-year horizon. These models are currently in a cycle of validation and refinement, with the expectation to progressively roll the forecasts out to distribution planners throughout 2021 to support testing of the Advanced Distribution Planning toolset.

ADVANCED DISTRIBUTION PLANNING (ADP)

As noted above, distribution planners have traditionally analyzed historical peak snapshots. More dynamic grid conditions driven by distributed resources and circuit switching capability require more complex hourly power flow analysis to study the effects of DERs and assess the effectiveness of both traditional and non-traditional solutions (or combinations of solutions). Duke has continued its work with CYME, an industry leader in distribution modeling, to develop an ADP tool capable of performing these detailed analyses and supporting evaluation of both traditional and non-traditional solutions on the system. The development and testing effort over the past year has largely focused on automation and integration to make complex evaluation processes more efficient for the planners. The project remains on-track for the basic ADP functionality to be progressively rolled out to DEC and DEP distribution planners for testing and validation beginning in late 2020 and throughout 2021. Subsequent development efforts will focus on broadening the data available to planners, improving the efficiency of the modeling systems through integration and automation, and adding more robust capabilities such as multi-circuit analysis and combinations of traditional and non-traditional solutions, etc.

The new functionality of the ADP toolset will enable planners to evaluate DERs (including energy storage) as a potential solution for capacity needs and identify the most likely hourly patterns where potential new DERs would be needed to address local issues. These DER profiles could then be included as an input to transmission and generation planning processes to further assess potential value at the transmission and bulk generation levels. The growth in the scope and volume of the detailed data required to perform these new integrated planning studies is driving the need for much more coordination between planning groups and integration between the respective models across distribution, transmission, and generation planning.

While the ADP development effort is underway, the Company has also worked on developing screening processes to efficiently identify distribution upgrade needs that could potentially be deferred with non-traditional solutions. This process provides an opportunity to study a variety of potential energy storage use cases and better understand the steps that would be needed to perform a more detailed analysis for any candidates of interest that did appear. In this initial analysis of existing traditional distribution projects, 3% of the population was found to be suitable for further study, which is ongoing. It should be noted that the screening process at this stage uses relatively generous assumptions to avoid screening out a potential high value candidate prior to gaining experience and refining the process through detailed studies.

As part of the Company's broader industry engagements, the ISOP and ADP teams participated in a multi-utility collaborative study in the first half of 2020 led by the Smart Electric Power Alliance (SEPA) on Integrated Distribution Planning. The feedback the Company received in this forum along with review of SEPA's draft publication which should be released in the near future increases the Company's confidence in its approach to ADP.

INTEGRATION WITH TRANSMISSION PLANNING PROCESSES

To complement existing NERC Standard and FERC Order compliance-based Transmission Planning processes, the Company is developing new modeling capabilities for examining long term transmission needs and DER integration on the grid at an hourly granularity using some of the advanced features of an industry standard third-party DC power flow model. Accomplishing this additional level of detailed analysis requires extensive development work to integrate models and data sources and allow for hourly power flow analysis to complement the industry standard third-party AC power flow model used for transmission planning today. The DC power flow analysis is being developed for screening over broad time periods to help planners identify specific time periods and operating conditions that may warrant more detailed AC power flow analysis using the conventional transmission planning tools.

These enhanced new transmission modeling tools and processes will be used to support comprehensive assessments of transmission needs as the system evolves with coal plant retirements and significant growth of distributed energy resources. These studies, in concert with regional and interregional planning studies, will help planners find ways to optimize the use of existing grid capabilities and plan cost effective options to upgrade grid capabilities needed to support integration of the array of new resources necessary to meet the clean energy planning objectives. These new tools being developed and deployed as part of the ISOP program are critical to answering important questions about how the utility will integrate diverse energy resources to reliably serve customers in the future and how the utility will balance economic priorities in this transition.

Over the last year, the Company has also worked on developing screening processes to efficiently identify transmission upgrade needs that could potentially be deferred with non-traditional solutions. Going through this process also helps to build shared understanding among the team regarding potential energy storage use cases and the opportunities and challenges of adding value through multiple use cases. In this initial screening analysis of current transmission projects in early development, none were found to be both cost-effective and technically viable. While this result was expected in light of near-term energy storage costs, it should not be considered indicative of long-term opportunities. As noted in Chapter 6, the cost of energy storage is projected to decline by about 50% by 2030, which would significantly improve opportunities for non-traditional solutions.

ENHANCED RESOURCE PLANNING AND ISOP OPTIMIZATION

To successfully examine pathways to meet clean energy objectives in the manner envisioned in ISOP, it is critical to consider the mix of both centralized and distributed energy supply resources in use over the planning period and examine the interactions of the energy resources with the delivery systems to ensure that energy can be efficiently managed and delivered on the grid. Creation of this collaborative planning process with Distribution and Transmission Planning also relies on complementary development efforts in the Resource Planning area to address broader planning challenges. In Resource Planning, the capacity expansion model and hourly production cost model provide planners the tools they need to explore a wide range of resource portfolios while performing optimization and detailed production cost studies to fully understand the behavior and costs of the system. To meet the rigors of the new planning challenges, the modeling tools and processes also need to allow planners to examine carbon compliance regimes, operational impacts of increasing levels of variable resources, utilization of different types of storage, applications of resources to address ancillary system needs and many other facets of future operations.

In 2020, the Company elected to move forward with deploying the EnCompass suite of resource planning models from Anchor Power Solutions to address these enhanced planning needs. The plans to shift to the new model were based, in part, on feedback from stakeholders as part of the IRP development process. The ISOP and Resource Planning teams are also working with the Fuels and System Optimization (FSO) Analytics team to study the effects of perfect foresight on production cost modeling results and explore the benefits of including their sub-hourly modeling and stochastic analysis to further refine modeling results for fast responding generation resources and storage to meet operational needs in the future with higher levels of variable renewable generation. The issue of "perfect foresight" in production cost modeling is addressed in more detail in Chapter 16.

Transitions to new models and functionality require time and substantial testing and integration efforts, which are currently underway with a goal of formally switching to EnCompass during the fourth quarter of 2020. As the Resource Planning team gains familiarity with these new tools, ISOP will also be assisting with development of new planning processes to support the collaboration between Resource Planning and the other planning disciplines and working toward integrating the new processes being developed in each of these areas. These integration efforts will involve development to support integration of modeling systems and also harmonizing inputs and coordinating planning cycles between the planning disciplines to allow for better flow of information and data required to produce the integrated planning results.

ISOP STAKEHOLDER ENGAGEMENT

Outreach has been and remains an important part of the ISOP effort. The Company's ISOP team has been gathering input from other utilities, national labs, EPRI, consultants, and academic groups to inform our vision and work-scope to better address the challenges of modeling renewables and energy storage at both the distribution and transmission levels. There is also interest in these ISOP development efforts from our regulators and customers, as well as environmental advocates, business interest groups, and other stakeholders. Duke initiated a series of stakeholder engagements in late 2019 to help address these interests, supported by ICF, an industry-leading consultant in advanced integrated planning and regulatory engagement.

The first stakeholder workshop in Raleigh on December 10, 2019 was well attended and provided a face-to-face opportunity for stakeholders to gain some insights from ICF on how integrated planning is unfolding across the industry, learn more about ISOP's development plans, and hear about some of the development work streams underway at that time. It also provided Duke participants with an opportunity to hear input and feedback from several of our stakeholders and to engage in discussions on what is important to them and to the participants who attended. Several stakeholders constituting a diverse set of viewpoints participated in two panel sessions that helped ensure the workshop communication and information transfer was multidirectional. Considering the complexity of the subject matter and the initial nature of stakeholder engagement, it was a very successful kick-off event.

The ISOP/ICF team subsequently hosted two stakeholder webinar sessions on January 30, 2020 and March 20, 2020 to continue discussions on our progress and introduce additional industry and ISOP topics for review and discussion with stakeholders. These exchanges provided productive opportunities for stakeholder feedback and discussions and helped support Duke's focus and priorities for future stakeholder sessions, as well as the information and services that will ultimately be shared as a result of ISOP efforts. All of the materials shared in these sessions and recordings of the sessions themselves are posted on the ISOP Information Portal[1] online for participants and other interested parties to review.

[1] https://www.duke-energy.com/our-company/isop.

As part of the broader ISOP stakeholder engagement effort, the Company has collaborated with North Carolina Electric Membership Corporation (NCEMC) to exchange ideas related to ISOP. As an extension of this collaboration, NCEMC has been working with the Company to improve coordination between the customer's Distribution Operator and the Company's Transmission Operator, and the two parties have developed a plan for coordinated testing of the wholesale customer's advanced DR and DER program for reliability coordination and local loading relief effects at the distribution and transmission levels. The parties have agreed to continue this collaboration beyond these initial steps as the ISOP process evolves to ensure that planning and operations are aligned. The Company will pursue additional ISOP-related interactions with other Distribution Operators within the balancing areas as future opportunities are identified through the normal course of outreach to these stakeholders.

ISOP hosted its second stakeholder workshop – a "Virtual Forum" due to pandemic safety concerns – on August 21, 2020 to update stakeholders on the continuing progress of the ISOP program and engage in more dialogue relating to what stakeholders consider important. A group of stakeholders presented on their desired outcomes from ISOP, which helped frame the different types of impact that ISOP could ultimately have, as well as further educate Duke participants on key issues that may be taken into consideration as the ISOP development process continues to unfold. All of the materials shared in the final session and recordings of the presentations will also be posted on the ISOP Information Portal online for participants and other interested parties to review. ICF will summarize the overall stakeholder engagement effort in a final, public-facing report in the fourth quarter of 2020.

The Company plans to provide future updates to stakeholders regarding the ISOP initiative through virtual webinars as our development effort progresses toward the initial introduction of ISOP processes in the 2022 IRP. To help with managing expectations, it is worth reiterating that technology costs, supply chain, regulatory policy, and other challenges may require five to ten years for non-traditional solutions to become competitive options on a regular basis. Given the lead time to implement and refine complex new analytical processes as well as the importance of these efforts to support an affordable and reliable transition to net-zero carbon, it is critical to continue investing in this important work.

16 SUSTAINING THE TRAJECTORY TO REACH TO NET-ZERO

This chapter discusses, in qualitative terms, key elements needed to accelerate CO_2 reductions and sustain a trajectory to the Company's net-zero carbon goal, some which are at or beyond the fifteen-year horizon of the IRP. In 2019, the Company announced a corporate commitment to reduce CO_2 emissions from power generation by at least 50 percent from 2005 levels by 2030, and to achieve net-zero by 2050. This shared goal is important to many of the Company's customers and communities, many of whom have also adopted their own clean energy initiatives. The Company has already made significant progress by reducing CO_2 emissions by 39% across its entire seven-state territory since 2005, well ahead of the industry average of 33%.

The Company also released the Duke Energy 2020 Climate Report in April 2020, which offered insights into the complexities and opportunities ahead and provided an enterprise-level scenario analysis with an illustrative path to net-zero. Among the key elements identified for the path to net-zero carbon were:

- Investments in the grid to allow significant growth in renewables and energy storage, including a transition to intelligent grid controls to support growth of distributed resources and increased customer options,
- Advancement of planning tools and integration of planning processes to address the increasingly complex and dynamic grid and leverage the potential of energy storage and innovative customer programs and rate designs (see Chapter 15),
- Advancements in demand side management and energy efficiency (see Chapter 4 and Appendix D),
- Natural gas as a component of near-term opportunities for lower cost accelerated coal retirements,
- Advancement of Zero Emitting Load Following Resource (ZELFR) technologies, to be ready for commercial operation by the mid-2030s

- Continued operation of the existing nuclear fleet,
- Consideration of pace and trajectory of CO_2 reduction relative to impacts on affordability and reliability for customers,
- Supportive policies to allow increased pace of interconnection and accelerated transmission and distribution infrastructure, and,
- Supportive policies for CO_2 reduction.

Support for a number of these elements has been evident in a variety of the Company's stakeholder engagement efforts. Key elements above that have been addressed in other Chapters of this IRP are referenced accordingly, while others are addressed below.

TRANSFORMATION OF THE ELECTRIC GRID

The nation's electric delivery system design is more than 100 years old, and much of the equipment installed across the country has been in place for decades. Since conventional generation resources have historically benefitted from economies of scale, the electric grid was designed to transport electricity from large centralized generation plants to customers. These centralized plants provided critical voltage support, and the downstream distribution system was designed for a one-way power flow from the transmission level down to the customer. This fundamental infrastructure is still the basis for the grid today, which has limitations in its capability to seamlessly integrate large amounts of renewable energy sources or fully leverage distributed resources, such as batteries at the local circuit level.

As the Company continues its shift away from traditional coal-fired generation sources in the Carolinas, the transmission and distribution grid infrastructure and associated control systems will need to transition to a more highly networked system capable of dynamically handling two-way power flows resulting from broader deployment of distributed energy resources and supporting new ways in which customers will consume energy. As a transformation to cleaner energy is occurring, customers' energy utilization is also expected to evolve in different ways through advancements in new customer options and movement toward electrification of transportation and other sectors of the economy.

These trends coupled with significant increased utilization of variable renewable energy sources and retirement of resources that have historically provided critical voltage support and full dispatchability over long durations help highlight the challenges ahead for utilities to identify and develop the grid infrastructure and interconnected resources that can efficiently and reliably serve customers' energy needs while also supporting CO_2 reductions.

Some of these emerging needs are already impacting the Company's planners and operators, but the transition needed to achieve carbon neutrality will introduce much more significant challenges. The Company has been proactive in identifying these trends and taking steps to develop the needed grid capabilities and in adapting Duke's planning processes with the Integrated System and Operations Planning (ISOP) initiative. These initiatives recognize the traditional one-way power flow capacity planning approach must be adjusted to reflect the need for flexible and advanced control systems to handle a much more dynamic grid. Keeping the grid running reliably is a balancing act, where the amount of power put into the grid must equal the amount taken out in real time. The utility's control systems continuously ramp central station generating units up or down to meet electric demand of the customers it serves. With the growing contribution of renewable energy sources, which have variable output from minute to minute, this balance becomes increasingly challenging to maintain. In a similar way, as distributed generation becomes more prevalent on circuits, it becomes necessary to introduce localized intelligent control systems that can also contribute at the system level.

Today, the Company is working to build these capabilities through its grid investments that begin to lay a critical foundation for embracing large amounts of private renewable energy. These investments include:

1) Self-optimizing grid (SOG) which fundamentally redesigns key portions of the distribution system and transforms it into a dynamic, smart-thinking, self-healing grid that can accommodate two-way power flows generated by the increased utilization of distributed resources.

2) Integrated Volt-Var Control (IVVC) will allow the Company to more closely monitor and control the voltage on the distribution system and more effectively manage voltage fluctuations due to intermittency of renewable energy sources, while enabling energy and peak demand savings to the Company's customers over time.

3) Distribution automation, which leverages modern and often remotely operated equipment that supports continuous system health monitoring.

4) Transmission system intelligence, which improves system device communication capabilities enabling better protection, monitoring and optimization of system health and equipment.

5) Advanced Metering Infrastructure (AMI) that enables net metering while also providing the data necessary to better understand customer usage and develop enhanced customer programs.

6) Advanced Distribution Planning (ADP) tools and analytic processes that will help enable the integrated system operations planning process needed to optimize future investment decisions in the distribution system as next-generation technologies emerge and advance to become cost-competitive relative to traditional distribution investments.

7) Battery storage at the substation level can help with reliability and potentially balance and optimize load during peaks as well as low renewable periods to maximize carbon free generation on a circuit level.

These represent foundational, no-regrets investments that equip the grid with capabilities and tools to successfully transition from legacy one-way circuits to modern two-way power flow circuits. This foundation enables the legacy electric grid to better support carbon reductions by allowing increased integration of distributed resources and advancement of programs to leverage flexible demand, while also enhancing circuit resilience to withstand and recover from extreme weather events.

Leveraging the ISOP process and the Advanced Distribution Planning (ADP) tool for analysis and prioritization will be key for making sound economic choices at the circuit level complementing transmission and generation capacity needs. There are opportunities to advance a greener circuit design process to combine and coordinate with customer-facing programs to enhance peak demand control of customer loads, enable DERs, and support electric vehicle growth. Managing cost drivers for maintaining the grid while meeting carbon reduction goals is a key value opportunity.

Embracing demand response through advanced customer options with load-shaping programs is an essential element in the overall effort to reach the shared interest goal of net-zero CO_2 emissions, making it easier for customers to manage their energy usage and carbon footprint while supporting a greener grid and power supply. To accomplish this, the local grid must become more responsive, requiring intelligent, robust controls and customer programs that help to optimize DER integration. This vision would include supporting customer programs for managing and coordinating home and fleet EV battery charging. Managed EV charging is an emerging and valuable tool to support lower carbon emissions by reducing existing load peaks and eliminating risks from new ones, such as the transportation sector.

Over time, applying a holistic, customer-focused design approach combining advanced circuit monitoring and control capabilities with innovative customer programs and rate designs will further reduce customer outage impacts while also enabling a more sustainable, efficient and greener grid. As new opportunities are identified, the ISOP process will ensure balanced choices that manage cost, while growing the DER portfolio and enabling customers with clean, renewable energy options.

BUILDING ON SUCCESS AND SUSTAINING THE TRAJECTORY TO REACH NET-ZERO

The Company has made strong progress reducing CO_2 emissions since 2005, achieving a 38% reduction across the combined DEC/DEP systems between 2005 and 2019 – well ahead of the industry average of 33%. This progress is notable considering that Duke Energy's carbon intensity in the Carolinas was already low in 2005 relative to the industry average due to the significant contribution of emissions-free nuclear energy. Over this timeframe, the Company has retired nearly 4 GW of coal resources in the Carolinas. These retirements were primarily enabled by replacement with modern efficient natural gas combined cycle generation, which reduces emissions by more than 50% for each MWh replaced while maintaining affordability and reliability for customers. The replacement of coal with gas resources has been the single largest factor contributing to the Company's success in reducing the combined DEC/DEP CO_2 emissions. The Company has also interconnected nearly 4GW of renewable generation over the past decade, supporting the Carolinas emergence as a national leader in solar capacity. Comparing the level of generation from these renewables in 2019 to average carbon emissions of dispatchable resources that would have otherwise been used to balance customer demand, the renewable resources contributed approximately 11% of the 38% carbon reduction.

While the contribution to carbon reduction from renewables is smaller than that of natural gas, both resources play important roles in the overall reduction of 38%. There is a learning opportunity in this experience. In adding roughly equivalent amounts of natural gas combined cycle and solar generation, the ability of natural gas combined cycle generation to displace the coal generation at much higher capacity factors drove the significantly larger portion of the 38% carbon reduction while keeping customer costs low. Finding the right balance between accelerating the pace of emissions reductions and new technology deployment while maintaining affordability for customers will continue to be an important consideration moving forward.

Although natural gas has and could continue to play a key role in accelerating coal retirements cost effectively[1], that role is expected to gradually change over the life of the natural gas assets, as noted in the Company's 2020 Climate Report. During the IRP Stakeholder process, some stakeholders voiced concerns about the risks of new gas generation assets becoming stranded. This was addressed by running a stress test case with an assumption of a shortened twenty-five-year life for natural gas units. With this assumption, the capacity expansion model continued to select natural gas units for the Base cases. There is also the possibility that generation, transport, and utilization of green hydrogen could become economic and extend the life of gas assets while reducing or eliminating carbon emissions. Blends of up to 10% hydrogen should be possible with the existing gas fleet with minimal tuning required, and new gas turbines are being designed for much higher capabilities of up to 100% hydrogen without modifications. The Company is partnering with Siemens and Clemson University on a proposal for a DOE study on the use of hydrogen for energy storage as a first step in exploring these opportunities.

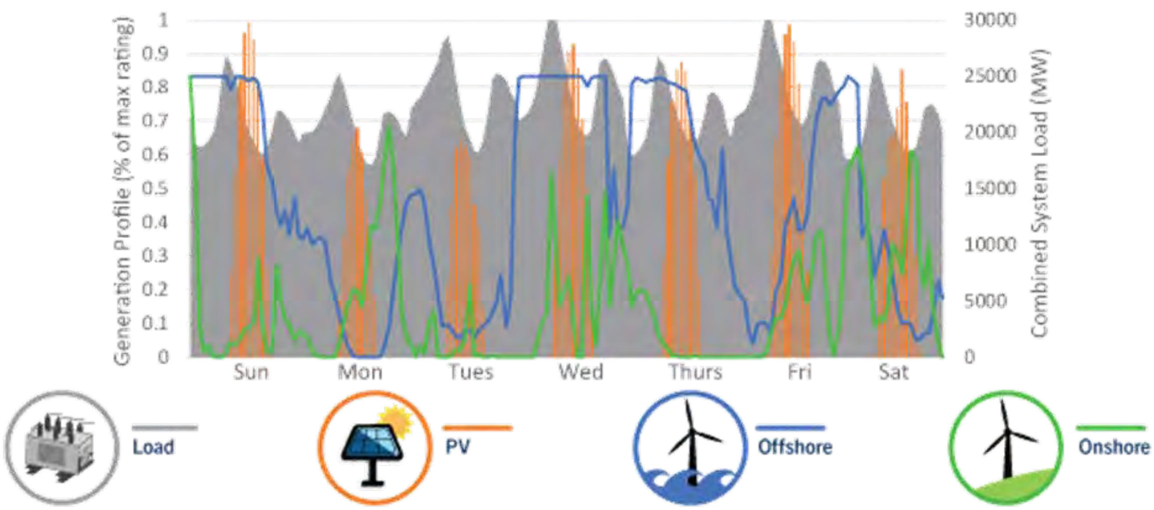
PACE OF ADOPTION AND BENEFITS OF RESOURCE DIVERSITY

Moving forward, it will be important to consider both the pace of adoption and the benefits of portfolio diversity to mitigate risks of being too dependent on a small group of technologies. The graph below illustrates the benefits of adding offshore wind and, to a lesser extent onshore wind to improve the contribution of renewables to winter peak demand, which drives the resource planning process. For these emerging technologies, a measured pace of adoption can simultaneously promote technology development and operational experience with new technologies, while also allowing customers to benefit from price declines over time. Also, as shown by the NREL Phase 1 Carbon Free Resource study, as more of a given type of renewable resource is added to the system, the energy benefit diminishes, which reinforces the benefits of favoring diversity among renewable resources as the level of installed renewables increases. The Company continues to work with NREL and stakeholders to better understand the potential impacts of high renewable portfolios as well as the benefits of improving the diversity of renewables by evaluating onshore and offshore wind. For this reason, the Company has included both onshore and offshore wind in this IRP, even though there are substantial technical and policy issues that would need to be addressed to make such a pathway plausible.

[1] Getting to Zero Carbon Emissions in the Electric Power Sector, Joule, Dec. 19, 2018

The Company continues to investigate these opportunities through participation with the NC Clean Energy Plan modeling working group and the NREL Phase 2 Carbon Free Resource study. Additionally, the Company has partnered with NREL and a number of other National Laboratories to submit a DOE proposal for an extensive study of Reliability and Resilience in Near-Future Power Systems.

CAROLINAS RENEWABLE ENERGY PROFILES



NEED FOR ENHANCEMENTS IN MODELING ASSUMPTIONS AND TECHNIQUES

One of the key uncertainties of these 2020 Carolinas modeling efforts is the feasibility of onshore wind. Aside from the policy barriers, there is a significant need for meteorological towers to collect wind speed history in key areas across the Carolinas to gain confidence in predicted capacity factors. The Carolinas onshore wind profiles used in this IRP were provided by a third party and are likely not based on wind speeds measured near the expected hub heights. The Company is working to improve the quality of Carolinas onshore wind profiles for use in future IRPs.

Beyond the current work with NREL and the NC Clean Energy Plan, there are a number of issues that require detailed modeling and analysis to better understand the operational risks associated with significantly increased reliance on energy storage for meeting capacity needs coupled with reliance on very high levels of renewable resources for energy. First, traditional production cost modeling, used in key processes ranging from IRP development to the unit commitment planning that drives actual daily operations, has "perfect foresight" of system load, renewable output, unplanned outages and derates, etc. While this is an unrealistic assumption, with the moderate levels of renewables and relatively low levels of energy storage today, the impact of the perfect foresight is small due to the abundance of dispatchable resources that do not require the precise timing that short duration energy storage does (for both charging and discharging) to ensure that the highest load hours are fully covered.

With some portfolios in this IRP containing approximately four times the present level of renewables and storage and a much smaller proportion of long duration dispatchable resources, new production cost modeling techniques and operational protocols will need to be developed to properly represent and actively manage the risks related to forecast error and imperfect foresight. Second, while there is considerable experience with managing the impacts of extreme weather events on the existing fleet with its current abundance of flexible, long duration dispatchable resources, there is no experience in the US or abroad with the scale of dependence on short duration energy storage represented by the 70% reduction and no new gas portfolios of this IRP. These issues require new modeling techniques to assess and manage the challenges to ensure operational implications of the transition are well understood.

Notably, the Company is participating with Duke University and other academic researchers and industry reviewers in a DOE project as part of the ARPA-E PERFORM program (Performance-based Energy Resource Feedback, Optimization, and Risk Management). This is a three-year study effort just getting underway which will focus on transforming the electric grid management through improved understanding of asset risk, system risk, and optimal utilization of all grid assets. This specific project will address two main problems in grid management: 1) day-ahead operational reserves are often set based on heuristic rules that are disconnected from the real conditions of the assets and the system, and, 2) generation resources are scheduled without considering their impact on exacerbation or reduction of system risk. The Company has shared their dynamic reserve management methodology with the research team and looks forward to exploring improvement opportunities in these areas as the study progresses.

ADVANCING ZERO EMISSIONS LOAD FOLLOWING RESOURCE (ZELFR) TECHNOLOGY

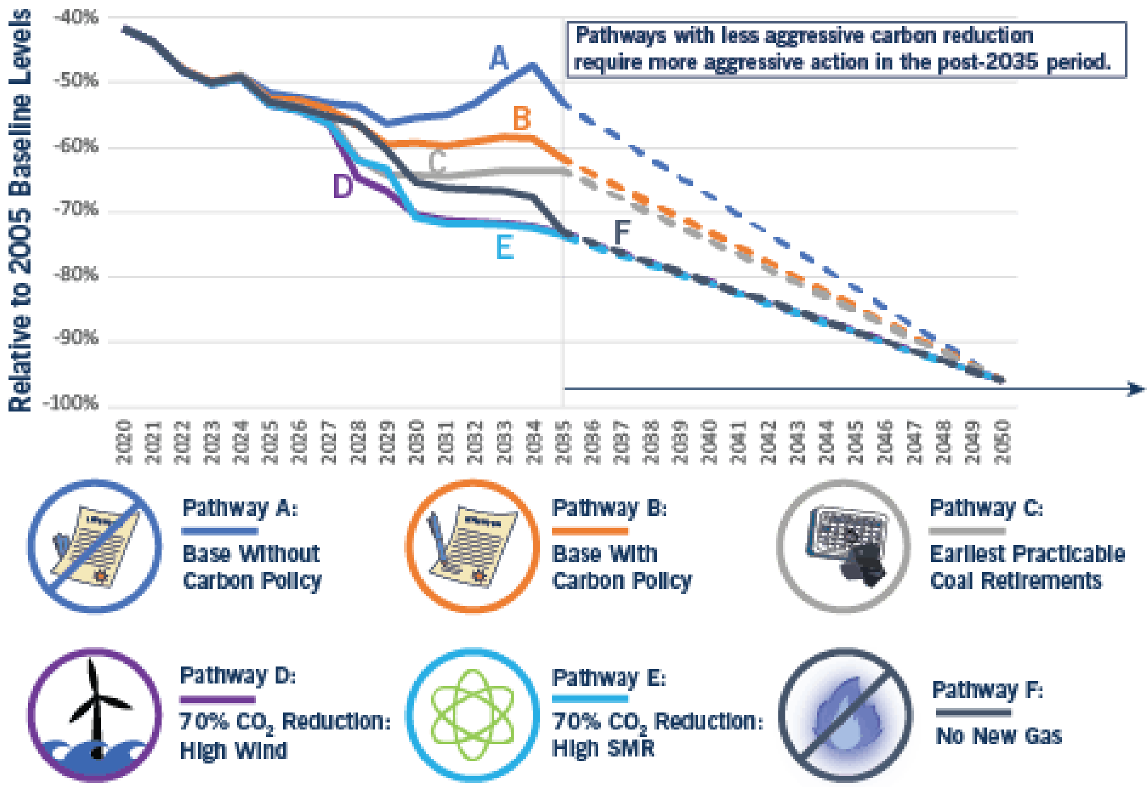
> *"The key technologies the energy sector needs to reach net-zero emissions are known today, but not all of them are ready."* [2]

As noted in the Climate Report and in independent studies and reports, to reach deep carbon reductions, very low- or zero-emitting technologies that can be dispatched to meet energy demand over long durations will be needed to replace carbon emitting resources.[3] Innovation is a critical part of Duke's path to achieving net-zero by 2050. With existing technologies, the Company can make important progress but cannot close the gap. To achieve net-zero, ZELFR technologies are needed that can respond to dynamic changes in both customer demand and renewable generation. The next decade is critical because these technologies need to be developed, demonstrated, refined and scaled on a very aggressive timeline to enable timely, cost-effective fossil retirements. While solar, wind and currently available energy storage have important roles to play now and in the future, as noted above their contribution begins to diminish as higher levels of renewable and storage penetration are reached, and resources capable of following load over long durations become increasingly needed to meet system capacity and energy needs reliably as fossil based resources are retired over time. ZELFRs will also ultimately be needed to replace the base load capability of existing nuclear units as they begin to retire in the 2050s and beyond. ZELFR technologies may include advanced nuclear; carbon capture, utilization and storage (CCUS); hydrogen and other gases; and long duration storage technologies such as molten salt, compressed/liquefied air, sub-surface pumped hydro, power to gas (e.g., hydrogen, discussed above) and advanced battery chemistries.

The 70% reduction cases in this IRP rely on the accelerated adoption of offshore wind and small modular reactors (SMRs) – a ZELFR technology – along with a significant investment in storage. Of the three portfolios reflecting the most aggressive carbon reductions, portfolio E (70% Reduction with High SMRs) yielded the lowest customer cost impact. To be clear, the Company does not expect to build SMRs by 2030 but included SMRs to illustrate the importance of support for advancing these technologies as part of a balanced plan to achieve net-zero carbon. These more aggressive portfolio transitions are more costly but, as illustrated below, could position the portfolio well for future climate policy by accelerating deployment of advanced technologies, requiring less aggressive action after 2035 to reach net-zero.

[2] IEA, Special Report on Clean Energy Innovation, Accelerating technology progress for a sustainable future.
[3] The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation, Nov. 18, 2018

CARBON REDUCTION TRAJECTORIES ON PATH TO NET-ZERO



The Company is actively engaged in industry efforts to support the development of ZELFRs. For example:

Advanced Nuclear: The Company has representatives on nuclear industry groups and advisory boards working on small modular reactor and advanced reactor technologies. The Company is also working with private and public sectors to drive research, development and demonstration of additional advanced reactor technologies under the DOE's Advanced Reactor Demonstration Program that supports innovative and diverse designs with the potential for commercialization in the mid-2030s.

Hydrogen/Other Gases: In addition to the research proposal with Siemens and Clemson University described earlier, the Company is a founding member of EPRI and GTI's Low Carbon Research Initiative. The overall goal of this initiative is to focus on fundamental advances in a variety of low-carbon electric generation technologies and low-carbon chemical energy carriers -- such as clean hydrogen, bioenergy, and renewable natural gas – which are needed to enable affordable pathways to economy-wide decarbonization.

Long Duration Energy Storage: As described earlier, Duke Energy has been involved with numerous battery energy storage pilots during the past 10 years. This has included active evaluation of long duration chemistries since 2016. The underlying chemistries of several pilots have the potential to provide daily or even seasonal energy storage, contributing to long duration storage applications in the future. Duke Energy will also increase the capacity at its Bad Creek facility in South Carolina by about 320 MW as it upgrades the facility. While this is not a pilot project, it represents an important contribution to Duke's long duration storage capacity in the Carolinas.

Carbon Capture: Duke Energy has a similarly long history of engagement in CCUS research, including pilot scale projects and partnerships with the Electric Power Research Institute, the Department of Energy, national labs and others. One recent example is a partnership to perform an initial engineering design for a commercial-scale, membrane-based CO_2 capture system at Duke Energy's 600-MW East Bend power plant in Kentucky. Notably, deployment of carbon capture in the Carolinas would likely be dependent on interstate transportation infrastructure or innovative utilization opportunities due to a lack of suitable geology for CO_2 storage.

The Company will continue to monitor, evaluate and support the most promising emerging technologies to advance understanding and be prepared to act if more aggressive state or federal regulations CO_2 requirements are enacted.

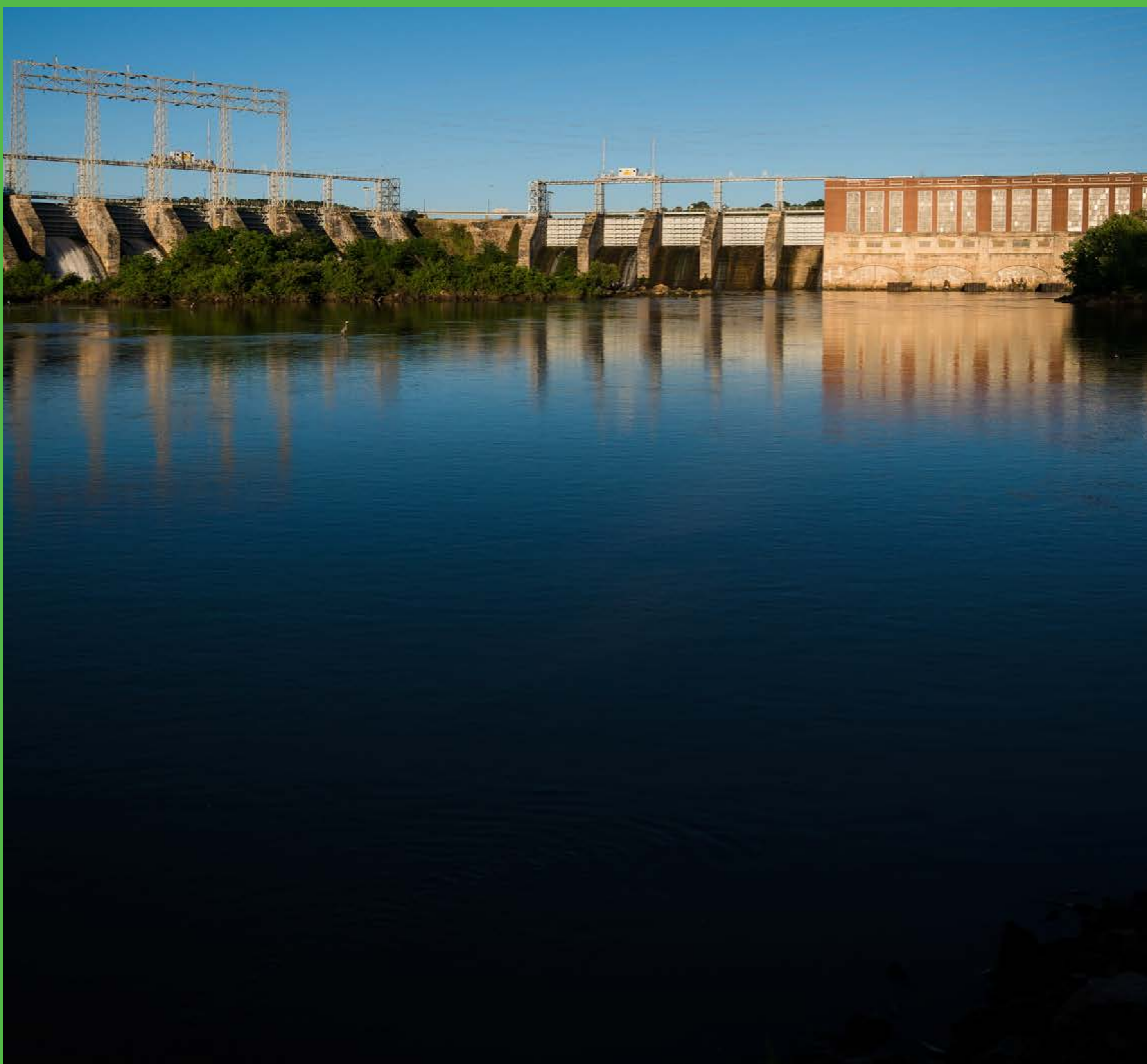
THE NEED FOR SUPPORTIVE POLICIES

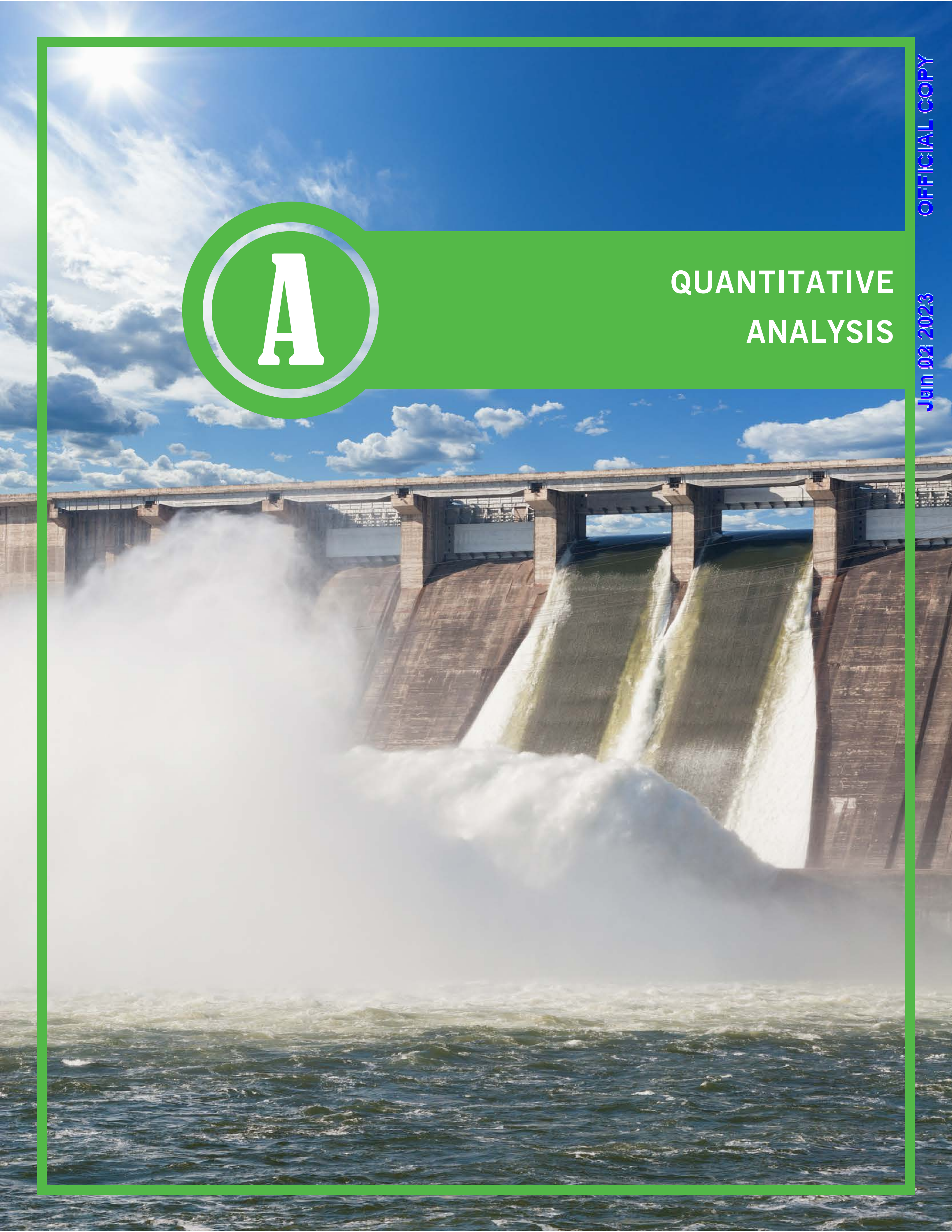
As shown by the Base without Carbon Policy pathway (A), from a modeling standpoint, carbon reductions could stall and reverse before reaching a 60% reduction in absence of policy to drive more aggressive additions of carbon-free resources. Carbon policy alone, however, is insufficient to address all the challenges associated with the dramatic transition of the grid and generation fleet to reach net-zero carbon, particularly for winter peaking, energy intensive Southeastern utilities. Federal policies are also critical to support and accelerate research, development, demonstration, and deployment of advanced technologies needed to meet this important goal. As noted in the Climate Report, for Duke Energy to achieve net-zero carbon emissions, the pace of interconnections over the next three decades is expected to be more than double that of the highest decade of generation growth in U.S. history, so the regulatory approvals of interconnection queue reform that the Company has been working on diligently with stakeholders over the last year is a critical hurdle. This pace of resource additions will also pose challenges for the interconnection-related transmission and distribution upgrades, transmission right-of-way acquisition, permitting, regulatory approval processes, supply chain, and generation siting as ideal sites are exhausted and suitable sites become increasingly scarce. These challenges are exacerbated if surrounding utilities are competing for the same resources to complete similar resource plans. It will be important to consider these factors and develop strategies to help create a supportive ecosystem for the deployment of carbon-free technologies and associated infrastructure as policymakers contemplate opportunities to accelerate the transition to net-zero while maintaining reliability and affordability for customers.

As described more fully in the 2020 Duke Energy Climate Report[4], policies will be increasingly important to support the changes required to transform the grid and drive advancement of carbon free resource technologies needed to reach the shared goal of net-zero carbon.

[4] https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en..

APPENDICES





QUANTITATIVE ANALYSIS

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. An evaluation of the economic retirement dates of DEP's coal plants helped establish the starting point for the quantitative analysis discussed in this appendix. Sensitivities on major inputs informed the development of multiple portfolios that were then evaluated under nine scenarios that varied combinations of fuel prices and CO_2 constraints. These portfolios were analyzed, identifying trade-offs between cost and carbon reductions, while considering opportunities and barriers to enable the portfolio's transition. Each of these plans account for the cost to customers, resource diversity, reliability and the long-term carbon intensity of the system and any of the six portfolios presented are potential pathways depending on future federal and state policies and technology advancements and cost trajectories.

The future resource needs were optimized for DEP and DEC independently. However, an additional case representative of jointly planning future capacity on a DEP/DEC combined system basis using the Base Case assumptions was also analyzed to demonstrate potential customer savings, if this option was available in the future.

OVERVIEW OF ANALYTICAL PROCESS

The analytical process consists of six steps:

1. Evaluate economic retirement dates of coal plants
2. Assess resource needs
3. Identify and screen resource options for further consideration
4. Develop base planning portfolio configurations and perform sensitivity analysis
5. Develop alternative portfolio configurations
6. Perform portfolio analysis over various scenarios

1. EVALUATE ECONOMIC SELECTION OF COAL PLANT RETIREMENT DATES

As discussed in Chapter 11, DEP conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. This analysis identified the retirement dates used in the Base Planning with Carbon Policy and Base Planning without Carbon Policy for each of DEP's coal plants. In addition to the economic retirement analysis, the Company also determined the earliest practicable retirement dates for each coal asset. The "earliest practicable" retirement date portfolio is discussed later in this appendix.

Through the process detailed in Chapter 11, following economic coal retirement dates were used in developing the base planning portfolios.

TABLE A-1
ECONOMIC RETIREMENT DATES OF DEP COAL PLANTS

	2019 IRP RETIREMENT YEAR (JAN 1)	2020 IRP MOST ECONOMIC RETIREMENT ANALYSIS RETIREMENT YEAR (JAN 1)
Mayo 1	2036	2029
Roxboro 1 & 2	2029	2029
Roxboro 3 & 4	2034	2028

2. ASSESS RESOURCE NEEDS

The required load and generation resource balance needed to meet future customer demand was assessed as outlined below:

- **Customer peak demand and energy load forecast** – identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape.

- **Existing supply-side resources** – summarized each existing generation resource's operating characteristics including unit capability, potential operational constraints and projected asset retirement dates.

- **Operating parameters** – determined operational requirements including target planning and operational reserve margins and other regulatory considerations.

Customer load growth, the expiration of purchased power contracts and additional asset retirements result in resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2020 resource plan:

- **Peak Demand and Energy Growth -** The growth in winter customer peak demand after the impact of energy efficiency averaged 0.8% from 2021 through 2035. The forecasted compound annual growth rate for energy is 0.7% after the impacts of energy efficiency programs are included.

- **Planned Generation Uprates and Additions –**

  - Nuclear uprates totaling 20 MW

- **Combustion Turbine Retirements –**

  - Weatherspoon 1-4 CTs assumed to retire in 2026
  - Blewett CTs assumed to retire in 2026

- **Expiring purchase contracts** are assumed to be replaced with like-kind purchase power contracts

- **Reserve Margin -** A 17% minimum winter planning reserve margin for the planning horizon

3. IDENTIFY AND SCREEN RESOURCE OPTIONS FOR FURTHER CONSIDERATION

The IRP process evaluated EE, DSM and traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the 2020 market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, nuclear, renewable, and energy storage). Supply-side options are initially screened based on the following attributes:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all Federal and State requirements
- Long-run reliability
- Reasonableness of cost parameters

The Company compared the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed in Appendix G.

RESOURCE OPTIONS

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

EE and DSM programs continue to be an important part of Duke Energy Progress' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

The base planning assumptions for EE and DSM portfolios incorporates projected program adoption rates, and costs based on a combination of both internal company expectations, inclusive of current programs, and projections based on information from the 2020 market potential study. The program costs used for this analysis leveraged the Company's internal projections for the first five years and in the longer term, utilized the updated market potential study data incorporating the impacts of customer participation rates over the range of potential programs. Additionally, the Company included the impacts on energy and winter peak demand from the addition of an IVVC peak shaving program discussed in Appendix D.

Over the 15-year planning horizon, EE and DSM programs, including the new IVVC program discussed in Appendix D, are expected to provide over 830 MW of winter peak demand reduction in the base planning scenarios.

SUPPLY-SIDE

The following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

DEC DISPATCHABLE (WINTER RATINGS)			
BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE NON- DISPATCHABLE (WINTER RATINGS)
1,224 MW, 2x2x1 Advanced Combined Cycle (Duct Fired, No Inlet Chiller)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
684 MW, 12 Small Modular Reactor Nuclear Units (NuScale)		50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW Fixed-Tilt (FT) Solar PV
			75 MW Single Axis Tracking (SAT) Solar PV
			75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

4. DEVELOP BASE PLANNING PORTFOLIO CONFIGURATIONS AND PERFORM SENSITIVITY ANALYSIS

The step is broken down into three sections. The first section discusses the key variables in portfolio development and those considered in sensitivity and portfolio analysis. The second discusses the Base Planning portfolio development and results. The final section details the overall quantitative analysis of the individual sensitivity screening cases that were analyzed in the sensitivity analysis to inform the development of the alternative portfolios.

VARIABLES CONSIDERED IN SENSITIVITY & PORTFOLIO ANALYSIS

The Company uses base planning assumptions for the development of the base cases. However, the Company also conducted sensitivity analysis of various drivers using the expansion planning simulation modeling software, *System Optimizer* (SO). The expansion plans from these sensitivities produced by SO were then processed through the more detailed hourly production cost model, PROSYM to provide production costs for each of the expansion plans. The results of the sensitivity analysis were used to inform the development of the alternative portfolios presented in the IRP. Each of the base planning and alternative portfolios were analyzed under combinations of fuel and carbon tax trajectories in PROSYM in order to compare the Present Value of Revenue Requirements (PVRR) of each portfolio under the various scenarios, as well as, develop an estimate of average residential monthly bill impact of implementing the various portfolios under base planning assumptions. An overview of the key variable assumptions for the development of the base cases and for the Sensitivity and Scenario Analyses considered in both SO and PROSYM are outlined below:

LOAD FORECAST

DEP modeled the impacts of changes to the load forecast on the expansion plans. The Company based these sensitivities on the near-term growth and recession scenarios provided by Moody's Analytics. The impacts to the load forecast are summarized below:

TABLE A-2

LOAD FORECAST SENSITIVITY PARAMETERS

	LOW	BASE	HIGH
2035 Winter Peak Demand, MW	15,830	15,966	16,086
2035 Annual Energy, MWh	69,797,797	70,446,299	70,983,725

IMPACT OF POTENTIAL CARBON CONSTRAINTS

The base CO_2 price was developed to incentivize less carbon intensive resources on the path to net zero carbon by 2050. Based on the earliest expected time to propose, pass and implement legislation or regulation the CO_2 price is set to begin in 2025. Ultimately, the CO_2 price will likely be dependent on many factors such as fuel and technology cost, tax incentives as well as pace of reduction goals.

In the 2019 IRP, the CO_2 price also started in 2025 at 5 $/ton and escalated at a rate of $3/ton per year, which incentivized CO_2 reductions of 60 to 70% by 2050 from a 2005 baseline. However, the price was not high enough to incentivize zero-emitting load-following resources (ZELFR) such as nuclear, hydrogen fueled generation or carbon capture and sequestration in lieu of natural gas generation prior to 2050.

In September 2019, after the filing of the 2019 IRP, Duke Energy announced an enterprise wide CO_2 reduction goal of at least 50% by 2030 and to be net zero carbon by 2050. In addition to accelerating coal retirements, additional renewables and storage, there is a need for ZELFR technologies in 2035 to 2050 timeframe to facilitate the replacement of remaining coal generation and existing natural gas combined cycle generation as they meet their projected retirement dates. The company's analysis showed a CO_2 price starting at $5/ton in 2025 increasing at a rate of $5/ton per year incentivized ZELFR technology in the 2040 to 2050 timeframe, where increasing at a rate of $7/ton accelerated the selection of ZELFRs in the 2035 to 2040 timeframe. Both the $5 and $7/ton per year price incentivize battery storage to meet a portion of new peaking need by 2030, additional renewables, accelerated coal retirements and limiting dispatch of carbon emitting generation.

There have been multiple federal legislative proposals that Duke has been tracking including:

Climate Leadership Council – $40/ton escalating at 5% per year

CLEAN Futures Act – A Clean Electricity Standard (CES) that incentivized similar reductions to $5/ton escalating at $7/ton per year

Energy Innovation and Carbon Dividend Act (H.R. 763) – $15/ton escalating at $10/ton per year

American Opportunity Carbon Free Act of 2019 (S. 1128) – $52/ton escalating at 8.5% per year

The Climate Leadership Council and CLEAN Futures Act each drive a similar pace of carbon reduction as the $5/ton and $7/ton per year carbon price trajectories. The higher CO_2 prices associated with H.R. 763 and S. 1128 would drive retirement of coal and gas generation at a faster pace which would accelerate the need for ZELFRs prior to 2035. However, the pace of CO_2 reduction would be limited by the amount of renewables and storage that could be interconnected in a given year, technological development and deployment of storage and ZELFRs technologies and the impact on customer rates.

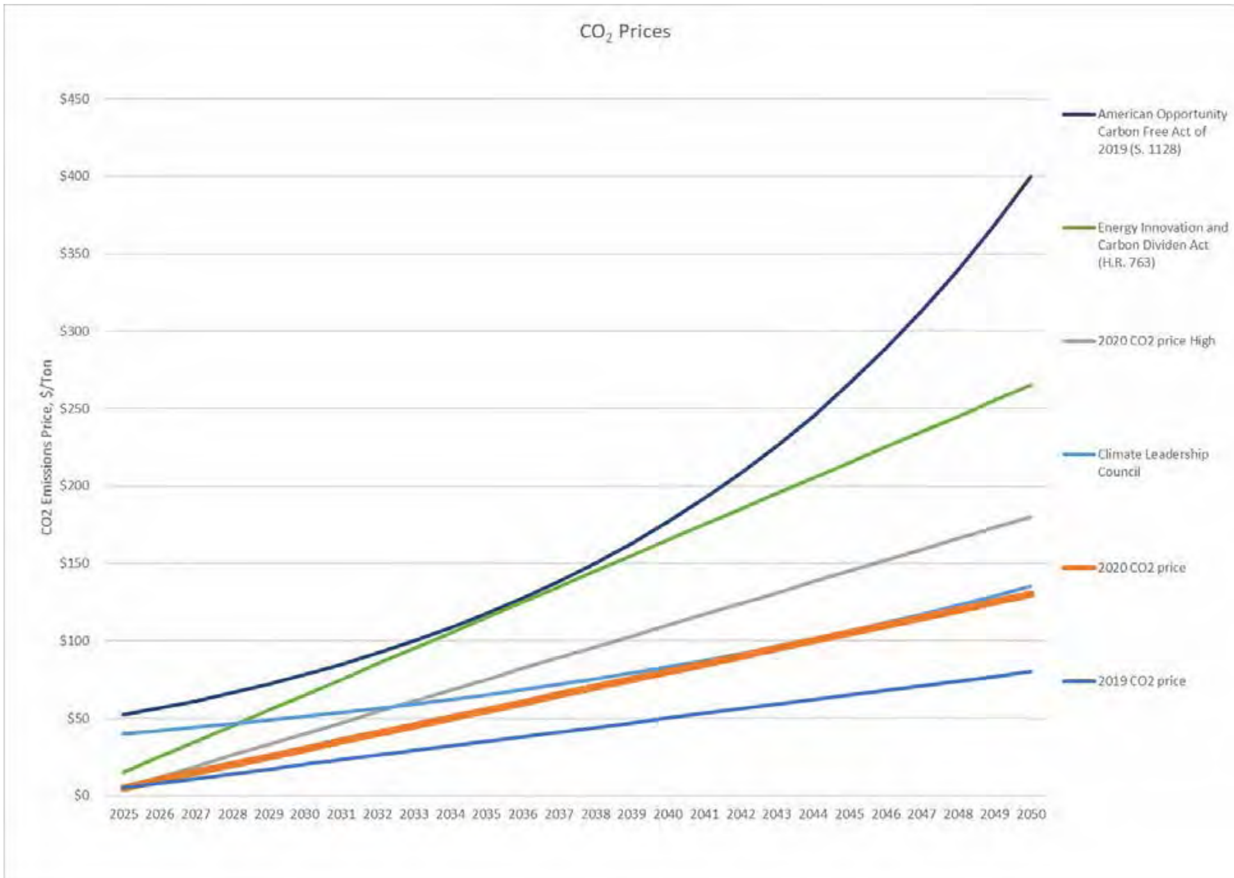
In consideration of the mentioned legislative proposals and consistent with Duke Energy's CO_2 reduction goal, the Reference 2020 CO_2 price is $5/ton starting in 2025 escalating at a rate of $5/ton per year. This CO_2 price trajectory incentivizes the continued adoption of renewables, storage, accelerated coal retirements which supports a path to net zero by 2050. When comparing alternative plans the inclusion of the CO_2 price in the overall project economics would be reflective of a carbon tax, and if excluded, would be reflective of a CO_2 mass cap or cap and trade with allowance allocations.

Base CO_2 Price – $5/ton in 2025 and escalating at $5/ton annually applied to all stack carbon emissions.

High CO_2 Price – $5/ton in 2025 and escalating at $7/ton annually applied to all stack carbon emissions.

FIGURE A-1

COMPARISON OF CO_2 PRICES AND OTHER CO_2 REFERENCE PRICES



COAL PLANT RETIREMENT DATES

As described in Chapter 11, DEP evaluated the economic coal retirement dates for each coal plant. These dates were used in the base planning cases presented in the IRP. Additionally, DEP determined the earliest practicable retirement dates for each plant which contemplated the earliest date, setting aside normal economic considerations, that each coal plant could be retired but still giving consideration to the time it would take to place replacement resources into service. While the earliest practicable dates are technically feasible it would likely take supporting policy to effectuate such an aggressive retirement schedule, The complexities in the siting, permitting, construction and regulatory approvals for such a large amount of replacement resources in a short period of time would, in all likelihood, not be feasible without new supporting policy. This is emphasized when taking into account the fact that the combined DEC/DEP systems would simultaneously be retiring all coal units prior to 2030 or in the case of Cliffside unit 6 cease burning coal by 2030 limiting future operations to entirely natural gas in this scenario. The earliest practicable coal retirement dates and additional considerations are discussed later in this appendix.

ENERGY EFFICIENCY

DEP modeled the adoption rate and program cost associated with EE based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Table A-3 provides the base, enhanced, and low EE MW and MWh impacts by 2035 including measures added in 2020 and beyond.

TABLE A-3
EE SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
2035 Winter Peak EE, MW	182	243	487
2035 Annual EE, MWh	1,192,739	1,590,318	1,780,573

DEMAND SIDE MANAGEMENT & IVVC

As discussed previously, DEP modeled the adoption rate and program cost associated with DSM based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Additionally, the Company included the peak shaving capability of DEP's IVVC program which provides a reduction to winter peak demand and overall energy consumption. Table A-4 provides the base, enhanced, and low DSM MW impacts by 2035 including measures added in 2020 and beyond. The base case was derived directly from the market potential study, while the enhanced case incorporated the market potential study and impacts associated with potential rate design demand response programs. The low case is simply a 25% reduction in adoption and cost impacts of DSM programs. The base IVVC program impacts are included in all three sensitivities.

TABLE A-4
DSM SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
2035 Winter Peak DSM, MW	468	589	1,011

SOLAR, SOLAR + STORAGE, AND WIND GENERATION

Three levels of renewable generation were evaluated as discussed in Appendix E. Each level included varying assumptions regarding penetration of solar and solar plus storage, wind availability, and annual interconnection limits. As discussed further in Appendix E, the base case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including expected growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

In addition to the base case, a high and low case were developed. These portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed

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In all three cases, incremental solar plus storage and onshore Carolinas wind were available for selection in the capacity expansion model. However, the annual amount of solar plus storage that could be selected in each case was limited. Additionally, as discussed in Appendix E (Renewables) standalone solar was not available for selection by the capacity expansion model due to increasing levels of solar curtailment on the DEP system. Table A-5 details the differences between the inputs of the three renewable cases.

TABLE A-5

RENEWABLES SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
Forced Solar by 2035, Nameplate MW	3,948	4,575	6,481
Forced Central US Wind by 2035, MW	0	0	422
Forced Offshore Carolinas Wind by 2035, MW	0	0	92
Allowed Solar coupled w/ Storage Annually, MW/Year	125	200	400
Allowed Onshore Carolinas Wind Annually, MW/Year	150	150	150

Additionally, as described in Chapter 7, transmission upgrade costs associated with interconnecting these distributed resources was estimated. These costs were applied after the technology was selected and are included in the PVRR and average residential bill impacts discussed later in this appendix.

FUEL PRICES

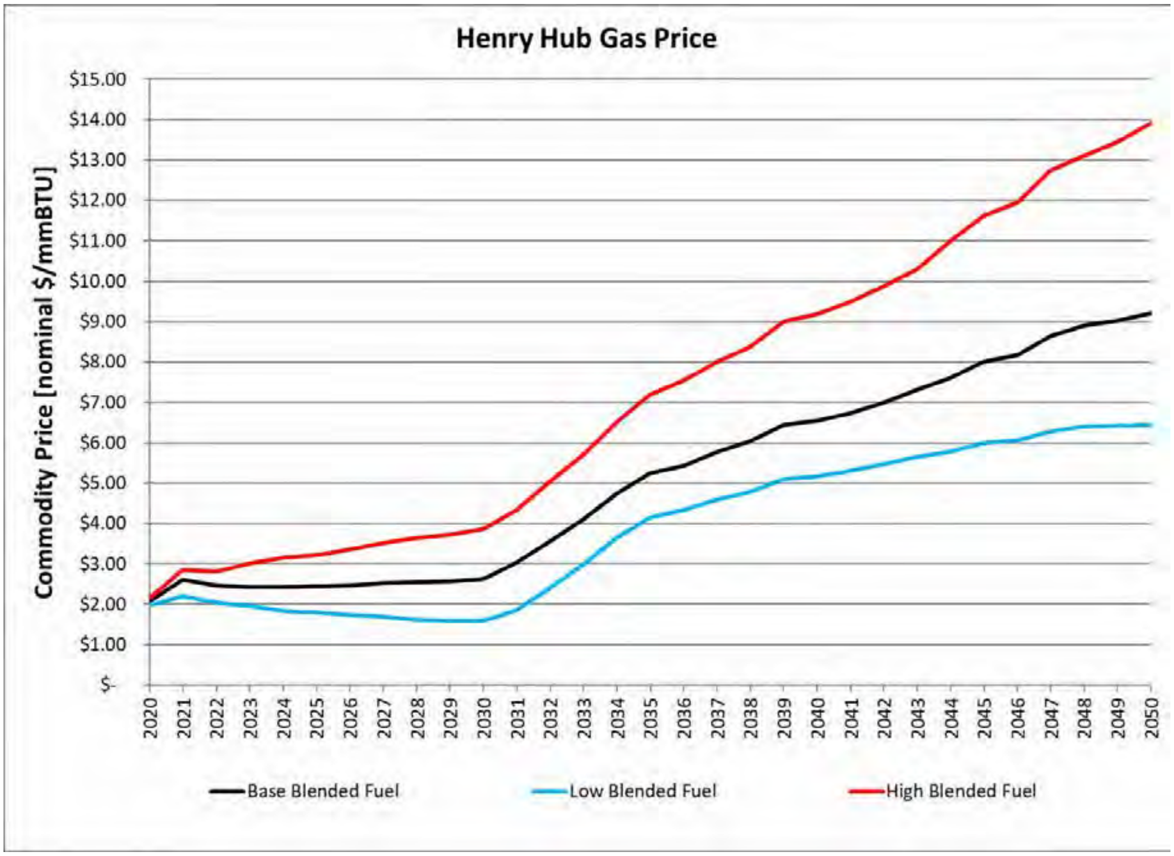
DEP continues to rely on 10-year market purchases of natural gas and 5-years of market observations of coal prices before transitioning to fundamental fuel forecasts for development of the IRP.

- Natural Gas based on market prices from 2021 through 2030 transitioning to 100% fundamental by 2035.

- Coal based on market observations through 2024 transitioning to 100% fundamental by 2030. In order to test the effects of changing fuel prices on resource selection and portfolio value, DEP developed high and low natural gas prices. By only changing natural gas prices, the impact on resource selection (CC vs. CT vs Renewables) and dispatch (coal vs. gas) can be evaluated. The natural gas prices evaluated in the 2020 IRP are shown in the chart below.

FIGURE A-2

NATURAL GAS PRICE SENSITIVITIES



The high and low natural gas price sensitivities were developed using a combination of high and low market and fundamental projections. The high and low market natural gas prices were developed using statistical analysis on market quotes to determine a 10th and 90th percentile probability. The high and low fundamental natural gas prices were derived using the base fundamental forecast and the EIA's 2020 Annual Energy Outlook (AEO) natural gas price forecasts from its Reference Case, Low Oil and Gas Supply Case, and High Oil and Gas Supply case.

CAPITAL COST SENSITIVITIES

Three capital cost sensitivities were performed. As discussed in Appendix G, most technologies include technology specific Technology Forecast Factors which were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO. More nascent technologies, such as battery storage and, to a lesser extent, PV solar, have relatively steep projected cost declines over time compared to more established technologies such as CCs and CTs. The first capital cost sensitivity evaluated the impact on the expansion plan of lower and higher reductions in solar PV costs as shown in Table A-6.

TABLE A-6

SOLAR & SOLAR + STORAGE CAPITAL COST SENSITIVITIES – PROJECTED PERCENT COST REDUCTION FROM 2020 TO 2029 BASED ON REAL 2020$

	LOW	BASE	HIGH
Solar PV % Reduction in Cost	-54%	-40%	-20%
Solar PV + Storage % Reduction in Cost	-61%	-46%	-26%

The second capital cost sensitivity evaluated the impact of reducing the asset life of a CT or CC from 35 years to 25 years. While the Company believes that natural gas is necessary for transitioning to a net-zero CO_2 emission future, this sensitivity considered the risk of new natural gas assets realizing an earlier than normal retirement.

The final capital cost sensitivity evaluated a reduction in battery storage costs to determine the impact on CT versus battery selection. Currently, the Company assumes that battery storage costs will decline by approximately 45% over the next decade. This sensitivity increases the cost decline to approximately 55%.

HIGH ENERGY REDUCTION FROM DEP'S DSDR PROGRAM

While the IRP base planning assumptions include energy reductions for DEP's Distribution System Demand Response Program, additional historical measurement and verification shows potential for further energy reduction from this program. The test year used for the IRP, 2018, provided approximately 100,000 MWhs of energy reduction by 2025, when the program would be fully implemented. Using a test year of 2017, the program could reduce energy by up to 400,000 MWhs, or 0.6% reduction in load for DEP, by the same timeframe. High level estimates suggest that this additional energy reduction, if realized, could result in approximately 140,000 ton of CO_2 reduction per year. While this additional energy reduction would further lower load on the DEP side, the reduction in load could also impact the energy transfer between utilities as part of the JDA. The additional reduction in energy will not impact the programs peak reduction capacity.

TECHNOLOGY ADVANCEMENTS

In some instances, certain technologies may not be considered "economic" within the planning horizon. However, these technologies may show significantly more value beyond the planning horizon particularly under strict carbon policies. Additionally, these resources may be required to achieve certain policy goals prior to the end of the planning horizon. For these reasons, the following technologies were evaluated in the 2020 IRP.

- **Small Modular Reactors (SMR) –** In order to achieve climate goals such as 70% CO_2 reduction by 2030 and net-zero carbon reduction by 2050, zero-emitting, load following resources (ZELFR) will be required. DEP evaluated SMRs as an example ZELFR within the planning horizon in several portfolios.

- **Offshore Wind –** While offshore wind was included in the Company's High Renewable sensitivity, several portfolios significantly increased the penetration of this resource to determine its impact on achieving 70% carbon reduction by 2030. This increase in penetration is reasonable, and is a likely outcome, if offshore wind is developed off the coast of the Carolinas.

- **Pumped Storage Hydro –** As non-dispatchable resources such as solar and wind become prevalent on the system, the need for storage increases to avoid curtailment and optimize utilization of these carbon free resources. As shown in the Company's Capacity Value of Battery Storage study, the value of short duration storage erodes rapidly as similar storage durations are added. For this reason, pumped hydro storage that can provide 8 or more hours of charging and generating was considered in cases that included renewable energy beyond that found in the base case. Importantly, pumped hydro storage is not well suited for the DEP footprint, however through the Joint Dispatch Agreement there is some transfer of energy between the two utilities that would potentially be impacted by the inclusion of PSH in DEC.

ENERGY STORAGE

140 MW of 4-hour Lithium ion batteries are included in all portfolios as placeholders for future assets to provide operational experience on the DEP system. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

In addition to these placeholders, solar coupled with storage was included in the various renewable cases and was available for selection in the capacity expansion model. Furthermore, as discussed in Chapter 11, the Company studied the impact of replacing CTs with 4-hour battery storage during various points over the planning horizon. Finally, as part of several of the portfolios presented later in this appendix, battery storage was viewed as a key resource in the presence of increasing renewable penetration and the efforts to achieve certain carbon reduction goals, as well as, in cases where new natural gas generation was not an available resource.

JOINT PLANNING

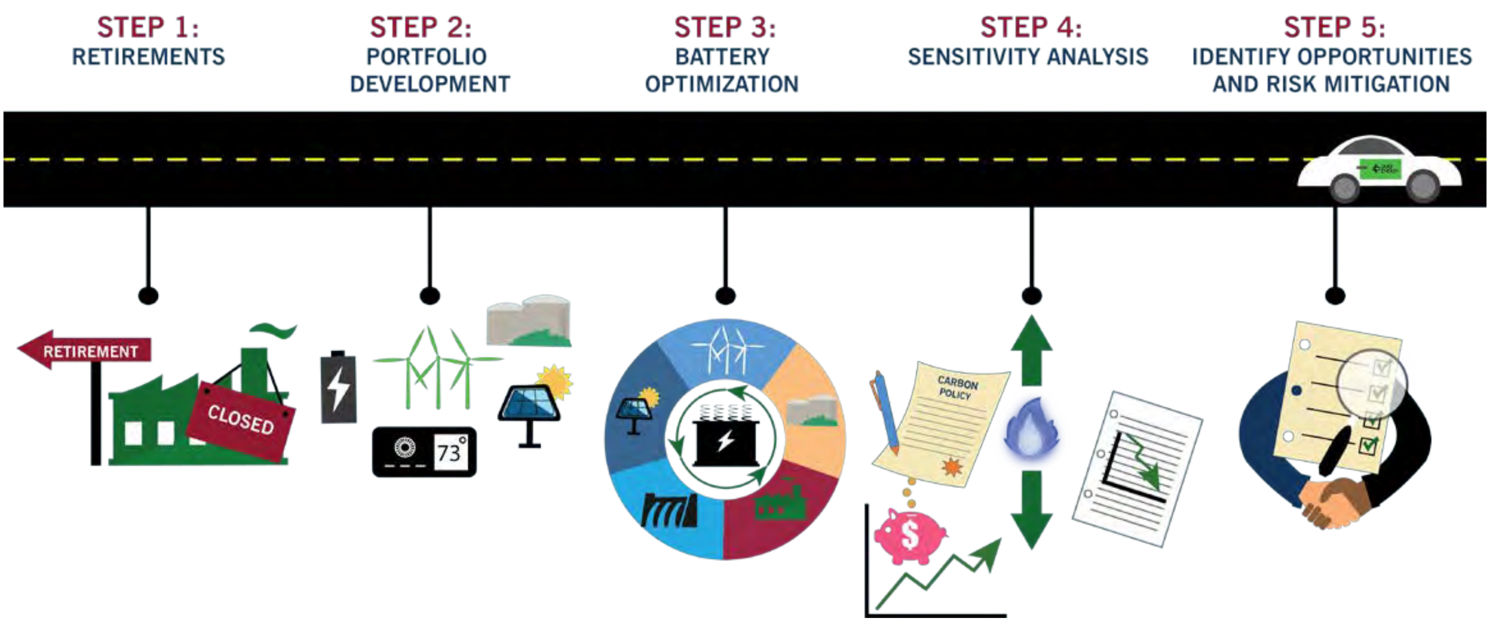
As required through the Joint Dispatch Agreement, DEP and DEC must plan to meet future capacity needs as individual utilities without the ability to share firm capacity. However, DEP performed a sensitivity assuming joint planning between DEP and DEC to investigate the benefits of shared resources and how new generation could be delayed. The Joint Planning analysis is discussed later in this appendix.

BASE CASE PORTFOLIO DEVELOPMENT AND RESULTS

The base cases utilize the company's current planning assumptions to determine least cost portfolios in scenarios with and without policy on carbon emissions from the electric generation fleet. These two (2) portfolios include the most economic retirement dates of the company's coal units, as discussed in Chapter 11. These portfolios utilize base planning assumptions for energy efficiency and demand response forecasts to reduce peak demand before incremental resource additions are evaluated. After the base case portfolios have been screened into the portfolio through the capacity expansion model, batteries were evaluated in a production cost model to optimize inclusion in the portfolios. Base Cases were then evaluated in sensitivity analysis to inform development of alternative portfolios. Below is a simplified process flow diagram for development of the Base Case portfolios.

FIGURE A-3

SIMPLIFIED PROCESS FLOW DIAGRAM FOR BASE CASE PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS

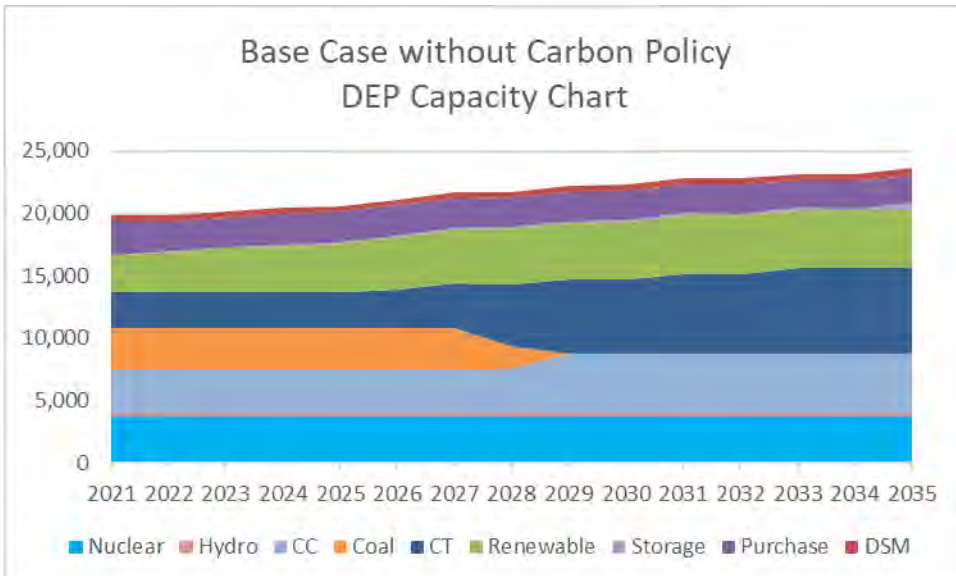


BASE CASE WITHOUT CARBON POLICY

PORTFOLIO AND RESULTS DISCUSSION

The Base Case without Carbon Policy largely selects new natural gas generation to replace retiring coal generation. This portfolio adds over 5,300 MW of gas capacity to replace the retiring 3,200 MW of coal capacity and meet load growth. Even with the replacement of expiring contracts with like in kind replacement contracts, DEP still has capacity needs in starting in 2026, with the retirement of the Weatherspoon and Blewett CTs, common across all portfolios evaluated. In this scenario without a carbon policy, the additions selected are mainly CTs until the coal units are retired in 2028 and 2029. The system relies on coal generation until it's retired and CTs are added in smaller amounts to avoid excess capacity for a period of time. There are no model selected solar additions in this portfolio, which indicates that above the forecasted solar additions, the system would likely require additional economic support from either a carbon price or other supporting energy policy to continue adding renewable generation to the system. Through the battery optimization in this Base Case, it was found that a battery would be economic in the place of a CTs built in 2035, in the last year of IRP planning horizon.

FIGURE A-4
DEP CAPACITY CHART - BASE CASE WITHOUT CARBON POLICY



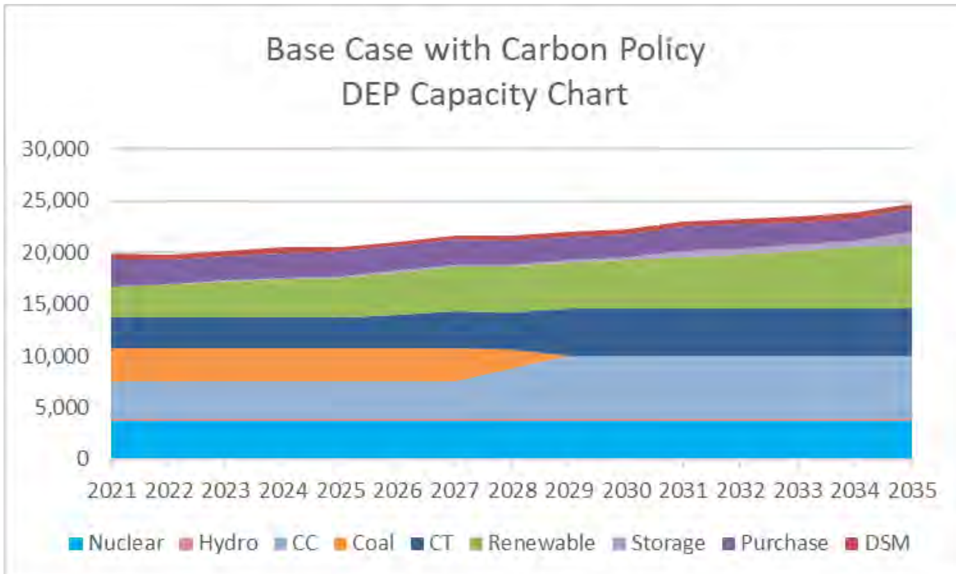
BASE CASE WITH CARBON POLICY

PORTFOLIO AND RESULTS DISCUSSION

The Base Case developed under the assumption of future carbon policy results in a more diverse set of resource additions than its no carbon policy counterpart. This case adds 900 MW less of natural gas generation by 2035 compared to the no Carbon Policy case, and instead adds 1,400 MW of additional solar and solar plus storage and 600 MWs of onshore Carolinas wind. This case also found nearly 900 MWs of batteries to be economic starting in 2030 to meet energy and capacity needs created from retiring coal. The addition of the carbon policy drove the model-selected additions of these non-carbon emitting resources in this year's IRP.

FIGURE A-5

DEP CAPACITY CHART - BASE CASE WITH CARBON POLICY



Below in Table A-7 is a comparison of the Base Case capacity expansion results:

TABLE A-7

BASE CASE CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY
PORTFOLIO	A	B
Coal Retirements [MW]	3,208	3,208
Incremental Solar [MW]┼	2,000	3,425
Incremental Onshore Wind [MW]┼	0	600
Incremental Offshore Wind [MW]	0	0
Incremental SMR Capacity [MW]	0	0
Incremental Storage [MW]╪	698	1,593
Incremental Gas [MW]	5,337	4,276
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]*	825	825

┼Combined forecasted and model-selected incremental additions by the end of 2035

╪Includes Standalone Storage and Storage at Solar plus Storage sites

*Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

SENSITIVITY ANALYSIS RESULTS

Following the development of the base planning portfolios, sensitivities were run to inform the development of the alternative portfolios. Table A-8 presents an overview of the year certain resources were selected by the capacity expansion model in each of sensitivities. Red indicates an earlier date than the Base Case with Carbon Policy, green indicates a later date than the Base Case with Carbon Policy, and orange indicates the resource was not selected during the planning horizon.

TABLE A-8

MATRIX OF FIRST SELECTION OF RESOURCES

	BASE		EE		DSM		LOAD		FUEL PRICE		RENEWABLES		SOLAR COST	
	W/ CO_2 POLICY	W/O CO_2 POLICY	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW
CT	2026	2026	2026	2029	2026	2028	2029	2026	2026	2026	2026	2026	2026	2026
CC	2028	2029	2028	2026	2028	2026	2026	2028	2028	2028	2028	2028	2028	2028
Solar Plus Storage	2030	N/A	2030	2030	2030	2029	2029	2029	2028	2031	2034	2029	N/A	2027
Offshore wind	2033	N/A	2031	2032	2032	2031	2031	2030	2029	2035	2034	2032	2031	2031

Several observations from the sensitivity analysis are discussed below:

- **Timing of new natural gas generation –** The timing of new natural gas generation does not change across sensitivities. In all cases, new gas generation is selected in the 2026 timeframe.

- **Type of new natural gas generation –** CTs are selected as the first natural gas resource in the majority of cases. Only in instances of increased load or those cases with lower penetration of demand side resources are CCs accelerated prior to CTs. The resource mix in DEC also likely plays a role in the resource selection in DEP, and vice versa, as the Joint Dispatch Agreement allows for the transfer of energy between the two utilities. While the capacity expansion model cannot optimize capacity needs between the two utilities, it can optimize energy resources to take advantage of the JDA.

- **Solar Plus Storage –** Solar coupled with storage was selected in 2030 in the Base Case with Carbon Policy. This resource was not selected in the Base Case without a carbon policy, nor was it selected in the high solar cost case. Alternatively, the selection of solar plus storage was accelerated in cases of low DSM and high load. As expected, this resource was delayed when fuel prices were low and solar costs were high, as well as when there were already significant levels of solar on the system already, as was the case in the High Renewable sensitivity.

- **Wind Energy –** Onshore Carolinas Wind was selected in most cases and, was accelerated in many of the sensitivities versus the Base Case with Carbon Policy. Similar to solar plus storage, wind was delayed with high fuel prices and high penetration of solar and wind on the system.

  The following tables (Table A-9 and A-10) provide greater detail on the impacts of each sensitivity performed including impact to PVRR, CO_2 emissions by 2030 and 2035, and resource selection through 2035.

TABLE A-9

PVRR ANALYSIS OF SENSITIVITIES THROUGH 2050, $ BILLIONS

	MASS CAP/CAP AND TRADE			CARBON TAX		
Base CO_2	$35.7			$43.7		
	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY
Base CO_2 - High Load	$36.7	$1.0	2.9%	$44.5	$0.8	1.8%
Base CO_2 - Low Load	$33.6	-$2.1	-5.8%	$39.4	-$4.3	-9.9%
Base CO_2 - High Fuel	$41.2	$5.6	15.6%	$47.8	$4.1	9.3%
Base CO_2 - Low Fuel	$33.2	-$2.5	-6.9%	$40.9	-$2.8	-6.3%
Base CO_2 - High Renewables	$38.2	$2.5	6.9%	$45.2	$1.5	3.5%
Base CO_2 - Low Renewables	$33.8	-$1.8	-5.2%	$42.0	-$1.7	-3.8%
Base CO_2 - High EE	$35.1	-$0.6	-1.6%	$42.9	-$0.8	-1.8%
Base CO_2 - Low EE	$36.2	$0.6	1.6%	$44.1	$0.4	0.8%
Base CO_2 - High DR	$34.7	-$1.0	-2.9%	$42.6	-$1.1	-2.4%
Base CO_2 - Low DR	$36.7	$1.0	2.8%	$44.3	$0.6	1.4%
Base CO_2 - High Renew Cost	$35.9	$0.2	0.5%	$43.6	-$0.1	-0.2%
Base CO_2 - Low Renew Cost	$35.3	-$0.3	-1.0%	$43.2	-$0.5	-1.2%
Base CO_2 - 25-Year Gas	$36.3	$0.6	1.8%	$44.2	$0.5	1.2%
Base CO_2 - Pumped Storage	$36.0	$0.3	1.0%	$44.1	$0.4	0.8%
Base CO_2 - DEP's High Energy DSDR	$35.7	$0.0	0.1%	$43.6	-$0.1	-0.2%
Min	$33.2	-$2.5	-6.9%	$39.4	-$4.3	-9.9%
Median	$35.9	$0.2	0.5%	$43.6	-$0.1	-0.2%
Max	$41.2	$5.6	15.6%	$47.8	$4.1	9.3%

TABLE A-10

DEC SENSITIVITY ANALYSIS RESULTS

	BASE		EE		DSM		Load		Fuel Price		Renewables		Solar Cost	
	w/ CO_2 Policy	w/o CO_2 Policy	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
CO_2 Reduction by 2030 / 2035	59% / 62%	56% / 53%	60% / 62%	60% / 62%	60% / 62%	59% / 62%	61% / 63%	63% / 70%	60% / 59%	59% / 60%	61% / 66%	60% / 61%	59% / 61%	60% / 63%
2035 Winter Peak Demand	15,966	15,966	15,722	16,027	15,966	15,966	16,086	15,830	15,966	15,966	15,966	15,966	15,966	15,966
EE	243	243	487	182	243	243	243	243	243	243	243	243	243	243
DSM	589	589	589	589	1,011	468	589	589	589	589	589	589	589	589
Generation Added Over Planning Horizon (Nameplate Winter MW) ┼														
Gas Generation	4,276	5,337	3,819	4,276	3,819	4,880	4,276	3,966	3,966	4,423	3,819	4,276	4,423	4,276
Solar╪	5,785	4,598	5,785	5,785	5,785	5,873	58,73	5,873	5,873	5,948	6,488	5,018	4,598	6,023
Wind	450	0	750	600	600	750	750	900	1,050	150	300	600	750	750
Storage	1,537	698	1,537	1,537	1,537	1,555	1,555	1,555	1,574	1,499	1,785	1,414	1,237	1,054

┼ MWs represent availability on January 1, 2035

╪Total Solar; Assumes 0.5% annual degradation

Several key takeaways from the sensitivity analysis include:

- Without a carbon policy, solar and wind resources are not economically selected.

- The incremental 190 Million MWh of EE by 2035, with a coincident peak contribution of 244 MW, in the High EE sensitivity provides $0.6B to $0.8B of value versus the base case. While this capacity and energy help avoid a CT over the planning horizon, there is executability risk with achieving these levels of energy efficiency. For this reason, these stretch targets were not included in the Base with and without Carbon Policy cases but were included in the aggressive CO_2 reduction portfolios.

- In cases where incremental capacity is needed, such as the High Load Forecast and Low EE, a CC is accelerated along with solar coupled with storage and wind resources. Notably, these renewable resources are only accelerated into the 2029 and 2030 timeframe. While these resources are projected to have steep cost declines, they are still relatively expensive compared to natural gas generation in the mid-2020 time period.

- While not economic until the 2030 timeframe, onshore Carolinas wind generation shows the greatest gains in penetration in most scenarios.

- As expected, higher fuel prices, lower solar costs, and carbon policy drive increases in solar plus storage resources.

- A review of the sensitivity PVRR analysis highlights that changes in fuel cost had the greatest impact on total PVRR. While the other variables influence incremental energy and resource selections, fuel presents the greatest cost opportunity and risk. The range of uncertainty supports continued diversity in fuel type and regional supply to minimize these risks.

  Several other sensitivities investigating the value of Pumped Hydro Storage, a 25-year life for natural gas assets versus the base assumption of a 35-year life, and lower battery storage costs were also developed.

PUMPED STORAGE HYDRO

As discussed previously, as non-dispatchable renewable resources increase in number in the Carolinas, longer duration energy storage will become critical to maintaining a reliable system. The sensitivity performed in this case was with Base Renewables along with DEP and DEC operating as separate utilities with current transmission capacity between the two utilities which limits the value of additions PSH. A scenario with higher renewable penetration and increased transmission capability between the two utilities would likely increase the value of PSH. The Company believes that under certain climate goals and carbon reduction policies, incremental PSH would be a valuable addition to the fleet.

25-YEAR NATURAL GAS ASSETS

Approximately 300 MW of gas generation was replaced with accelerated wind and solar plus storage in the case where the asset life of natural gas CCs and CTs was reduced to 25-years from 35-years. Both wind and solar plus storage generation were accelerated to 2029, which was very similar to the results of the High Fuel scenario shown above.

BATTERY STORAGE COSTS

In the Base Case with Carbon Policy, battery storage was determined to be economic beginning in the 2030 time period. A CT in 2030 and a CT in 2034 were replaced with 4-hour battery storage. To test the impact of lower battery storage costs, the Company tested the PVRR cost effectiveness of a CT vs 4-hour Li-ion battery storage that was 15% lower cost than the original planning assumption. In DEP, the opportunity to replace a CT with battery storage occurs in 2025, 2028, 2030, and 2034. With these lower costs, the 2028 CT would also be replaced with battery storage. Regardless of this exercise, as noted in Chapter 11 at the time new resources are needed on the DEP system, the Company will solicit bids to fill the resource gap as part of the CPCN process for new generation resources. Only then, will the true costs of competing technologies be fully known.

5. DEVELOPMENT OF ALTERNATIVE PORTFOLIO CONFIGURATIONS

While Base Cases with and without Carbon Policy provide insight into the larger theme of the impact of carbon policies to drive reductions from a business as usual case, the company's approach in this

IRP was to analyze multiple pathways that align to the of interest to stakeholders. These portfolios attempt to achieve desired outcomes of ceasing to burn coal in the Company's generation fleet, meeting aggressive carbon reductions goals, and in one scenario transition the fleet without the deployment of new gas generation. The work described in the previous section with respect to sensitivity analysis also helped inform the development of these pathways. While each of these pathways attempts to accomplish its own desired outcomes, the detailed examinations also help quantify tradeoffs of total costs of the implementation and operation of the portfolio, pace of change and impact to the average residential monthly bill, dependency on technological development and deployment, and dependency on policy to enable the transition. This section highlights the additional portfolios analyzed and discusses some of the different requirements for each of the portfolios.

ALTERNATIVE PLANNING CASE RESULTS

EARLIEST PRACTICABLE COAL RETIREMENTS

EARLIEST PRACTICABLE COAL RETIREMENT ANALYSIS

In the 2020 IRP, the Company evaluated the potential factors that would restrict the Utility from retiring the current coal fleet at their earliest practicable dates. To retire over 3,200 MWs in DEP as earliest as practicable, this analysis suspends traditional "least cost" economic planning considerations, focusing on procurement and construction timelines for replacement capacity. The evaluation of these accelerations is often restricted by infrastructure to enable the replacements. Some of the most impactful factors contributing to earliest practical retirement dates are discussed below:

UTILITY PLANNING RESERVE MARGIN LENGTH

As with the most economic coal retirement analysis, the earliest practicable coal retirements also considered immediate planning reserve margin length of the utility to retire the capacity without replacement. To the extent possible, units were accelerated based on the available capacity length beyond the minimum planning reserve margin.

RETIRING COAL SITE TRANSMISSION

After retirements with excess planning capacity, the coal sites were considered for transmission grid impacts. With over 50 years of operations in the Carolinas, some the existing coal sites have become critical for reliability and stability of the grid. Retirements of these stations without replacement onsite often require additional transmission projects which can further lead to delays in retirement of the coal fleet. To the extent possible, replacement generation in the Earliest Practicable case was located at the site of the retiring coal plants to avoid transmission projects which would further delay the retirement of these assets if replacement generation was built offsite.

INTERCONNECTION TO TRANSMISSION SYSTEM OF REPLACEMENT GENERATION

Also contributing to the ability to accelerate retirement of these assets is the need for infrastructure associated with new replacement generation sites, usually consisting of transmission interconnection, and possible requirements for gas and water infrastructure. The current process for getting through the interconnection queue could be significant given the size of the queue. Once interconnection studies are complete, depending on the outcome of those studies, transmission upgrades to interconnect the replacement capacity may then be required which can add years to the process of replacing existing generation. These timelines were accounted for when considering options for offsite replacement capacity.

LEVERAGING EXISTING INFRASTRUCTURE

Leveraging existing infrastructure rather than constructing new generation at greenfield sites can enable accelerated retirement of these assets. Siting replacement capacity generation at existing sites can alleviate the need for new land, water sources and reduce transmission upgrades that may be required to maintain grid stability should generation cease to exist at existing coal sites. Where necessary, additional consideration was taken for incremental interstate gas pipeline to provide adequate gas supply to certain transmission advantageous sites.

TABLE A-11

EARLIEST PRACTICABLE COAL RETIREMENT DATES OF DEP COAL PLANTS

	BASE CASE MOST ECONOMIC RETIREMENT YEAR (JAN 1)	EARLIEST PRACTICABLE COAL RETIREMENT YEAR (JAN 1)	CONSTRAINING FACTOR
Mayo 1	2029	2026	Build-up of transmission-advantageous battery energy storage
Roxboro 1 & 2	2029	2028	Construction of onsite gas capacity
Roxboro 3 & 4	2028	2028	Construction of onsite gas capacity

FACTORS INFLUENCING EARLIEST PRACTICABLE COAL RETIREMENT DATES

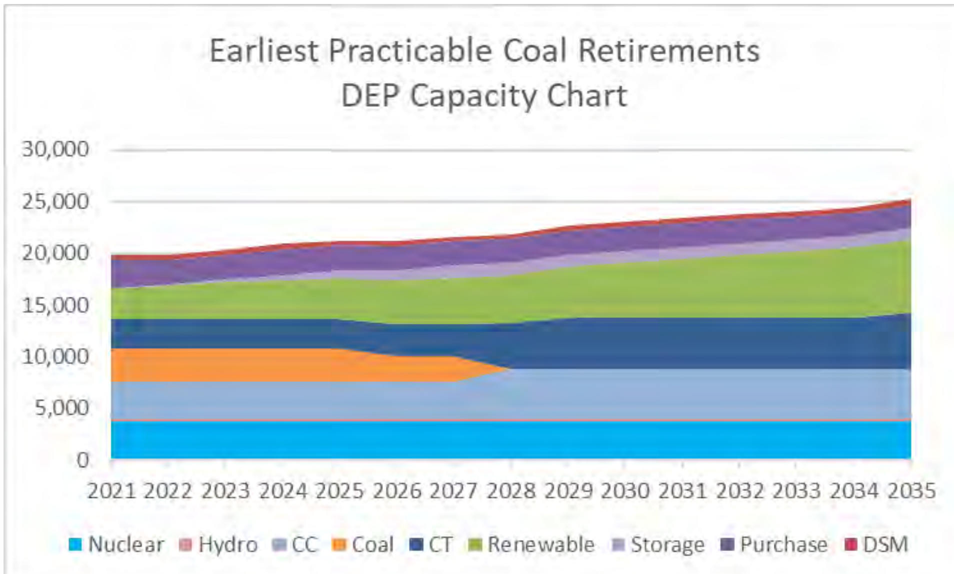
As discussed, the primary consideration in the development of the “earliest practicable” coal retirement dates is the timeline to bring replacement resources into service. Demand-side efforts identified in the IRP help to reduce the amount of resources needed to supply a growing customer base. However, the net demand and energy forecast after all demand-side initiatives is still positive. Hence any retirement of existing capacity resources creates a need for reliable replacement capacity to maintain overall system reliability. With respect to market purchases, it was assumed that in the aggregate expiring purchase contracts of existing traditional fossil resources and renewable energy resources where either extended or replaced in-kind through future RFP activities. This assumption further reduces the need for additional resources that would otherwise be required from the expiry of current purchase power contracts. Additional capacity purchases from neighboring balancing areas was not assumed eligible for replacement capacity in this analysis given the uncertain nature of the availability and cost of such potential purchases as well as the associated transmission requirements to bring in such purchases. More discussion on the ability and costs to increase transfer limits with neighboring service territories is outlined in Chapter 7. Finally, the consideration of earliest practicable coal retirement dates assumes a continued aggressive growth in year-over-year renewable resources as depicted in the Base with Carbon Policy portfolio. After first considering the total impact of demand-side activities, market purchases and renewable additions it was determined that additional reliable capacity would be required in order to enable coal retirements while maintaining adequate planning reserves as discussed in Chapter 9. As a result, to arrive at the earliest practicable coal retirement dates requires minimizing the time to site, permit, construct and obtain regulatory approval for replacement capacity resources and supporting infrastructure. As previously mentioned, for the "earliest practicable" portfolio this time lag was assumed to be minimized by replacement resources being sited largely at the retiring coal facility locations to leverage existing land, water and transmission infrastructure.

PORTFOLIO AND RESULTS DISCUSSION

With the earliest practicable retirement dates established, the capacity expansion model was run to optimize the replacement capacity needs while adhering to the prescribed replacements required to enable retirements. This plan utilizes base renewable, energy efficiency and demand response projections, as the high integration rate and high energy efficiency and demand response program penetration may not be practicable. Similar to both Base Case scenarios, the plan adds CT capacity in 2026 to meet the first capacity need in DEP. In the earliest practicable retirement date analysis, it was determined that Mayo could be retired in 2026 with the deployment of utility scale battery storage more quickly than replacing with other traditional on- or offsite capacity. This battery storage build-out from 2023 through 2027 allows for the retirement of the Mayo coal facility, by accelerating battery storage in the early 2030s from the Base Case with Carbon Policy. When all four units at Roxboro Station are retired in 2028, a combined cycle and CTs replace these retiring coal units on-site to avoid the transmission upgrades that would be required if the retiring capacity was replaced offsite. The year 2028 was determined to be the earliest that replacement capacity and transmission projects could be completed in DEP to enable the retirement of the 2,400 MWs at Roxboro Station. Additional build out of battery storage or gas at an offsite location would likely require more time and therefore these retirement dates were selected. This portfolio maintains considerable additions of solar and solar plus storage on par with the Base Case with Carbon Policy, and 750 additional MWs of onshore central Carolinas wind over the Base Case with carbon policy. While the practicality of this plan is challenging, the company believes that with proper policy support to enable this transition, the plan is feasible.

FIGURE A-6

DEP CAPACITY CHART - EARLIEST PRACTICABLE COAL RETIREMENTS



70% CO_2 REDUCTION: HIGH WIND

The 70% CO_2 Reduction: High Wind portfolio outlines a pathway to reduce CO_2 system emissions by 70% by 2030, from a 2005 baseline, by tapping into offshore wind resources off the coast of the Carolinas. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing these resources into the company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals, but requires access to diverse types of lower and carbon-free energy.

PORTFOLIO AND RESULTS DISCUSSION

The assumption of earliest practicable retirement dates underlies this plan to enable further reduction in carbon emissions by 2030. This plan also assumes high renewables, energy efficiency, and demand response projections to provide carbon-free capacity and energy to further reduce CO_2 emissions. Critically, the earliest practicable retirement dates, along with high levels of renewable penetration (nearly

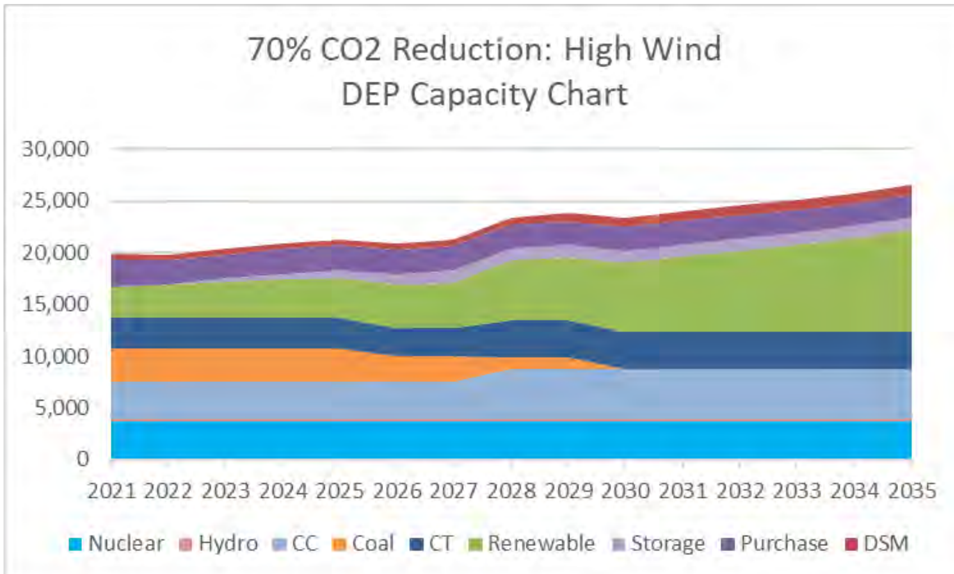
4,000 MWs of solar as a combined system above the Base Case with Carbon Policy, by 2035), is not enough to achieve 70% CO_2 reduction and additional carbon-free resources, such as offshore wind are needed. As with the previous case, gas generation will be required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes 1,200 MWs of offshore wind are incorporated into the DEP service territory by 2030. To maintain enough capacity reserves before the offshore wind can be constructed and connected to the system, Roxboro 1 & 2 retirements are delayed two (2) years from the earliest practicable retirement dates to 2030. Due to the geographical location of the offshore wind resource, significant transmission infrastructure will be required to deliver this energy to the load centers in DEP. While offshore wind can provide bulk carbon free energy, it does not provide one-for-one reliability equivalency. As an intermittent resource, the system will have to respond to variances in output from the offshore wind farm. Additionally, offshore wind is estimated to provide approximately 55% of its nameplate capacity towards meeting DEP's winter peak demand. While offshore wind capacity helps meet DEP's energy needs, the Company still requires traditional gas generation to accelerate coal retirements in this case and provide the needed capacity reserves to fulfill the Company's obligation to serve load.

While this portfolio achieves its intended outcome, it will likely require accelerated technological deployment enhancements and policy support to enable this pathway. While Offshore wind is not necessarily a new technology, deployment in the US at large scale is yet to be demonstrated. The cost of the resource and getting the energy from coastal Carolinas to the load centers in the central part of the states will present implementation challenges. These challenges can be mitigated with effective political and regulatory support and policy.

FIGURE A-7

DEP CAPACITY CHART - 70% CO_2 REDUCTION: HIGH WIND



70% CO_2 REDUCTION: HIGH SMR

The 70% CO_2 Reduction: SMR portfolio outlines a pathway to reduce CO_2 system emissions by 70% by 2030, from a 2005 baseline, by deploying advanced nuclear technologies by the end of this decade. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing advanced nuclear technologies into the Company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals. As with the 70% CO_2 Reduction: High Wind pathway, 70% CO_2 emissions reduction by 2030 requires access to additional lower carbon and carbon-free energy.

PORTFOLIO AND RESULTS DISCUSSION

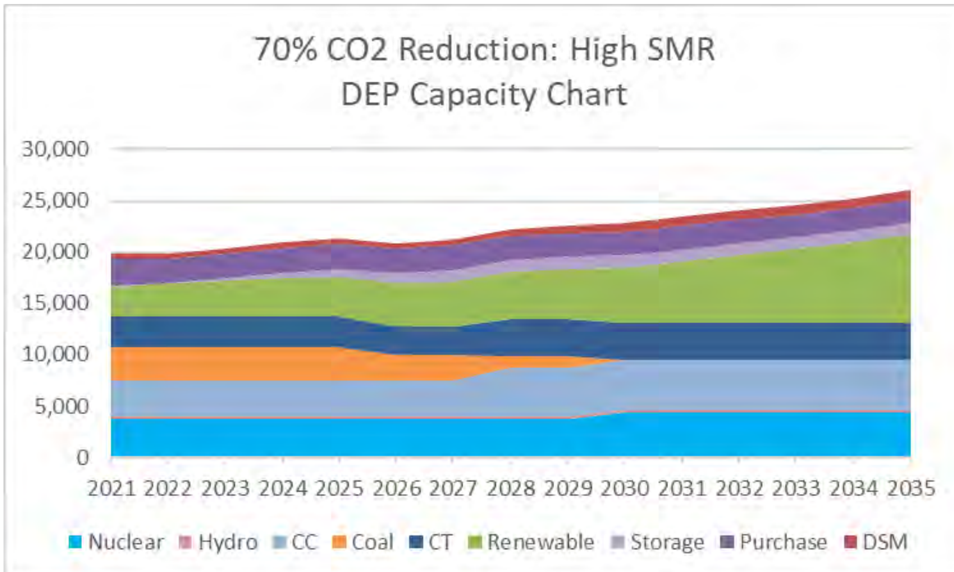
As with the previous 70% CO_2 Reduction case, the assumption of earliest practicable retirement dates underlies this plan, enabling this plan to further reduce carbon emissions by 2030. Similarly, in this case, earliest practicable retirement dates (with the two year delay for Roxboro 1&2 retirement to 2030), along with high levels of renewable penetration (nearly 4,000 MWs of solar as a combined system above the Base Case with Carbon Policy by 2035), is not enough to achieve the desired carbon reduction goals and additional carbon free resources, such as small modular nuclear reactors (SMRs) are needed. As with the previous cases, gas generation will be required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes the deployment of a 684 MW SMR nuclear plant in DEP by 2030. This technology presents an opportunity for a carbon-free resource that can adjust output up and down to follow trends in load. The addition of SMR capacity in this case is relatively small compared to the DEP system nameplate capacity, but on an energy basis, these dispatchable resources provide a greater density of carbon-free energy as compared to their intermittent renewable counter parts. While the system benefits from these attributes, the ability to license, permit, and construct this emerging technology by 2030 presents a significant challenge. The first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEP.

While this portfolio achieves its intended outcome, it will require highly effective coordination between the utility, regulatory bodies, and stakeholders to enable this pathway. While nuclear reactors are not a new technology, development and deployment of this new design is yet to be demonstrated at large scale. Uncertainty in the project cost and timeline is another factor that will need to be understood before embarking on a groundbreaking project of this magnitude.

FIGURE A-8

DEP CAPACITY CHART - 70% CO_2 REDUCTION: HIGH SMR



NO NEW GAS GENERATION

There is growing interest from environmental advocates and Environmental, Social, and Corporate Governance (ESG) investors to understand the impacts of no longer relying on natural gas as a bridge fuel to a net-zero carbon future. This scenario explores a pathway, given the proper technological and policy advancements, to bridge the gap between now and 2050 without building new gas generation. While gas generation is a mature, economical, and reliable resource, the reliance on natural gas as a bridge fuel has been challenged due to its continued reliance on fossil fuels and risks of stranding these assets. More discussion about the shortening of the book life of new gas assets and utilizing existing gas infrastructure in a net-zero carbon future were discussed earlier in this appendix and in Chapter 16. To evaluate the cost and operability of the system without gas as a transition fuel, this pathway assumes no new gas generation projects and meets the remaining capacity and energy needs of the DEP system with existing and emerging zero-carbon emitting resources, including solar, storage, wind and SMRs.

PORTFOLIO AND RESULTS DISCUSSION

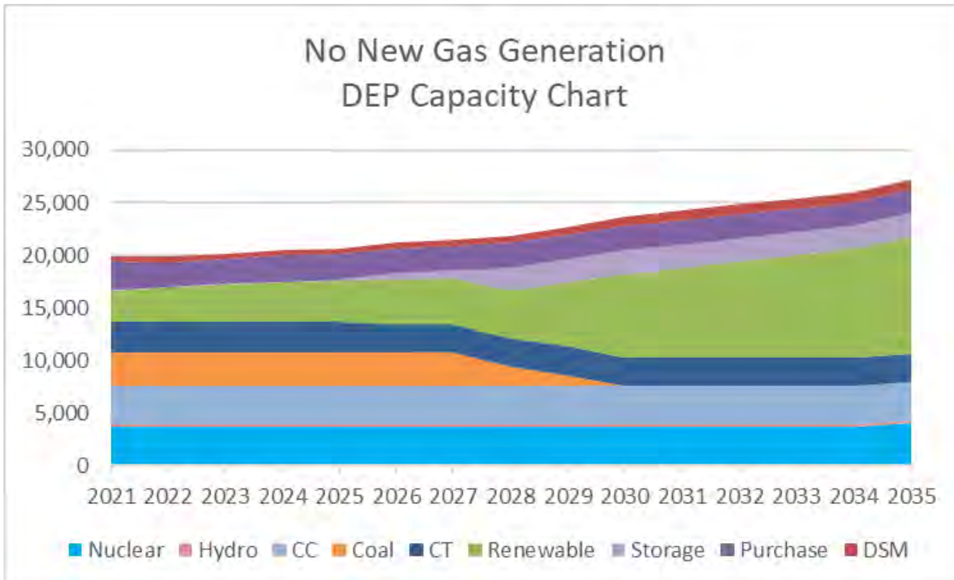
In a scenario where economical gas generation additions are eliminated, and firm winter capacity remains the binding constraint, the system must rely on the existing portfolio until existing technologies, such as batteries, can be built up on the system and emerging technologies become available, before retiring units in the current fleet. In order to allow technologies to reach maturity and decline in price, the most economic coal retirement dates were used in this scenario. This coal capacity, with a secure fuel source and ability to match generation output with demand, will provide the needed capacity until the nascent technologies needed in the mix can be implemented throughout the systems at scale.

In DEP, even with the slightly later coal retirement dates, the utility must quickly begin procuring replacement resources. This case utilizes a high penetration solar, solar plus storage, and standalone grid tied batteries. By 2030, to ensure the retirement of these units, the utility must add 3,400 MW of 4-hr and 6-hr batteries to the system. Additionally, DEP will need to procure 2,400 MW of offshore wind to help meet energy and capacity needs by 2030. Finally, by the end of the IRP planning horizon, the utility will need to add another 1,000 MW of battery storage and incorporate over 1,700 MW of central Carolinas and high-quality midcontinent wind resources, to keep up with system demand and declining capacity value of battery storage. Without the ability to wait for these technologies to mature, both operationally and economically, DEP is forced to deploy these at large penetrations before they have proven their effectiveness and economic maturity.

Even with high levels of EE and DR, the utility would have to act quickly to develop a system void of new natural gas resources and rely on the current portfolio for longer until these emerging technology resources can be implemented. The challenge does not get easier after the planning window as additional resources begin retiring, which will pose additional new challenges in meeting energy and capacity needs until more zero-emitting, load following resources can be deployed.

FIGURE A-9

DEP CAPACITY CHART - NO NEW GAS GENERATION



The following Table A-12 is a summary of the system capacity changes in the IRP planning horizon for the Base Cases and Alternative Portfolios. Additionally, Table A-13 provides the assumed retirement date of each DEP coal plant under each portfolio.

TABLE A-12

BASE CASE AND ALTERNATIVE PORTFOLIO CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

	DUKE ENERGY PROGRESS					
	BASE WITHOUT CARBON POLICY	BASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
PORTFOLIO	A	B	C	D	E	F
Coal Retirements [MW]	3,208	3,208	3,208	3,208	3,208	3,208
Incremental Solar [MW]†	2,000	3,425	3,500	4,835	4,835	4,985
Incremental Onshore Wind [MW]†	0	600	1,350	1,729	1,729	1,729
Incremental Offshore Wind [MW]	0	0	0	1,292	92	2,492
Incremental SMR Capacity [MW]	0	0	0	0	684	0
Incremental Storage [MW]‡	698	1,593	1,595	2,010	2,010	5,011
Incremental Gas [MW]	5,337	4,276	3,966	2,138	2,138	0
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]*	832	832	832	1,499	1,499	1,499

†Combined forecasted and model-selected incremental additions by the end of 2035

‡Includes Standalone Storage and Storage at Solar plus Storage sites

*Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

TABLE A-13

COAL UNIT RETIREMENTS BY PORTFOLIO

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITHOUT CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: SMR	NO NEW GAS GENERATION
Mayo 1	2029	2029	2026	2026	2026	2029
Roxboro 1 & 2	2029	2029	2028	2030*	2030*	2030**
Roxboro 3 & 4	2028	2028	2028	2028	2028	2028

*Delayed from Earliest Practicable Coal Retirement Dates for integration of offshore wind/SMR by 2030

**Delayed from Most Economic Coal Retirement Dates for integration of offshore wind by 2030

6. PERFORM PORTFOLIO ANALYSIS OVER VARIOUS SCENARIOS

PORTFOLIO PVRR ANALYSIS

Each of the six pathways identified in the portfolio development analysis were evaluated in more detail with an hourly production cost model (PROSYM) under future fuel price and CO_2 scenarios to determine the robustness of each portfolio under varying fuel and carbon futures. The run matrix for the nine scenarios is illustrated in Table A-14 below.

TABLE A-14

PORTFOLIO ANALYSIS RUN MATRIX

	NO CO_2	BASE CO_2	HIGH CO_2
Low Fuel			
Base Fuel			
High Fuel			

The PROSYM model provided the system production costs for each portfolio under the scenarios illustrated above. The model included DEP's non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEC, and as such, the model optimized both DEP and DEC and provided total system (DEP + DEC) production costs. The PROSYM results were separated to reflect system production costs that were solely attributed to DEP to account for the impacts of the JDA. The DEP specific system production costs were then added to the DEP specific capital costs for each portfolio to develop the total PVRR for each portfolio under the given fuel price and CO_2 conditions. The results of this total cost analysis, excluding the explicit cost of the carbon tax to customers (as if the carbon policy were applied as a Cap and Trade program with allowances), is summarized in Table A-15 below.

TABLE A-15

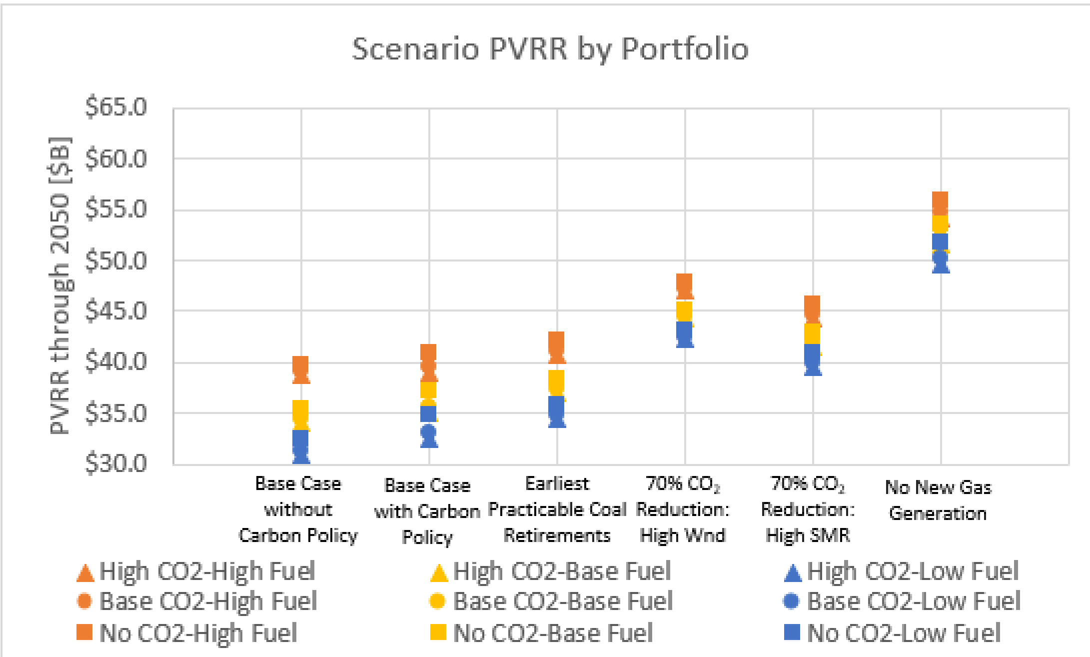
SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$38.8	$39.1	$40.8	$47.2	$44.3	$54.1
High CO_2-Base Fuel	$34.0	$35.1	$37.0	$44.3	$41.5	$51.6
High CO_2-Low Fuel	$31.0	$32.5	$34.5	$42.4	$39.6	$49.7
Base CO_2-High Fuel	$39.1	$39.7	$41.1	$47.3	$44.7	$54.7
Base CO_2-Base Fuel	$34.4	$35.7	$37.3	$44.5	$41.9	$52.1
Base CO_2-Low Fuel	$31.4	$33.1	$34.9	$42.5	$39.9	$50.3
No CO_2-High Fuel	$39.9	$41.0	$42.1	$47.9	$45.7	$56.0
No CO_2-Base Fuel	$35.4	$37.3	$38.4	$45.0	$42.9	$53.6
No CO_2-Low Fuel	$32.5	$34.8	$35.9	$43.1	$41.0	$51.8

Min	$31.0	$32.5	$34.5	$42.4	$39.6	$49.7
Median	$34.4	$35.7	$37.3	$44.5	$41.9	$52.1
Max	$39.9	$41.0	$42.1	$47.9	$45.7	$56.0

FIGURE A-10

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS



As seen in Figure A-10 above, each portfolio, when excluding the cost of carbon, have relatively tightly dispersed total PVRR costs. The plan most affected by the variance in natural gas prices is the Base Case without Carbon Policy, which relies almost exclusively on new gas generation to meet future energy needs. As carbon policy, restrictions on resources, and carbon reduction goals grow, the cost of the plans generally rise, but the dispersion of variance relative to fuel prices shrinks. This is expected, as those plans shift away from natural gas and are naturally less sensitivity to fluctuations in gas price. While the 70% CO_2 reduction and No New Gas Generation cases are less sensitive to gas prices, they are overall more expensive plans, as a result of the costs to add more expensive resources with lower Effective Load Carrying Capabilities (ELCC) and energy output as well as the transmission needed to enable these resources. Shown summarized in Table A-16 below are the results of the same total cost analysis as above, but now including the explicit cost of the carbon tax to customers (as if the carbon policy were applied as tax on carbon emission).

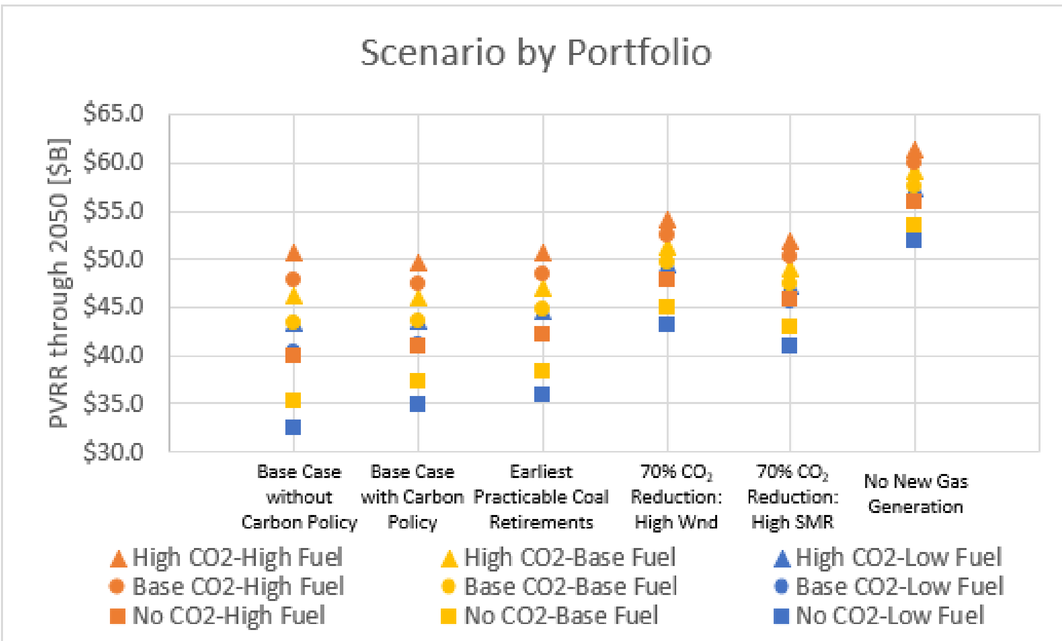
TABLE A-16

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$50.6	$49.7	$50.7	$54.2	$51.9	$61.3
High CO_2-Base Fuel	$46.2	$46.0	$47.0	$51.4	$49.1	$59.1
High CO_2-Low Fuel	$43.3	$43.5	$44.6	$49.5	$47.2	$57.3
Base CO_2-High Fuel	$47.8	$47.4	$48.4	$52.5	$50.3	$59.9
Base CO_2-Base Fuel	$43.3	$43.7	$44.7	$49.7	$47.5	$57.6
Base CO_2-Low Fuel	$40.5	$41.2	$42.3	$47.8	$45.6	$55.9
No CO_2-High Fuel	$39.9	$41.0	$42.1	$47.9	$45.7	$56.0
No CO_2-Base Fuel	$35.4	$37.3	$38.4	$45.0	$42.9	$53.6
No CO_2-Low Fuel	$32.5	$34.8	$35.9	$43.1	$41.0	$51.8
Min	$32.5	$34.8	$35.9	$43.1	$41.0	$51.8
Median	$43.3	$43.5	$44.6	$49.5	$47.2	$57.3
Max	$50.6	$49.7	$50.7	$54.2	$51.9	$61.3

FIGURE A-11

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS



In contrast to the previous view, when the costs of carbon are included in the total cost of the plan, the range of PVRRs for each plan is increased. It can be seen that the Base Case without Carbon Policy is again the portfolio that is most sensitive to fuel and carbon policies. While the lowest cost for the Base Case with Carbon Policy and Earliest Practicable Retirements is higher than Base Case without Carbon Policy, the cost ceiling is lower, due to less natural gas on the system, with its associated carbon emissions and cost based on the price of natural gas. Again, the highest reduction plans, the 70% CO_2 Reduction plans and the No New Gas Generation Plan are less sensitive to the fuel and carbon variables, but are overall more expensive plans, though the gap is smaller when the cost of carbon is considered. The results of these PVRRs are dependent on the structural and policy changes that enable carbon reductions, which will be discussed later in this appendix.

AVERAGE RESIDENTIAL MONTHLY BILL IMPACT

The total present value revenue requirement (PVRR) of a plan is a common and useful financial metric in Integrated Resource Planning to measure the cost of the plan over a long period of time. This metric will capture the costs and benefit of accelerating retirements, building new generation and associated transmission, and changing fuel prices and operation costs over time. While this is an important metric, the company is also concerned about the cost to customers on an immediate basis, as providing affordable energy is critical to the company's mission. The analysis of estimating the average residential monthly bill impact attempts to quantify how much a residential customer, using 1,000 kWh of energy a month, can expect to see their bill increase over 2020 costs of service due to the changes identified in this IRP. Table A-17 that shows the resulting increase to a residential customers bill for each of the plans through 2030 and 2035 and the average annual percentage change from 2020 through 2030 and 2035, in the company's base gas price and base carbon price scenario, while excluding the explicit cost of the carbon tax to customer.

TABLE A-17

SCENARIO ANALYSIS AVERAGE MONTHLY RESIDENTIAL BILL IMPACT FOR A HOUSEHOLD USING 1000 KWH

	2030		2035	
	AVERAGE RESIDENTIAL MONTHLY BILL IMPACT	AVERAGE ANNUAL PERCENTAGE CHANGE IN RESIDENTIAL BILLS	AVERAGE RESIDENTIAL MONTHLY BILL IMPACT	AVERAGE ANNUAL PERCENTAGE CHANGE IN RESIDENTIAL BILLS
Base Case without Carbon Policy	$13	1.2%	$21	1.2%
Base Case with Carbon Policy	$15	1.3%	$27	1.5%
Earliest Practicable Coal Retirements	$16	1.4%	$24	1.4%
70% CO_2 Reductions: High Wind	$31	2.7%	$39	2.1%
70% CO_2 Reductions: High SMR	$27	2.4%	$36	1.9%
No New Gas Generation	$49	4.0%	$58	2.9%

Table A-17 shows that the plans with earlier transitions to lower carbon future portfolios and more expensive technologies will see greater cost increase to their bills earlier, while the plans that wait longer to transition, and allow for emerging technologies to decease in price, may lessen and defer some of those costs increases. With projected declining cost curves for emerging carbon free resources the pace of adoption plays a critical role in the ultimate cost to consumers.

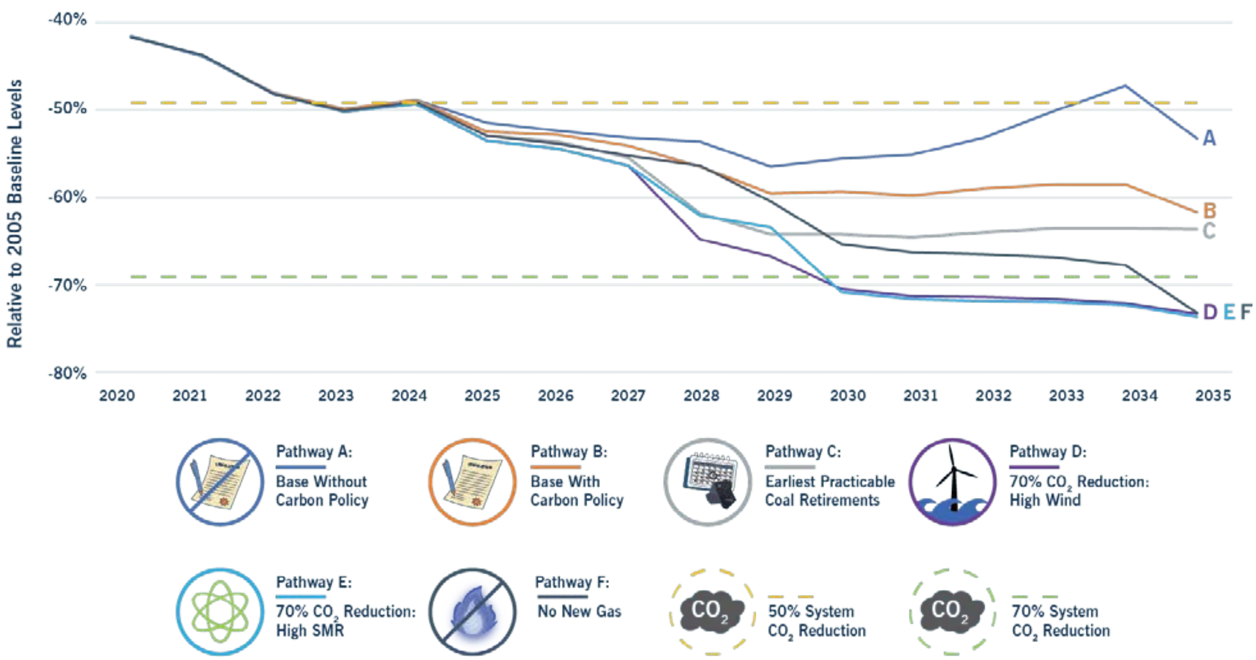
It should be noted that integrating large scale regional energy infrastructure projects, such as bringing offshore wind energy into the Carolinas, would likely require statewide policies. It is likely that the resource and the transmission infrastructure costs to move the energy from the coast to load centers could be spread across all customers in the state rather than those of a single utility. Notwithstanding this possibility, for the purposes of developing No New Gas Portfolio all energy, capacity and associated costs for the results shown are for DEP only, with the recognition that future energy policy could more evenly spread costs across utilities.

PORTFOLIO CARBON REDUCTIONS ANALYSIS

While cost is undoubtably an important factor, one of the most crucial aspects analyzed in this IRP is the trade-off between costs and carbon reductions. The graph below charts the carbon reductions for the combined DEP/DEC system of each of the portfolios in the base fuel and base carbon scenario through the IRP planning window. The resources added throughout time, price on carbon emissions (or lack thereof), and relative price between carbon intense fuels influence these carbon emissions. Additional discussion is presented below

FIGURE A-12

COMBINED DEP/DEC CARBON REDUCTION BY PORTFOLIO IN BASE FUEL AND BASE CARBON SCENARIO



Through 2024 there are no notable changes in carbon emission reductions between the portfolios. Base Planning without Carbon Policy (Pathway A) continues a trajectory of lowering carbon emissions through 2029, albeit at a slower pace than other pathways, as low cost, lower carbon intense natural gas and increasing penetration of solar offsets higher carbon intense coal generation. As gas price begins to rise in the transition from market fuel prices to fundamental fuel prices, less expensive coal generation becomes more prevalent when a carbon tax is not present. Upon retirement, and replacement of Marshall station in 2035, and replacement with gas generation, pathway A sees a reduction in carbon emission again at the end of the planning horizon.

In 2025 the carbon tax comes into effect in pathways B through F, driving the emissions from carbon intense resources down. Increasing additions of solar generation along with the economic pressure of the price on carbon continues to drive down carbon reductions in the Base Planning with Carbon Policy (Pathway B). Growing load and rising gas prices minimize the reductions realized by renewables additions in the 2030, resulting in flat CO_2 reduction until 2035, when Marshall is retired.

As coal and other traditional generation retirements take place throughout the mid-2020s, the carbon reductions between the pathways begin to diverge, resulting in a range of carbon reduction of 56% to 71% from 2005 baseline. Pathways D and E continue to rise to 70% with the retirement of Belews Creek and Marshall Stations in these scenarios by 2030, where Pathways F flattens out from 2029 through 2035, when Marshall retires in this case. By 2035, Pathways D, E, and F converge again around 73%, when the resource types in these portfolios converge at the end of the IRP horizon with similar penetrations of non-carbon emitting resources.

TABLE A-18

SCENARIO REDUCTIONS IN 2030 FOR EACH PORTFOLIO

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	55.9%	58.7%	64.3%	70.5%	70.9%	64.9%
High CO_2-Base Fuel	56.6%	59.4%	64.3%	70.5%	70.8%	65.5%
High CO_2-Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.6%
Base CO_2-High Fuel	55.7%	58.5%	64.3%	70.5%	70.8%	64.7%
Base CO_2-Base Fuel	56.4%	59.3%	64.2%	70.5%	70.8%	65.4%
Base CO_2-Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.5%
No CO_2-High Fuel	53.4%	56.5%	64.2%	70.4%	70.8%	63.6%
No CO_2-Base Fuel	55.5%	58.4%	64.1%	70.4%	70.7%	64.6%
No CO_2-Low Fuel	56.0%	58.9%	63.9%	70.2%	70.4%	65.1%
Reduction Range	3.4%	3.0%	0.4%	0.3%	0.5%	2.0%

TABLE A-19

SCENARIO REDUCTIONS IN 2035 FOR EACH PORTFOLIO

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	56.3%	61.1%	63.6%	73.3%	73.7%	72.6%
High CO_2-Base Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.3%
High CO_2-Low Fuel	57.3%	62.0%	63.6%	73.3%	73.6%	73.5%
Base CO_2-High Fuel	54.3%	59.3%	63.6%	73.3%	73.6%	72.1%
Base CO_2-Base Fuel	57.0%	61.7%	63.6%	73.3%	73.6%	73.2%
Base CO_2Low Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.5%
No CO_2-High Fuel	49.4%	54.9%	63.6%	73.3%	73.6%	68.1%
No CO_2-Base Fuel	53.2%	58.3%	63.6%	73.3%	73.6%	71.1%
No CO_2-Low Fuel	55.5%	60.4%	63.5%	73.2%	73.5%	72.6%
Reduction Range	7.9%	7.1%	0.2%	0.1%	0.1%	5.4%

Through 2030, the plans with the most sensitivity in carbon emissions are the Base Cases, again due to their continued operations of Coal through the most economic retirement dates, and the additions of natural gas generation throughout the planning horizon. The CO_2 reduction range for the remaining four portfolios is relatively tight, within a 0.5% or less variance for the plans the utilize the earliest practicable retirement dates, and 2% for No New Gas Generation, which does not deploy new natural gas, but relies on the most economic retirement dates of the coal units for deployment of other existing and emerging technologies to replace the retiring capacity.

These observations though 2030 are amplified by 2035. The cases with the most economic coal retirement dates see ranges of carbon reductions from 7.9% in the Base Case without Carbon Policy to 5.4% in the No New Gas Generation plan. Conversely, the plans with the higher costs also deliver consistency in carbon reductions, with emission varying very little with changes to carbon and fuel pricing.

IDENTIFYING OPPORTUNITIES AND RISK MITIGATION

While each of these plans comes with inherent risks, such as exposure to fuel and carbon pricing or early adoption of emerging technologies with cost and operational uncertainties, the utility will have to continue to have constructive conversations with stakeholders, regulators, and customers to identify and mitigate risks that would prevent the company from providing clean, affordable, and reliable energy. Below discusses some of these risks and mitigating measure:

- **Earliest Practicable Coal Retirements –** While the PVRR and Average Residential Monthly Bill Impact results for Earliest Practicable Coal Retirements are relatively comparable to the Base Case with Carbon Policy, this portfolio does present additional potential tradeoffs and dependency on a number of factors. The regulatory approval and feasibility of procuring the replacement generation are foremost on this list. Additionally, some of the earliest practicable coal retirement are predicated on replacement onsite, leveraging existing infrastructure. This assumption avoids transmission upgrades at some of the retiring coal sites to reduce replacement timelines, and results in lower costs of the plan. The most economic retirement dates of the coal units do not assumed replacement at site, and do not benefit from this cost saving. This provides optionality in the replacement process for the cheapest alternatives to be selected but does incur more cost to the plan for the associated transmission upgrades. Project cost risks associated with these accelerated retirements may put stresses on supply chain driving price variations. Furthermore, deploying economically maturing technologies, like batteries, at large scale may increase cost and operational risk, while opting for earlier retirement of coal units by relying on natural gas may impact of deploying lower carbon and ZEFLR technologies in the future or the associated customer impact to do so.

- **Solar Interconnection –** While solar and other intermittent technologies may help lower exposure to variability in the price of fuels and can help reduce carbon emissions, the interconnection and operation of these resources will have to continue to be studied and advanced to allow for affordable and reliable operation of the system.

- **Onshore Wind Integration –** Several studies throughout the industry identify the value of combining variable energy resources like solar and wind with different but potentially complimentary production profiles. Integration of these resources can help continue to lower carbon emissions and spur economic development in the region, but overcoming the historic challenges to siting onshore wind in the Carolinas is an issue that requires further study.

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- **Offshore Wind Integration –** A largely untapped resource sits just a few miles off the coast of the Carolinas. While there are several hurdles to incorporating this new generation source in the Carolinas systems, such as construction of these wind resources, transmitting that energy to land and then delivering it to the Company's load centers, there is a great opportunity to further reduce carbon emissions and add bulk amounts of zero fuel cost generation to the fleet.

- **ZELFR Development –** While emerging technologies, such as SMRs, were deployed in this IRP, the general development of zero-emitting, load following resources across a range of options will be important to de-risking the transition to a net-zero carbon future.

- **System Operability –** The system operators will have to continue to learn and adapt to new, intermittent and variable energy resources on the system to balance load and generation, utilizing and advancing the flexibility of the existing fleet, while leveraging resources like energy storage and demand side management to continue to provide safe and reliable energy. These transformations envisioned will also rely on significant advancements in the sophistication of the grid control systems needed to manage system operations with these more diverse and distributed new energy resources.

OTHER FINDINGS AND INSIGHTS

- **Gas as a transition fuel - T**he No New Gas Generation portfolio in this IRP demonstrates that natural gas remains a cost-effective way to accelerate the remaining coal retirements over the term of this IRP. Many independent studies and articles have supported the continued role of natural gas to balance the intermittency of renewables and continue to decarbonize the system. As shown in the emissions trajectories graph, the No New Gas portfolio emits more CO_2, over the fifteen-year period through 2035 and is significantly more costly than the 70% Carbon Reduction by 2030 portfolios (D and E) that include natural gas as a replacement resource. Eliminating natural gas generation as an option is likely to have the unintended effect of delaying coal retirements and increasing CO_2 in the interim, as more coal generation is required to serve load without new efficient natural gas resources as a transition technology.

- **Gas transportation services -** On July 5th, 2020 Dominion Energy and Duke Energy announced the cancellation of Atlantic Coast Pipeline (ACP) citing anticipated delays and increasing cost uncertainty due to on-going permitting and legal challenges. DEP and DEC still need additional firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. The 2020 IRP assumes incremental firm transportation service volumes as contemplated in the ACP project are needed from alternate pipeline providers to cost effectively support both existing natural gas generation fleet and future combined cycle natural gas generation growth. Additionally, incremental firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this IRP along with firm transportation service cost estimates. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented. Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are planned as dual fuel units that are ultimately connected to Transco Zone 5 and will rely on delivered Zone 5 gas supply or if needed ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or gas is higher priced than the cost to operate on fuel oil. Additional discussion on ACP and Fuel Supply can be found in Appendix F.

- **Discussion on Levelized Cost of Energy (LCOE) -** A common source of confusion over the economics of replacement generation for coal retirements are "Levelized Cost of Energy" reports that attempt to compare all-in costs divided by total energy production on a $/MWh basis. While this can be a useful high-level economic screening tool, it does not speak to the capacity value of a resource, nor does it recognize time value differences in energy production, which can vary dramatically as is the case with high levels of renewable resources. Simple LCOE analysis ignores the reality that it can take several times the amount of installed capacity of certain intermittent resources to produce the same reliability of dispatchable resources, even if those resources are paired with energy storage. This multiplier effect can create additional hurdles related to the permitting and interconnection of a significantly larger amount of resources (on a nameplate MW basis), which naturally has cost implications. To illustrate the multiplier effect, the Company has developed a Portfolio Screening Tool which will be released to the public shortly after the IRP filing.

- **Emerging Technologies Decommissioning Costs –** Industry research is beginning to address decommissioning challenges in cost and potential materials recycling opportunities for these new and emerging technologies. While there are allowances for some costs at end of life, more information will be needed to forecast these costs and the resource selections are being made.

- **A balanced approach to aggressive carbon reduction goals** – The company has stated that a balanced portfolio of resources with varying attributes to produce carbon-free energy, respond to variations in load and generation, shift energy, and reduce overall energy and demand is an important aspect for the Company to consider in resource planning. A combination and blend of these resources in the portfolio may help reduce reliance on the development or price declines of a single resource type and provide the system with the balance of attributes to reliably and more affordably meet the customers' energy needs.

VALUE OF JOINT PLANNING

To demonstrate the value of sharing capacity with DEC, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Case with Carbon Policy plans for DEP and DEC would change if a 17% minimum winter planning reserve margin was applied at the combined system level, rather than the individual company level.

An evaluation was performed comparing the Base Case with Carbon Policy plans for DEP and DEC to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEP and DEC to meet the 17% minimum winter planning reserve margin. Table A-20 shows the base expansion plans (Base Case with Carbon Policy for both DEP and DEC) through 2035, if separately planned, compared to the Joint Planning Case. The sum of the two combined resource requirements is then compared to the amount of resources needed if DEP and DEC could jointly plan for capacity. Planned projects and the economic selection of renewables and batteries were not reoptimized for this sensitivity. Delaying and accelerating of gas units was used to preserve the joint system's 17% reserve margin. Years where the Joint Planning Case differ from the individual Utility cases are highlighted.

TABLE A-20

COMPARISON OF BASE CASE WITH CARBON POLICY OF INDIVIDUAL UTILITY PLANNING TO JOINT PLANNING SENSITIVITY

	INDIVIDUAL UTILITY PLANNING					
	DEP		DEC		COMBINED SYSTEM	
	CC	CT	CC	CT	CC	CT
2021	0	0	0	0	0	0
2022	0	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	0	0	0
2026	0	457	0	0	0	457
2027	0	914	0	0	0	914
2028	1,224	914	0	0	1,224	914
2029	2,448	1,828	0	0	2,448	1,828
2030	2,448	1,828	0	457	2,448	2,285
2031	2,448	1,828	0	914	2,448	2,742
2032	2,448	1,828	0	914	2,448	2,742
2033	2,448	1,828	0	914	2,448	2,742
2034	2,448	1,828	0	914	2,448	2,742
2035	2,448	1,828	1,224	1,828	3,672	3,656

	JOINT PLANNING	
	COMBINED SYSTEM	
	CC	CT
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	457
2027	0	457
2028	1,224	914
2029	2,448	1,828
2030	2,448	1,828
2031	2,448	2,285
2032	2,448	2,285
2033	2,448	2,742
2034	2,448	2,742
2035	3,672	3,199

A comparison of the DEP and DEC Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer a CT resource starting in 2027. Consequently, the Joint Planning Case also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Case, which averaged 18.3% and 18.2%, respectively, from the first need in DEP in 2026 over the remaining IRP planning horizon. The ability to share resources and achieve incrementally lower reserve margins from year to year in the Joint Planning Case illustrates the efficiency and economic potential for DEP and DEC when planning for capacity jointly. Finally, as discussed in the Company's updated Resource Adequacy Study the benefits of a joint system can have beneficial results and could potentially lead to even a slightly lower reserve margin than the 17% examined in the Joint Planning Case.

B

DUKE ENERGY PROGRESS OWNED GENERATION

APPENDIX B: DUKE ENERGY PROGRESS OWNED GENERATION

Duke Energy Progress' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Progress-owned generation, as well as purchased power, is evaluated on a real-time basis to select and dispatch the lowest-cost resources to meet system load requirements.

The tables below list the Duke Energy Progress' plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

EXISTING GENERATING UNITS AND RATINGS [A, B, C, D, E]

ALL GENERATING UNIT RATINGS ARE AS OF JANUARY 1, 2020 UNLESS OTHERWISE N

COAL									
PLANT	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Mayo [2]	1	746	727	Roxboro, NC	Coal	Intermediate	36	9	N/A
Roxboro	1	380	379	Semora, NC	Coal	Intermediate	53	9	N/A
Roxboro	2	673	668	Semora, NC	Coal	Intermediate	51	9	N/A
Roxboro [2]	3	698	694	Semora, NC	Coal	Intermediate	46	8	N/A
Roxboro [2]	4	711	698	Semora, NC	Coal	Intermediate	39	8	N/A
	Total Coal	3,208	3,166						

COMBUSTION TURBINES									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ES REMAINING LIFE	STATUS
Asheville	3	185	160	Arden, NC	Natural Gas/Oil	Peaking	20	20	N/A
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking	19	20	N/A
Blewett	1	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	2	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	3	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	4	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Darlington	1	63	52	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	2	64	48	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	3	63	52	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	4	66	50	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	6	62	45	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	7	65	51	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	8	66	48	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	10	65	51	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking	22	18	N/A
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking	22	18	N/A
Smith [4]	1	197	157	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith [4]	2	197	156	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith [4]	3	197	155	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A

COMBUSTION TURBINES (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Smith [4]	4	197	159	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith [4]	6	197	145	Hamlet, NC	Natural Gas/Oil	Peaking	17	22	N/A
Sutton	4	49	39	Wilmington, NC	Natural Gas/Oil	Peaking	2	34	N/A
Sutton	5	49	39	Wilmington, NC	Natural Gas/Oil	Peaking	2	34	N/A
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	3/12	197	173	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	4/13	197	170	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	5/14	197	163	Goldsboro, NC	Oil/Natural Gas	Peaking	19	30	N/A
Weatherspoon	1	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	49	6	N/A
Weatherspoon	2	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	49	6	N/A
Weatherspoon	3	41	32	Lumberton, NC	Natural Gas/Oil	Peaking	48	6	N/A
Weatherspoon	4	41	30	Lumberton, NC	Natural Gas/Oil	Peaking	48	6	N/A

COMBUSTION TURBINES (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSIN G STATUS
Total NC		2,660	2,203						
Total SC		780	613						
Total CT		3,440	2,816						

COMBINED CYCLE									
		WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ERL	RELICENSING STATUS
Asheville	CT5	190	153	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Asheville	ST6	90	84	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Asheville	CT7	190	153	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Asheville	ST8	90	84	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Lee	CT1A	225	170	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Lee	CT1B	227	170	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Lee	CT1C	228	170	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Smith [4]	CT7	194	154	Hamlet, NC	Natural Gas/Oil	Base	17	23	N/A
Smith [4]	CT8	194	154	Hamlet, NC	Natural Gas/Oil	Base	17	23	N/A
Smith [4]	ST4	182	169	Hamlet, NC	Natural Gas/Oil	Base	17	23	N/A
Smith [4]	CT9	216	180	Hamlet, NC	Natural Gas/Oil	Base	8	32	N/A
Smith [4]	CT10	216	180	Hamlet, NC	Natural Gas/Oil	Base	8	32	N/A
Smith [4]	ST5	248	248	Hamlet, NC	Natural Gas/Oil	Base	8	32	N/A
Sutton	CT1A	224	170	Wilmington, NC	Natural Gas/Oil	Base	6	34	N/A
Sutton	CT1B	224	171	Wilmington, NC	Natural Gas/Oil	Base	6	34	N/A
Sutton	ST1	271	266	Wilmington, NC	Natural Gas/Oil	Base	6	34	N/A
	Total CC	3,588	3,054						

HYDRO									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	EST REMAINING LIFE	STATUS
Blewett	1	4	4	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	2	4	4	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	3	4	4	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	4	5	5	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	5	5	5	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	6	5	5	Lilesville, NC	Water	Intermediate	107	N/A	2055
Marshall	1	2	2	Marshall, NC	Water	Intermediate	34	N/A	Exempt
Marshall	2	2	2	Marshall, NC	Water	Intermediate	34	N/A	Exempt
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate	91	N/A	2055
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate	91	N/A	2055
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate	91	N/A	2055
Tillery	4	24	24	Mt. Gilead, NC	Water	Intermediate	59	N/A	2055
Walters	1	36	36	Waterville, NC	Water	Intermediate	89	N/A	2034
Walters	2	40	40	Waterville, NC	Water	Intermediate	89	N/A	2034
Walters	3	36	36	Waterville, NC	Water	Intermediate	89	N/A	2034
Total Hydro		227	227						

NUCLEAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	EST REMAINING LIFE	RELICENSING STATUS
Brunswick [2]	1	975	938	Southport, NC	Uranium	Base	42	37	2036
Brunswick[2]	2	953	932	Southport, NC	Uranium	Base	44	35	2034
Harris [2]	1	1009	964	New Hill, NC	Uranium	Base	32	47	2046
Robinson	2	793	759	Hartsville, SC	Uranium	Base	48	31	2030
Total NC		2,937	2,834						
Total SC		793	759						
Total Nuclear		3,730	3,593						

SOLAR [5]									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
NC Solar		141	141	NC	Solar	Intermittent	Various	N/A	N/A
Total Solar		141	141						

ENERGY STORAGE									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)		STATUS
Asheville-Rock Hill		8.8	8.8	Asheville, NC	Energy Storage	Intermittent	0	N/A	N/A
Energy Storage Total		8.8	8.8						

TOTAL GENERATION CAPABILITY		
	WINTER CAPACITY (MW)	SUMMER CAPACITY (MW)
TOTAL DEP SYSTEM - N.C.	12,770	11,634
TOTAL DEP SYSTEM - S.C.	1,573	1,372
TOTAL DEP SYSTEM	14,343	13,006

NOTE A: Ratings reflect compliance with NERC reliability standards.

NOTE B: Duke Energy Progress completed the purchase from NCEMC of jointly owned Roxboro 4, Mayo 1, Brunswick 1 & 2 and Harris 1units effective 7/31/2015.

NOTE C: Resource type based on NERC capacity factor classifications which may alternate over the forecast period.

NOTE D: Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

NOTE E: Solar capacity ratings reflect nameplate winter and summer peak values.

PLANNED UPRATES			
UNIT	COMPLETION DATE	WINTER MW	SUMMER MW
Brunswick 1	Spring 2024	4	2
Brunswick 2	Spring 2027	6	4
Brunswick 2	Spring 2029	4	2
Brunswick 2	Spring 2029	6	4

NOTE: This capacity not reflected in unit ratings in above tables.

RETIREMENTS					
UNIT & PLANT NAME	LOCATION	CAPACITY (MW) WINTER / SUMMER		FUEL TYPE	RETIREMENT DATE
Asheville	Arden, NC	158	155	Coal	1/29/2020
Asheville	Arden, NC	192	189	Coal	1/29/2020
Cape Fear 5	Moncure, NC	148	144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175	172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14	11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14	12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15	12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14	11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12	11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12	7	Steam Turbine	3/31/11
Darlington 5	Hartsville, SC	66	51	Combustion Turbine	5/31/18
Darlington 9	Hartsville, SC	65	50	Combustion Turbine	6/30/17
Darlington 11	Hartsville, SC	67	52	Combustion Turbine	11/8/15
Lee 1	Goldsboro, NC	80	74	Coal	9/15/12
Lee 2	Goldsboro, NC	80	68	Coal	9/15/12
Lee 3	Goldsboro, NC	252	240	Coal	9/15/12

RETIREMENTS (CONT.)					
UNIT & PLANT NAME	LOCATION	CAPACITY (MW) WINTER / SUMMER		FUEL TYPE	RETIREMENT DATE
Lee 1	Goldsboro, NC	15	12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15	12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, SC	179	177	Coal	10/1/12
Robinson 1	Hartsville, SC	15	11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79	74	Coal	9/30/11
Sutton 1	Wilmington, NC	98	97	Coal	11/27/13
Sutton 2	Wilmington, NC	95	90	Coal	11/27/13
Sutton 3	Wilmington, NC	389	366	Coal	11/4/13
Sutton GT1	Wilmington, NC	12	11	Combustion Turbine	3/1/17
Sutton GTA	Wilmington, NC	31	23	Combustion Turbine	7/8/17
Sutton GTB	Wilmington, NC	33	25	Combustion Turbine	7/8/17
Total		2,504	2,316		

NOTE: This capacity not reflected in unit ratings in above tables.

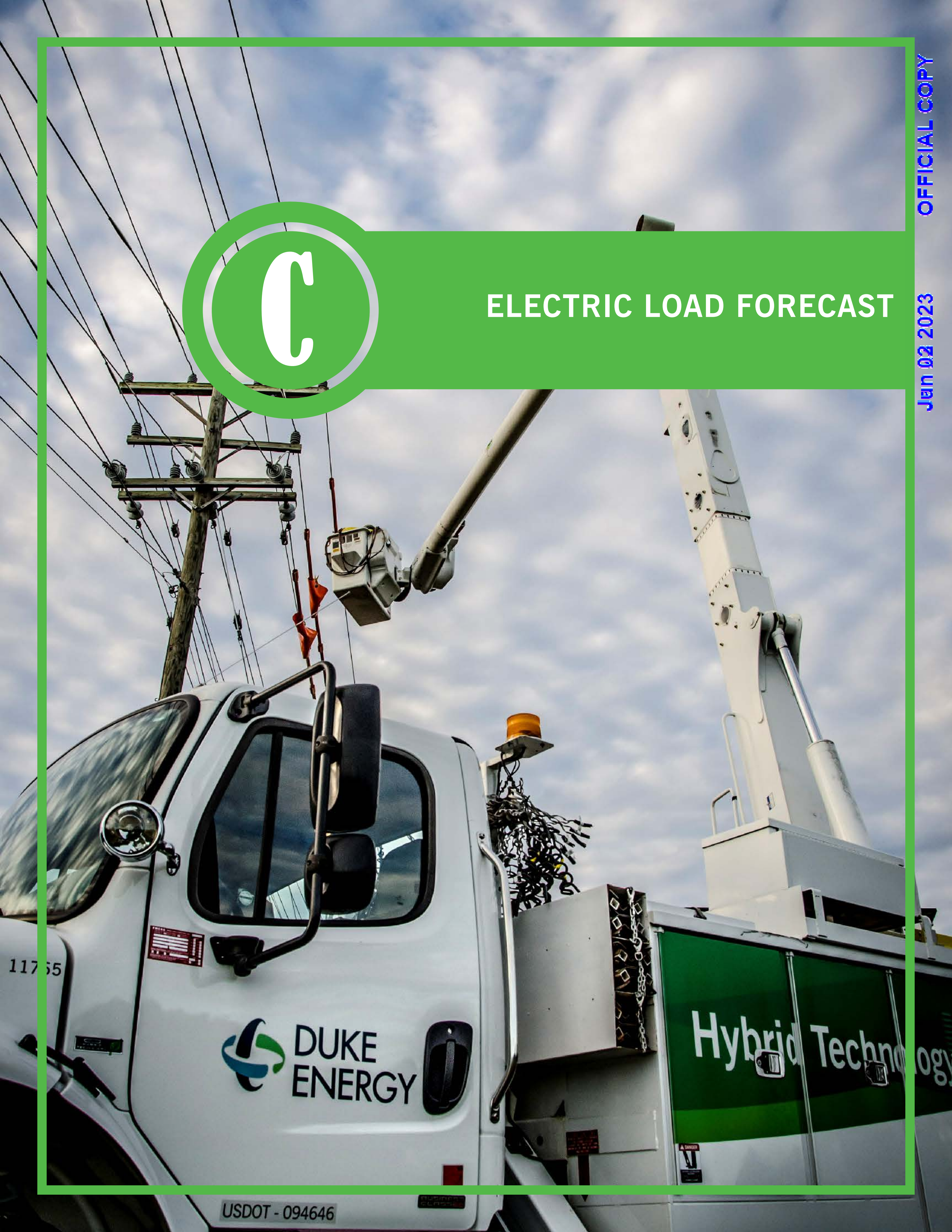
PLANNING ASSUMPTIONS – UNIT RETIREMENTS [A, B, C]					
UNIT & PLANT NAME	LOCATION	WINTER CAPACITY (MW)	SUMMER CAPACITY (MW)	FUEL TYPE	EXPECTED RETIREMENT
Mayo 1	Roxboro, N.C.	746	727	Coal	12/2028
Roxboro 1	Semora, N.C.	380	379	Coal	12/2028
Roxboro 2	Semora, N.C.	673	665	Coal	12/2028
Roxboro 3	Semora, N.C.	698	691	Coal	12/2027
Roxboro 4	Semora, N.C.	711	698	Coal	12/2027
Blewett 1	Lilesville, N.C.	17	13	Oil	12/2025
Blewett 2	Lilesville, N.C.	17	13	Oil	12/2025
Blewett 3	Lilesville, N.C.	65	13	Oil	12/2025
Blewett 4	Lilesville, N.C.	66	13	Oil	12/2025
Weatherspoon 1	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2025
Weatherspoon 2	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2025
Weatherspoon 3	Lumberton, N.C.	41	33	Natural Gas/Oil	12/2025
Weatherspoon 4	Lumberton, N.C.	41	31	Natural Gas/Oil	12/2025
Total		3,537	3,340		

NOTE a: Retirement assumptions are for planning purposes only; Coal retirement dates represent the economic retirement dates determined in the Coal Retirement Analysis (as discussed in Chapter 11). Other technology units represent retirement dates based on the depreciation study approved as part of the most recent DEP rate case.

NOTE b: For planning purposes, all portfolios in the 2020 IRP assume subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses.

NOTE c: Asheville coal units and Darlington CT units have been officially retired as of January 2020 and March 2020, respectively. Darlington CT units are included in this table as their retirement shows up in the Winter of 2021 in the LCR tables.

ELECTRIC LOAD FORECAST



APPENDIX C: ELECTRIC LOAD FORECAST

METHODOLOGY

The Duke Energy Progress Spring 2020 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2021 – 2035 and represents the needs of the following customer classes:

DEP LOAD FORECAST CUSTOMER CLASSES

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the residential customer model.

The economic projections used in the Spring 2020 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North and South Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

The Spring 2020 forecast was developed using Moody's economic inputs as of January 2020. Therefore; the disruptions experienced due to COVID-19 are not incorporated in this forecast. DEP is continuing to monitor the impacts seen to both energies and peaks, and currently think that the longer-term impacts will be minimal. The Company will however continue to evaluate the impacts, and update future forecasts for expected impacts.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.
The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The average annual growth rate of residential in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021 – 2035 is 1.4%.

The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the commercial class are offices, education and retail. Commercial energy sales are expected to grow 0.1% per year over the forecast horizon.
The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

Weather impacts are incorporated into the models by using Heating Degree Days with a base temperature of 59 and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 30-year average, which is updated every year.

The appliance saturation and efficiency trends are developed by Itron using data from the Energy Information Administration (EIA). Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

FORECAST ENHANCEMENTS

In 2013 the Company began using the SAE model projections to forecast sales and peaks. The end use models provide a better platform to recognize trends in equipment /appliance saturation and changes to efficiencies, and how those trends interact with heating, cooling, and “other” or non-weather-related sales. These appliance trends are used in the residential and commercial sales models. In conjunction with peer utilities and ITRON, the company continually looks for refinements to its modeling procedures to make better use of the forecasting tools and develop more reliable forecasts.

Each time the forecast is updated, the most currently available historical and projected data is used. The current 2020 forecast utilizes:

- Moody’s Analytics January 2020 base and consensus economic projections.
- End use equipment and appliance indexes reflect the 2019 update of ITRON’s end-use data, which is consistent with the Energy Information Administration’s 2019 Annual Energy Outlook.
- A calculation of normal weather using the period 1990-2019.

The Company also researches weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy. As a result of continuous improvement efforts, refinements to peak history were identified during the Spring 2020 update, which lowered peak history. Peak history is a key driver in the peak forecast, so the revisions also contributed to the decrease in the peak forecast. Historical peaks and forecasted peaks can be viewed later in this appendix.

ASSUMPTIONS

Below are the projected average annual growth rates of several key drivers from DEP's Spring 2020 Forecast.

TABLE C-1
KEY DRIVERS

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of UEE, as well as projected effects of electric vehicles and behind the meter solar technology.

UTILITY ENERGY EFFICIENCY

Utility Energy Efficiency (UEE) Programs continue to have a large impact in the acceleration of the adoption of energy efficiency. When including the impacts of UEE on energy and peaks, careful attention must be paid to avoid the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach. To ensure there is not a double counting of these efficiencies, the forecast "rolls off" the UEE savings at the conclusion of its measure life. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted ("rolled off") from the total cumulative UEE. With the SAE model's framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process on sales:

TABLE C-2

UEE PROGRAM LIFE PROCESS (GWH)

YEAR	FORECAST BEFORE UEE	HISTORICAL UEE ROLL OFF	FORECAST WITH HISTORICAL ROLL OFF	FORECASTED UEE INCREMENTAL ROLL ON	FORECASTED UEE INCREMENTAL ROLL OFF	UEE TO SUBTRACT FROM FORECAST	FORECAST AFTER UEE
2021	63,726	5	63,731	(651)	309	(342)	63,389
2022	64,097	20	64,117	(1,013)	464	(549)	63,568
2023	64,476	49	64,525	(1,367)	619	(749)	63,776
2024	64,996	101	65,097	(1,713)	774	(940)	64,157
2025	65,423	177	65,600	(2,054)	929	(1,125)	64,475
2026	65,924	268	66,192	(2,382)	1,085	(1,297)	64,895
2027	66,453	371	66,824	(2,688)	1,243	(1,445)	65,379
2028	67,066	473	67,538	(2,973)	1,404	(1,569)	65,969
2029	67,601	558	68,159	(3,236)	1,586	(1,650)	66,509
2030	68,159	622	68,781	(3,477)	1,807	(1,670)	67,111
2031	68,746	666	69,412	(3,699)	2,041	(1,659)	67,754
2032	69,382	688	70,070	(3,912)	2,277	(1,635)	68,435
2033	69,956	698	70,655	(4,124)	2,528	(1,595)	69,059
2034	70,574	702	71,276	(4,334)	2,784	(1,550)	69,726
2035	71,223	702	71,925	(4,543)	3,064	(1,479)	70,446

ROOFTOP SOLAR AND ELECTRIC VEHICLES

Rooftop solar photovoltaic (PV) and electric vehicles (EVs) are considered load modifiers: behind-the-meter solar PV generation reduces the effective load that Duke Energy serves, while plug-in EV charging increases load on the system. Rooftop solar generation and EV load are forecasted independently and then combined with base load and UEE impacts to produce the final electric load forecast. Impacts from existing rooftop solar and EVs are embedded in the historical data that the base load forecast is derived from. Therefore, forecasts for rooftop solar and EVs include impacts from only incremental or "net new" resources projected to be added within the planning horizon.

With the variable characteristics of solar generation and mobility of EVs, utilities will need to employ advanced system controls and/or time-of-use incentives for optimal grid management in order to provide safe, reliable and cost-effective service to customers. Given that DEP does not currently have dispatch control of rooftop solar or EVs, DEP's load forecast accounts for the variability of uncontrolled generation and charging. If advanced controls are employed in the future, the forecasted shape would better align with system capabilities and needs.

The markets for rooftop solar and EVs are growing rapidly, so it will become increasingly important to understand and accurately forecast their impacts on electric load. Additional discussion related to regulatory policy and technology can be found in Appendix E.

ROOFTOP SOLAR

Rooftop solar refers to behind-the-meter solar PV generation for residential, commercial and industrial customers. Energy produced by the solar array is consumed by the customer, offsetting their demand on the electric grid. Any excess energy is exported to the grid and credited to the customer at full retail rates under current net energy metering (NEM) policies in North and South Carolina. Both NC and SC have requirements to revisit their NEM tariffs, so while DEP assumes there will be changes to the current program within the planning horizon, it is not yet clear what those changes may be. For this IRP, DEP assumes that NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers, such that bill savings would gradually decrease over time. This reduction is offset by declining technology costs and increased customer preferences for self-generation, leading to a forecasted net increase in rooftop solar adoption.

Rooftop solar exports are beneficial as a source of carbon-free energy, but present challenges for grid operators due to intermittency associated with solar generation, reduced visibility of the resource and lack of control of energy supply.

Under full retail net metering policy, rooftop solar systems have typically been sized to offset 100% of a customer's annual average demand, within the constraints of state policy. Residential customers are limited to 20 kW-AC, and non-residential customers are limited to the lesser of 1 MW-AC or 100% demand per NC HB 589 and SC Act 62.

TABLE C-3

AVERAGE ROOFTOP SOLAR CAPACITY (KW-AC)

CUSTOMER CLASS	DEP-NC	DEP-SC
Residential	6.4	7.7
Non-Residential	60	158

The rooftop solar generation forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial and industrial customer classes.

Each capacity forecast is the product of a customer adoption forecast and an average capacity value. Adoption forecasts are based on linear regression modeling in Itron MetrixND using customer payback period as the primary independent variable. Payback periods are a function of installed cost, regulatory incentives and electric bill savings. Historical and projected technology costs are provided by Navigant. Projected incentives and bill savings are based on current regulatory policies and input from internal subject matter experts. Average capacity values are based on trends in historical adoption.

Hourly production profiles have "12x24" resolution meaning there is one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar PV modeling. Modeling is performed in PVsyst using over 20 years of historical irradiance data from Solar Anywhere and Solcast. Models are created for 9 irradiance locations across DEP's service area and 21 tilt/azimuth configurations. Results are combined on a weighted average basis to produce final profiles.

Table C-4 shows the projected incremental additions of rooftop solar customers, along with the impacts on capacity and energy, in NC and SC, at the beginning and end of the planning horizon.

TABLE C-4
ROOFTOP SOLAR, NET NEW FROM 2020

YEAR	STATE	NUMBER OF CUSTOMERS	PERCENT OF CUSTOMERS	CAPACITY (MW)	ENERGY (MWH/YEAR)
2021	NC	9,000	0.6%	79	83,000
	SC	1,400	0.8%	14	13,000
2035	NC	64,200	3.8%	550	722,000
	SC	11,400	5.5%	114	141,000

ELECTRIC VEHICLES

EV charging represents a significant opportunity for load growth in the planning horizon. Wood Mackenzie projects EV charging infrastructure to nearly quintuple by 2025[1], and BloombergNEF projects EVs to increase U.S. load by 2% in 2030 and 10% in 2040[2].

Duke Energy's EV load forecast is derived from a series of EV forecasts and load profiles.

The Electric Power Research Institute (EPRI) provides EV forecasts specific to DEP's service area for three adoption cases (low, medium and high) and five vehicle types. In recent years Duke Energy has used EPRI's medium adoption case with minor adjustments as needed for known or expected changes in the market. Vehicle types include plug-in EVs with 10-, 20- and 40-mile range and fully electric vehicles with 100 and 250-mile range.

Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential and public charging.
Table C-5 shows the projected incremental additions of EVs in operation, along with the impacts on energy, at the beginning and end of the planning horizon.

[1] Wood Mackenzie: US DER Outlook (June 2020).
[2] BloombergNEF: 2020 Electric Vehicle Outlook: U.S. Update (June 2020).

TABLE C-5

ELECTRIC VEHICLES, NET NEW FROM 2020, INCLUDES NC AND SC

YEAR	EVS IN OPERATION	PERCENT OF VEHICLE FLEET	LOAD (MWH/YEAR)
2021	13,900	0.2%	17,000
2035	241,200	8.1%	856,000

NET IMPACT OF ROOFTOP SOLAR AND ELECTRIC VEHICLES

Figures C-1, C-2 and C-3 illustrate the impacts on annual energy, winter peak demand and summer peak demand from rooftop solar and EVs by customer class across the planning horizon.

FIGURE C-1

PERCENT IMPACT OF PV AND EV ON ANNUAL LOAD, NET NEW FROM 2020

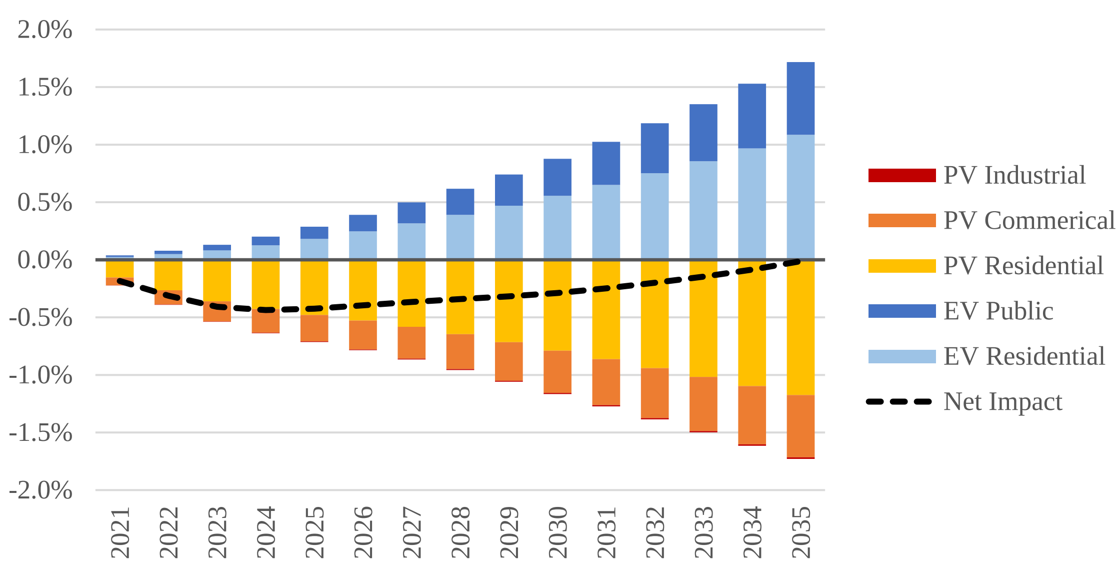


FIGURE C-2

PERCENT IMPACT OF PV AND EV ON WINTER PEAK LOAD, NET NEW FROM 2020

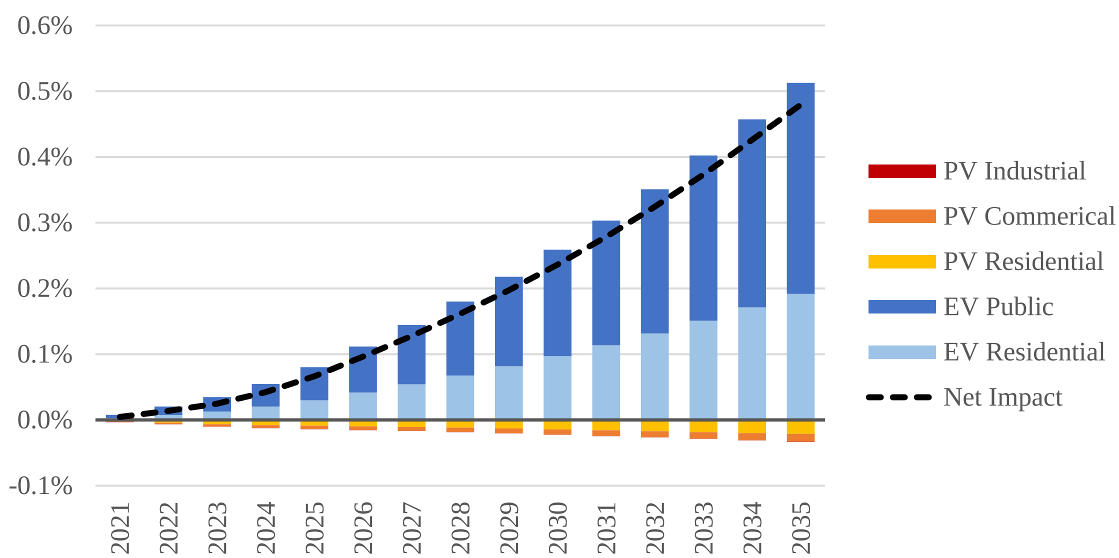
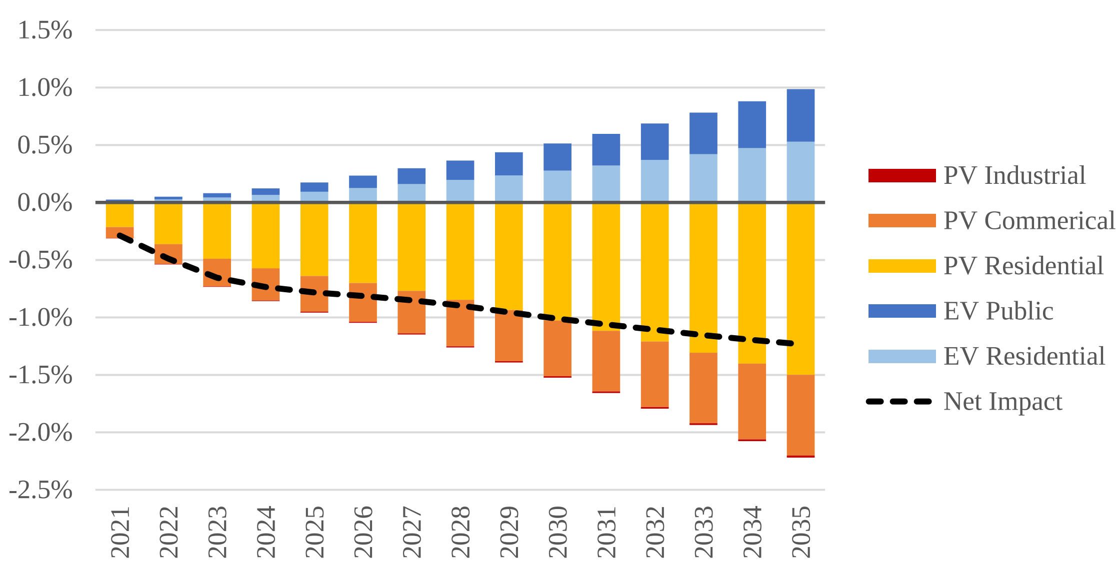


FIGURE C-3

PERCENT IMPACT OF PV AND EV ON SUMMER PEAK LOAD, NET NEW FROM 2020



CUSTOMER GROWTH

Tables C-6 and C-7 show the history and projections for DEP customers

TABLE C-6

RETAIL CUSTOMERS (ANNUAL AVERAGE IN THOUSANDS)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2010	1,216	216	5	2	1,439
2011	1,221	217	4	2	1,445
2012	1,231	219	4	2	1,457
2013	1,242	222	4	2	1,470
2014	1,257	223	4	2	1,486
2015	1,275	226	4	2	1,507
2016	1,292	229	4	2	1,527
2017	1,310	232	4	1	1,547
2018	1,331	235	4	1	1,571
2019	1,349	237	4	1	1,591
Avg. Annual Growth Rate	1.2%	1.0%	-1.4%	-7.8%	1.1%

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TABLE C-7

RETAIL CUSTOMERS (THOUSANDS, ANNUAL AVERAGE)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2021	1,388	239	4	1	1,632
2022	1,406	240	4	1	1,652
2023	1,423	242	4	1	1,670
2024	1,441	243	4	1	1,689
2025	1,458	244	4	1	1,708
2026	1,475	245	4	1	1,725
2027	1,492	246	4	1	1,743
2028	1,509	247	4	1	1,762
2029	1,527	248	4	1	1,780
2030	1,545	249	4	1	1,799
2031	1,564	250	4	1	1,819
2032	1,582	251	4	1	1,838
2033	1,601	251	4	1	1,858
2034	1,619	252	4	1	1,877
2035	1,638	253	4	1	1,896
Avg. Annual Growth Rate	1.2%	0.4%	-0.3%	0.0%	1.1%

ELECTRICITY SALES

Table C-8 shows the actual historical gigawatt hour (GWh) sales. As a note, the values in Table C-8 are not weather adjusted Sales.

TABLE C-8

ELECTRICITY SALES (GWH)

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	MILITARY & OTHER GWH	RETAIL GWH	WHOLESALE GWH	TOTAL SYSTEM GWH
2010	17,117	13,639	10,375	1,497	42,628	12,772	55,400
2011	19,108	14,184	10,677	1,574	45,544	12,772	58,316
2012	17,764	13,709	10,573	1,591	43,637	12,267	55,903
2013	16,663	13,581	10,508	1,602	42,355	12,676	55,031
2014	18,201	13,887	10,321	1,614	44,023	13,578	57,601
2015	17,954	14,039	10,288	1,597	43,876	15,782	59,658
2016	17,686	14,082	10,274	1,563	43,606	18,676	62,282
2017	17,228	13,903	10,391	1,531	43,053	18,242	61,295
2018	18,939	14,219	10,475	1,560	45,194	19,331	64,525
2019	18,177	13,992	10,534	1,537	44,241	18,694	62,935
Avg. Annual Growth Rate	0.7%	0.3%	0.2%	0.3%	0.4%	4.3%	1.4%

NOTE: The wholesale values in Table C-8 exclude NCEMPA sales for all years before 2015 and is only partially included in 2015.

SYSTEM PEAKS

Figures C-4 and C-5 show the historical actual and weather normalized peaks for the system:

FIGURE C-4

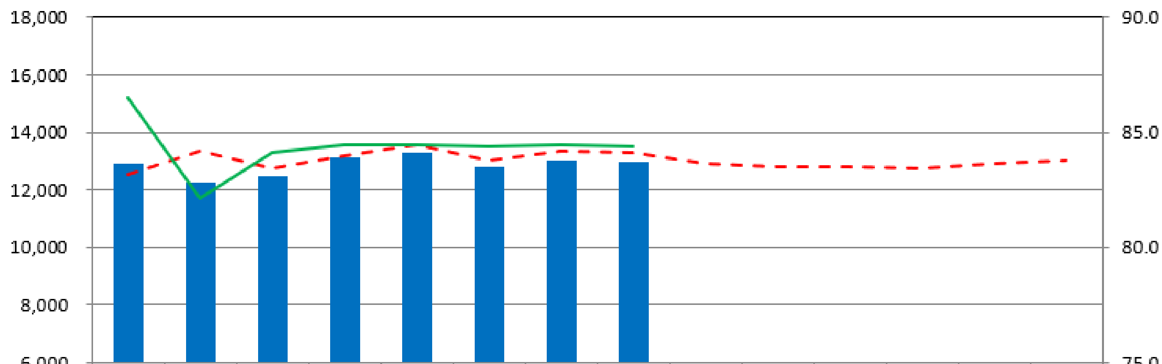
DEP ACTUALS, WEATHER NORMAL AND FORECASTED WINTER PEAKS

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actuals	11,440	12,376	14,453	16,080	13,357	14,583	15,897	13,715	12,196					
WN Peak/Forecast	12,261	12,161	13,635	13,377	13,556	14,356	14,797	14,640	13,079	14,118	14,141	14,124	14,281	14,367
Temp	31.5	27.1	19.1	20.1	26.0	23.5	19.8	29.2	35.5					

NOTE: WN Peak/Forecast values in years 2021-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak

FIGURE C-5

DEP ACTUAL AND WEATHER NORMAL AND FORECASTED SUMMER PEAKS



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actuals	12,912	12,273	12,497	13,134	13,296	12,792	13,029	12,953						
WN Peak/Forecast	12,520	13,378	12,778	13,188	13,554	13,038	13,339	13,279	12,925	12,819	12,792	12,775	12,892	13,001
Temp	86.5	82.2	84.1	84.5	84.5	84.4	84.5	84.4						

NOTE: WN Peak/Forecast values in years 2020-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

FORECAST RESULTS

A tabulation of the utility's sales and peak forecasts are shown as charts below:

- Table C-9: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table C-10: Forecast energy sales – gross load to net load (walkthrough of impacts from UEE, rooftop solar, electric vehicles and voltage control program)
- Table C-11: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table C-12: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

These projections include Wholesale, and all the loads and energy in the tables and charts below are at generation, except for the class sales forecast, which is at the meter.
Load duration curves, with and without UEE programs are shown as Figures C-6 and C-7.

The values in these tables reflect the loads that Duke Energy Progress is contractually obligated to provide and cover the period from 2021 to 2035.

TABLE C-9

FORECASTED ENERGY SALES BY CLASS

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	OTHER GWH	RETAIL GWH
2021	18,183	13,931	10,424	1,539	44,077
2022	18,303	13,905	10,323	1,530	44,061
2023	18,459	13,874	10,223	1,521	44,077
2024	18,668	13,871	10,160	1,514	44,214
2025	18,893	13,866	10,129	1,506	44,394
2026	19,144	13,873	10,089	1,499	44,606
2027	19,412	13,891	10,086	1,493	44,882
2028	19,705	13,920	10,105	1,489	45,219
2029	20,006	13,954	10,130	1,485	45,575
2030	20,343	13,996	10,153	1,481	45,973
2031	20,701	14,042	10,179	1,478	46,401
2032	21,081	14,086	10,183	1,475	46,826
2033	21,455	14,129	10,180	1,471	47,235
2034	21,844	14,178	10,172	1,469	47,662
2035	22,236	14,240	10,187	1,467	48,131
Avg. Annual Growth Rate	1.4%	0.2%	-0.2%	-0.3%	0.6%

NOTE: Values are at meter.

TABLE C-10

FORECASTED ENERGY SALES – GROSS LOAD TO NET LOAD

YEAR	GROSS RETAIL SALES	ENERGY EFFICIENCY	ROOFTOP SOLAR	ELECTRIC VEHICLES	VOLTAGE CONTROL (IVVC)	NET RETAIL SALES
2021	44,498	(342)	(96)	17		44,077
2022	44,746	(549)	(170)	35		44,061
2023	45,013	(749)	(236)	57	(8)	44,077
2024	45,363	(940)	(282)	89	(17)	44,214
2025	45,792	(1,125)	(318)	129	(83)	44,394
2026	46,165	(1,297)	(354)	176	(83)	44,606
2027	46,578	(1,445)	(394)	227	(84)	44,882
2028	47,029	(1,569)	(441)	284	(84)	45,219
2029	47,457	(1,650)	(493)	345	(85)	45,575
2030	47,864	(1,670)	(548)	413	(85)	45,973
2031	48,263	(1,659)	(605)	488	(86)	46,401
2032	48,643	(1,635)	(667)	571	(87)	46,826
2033	48,989	(1,595)	(729)	657	(87)	47,235
2034	49,342	(1,550)	(795)	753	(88)	47,662
2035	49,704	(1,479)	(862)	856	(88)	48,131

NOTE: Values are at meter.

TABLE C-11

SUMMARY OF THE LOAD FORECAST WITHOUT UEE PROGRAMS AND EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	12,885	14,161	63,731
2022	12,909	14,221	64,117
2023	12,913	14,240	64,525
2024	13,063	14,431	65,097
2025	13,207	14,566	65,600
2026	13,381	14,670	66,192
2027	13,461	14,867	66,824
2028	13,589	14,998	67,538
2029	13,833	15,248	68,159
2030	13,917	15,310	68,781
2031	14,075	15,506	69,412
2032	14,241	15,672	70,070
2033	14,361	15,792	70,655
2034	14,499	15,920	71,276
2035	14,757	16,210	71,925
Avg. Annual Growth Rate	1.0%	1.0%	0.9%

FIGURE C-6

LOAD DURATION CURVE WITHOUT ENERGY EFFICIENCY PROGRAMS AND BEFORE DEMAND RESPONSE PROGRAMS

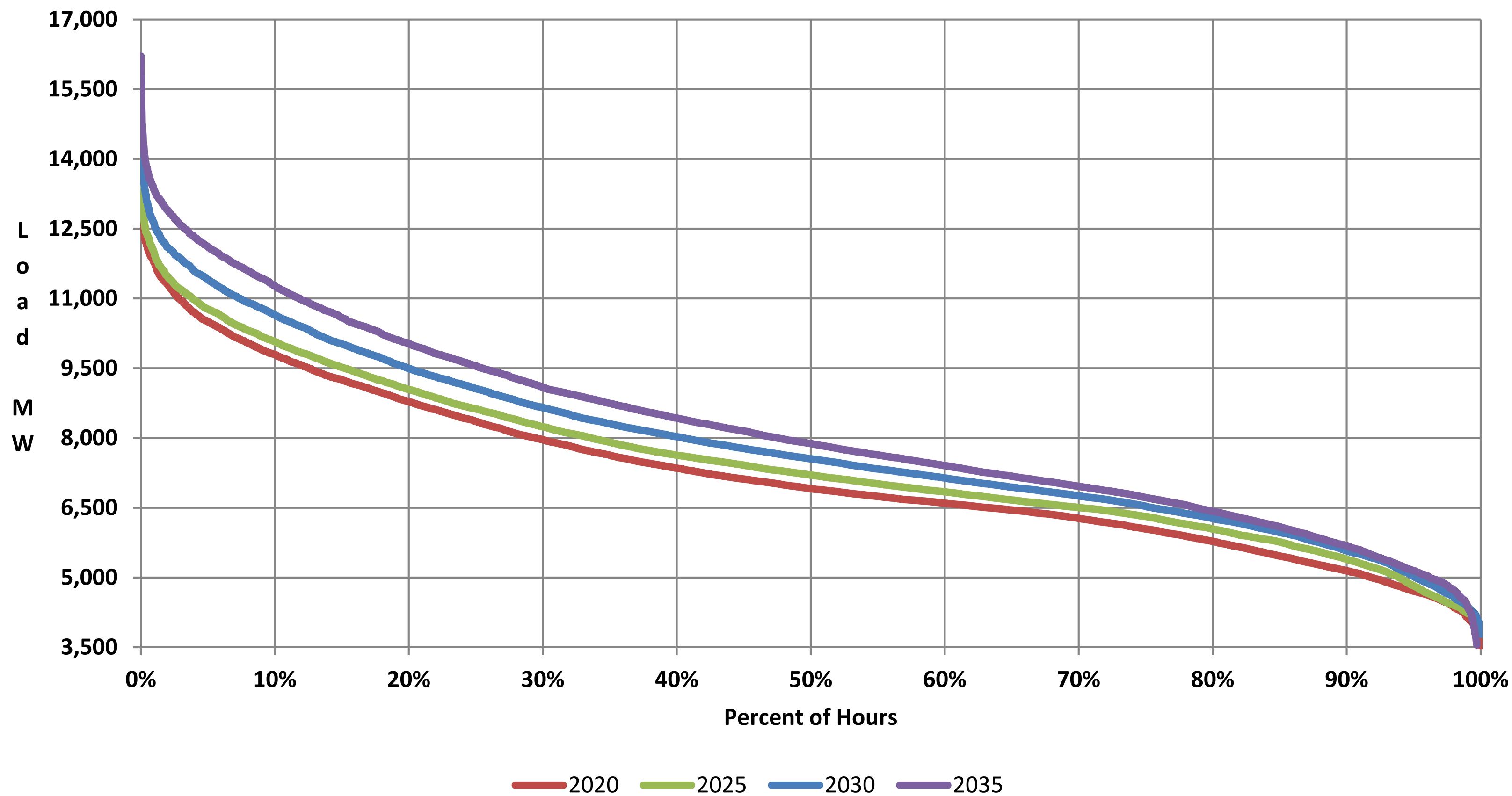


TABLE C-12

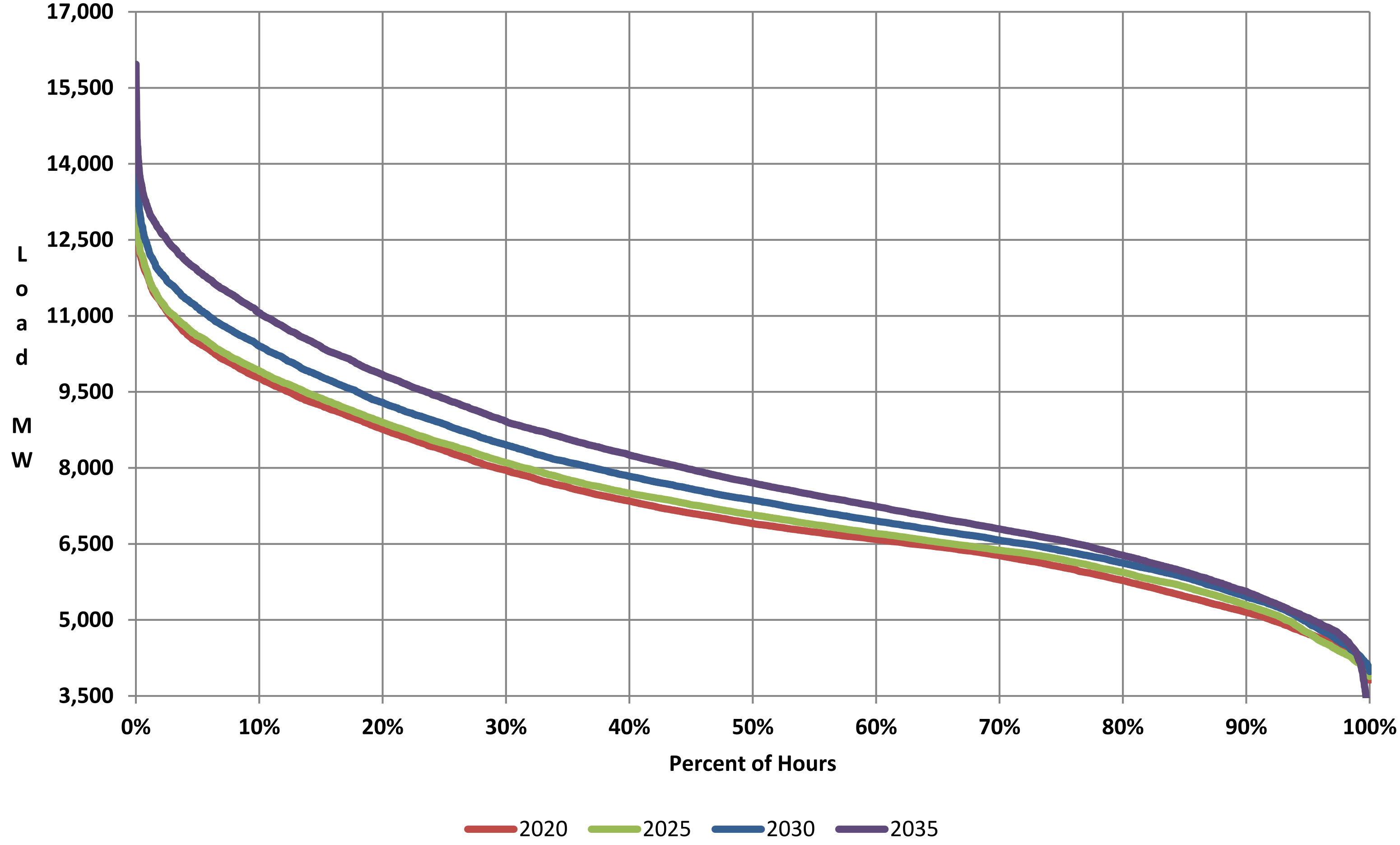
SUMMARY OF THE LOAD FORECAST WITH UEE PROGRAMS AND EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	12,818	14,118	63,389
2022	12,807	14,143	63,568
2023	12,780	14,130	63,776
2024	12,901	14,290	64,157
2025	13,016	14,381	64,475
2026	13,161	14,456	64,895
2027	13,216	14,629	65,379
2028	13,324	14,740	65,969
2029	13,552	14,976	66,509
2030	13,649	15,035	67,111
2031	13,810	15,233	67,754
2032	13,959	15,404	68,435
2033	14,107	15,531	69,059
2034	14,252	15,666	69,726
2035	14,520	15,966	70,446
Avg. Annual Growth Rate	0.9%	0.9%	0.8%

NOTE: Values are at generation level. Values differ from Tables 12-E and 12-F due to 150 MW firm sale in years 2021 – 2024.

FIGURE C-7

LOAD DURATION CURVE WITH ENERGY EFFICIENCY PROGRAMS & BEFORE DEMAND RESPONSE PROGRAMS



D

ENERGY EFFICIENCY, DEMAND SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

APPENDIX D:ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS:

DEP continues to pursue a long-term, balanced capacity and energy strategy to meet the future electricity needs of its customers. This balanced strategy includes a strong commitment to demand- side management (DSM) and energy efficiency (EE) programs, investments in renewable and emerging energy technologies, and state-of-the art power plants and delivery systems.

DEP uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs).

Following are the EE and DSM programs currently available through DEP as of December 31, 2019:

RESIDENTIAL EE PROGRAMS	NON-RESIDENTIAL EE PROGRAMS	COMBINED RESIDENTIAL / NON-RESIDENTIAL EE PROGRAMS	RESIDENTIAL DSM PROGRAMS	NON-RESIDENTIAL DSM PROGRAMS
Energy Efficient Appliances and Devices	Non-Residential Smart $aver® Energy Efficiency Products and Assessment	Energy Efficient Lighting	EnergyWise℠ Home	CIG Demand Response Automation
Energy Efficiency Education	Non-Residential Smart $aver® Performance Incentive	Distribution System Demand Response (DSDR)		Large Load Curtailable Rates & Riders
Multi-Family Energy Efficiency	Small Business Energy Saver			EnergyWise® Business
My Home Energy Report				
Neighborhood Energy Saver (Low-Income)				
Residential Energy Assessments				
Residential New Construction				
Residential Smart $aver® Energy Efficiency				

ENERGY EFFICIENCY PROGRAMS

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[1]) since the inception of these existing programs through the end of 2019 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for the specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEP's existing EE programs.

RESIDENTIAL EE PROGRAMS

Energy Efficient Appliances and Devices Program

The Energy Efficient Appliances and Devices Program is a new program that combines DEP's previous "Save Energy and Water Kit" with a variety of high efficiency products available through the Company's Online Savings Store, including but not limited to Air Purifiers, Dehumidifiers and LED Fixtures. The Save Energy and Water kit offers low flow water fixtures and insulating pipe tape to residential single-family homeowners with electric water heaters. Program participants are eligible for one kit shipped free of charge to their home. Kits are available in two sizes for homes with one or more full bathrooms and contain varying quantities of shower heads, bathroom aerators, kitchen aerator and insulating pipe tape.

Appliances and Devices				
Cumulative as of:	Number of Participants	Gross Savings (at plant)		
		MWh Energy	Peak SkW	Peak WkW
December 31, 2019	1,422,191	84,455	25,876	21,582

[1] "Gross of Free Riders" means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. "At the Plant" means that the impacts associated with the EE programs have been increased to include line losses.

ENERGY EFFICIENCY EDUCATION PROGRAM

The Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Progress. The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the current curriculum is a live theatrical production performed by two professional actors that is focused on concepts such as energy, renewable fuels and energy efficiency.

Following the performance, students are encouraged to complete a home energy survey with their family to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption and is available at no cost to student households at participating schools. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

ENERGY EDUCATION PROGRAM FOR SCHOOLS				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	47,949	14,849	4,854	2,056

MULTI-FAMILY ENERGY EFFICIENCY PROGRAM

The Multi-Family Energy Efficiency Program provides energy efficient lighting and water measures to reduce energy usage in eligible multi-family properties. The Program allows Duke Energy Progress to target multi-family apartment complexes with an alternative delivery channel. The measures are installed in permanent fixtures by the program administrator or the property management staff. The program offers LEDs including A-Line, Globes and Candelabra bulbs and energy efficient water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap.

MULTI-FAMILY ENERGY EFFICIENCY				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	1,459,233	75,502	9,400	7,384

MY HOME ENERGY REPORT PROGRAM

The My Home Energy Report (MyHER) Program provides residential customers with a comparative usage report that engages and motivates customers by comparing energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. The report also empowers customers to become more efficient by providing them with specific energy saving recommendations to improve the efficiency of their homes. The actionable energy savings tips, as well as measure-specific coupons, rebates or other Company program offers that may be included in a customer's report are based on that specific customer's energy profile.

The program includes an interactive online portal that allows customers to further engage and learn more about their energy use and opportunities to reduce usage. Electronic versions of the My Home Energy Report are sent to customers enrolled on the portal. In addition, all MyHER customers with an email address on file with the Company receive an electronic version of their report monthly.

MY HOME ENERGY REPORT				
		GROSS SAVINGS (AT PLANT)		
CAPABILITY AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	769,490	154,602	54,248	42,160

NEIGHBORHOOD ENERGY SAVER (LOW-INCOME) PROGRAM

DEP's Neighborhood Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within the households of income qualifying residential customers. The Program utilizes a Company-selected vendor to: (1) provide an on-site energy assessment of the residence to identify appropriate energy conservation measures, (2) install a comprehensive package of energy conservation measures at no cost to the customer, and (3) provide one-on-one energy education. Program measures address end-uses in lighting, refrigeration, air infiltration and HVAC applications.

Program participants receive a free energy assessment of their home followed by a recommendation of energy efficiency measures to be installed at no cost to the resident. A team of energy technicians will install applicable measures and provide one-on-one energy education about each measure emphasizing the benefit of each and recommending behavior changes to reduce and control energy usage.

NEIGHBORHOOD ENERGY SAVER				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	46,842	25,717	1,934	1,356

RESIDENTIAL ENERGY ASSESSMENTS PROGRAM

The Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment, performed by a Building Performance Institute (BPI) certified energy specialist and designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90-minute walk through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficient lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet. Additional energy efficient bulbs are available to be installed by the auditor if needed.

RESIDENTIAL ENERGY ASSESSMENTS				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	144,853	31,026	3,787	2,939

RESIDENTIAL NEW CONSTRUCTION PROGRAM

The Residential New Construction Program provides incentives for new single family and multi-family residential dwellings (projects of three stories and less) that fall within the 2012 North Carolina Residential Building Code to meet or exceed the 2012 North Carolina Energy Conservation Code High Efficiency Residential Option (HERO). If a builder or developer constructing to the HERO standard elects to participate, the Program offers the homebuyer an incentive guaranteeing the heating and cooling consumption of the dwelling's total annual energy costs. Additionally, the Program incents the installation of high-efficiency heating ventilating and air conditioning (HVAC) and heat pump water heating (HPWH) equipment in new single family, manufactured, and multi-family residential housing units.

New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or costlier to install at a later time.

RESIDENTIAL NEW CONSTRUCTION				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	39,880,246	60,788	21,030	21,201

NOTE: The participants and impacts are from both the Residential New Construction program and the previous Home Advantage program.

RESIDENTIAL SMART $AVER® EE PROGRAM (FORMERLY KNOWN AS THE HOME ENERGY IMPROVEMENT PROGRAM)

The Residential Smart $aver® EE Program offers DEP customers a variety of energy conservation measures designed to increase energy efficiency in existing residential dwellings. The Program utilizes a network of participating contractors to encourage the installation of: (1) high efficiency central air conditioning (AC) and heat pump systems with optional add on measures such as Quality Installation and Smart Thermostats, (2) attic insulation and sealing, (3) heat pump water heaters, and (4) high efficiency variable speed pool pumps.

The prescriptive menu of energy efficiency measures provided by the program allows customers the opportunity to participate based on the needs and characteristics of their individual homes. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs.

This program previously offered HVAC Audits and Room AC's, however, those measures were removed due to no longer being cost-effective.

The tables below show actual program performance for all current and past program measures.

RESIDENTIAL SERVICE – SMART $AVER				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	187,702	73,009	9,094	2,898

NON-RESIDENTIAL EE PROGRAMS

Non-Residential Smart $aver Energy Efficient Products and Assessment Program (formerly known as the Energy Efficiency for Business Program)

The Non-Residential Smart $aver Energy Efficient Products and Assessment Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

Commercial and industrial customers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the Program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products.

The program provides incentives through prescriptive measures, custom measures and technical assistance.

- ***Prescriptive Measures***: Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment. The program will no longer offer A-Line bulb incentives after 2020.

- *Custom Measures*: Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Prescriptive measure list. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike the Prescriptive portion of the program, all Custom measure incentives require pre-approval prior to the project implementation. The program will no longer offer A-Line bulb incentives after 2020.

- *Energy Assessments and Design Assistance*: Incentives are available to assist customers with energy studies such as energy audits, retro commissioning, and system-specific energy audits for existing buildings and with design assistance such as energy modeling for new construction. Customers may use a contracted Duke Energy vendor to perform the work or they may select their own vendor. Additionally, the Program assists customers who identify measures that may qualify for Smart $aver Incentives with their applications. Pre-approval is required. In 2019, the program modified its approach to a Virtual Energy Assessment utilizing an energy modeling software to complete the assessment in 2-3 weeks at a lower cost.

NON-RESIDENTIAL SMART SAVER ENERGY EFFICIENCY PRODUCTS AND ASSESSMENT				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	76,167,085	759,203	73,327	49,442

* NOTE: Participants have different units of measure.

NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE PROGRAM

The Non-Residential Smart $aver® Performance Incentive Program offers financial assistance to qualifying commercial, industrial and institutional customers to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program encourages the installation of new high efficiency equipment in new and existing nonresidential establishments as well as efficiency-related repair activities designed to maintain or enhance efficiency levels in currently installed equipment. Incentive payments are provided to offset a portion of the higher cost of energy efficient installations that are not eligible under the Smart $aver® EE Products and Assessment program. The Program requires pre-approval prior to project initiation.

The types of projects covered by the Program include projects with some combination of unknown building conditions or system constraints, or uncertain operating, occupancy, or production schedules. The intent of the Program is to broaden participation in non-residential efficiency programs by being able to provide incentives for projects that previously were deemed too unpredictable to calculate an acceptably accurate savings amount, and therefore ineligible for incentives. This Program provides a platform to understand new technologies better. Only projects that demonstrate that they clearly reduce electrical consumption and/or demand are eligible for incentives.

The key difference between this program and the custom component of the Non-Residential Smart $aver Energy® Efficient Products and Assessment program is that Performance Incentive participants get paid based on actual measure performance, and involves the following two step process.

- *Incentive #1:* For the portion of savings that are expected to be achieved with a high degree of confidence, an initial incentive is paid once the installation is complete.

- *Incentive #2:* After actual performance is measured and verified, the performance-based part of the incentive is paid. The amount of the payout is tied directly to the savings achieved by the measures.

NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	100	3,871	325	347

SMALL BUSINESS ENERGY SAVER PROGRAM

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM Rider and have an average annual demand of 180 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Progress. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The Company-authorized vendor schedules the installation of the energy efficiency measures at a convenient time for the customer, and electrical subcontractors perform the work.

SMALL BUSINESS ENERGY SAVER				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	198,207,936	266,094	36,779	17,322

NOTE: Participants have different units of measure.

COMBINED RESIDENTIAL/NON-RESIDENTIAL CUSTOMER

ENERGY EFFICIENT LIGHTING PROGRAM

The Energy Efficient Lighting Program partners with lighting manufacturers and retailers across North and South Carolina to provide marked-down prices at the register to DEP customers purchasing energy efficient lighting products. Starting in 2017, the Program removed CFLs and only offers LEDs and energy-efficient fixtures.

As the program enters its eighth year, the DEP Energy Efficient Lighting Program will continue to encourage customers to adopt energy efficient lighting through incentives on a wide range of energy efficient lighting products. Customer education is imperative to ensure customers are purchasing the right bulb for the application in order to obtain high satisfaction with lighting products and subsequent purchases.

ENERGY EFFICIENT LIGHTING				
		GROSS SAVINGS (AT PLANT)		
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	34,575,395	1,798,852	98,945	18,845

DISTRIBUTION SYSTEM DEMAND RESPONSE PROGRAM (DSDR)

Duke Energy Progress' Distribution System Demand Response (DSDR) program manages the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Progress distribution system. In general, the program tends to optimize the operation of these devices, resulting in a "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation and capacitors, line capacitors and line voltage regulators while integrating them into a single control system. This control system continuously monitors and operates the voltage regulators and capacitors to maintain the desired "flat" voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage at the substation, results in an immediate reduction of system loading during peak conditions.

DISTRIBUTION SYSTEM DEMAND RESPONSE			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)	
		MWH ENERGY	SUMMER MW CAPABILITY
December 31, 2019	N/A	38,084	251

Since DEP's last biennial resource plan was filed on September 1, 2018, there have been 25 voltage control activations through July 30, 2020. The following table shows the date, starting and ending time, and duration for all voltage control activations from July 2018 through July 2020.

VOLTAGE CONTROL ACTIVATIONS			
DATE	START TIME	END TIME	DURATION (H:MM)
10/8/2018	9:27	9:41	0:14
11/21/2018	12:55	13:06	0:11
11/28/2018	6:30	9:30	3:00
11/29/2018	6:00	10:00	4:00
1/17/2019	9:16	9:25	0:09
1/21/2019	6:00	9:12	3:12
1/22/2019	6:00	9:40	3:40
1/31/2019	6:00	9:30	3:30
3/6/2019	6:00	8:00	2:00
3/7/2019	6:00	9:00	3:00
4/1/2019	6:00	8:30	2:30
4/3/2019	6:00	10:00	4:00
4/21/2019	11:08	11:48	0:40
4/24/2019	18:00	21:30	3:30
4/25/2019	18:30	21:30	3:00
8/11/2019	8:44	8:58	0:14
8/13/2019	16:00	16:52	0:52
8/14/2019	16:00	19:00	3:00
10/2/2019	16:00	20:00	4:00
10/3/2019	16:00	20:00	4:00
11/13/2019	6:00	9:30	3:30

VOLTAGE CONTROL ACTIVATIONS			
DATE	START TIME	END TIME	DURATION (H:MM)
11/14/2019	6:00	9:30	3:30
6/4/2020	18:00	20:30	2:30
7/16/2020	18:05	21:00	2:55
7/30/2020	18:00	21:00	3:00

DEMAND-SIDE MANAGEMENT PROGRAMS

RESIDENTIAL:

ENERGYWISE℠ HOME PROGRAM

The EnergyWise℠ Home Program allows DEP to install load control switches at the customer's premise to remotely control the following residential appliances:

- Central air conditioning or electric heat pumps
- Auxiliary strip heat on central electric heat pumps (Western Region only)
- Electric water heaters (Western Region only).

For each of the appliance options above, an initial one-time bill credit of $25 following the successful installation and testing of load control device(s) and an annual bill credit of $25 is provided to program participants in exchange for allowing the Company to control the listed appliances.

ENERGYWISE℠ HOME			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS*	2017 CAPABILITY (MW@GEN)	
		SUMMER	WINTER
December 31, 2019	196,192	405	14.1

* Number of participants represents the number of measures under control.

The following table shows Residential EnergyWise℠ Home Program activations that were for the general population from July 1, 2018 through December 31, 2019.

ENERGYWISE℠ HOME PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
11/28/2018	6:30 am	9:00 am	150	11.7
11/29/2018	6:30 am	9:00 am	150	10.9
1/31/2019	6:30 am	9:00 am	150	13
7/2/2019	4:30 pm	5:00 pm	30	311
7/17/2019	3:30 pm	6:00 pm	150	173
11/13/2019	6:00 am	9:30 am	150	6

EnergyWise℠ Home added a summer cooling Bring Your Own Thermostat (BYOT) option in late December 2019. Customer acquisition for this program option year to date through June 2020 is 6,800 participants. No activations of this program option have been administered through June 2020.

NON-RESIDENTIAL

DEMAND RESPONSE – CURTAILABLE PROGRAMS AND RELATED RATE STRUCTURES

The DEP non-residential demand response portfolio consists of a combination of programs that rely either on the customer's ability to respond to a utility-initiated notification or on receipt of a signal to control customer equipment, including small business thermostats. Customers are offered ongoing incentives commensurate to the amount of load they are capable of curtailing.

The recent Nexant Market Potential Study forecasted minimal summer and winter non-residential DSM growth opportunities in the Carolinas, particularly for the small and medium business segment. Further, given the impact of the Enhanced scenario's doubling of incentives on program cost-effectiveness and future DSM rate adjustments, the Base scenario would be considered more applicable for the large non-residential segment. The large business demand response programs are actively marketed to all customer segments that are known to possess the flexibility to curtail load and have demands high enough to comply with program minimums, which means that there is a simultaneous effort to maximize both winter and summer resources. Although they provide for flexibility in contracting for different winter and summer commitments due to seasonal variations in customers' loads and operational characteristics, the programs are designed to incent participants to provide curtailable demand year-round. This allows for availability of the programs even in off-peak months when scheduled generation maintenance, in conjunction with unseasonable temperatures or other weather events, could lead to the need for demand-side management resources.

Duke Energy Progress' current curtailable programs include:

COMMERCIAL, INDUSTRIAL, AND GOVERNMENTAL (CIG) DEMAND RESPONSE AUTOMATION PROGRAM

The CIG Demand Response Automation Program allows DEP to install load control and data acquisition devices to remotely control and monitor a wide variety of electrical equipment capable of serving as a demand response resource. The goal of this program is to utilize customer education, enabling two-way communication technologies, and an event-based incentive structure to maximize load reduction capabilities and resource reliability. The primary objective of this program is to reduce DEP's need for additional peaking generation. This is accomplished by reducing DEP's seasonal peak load demands through deployment of load control and data acquisition technologies.

CIG DEMAND RESPONSE AUTOMATION STATISTICS			
	NUMBER OF	MW CAPABILITY	
CUMULATIVE AS OF:	PARTICIPANTS	SUMMER	WINTER
December 31, 2019	85	22.6	12.1

The table below shows information for each CIG Demand Response Automation Program non-test control event from January 1, 2018 through December 31, 2019.

CIG DEMAND RESPONSE AUTOMATION PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
1/2/2018	7:00 am	10:00 am	180	7.5
1/7/2018	6:00 am	11:00 am	300	8.7
1/15/2018	5:00 am	10:00 am	300	8.1
1/18/2018	5:30 am	9:30 am	240	7.1
6/19/2018	1:00 pm	7:00 pm	360	22.2
8/8/2018	1:00 pm	7:00 pm	360	21.7
8/28/2018	1:00 pm	7:00 pm	360	20.7
7/2/2019	1:00 pm	7:00 pm	360	27.1
7/17/2019	1:00 pm	7:00 pm	360	25.7
8/14/2019	1:00 pm	7:00 pm	360	25.8

Large Load Curtailable Rates & Riders: Participants agree contractually to reduce their electrical loads to specified levels upon request by DEP. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

LARGE LOAD CURTAILABLE STATISTICS			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MW CAPABILITY	
		SUMMER	WINTER
December 31, 2019	58	283	255

LARGE LOAD CURTAILABLE PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
1/2/2018	6:30 am	10:00 am	210	262
1/7/2018	6:00 am	11:00 am	300	201
1/15/2018	5:00 am	10:00 am	300	262
1/18/2018	5:30 am	9:30 am	240	262

ENERGYWISE® BUSINESS PROGRAM

EnergyWise® Business is both an energy efficiency and demand response program for non-residential customers that allows DEP to reduce the operation of participants' air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEP will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEP anywhere they have internet access. In addition to the portal access, participants will also receive conservation period notifications, so they can make adjustments to their schedules or notify their employees of upcoming conservation periods.

ENERGYWISE® BUSINESS				
		MW CAPABILITY		MWH ENERGY SAVINGS (AT PLANT)
CUMULATIVE AS OF:	PARTICIPANTS*	SUMMER	WINTER	
December 31, 2019	6,403	5.4	0.6	12.6

* Number of participants represents the number of measures under control.

The following table shows EnergyWise® Business program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

ENERGYWISE® BUSINESS PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
8/28/2018	4:00 pm	6:00 pm	120	2.8
7/2/2019	4:00 pm	6:00 pm	120	4.4
7/17/2019	4:00 pm	6:00 pm	120	4.5

DISCONTINUED DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

Since the last biennial Resource Plan filing, no DEP DSM/EE programs have been discontinued.

DSM/EE PROGRAMS PRIOR TO NC SENATE BILL 3

Prior to the passage of North Carolina Senate Bill 3 in 2007, DEP had a number of DSM/EE programs in place. These programs are available in both North and South Carolina and include the following:

ENERGY EFFICIENT HOME PROGRAM

PROGRAM TYPE: ENERGY EFFICIENCY

In the early 1980s, DEP introduced an Energy Efficient Home program that provides residential customers with a 5% discount of the energy and demand portions of their electricity bills when their homes met certain thermal efficiency standards that were significantly above the existing building codes and standards. Homes that pass an ENERGY STAR® test receive a certificate as well as a 5% discount on the energy and demand portions of their electricity bills.

CURTAILABLE RATES
PROGRAM TYPE: DEMAND RESPONSE

DEP began offering its curtailable rate options in the late 1970s, whereby industrial and commercial customers receive credits for DEP's ability to curtail system load during times of high energy costs and/or capacity constrained periods. There were no curtailable rate activations during the period from July 1, 2016 through December 31, 2017.

TIME-OF-USE RATES
PROGRAM TYPE: DEMAND RESPONSE

DEP has offered voluntary Time-of-Use (TOU) rates to all customers since 1981. These rates provide incentives to customers to shift consumption of electricity to lower-cost off-peak periods and lower their electric bill.

THERMAL ENERGY STORAGE RATES
PROGRAM TYPE: DEMAND RESPONSE

DEP began offering thermal energy storage rates in 1979. The present General Service (Thermal Energy Storage) rate schedule uses two-period pricing with seasonal demand and energy rates applicable to thermal storage space conditioning equipment. Summer on-peak hours are noon to 8 p.m. and non-summer hours of 6 a.m. to 1 p.m. weekdays.

REAL-TIME PRICING
PROGRAM TYPE: DEMAND RESPONSE

DEP's Large General Service (Experimental) Real Time Pricing tariff was implemented in 1998. This tariff uses a two-part real-time pricing rate design with baseline load representative of historic usage.

Hourly rates are provided on the prior business day. A minimum of 1 MW load is required. This rate schedule is presently fully subscribed.

The following table provides current information available at the time of this report on DEP's pre-Senate Bill 3 DSM/EE programs (i.e., those programs that were in effect prior to January 1, 2008). This information, where applicable, includes program type, capacity, energy, and number of customers enrolled in the program as of the end of 2019, as well as load control activations since those enumerated in DEP's last biennial resource plan. The energy savings impacts of these existing programs are embedded within DEP's load and energy forecasts.

PROGRAM DESCRIPTION	TYPE	SUMMER CAPACITY (MW)	WINTER CAPACITY (MW)	ANNUAL ENERGY (MWH)	PARTICIPANTS	ACTIVATIONS SINCE LAST BIENNIAL REPORT
Energy Efficiency Programs[2]	EE	458	N/A	N/A	N/A	N/A
Real Time Pricing (RTP)	DSM	29.8	49.7	N/A	99	N/A
Commercial & Industrial TOU	DSM	12.0	12.0	N/A	33,791	N/A
Residential TOU	DSM	5.2	5.2	N/A	23,587	N/A
Curtailable Rates	DSM	284	255	N/A	58	4

FUTURE EE AND DSM PROGRAMS

DEP is continually seeking to enhance its DSM/EE portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results, and (3) other EE pilots.

DEP plans to evaluate and consider the addition/expansion of cost-effective winter measures to the **EnergyWise[SM] Home** program in 2020. These measures include addition of winter BYOT, and expanding water heating control, and heat pump heat strip control to the rest of the system territory (beyond DEP West).

[2] Impacts from these existing programs are embedded within the load and energy forecast.

Potential new programs and/or measures will be reviewed with the DSM Collaborative then submitted to the Public Utility Commissions as required for approval.

EE AND DSM PROGRAM SCREENING

The Company evaluates the costs and benefits of DSM and EE programs and measures by using the same data for both generation planning and DSM/EE program planning to ensure that demand-side resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand-side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test, Rate Impact Measure Test, Total Resource Cost Test, and Participant Test (PCT).

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAM FORECASTS

FORECAST METHODOLOGY

In 2019, DEP commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEP service area. The final reports (one for South Carolina and one for North Carolina) were prepared by Nexant Inc. and issued in May 2020 with a final revision completed in June 2020.

The Nexant study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEP program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors.

The Nexant market potential study (MPS) included projections of Energy Efficiency impacts over a 25-year period for a Base, Enhanced and Avoided Energy Cost Sensitivity Scenario, which were used in conjunction with expected EE savings from DEP's five-year program plan to develop the Base, High and Low Case EE savings forecasts for this IRP.

The Base Case EE savings forecast represents a merging of the projected near-term savings from DEP's five-year plan (2020-2024) with the long-term savings from the Nexant MPS (2030-onward). Savings during the five-year period (2025-2029) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition.

The High Case EE savings forecast was developed using the same process as the Base case, however; for the Nexant MPS portion of the forecast, the difference between the Avoided Energy Cost Sensitivity and Base Scenarios for all years was added to the Enhanced Case forecast. This method captures the higher EE savings resulting from both the higher avoided energy cost assumptions as well as from increased customer incentives in the Enhanced case.

Finally, the Low Case was developed by applying a reduction factor to the Base Case forecast. Additionally, the cumulative savings projections for the Base, High and Low Case EE forecasts included an assumption that when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts, a process defined as “rolloff”.

The tables below provide the projected MWh load impacts for the Base, High and Low Case forecasts of all DEP EE programs implemented since 2008 on a Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2008 through the end of 2019, which accounts for approximately an additional 2,600 gigawatt-hours (GWh) of net energy savings.

The following forecast is presented without the effects of "rolloff":

PROJECTED MWH IMPACTS OF EE PROGRAMS
BASE CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2008
2008-19		2,603,928
2020	382,403	2,986,331
2021	594,043	3,197,971
2022	797,571	3,401,499
2023	993,570	3,597,498
2024	1,181,566	3,785,494
2025	1,366,448	3,970,376
2026	1,529,702	4,133,630
2027	1,671,328	4,275,256
2028	1,791,325	4,395,253
2029	1,889,695	4,493,623
2030	1,966,436	4,570,364
2031	2,025,870	4,629,798
2032	2,083,615	4,687,543
2033	2,139,751	4,743,679
2034	2,194,754	4,798,682
2035	2,248,708	4,852,636

**The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

PROJECTED MWH IMPACTS OF EE PROGRAMS
HIGH CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2008
2008-19		2,603,928
2020	382,403	2,986,331
2021	615,166	3,219,094
2022	839,006	3,442,934
2023	1,054,565	3,658,493
2024	1,261,319	3,865,247
2025	1,464,574	4,068,502
2026	1,645,430	4,249,358
2027	1,803,887	4,407,815
2028	1,939,945	4,543,873
2029	2,053,605	4,657,533
2030	2,144,866	4,748,794
2031	2,217,588	4,821,516
2032	2,287,784	4,891,712
2033	2,355,661	4,959,589
2034	2,421,746	5,025,674
2035	2,486,249	5,090,177

**The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

PROJECTED MWH IMPACTS OF EE PROGRAMS
LOW CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2008
2008-19		2,603,928
2020	286,802	2,890,730
2021	445,532	3,049,460
2022	598,178	3,202,106
2023	745,178	3,349,106
2024	886,174	3,490,102
2025	1,024,836	3,628,764
2026	1,147,276	3,751,204
2027	1,253,496	3,857,424
2028	1,343,494	3,947,422
2029	1,417,271	4,021,199
2030	1,474,827	4,078,755
2031	1,519,403	4,123,331
2032	1,562,711	4,166,639
2033	1,604,813	4,208,741
2034	1,646,066	4,249,994
2035	1,686,531	4,290,459

**The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The table below provides the projected summer and winter peak MW load impacts of all current and projected DEP DSM programs.

Projected MW Load Impacts of DSM Programs

YEAR	SUMMER PEAK MW REDUCTION					
	ENERGYWISE HOME	CIG DEMAND RESPONSE	DSDR	LARGE LOAD CURTAILABLE	ENERGYWISE FOR BUSINESS	TOTAL SUMMER PEAK
2020	408	28	226	283	13	958
2021	419	31	227	286	16	979
2022	420	35	226	289	19	989
2023	420	39	229	292	22	1002
2024	421	43	230	295	22	1010
2025	421	45	231	298	22	1017
2026	422	45	233	299	22	1021
2027	424	45	235	299	22	1024
2028	425	45	237	299	22	1028
2029	428	45	239	299	22	1032
2030	431	45	240	299	22	1037
2031	434	45	244	299	22	1044
2032	437	45	247	299	22	1050
2033	441	45	248	299	22	1055
2034	443	45	251	299	22	1061
2035	446	45	254	299	22	1065

NOTE: For DSM programs, Gross and Net are the same.

Projected MW Load Impacts of DSM Programs

YEAR	WINTER PEAK MW REDUCTION					
	ENERGYWISE HOME	CIG DEMAND RESPONSE	DSDR	LARGE LOAD CURTAILABLE	ENERGYWISE FOR BUSINESS	TOTAL WINTER PEAK
2020	15	15	215	253	1	499
2021	20	16	216	255	1	509
2022	26	18	215	258	2	519
2023	30	21	218	260	2	531
2024	33	23	219	263	2	539
2025	36	25	220	266	2	549
2026	41	25	222	268	2	558
2027	48	25	223	268	2	567
2028	58	25	225	268	2	579
2029	72	25	227	268	2	594
2030	89	25	229	268	2	613
2031	109	25	232	268	2	636
2032	130	25	235	268	2	660
2033	152	25	236	268	2	683
2034	172	25	239	268	2	706
2035	189	25	242	268	2	725

NOTE: For DSM programs, Gross and Net are the same.

Pursuing EE and DSM initiatives is not expected to meet the growing demand for electricity. DEP still envisions the need to secure additional generation, as well as cost-effective renewable generation, but the EE and DSM programs offered by DEP will address a significant portion of this need if such programs perform as expected.

PROGRAMS EVALUATED BUT REJECTED

Duke Energy Progress has not rejected any cost-effective programs as a result of its EE and DSM program screening.

CURRENT AND ANTICIPATED CONSUMER EDUCATION PROGRAMS

In addition to the DSM/EE programs previously listed, DEP also has the following informational and educational programs.

- On Line Account Access
- "Lower My Bill" Toolkit
- Online Energy Saving Tips
- Energy Resource Center
- Large Account Management
- Business Energy Advisors/ Web page
- Community Events
- Energy Efficiency Engineers
- Virtual Energy Assessments
- New Construction Energy Efficiency Design Assistance
- Newsletters

ON LINE ACCOUNT ACCESS

On Line Account Access provides energy analysis tools to assist customers in gaining a better understanding of their energy usage patterns and identifying opportunities to reduce energy consumption. The service allows customers to view their past 24 months of electric usage including the date the bill was mailed; number of days in the billing cycle; and daily temperature information. This program was initiated in 1999.

"LOWER MY BILL" TOOLKIT

This tool, implemented in 2004, provides on-line tips and specific steps to help customers reduce energy consumption and lower their utility bills. These range from relatively simple no-cost steps to more extensive actions involving insulation and heating and cooling equipment.

ONLINE ENERGY SAVING TIPS

DEP has been providing tips on how to reduce home energy costs since approximately 1981. DEP's web site includes information on household energy wasters and how a few simple actions can increase efficiency.

ENERGY RESOURCE CENTER

In 2000, DEP began offering its large commercial, industrial, and governmental customers a wide array of tools and resources to use in managing their energy usage and reducing their electrical demand and overall energy costs. Through its Energy Resource Center, located on the DEP web site, DEP provides newsletters, online tools and information which cover a variety of energy efficiency topics such as electric chiller operation, lighting system efficiency, compressed air systems, motor management, variable speed drives and energy audits.

LARGE ACCOUNT MANAGEMENT

All DEP commercial, industrial, and governmental customers with an annual electric bill greater than $250,000 are assigned to a DEP Account Executive (AE). The AEs are available to personally assist customers in evaluating energy improvement opportunities and can bring in other internal resources to provide detailed analyses of energy system upgrades. The AEs provide their customers with a monthly electronic newsletter, which includes energy efficiency topics and tips. They also offer numerous educational opportunities in group settings to provide information about DEP's new DSM and EE program offerings and to help ensure the customers are aware of the latest energy improvement and system operational techniques.

BUSINESS ENERGY ADVISORS/ WEB PAGE

Business Energy Advisors (BEA's) provide guidance for commercial and industrial energy needs. They implement a holistic approach to solving customer's energy problems. The approach includes developing and leveraging customer relationships to deliver high quality solutions to SMB customers through a portfolio of products and services that drive customer engagement and loyalty. BEA's portfolio focus primarily on customers with $60,000-$250,000 annual electricity spend. In addition, BEA's assist Large Account Managers (LAM) with EE solutions as well as leads and inquiries coming from other departments including the Customer Call Center.

COMMUNITY EVENTS

DEP representatives participated in community events across the service territory to educate customers about DEP's energy efficiency programs and rebates and to share practical energy saving tips. DEP energy experts attended conference events and forums to host informational tables and displays, and distributed handout materials directly encouraging customers to learn more about and sign up for approved DSM/EE energy saving programs.

ENERGY EFFICIENCY ENGINEERS

Energy Efficiency Engineers (EEE) are available to work with Duke Energy's non-residential sector largest customers to review, evaluate, and provide guidance with customer energy efficiency projects. The EEE has the energy efficiency knowledge to interact with customers, customer engineers and vendors. EEEs also educate customers on program requirements and processes, the identification of potential projects, the evaluation of data and measures, and the calculations required for the identified projects.

VIRTUAL ENERGY ASSESSMENTS

A building is the face of any organization and it makes an important impression. A virtual assessment is an ideal service for medium and large facilities to take control of their energy consumption – driving down operational costs, increasing efficiency, meeting sustainability goals and addressing aging infrastructure. Using state-of-the-art software, DEP's innovative approach to energy assessments will jump-start you toward your goals. Instead of taking months analyzing data, a virtual assessment can be completed in only a few weeks. Less engineering time and more technology free up resources that can be put toward projects that will save for years to come.

NEW CONSTRUCTION ENERGY EFFICIENCY DESIGN ASSISTANCE

Duke Energy has a dedicated team ready to help businesses integrate energy saving systems into existing buildings and new construction. The DEP team will work with you and your staff to provide cost-effective, energy efficiency system design options that will reduce long-term operating costs. DEP will provide energy consulting services, whole building energy modeling, system design options for you to choose from with estimated savings and cost/payback metrics, and then provide assistance with the Smart Saver Incentive Application process.

NEWSLETTERS

Duke Energy uses Questline to send regular newsletters to small, medium, large businesses, and trade allies with current articles focused on the importance of energy efficiency. The newsletters offer tools and contacts to help in the Smart $aver application process.

DISCONTINUED CONSUMER EDUCATION PROGRAMS

DEP has not discontinued any consumer education programs since the last biennial Resource Plan filing.

EE SAVINGS VARIANCE SINCE LAST IRP

In response to Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRPs, the Base Portfolio EE savings forecast of MWh is within 10% of the forecast presented in the 2018 IRP when compared on the cumulative achievements at year 2035 of the forecasts as shown in the table below.

YEAR	2018 IRP ANNUAL MWH LOAD REDUCTION - NET: INCLUDING MEASURES ADDED IN 2018 AND BEYOND	2018 IRP ANNUAL MWH LOAD REDUCTION - NET: INCLUDING MEASURES ADDED SINCE 2009	2020 IRP ANNUAL MWH LOAD REDUCTION - NET: INCLUDING MEASURES ADDED IN 2020 AND BEYOND	2020 IRP ANNUAL MWH LOAD REDUCTION - NET: INCLUDING MEASURES ADDED SINCE 2009	% CHANGE FROM 2018 TO 2020 IRP
2018	230,996	2,347,887			
2019	422,130	2,539,021		2,603,928	2.6%
2020	605,468	2,722,359	382,403	2,986,331	9.7%
2021	777,345	2,894,236	594,043	3,197,971	10.5%
2022	945,787	3,062,678	797,571	3,401,499	11.1%
2023	1,114,230	3,231,121	993,570	3,597,498	11.3%
2024	1,282,674	3,399,565	1,181,566	3,785,494	11.4%
2025	1,451,119	3,568,010	1,366,448	3,970,376	11.3%
2026	1,619,565	3,736,456	1,529,702	4,133,630	10.6%
2027	1,788,012	3,904,903	1,671,328	4,275,256	9.5%
2028	1,956,460	4,073,351	1,791,325	4,395,253	7.9%
2029	2,125,763	4,242,654	1,889,695	4,493,623	5.9%
2030	2,295,309	4,412,200	1,966,436	4,570,364	3.6%
2031	2,466,556	4,583,447	2,025,870	4,629,798	1.0%
2032	2,639,409	4,756,300	2,083,615	4,687,543	-1.4%
2033	2,812,935	4,929,826	2,139,751	4,743,679	-3.8%
2034	2,988,465	5,105,356	2,194,754	4,798,682	-6.0%
2035	3,166,853	5,283,744	2,248,708	4,852,636	-8.2%

Base Case Comparison to 2018 DEP IRP

INTEGRATED VOLT-VAR CONTROL

PROGRAM DESCRIPTION

Distribution System Demand Response (DSDR) is an operational mode of Volt Var Optimization (VVO) that supports peak shaving and emergency MW (demand) reduction. Duke Energy Progress (DEP) implemented DSDR in 2014. The DSDR mode of operation is implemented by the software within a centralized Distribution Management System (DMS). The DMS obtains telemetered data via 2-way communications from substation devices, distribution line voltage regulators, distribution line capacitor banks, medium voltage sensors, and low voltage sensors. The DMS software performs a power load flow analysis based on near real-time measurement inputs. Afterwards, it sends out commands to the voltage regulators and capacitor banks to optimize the voltage for DSDR. Currently, DSDR can provide peak shaving voltage reduction of approximately 3.6% across the distribution network in DEP. The DMS in DEP is capable of optimized modes (i.e.- DSDR) or non-optimized (i.e. – emergency) modes. The emergency modes are designed for a speedy, temporary response during bulk power emergencies with voltage reduction capability of up to 5.0%. Initially, the DEP DSDR targeted approximately 310 MW of peak demand reduction capability to defer construction of a new Combustion Turbine (CT) plant. The North Carolina Utility Commission classified DSDR as an Energy Efficiency program with rider recovery. The goal was exceeded and DEP achieved 322 MW of load reduction.

The initial implementation of DSDR not only included a Distribution Management System (DMS), but also a significant amount of circuit conditioning (such as installing voltage regulating devices and capacitors, balancing load on distribution circuits, and reconductoring some distribution lines to larger wire sizes). These forms of circuit conditioning help reduce line losses, which improve grid efficiency, reduce reactive power on the grid, and enable a higher voltage reduction to achieve maximum peak shaving. Additional devices, such as medium voltage sensors and low voltage sensors, were deployed to provide additional telemetry on the system. The substation and distribution line devices needed for DSDR were deployed in the optimal locations and equipped with 2-way communications ability.

The purpose of this evaluation is to conduct a cost/benefit analysis of moving DEP from the current DSDR (peak shaving) operational strategy to a Conservation Voltage Reduction (CVR) operational strategy. Conservation Voltage Reduction (CVR) is an operational mode of VVO that supports voltage reduction and energy conservation. The CVR functionality would target an estimated 2% voltage reduction for the majority of the hours in the year. This voltage reduction is estimated to result in an approximate 1.4% load reduction on average for enabled circuits. The substation, distribution, telecommunications, and IT infrastructure are already in place because DSDR already exists in DEP. As such, it is expected that few new devices will be installed. The current DEP DMS will transition to the enterprise DMS platform in the future. The software within the future enterprise DMS platform will have the ability to operate in various modes, including the current DSDR mode and CVR mode. This evaluation assumes the future version of the DMS platform will have already been deployed with the software capability to operate in DSDR or CVR mode, and that comprehensive testing will have already been performed on the required changes to the DMS system. Because the 2-way communications and control infrastructure are already in place in DEP, the settings on the substation and distribution devices can be programmed to enable these devices to properly operate when the DMS is in CVR mode or DSDR mode.

Changing the predominant operational strategy in DEP from DSDR to CVR would affect the amount of maximum peak shaving capability. If the DMS is operating in CVR mode, transitioning to DSDR mode when load has already been reduced will not provide the peak shaving benefit realized today. The net result is that the amount of peak shaving would be reduced, and therefore will require relief from the current DSDR peak shaving obligation. This evaluation shows the incremental cost/benefits of transitioning to CVR operational mode. However, the lost benefits (including the initial deferral of peaking units), due to the reduction of peak shaving capability have yet to be calculated. To make an informed decision, further analysis will be required to accurately quantify the impacts on DSDR. When the DMS upgrade is complete, Duke Energy will be able to conduct additional testing and a more thorough analysis of the peak shaving capability impact.

BENEFITS:

- Reduced distribution line losses due to lower overall voltage
- More efficient grid due to lower line losses and reduced reactive power
- Less generation fuel consumed and lower emissions due to grid efficiencies
- Integrated control of capacitor banks provides greater ability to reduce reactive power, resulting in less apparent load on the system
- Less peak load on the grid could result in a reduced need to build additional peaking generation
- Optimized control of volt/VAR devices improves the grid's ability to respond to intermittency
- Helps to manage integration of distributed energy resources

IVVC is part of the proposed Duke Energy Carolinas Grid Improvement Plan. The deployment of an IVVC program for DEP is anticipated to take approximately four years. In the meantime, DSDR will continue to operate as planned as a peak shaving resource until it is fully rolled into IVVC in 2025.

SUMMARY DEP (NORTH CAROLINA & SOUTH CAROLINA) DISTRIBUTION SYSTEM DEMAND RESPONSE (DSDR) CONVERSION TO YEAR-ROUND CONSERVATION VOLTAGE REDUCTION (CVR) ANNUAL ESTIMATED ENERGY REDUCTION (KWH) OPERATING CONSERVATION VOLTAGE REDUCTION (CVR) 90% OF THE HOURS ON DISTRIBUTION RETAIL CIRCUITS*		
YEAR	DSDR TO CVR DEPLOYMENT (%)	TOTAL REDUCTION (KWH)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	8,639,128
2024	20%	17,433,760
2025	100%	87,953,319
2026	100%	88,744,899
2027	100%	89,543,603
2028	100%	90,349,495
2029	100%	91,162,641
2030	100%	91,983,105
2031	100%	92,810,953
2032	100%	93,646,251
2033	100%	94,489,067
2034	100%	95,339,469
2035	100%	96,197,524
2036	100%	97,063,302

*(Energy reduction does not account for system losses upstream of distribution retail substations)

DEP (NORTH CAROLINA & SOUTH CAROLINA)
IVVC PEAK-SHAVING MODE APPROXIMATELY <10% OF HOURS PER YEAR (KW)*

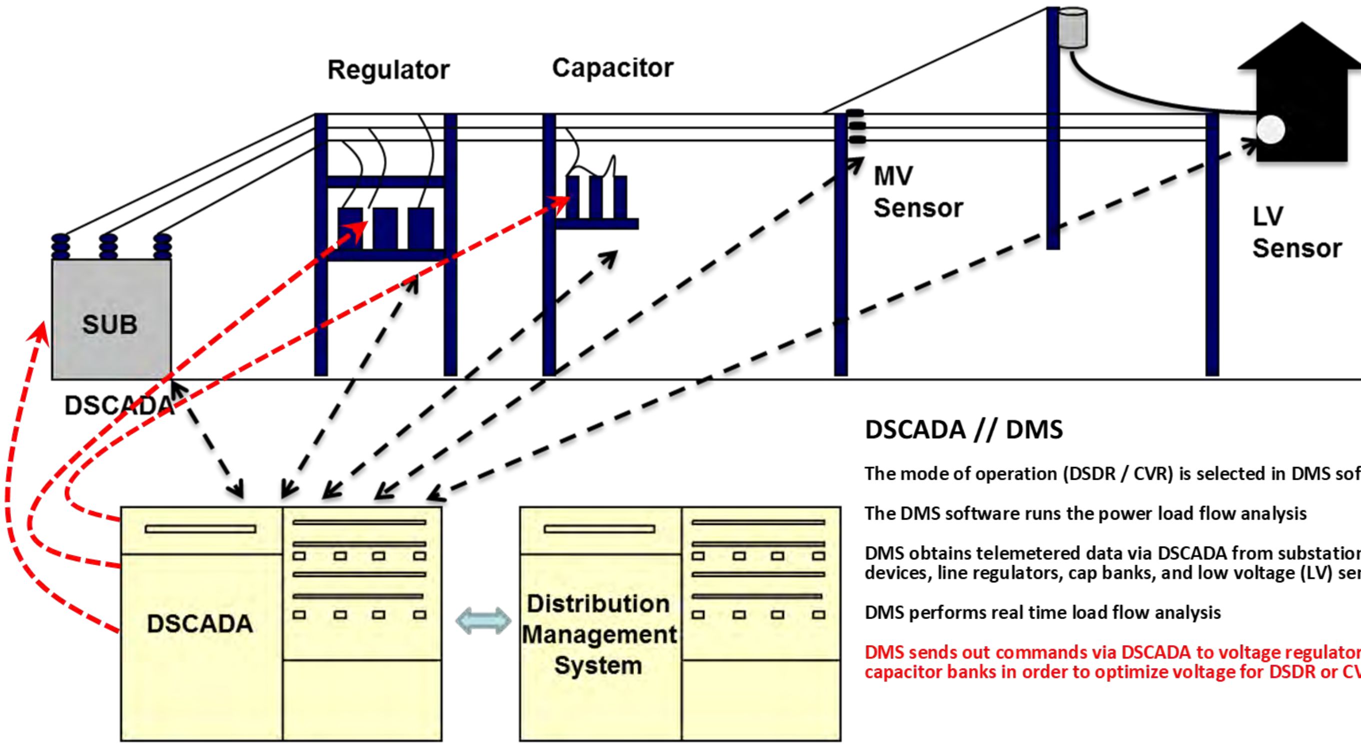
YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KW)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	9,432
2024	20%	19,035
2025	100%	96,030
2026	100%	96,895
2027	100%	97,767
2028	100%	98,647
2029	100%	99,534
2030	100%	100,430
2031	100%	101,334
2032	100%	102,246
2033	100%	103,166
2034	100%	104,095
2035	100%	105,032
2036	100%	105,977

*(Demand reduction does not account for system losses upstream of distribution retail substations)

VOLT - VAR OPTIMIZATION TERMINOLOGY

VVO	*Volt-VAR Optimization*	Management of Voltage levels and Reactive Power at optimal levels to operate the grid more efficiently
IVVC	*Integrated Volt-VAR Control*	Full coordination and configuration of intelligent field devices and a management/control system (e.g., DMS, DSCADA) that uses grid data to achieve efficient grid operation while maintaining distribution voltages within acceptable operating limits
DMS	*Distribution Management System*	Primary information system used to monitor, analyze, and control the distribution grid efficiently and reliably
DSDR	*Distribution System Demand Response*	Operational mode of VVO that supports peak shaving and emergency MW *(demand)* reduction (alternative to building peaking plant generation)
CVR	*Conservation Voltage Reduction*	Operational mode of VVO that supports 24/7 voltage reduction and energy conservation (alternative to building base load generation)

DEP DSDR / CVR ILLUSTRATIVE OVERVIEW



DSCADA // DMS

The mode of operation (DSDR / CVR) is selected in DMS software

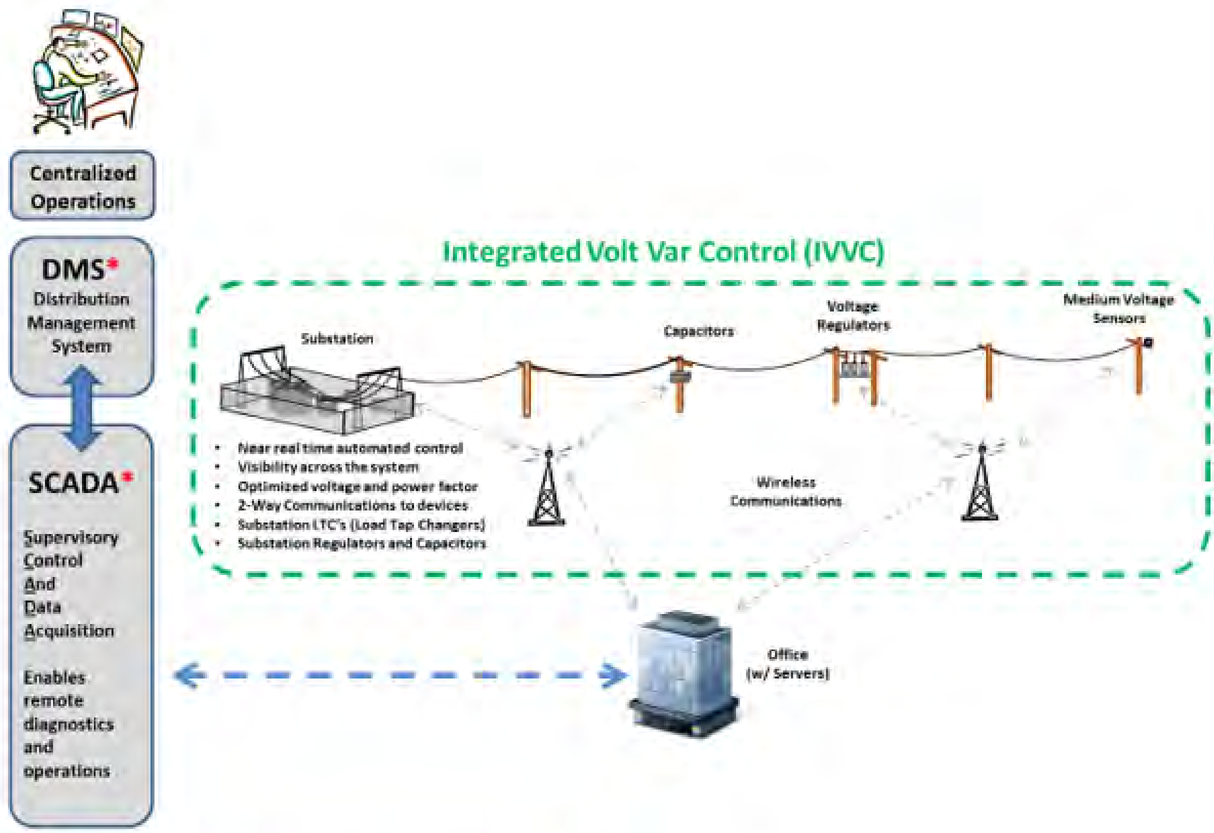
The DMS software runs the power load flow analysis

DMS obtains telemetered data via DSCADA from substation devices, line regulators, cap banks, and low voltage (LV) sensors

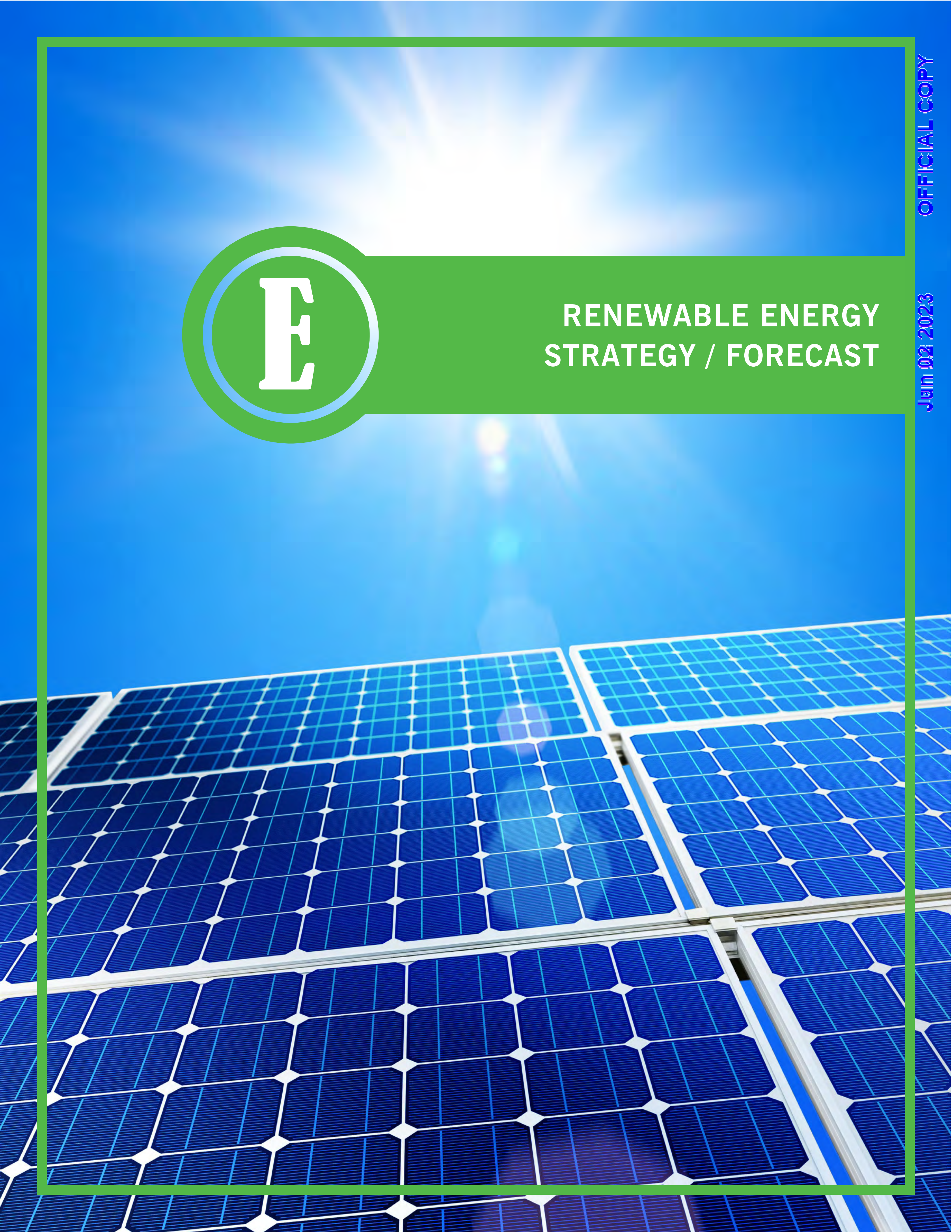
DMS performs real time load flow analysis

DMS sends out commands via DSCADA to voltage regulators and capacitor banks in order to optimize voltage for DSDR or CVR

"HIGH LEVEL" CONCEPTUAL DESIGN



- DSM & SCADE already exists and is not in scope of this project.
- Devices will be integrated into the existing DMS/SCADA



RENEWABLE ENERGY STRATEGY / FORECAST

APPENDIX E: RENEWABLE ENERGY STRATEGY/FORECAST

The growth of renewable generation in the United States continued in 2019. According to EIA, in 2019, 9.1 GW of wind and 5.3 GW of utility-scale solar capacity were installed nationwide. The EIA also estimates 3.7 GW of small scale solar was added as well.[1] Notably, U.S. annual energy consumption from renewable sources exceeded coal consumption for the first time since before 1885.[2]

North Carolina ranked sixth in the country in solar capacity added in 2019 and remains second behind only California in total solar capacity online, while South Carolina ranked seventh in solar capacity added in 2019.[3][4] Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high investment in solar.

RENEWABLE ENERGY OUTLOOK FOR DUKE ENERGY IN THE CAROLINAS

The future is bright for opportunities for continued renewable energy development in the Carolinas as both states have supportive policy frameworks and above average renewable resource availability, particularly for solar. The Carolinas also benefits from substantial local expertise in developing and interconnecting large scale solar projects and the region will benefit from such a concentration of skilled workers. Both states are supporting future renewable energy development via two landmark pieces of legislation, HB 589 in North Carolina (2017) and Act 62 in South Carolina (2019). These provide opportunities for increased renewable energy, particularly for utility customer programs for both large and small customers who want renewable energy. These programs have the potential to add significant renewable capacity that will be additive to the historic reliance on administratively-established standard offer procurement under PURPA in the

[1] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.
[2] https://www.eia.gov/todayinenergy/detail.php?id=43895
[3] https://www.seia.org/states-map
[4] https://www.eia.gov/electricity/data/eia860M/; February month end data

Carolinas. Furthermore, the Companies' pending request to implement Queue Reform—a transition from a serial study interconnection process to a cluster study process—will create a more efficient and predictable path to interconnection for viable projects, including those that are identified through any current or future procurement structures. It is also worth noting that that there are solar projects that appear to be moving forward with 5-year administratively-established fixed price PURPA contracts and additional solar projects that will likely be completed as part of the transition under Queue Reform.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

DRIVERS FOR INCREASING RENEWABLES IN DEP

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the Federal ITC, and declining installed solar costs continue to make solar capacity the Company's primary renewable energy resource in the 2020 IRP. However, achieving the Company's goal of net-zero carbon emissions by 2050 will require a diverse mix of renewable, and other zero-emitting, load following resources. Wind generation, whether onshore wind generated in the Carolinas or wheeled in from other regions of the country, or offshore wind generated off the coast of the Carolinas, may become a viable contributor to the Company's resource mix over the planning horizon.

The following key assumptions regarding renewable energy were included in the 2020 IRP:

- Through existing legislation such as NC HB 589 and SC Act 62, along with materialization of existing projects in the distribution and transmissions interconnection queues, installed solar capacity increases in DEP from 3,144 MW in 2021 to 4,575 MW in 2035 with approximately 85 MW of usable AC storage coupled with solar included

- Additional solar coupled with storage was available to be selected by the capacity expansion model to provide economic energy and capacity. Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 200 MW per year over the planning horizon in DEP.

- Up to 150 MW of onshore Carolinas wind generation, assumed to be located in the central Carolinas, could be selected by the capacity expansion model annually to provide a diverse source of economic energy and capacity.

- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases

- Achievement of the SC Act 236 goal of 39 MW of solar capacity located in DEP.

- Implementation of NC HB 589 and SC Act 62 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements

NC HB 589 COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE)

NC HB 589 established a competitive solicitation process, known as the Competitive Procurement of Renewable Energy (CPRE), which specified for the addition of up to 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period ending November 2021. On July 10, 2018, Duke issued a request for bids for the first tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. On April 9, 2019 the independent administrator selected 12 projects totaling 515 MW in DEC and two projects totaling 86 MW in DEP. Both DEP projects are third party owned, and one of the DEP projects will be transmission tied in NC and the other will be distribution tied in SC. See the annual CPRE Program Plan included as Attachment II for additional details.

CPRE tranche 2 requested bids for 600 MW in DEC and 80 MW in DEP. The bid window closed March 9, 2020. Initial results showed DEP receiving 6 bids for approximately 440 MW. Five of the bids, representing approximately 365 MW are located within NC and the remaining bid and 75 MW is located within SC. One proposal was submitted with energy storage. Each of the six projects requested transmission interconnection.

One finalist was selected from the initial bid list. This is a 75 MW project located in NC, with plans to employ a single axis tracking configuration. There is no storage associated with this project and the price decrement is approximately $6.25/MWh. A contract has yet to be executed and the contract negotiation window will close October 15, 2020.

The volume of any future tranches of CPRE will depend on the final results of tranche 2, as well as, the continued increases in capacity referred to in this document as the “Transition MW”. These “Transition MW” represent the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are (1) already connected; or (2) have entered into purchase power agreements (PPAs) and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. The total CPRE target of 2,660 MW will vary based on the amount of Transition MW at the end of the 45-month period, which NC HB 589 expected to total 3,500 MW. If the aggregate capacity in the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount and vice versa. As of May 2020, there is approximately 4,020 MW of solar capacity and 280 MW of non-solar capacity that meet NC HB 589’s definition of “Transition MW”, meaning CPRE will be reduced by a minimum of 800 MW. The company believes the Transition may ultimately exceed 3,500 MW by as much as 1,850 MW, and possibly more depending on the extent to which SC Act 62 and Interconnection Queue reform drive new solar growth in SC by the end of the 45-month CPRE period.

NC AND SC INTERCONNECTION QUEUES

Through the end of 2019, DEP had nearly 2,750 MW of utility scale solar on its system, with approximately 240 MW interconnecting in 2019. When renewable resources were evaluated for the 2020 IRP, DEP reported approximately 240 MW of third-party solar construction in progress and approximately 7,000 MW in the interconnection queue. Details of the number of pending projects and pending capacity by state are included in Appendix K.

Projecting future solar connections from the interconnection queue presents a significant challenge due to the large number of project cancellations, ownership transfers, interconnection studies required, and the unknown outcome of which projects will be selected through the CPRE program. Additionally, any future efforts to reform the transmission or distribution interconnection queues could cause these projections to vary.

DEP’s contribution to the Transition depends on many variables including connecting projects under construction, the expected number of renewable projects in the queue with a PPA and IA, SC Act 62, and SC DER Program Tier I. As of May 31, 2020, DEP had nearly 450 MW of solar capacity with a PPA and IA, and roughly 140 MW of non-solar renewable capacity with PPA's that extend through the 45-month CPRE period. A number of additional projects in the queue are expected to acquire both a PPA and IA prior to the expiration of the 45-month period defined in NC HB 589, potentially resulting in approximately an additional 700 MW contributing to the Transition. In total, DEP may contribute roughly three-quarters of the Transition MW with DEC accounting for the remaining one-quarter.

NC REPS COMPLIANCE

DEP remains committed to meeting the requirements of NC REPS, including the solar, poultry waste, and swine waste set-asides, and the general requirement, defined as the total REPS requirement net of the three set-asides, which will be met with additional renewable and energy efficiency resources. DEP's long-term general compliance needs are expected to be met through a combination of renewable resources, including RECs obtained through the NC HB 589 competitive procurement process. For details of DEP's NC REPS compliance plan, please reference the NC REPS Compliance Plan, included as Attachment I to this IRP.

NC HB 589 COMPETITIVE PROCUREMENT AND UTILITY-OWNED SOLAR

DEP continues to evaluate utility-owned solar additions to grow its renewables portfolio. DEP owns and operates four utility-scale solar projects, totaling 141 MW-AC, as part of its efforts to encourage emission free generation resources and help meet its compliance targets:

- Camp Lejeune Solar Facility – 13 MW, located in Onslow County, NC placed in service in November 2015;

- Warsaw Solar Facility – 65 MW, located in Duplin County, NC placed in service in December 2015;

- Fayetteville Solar Facility – 23 MW, located in Bladen County, NC placed in service in December 2015; and

- Elm City Solar Facility – 40 MW, located in Wilson County, NC placed in service in March 2016.

No more than 30% of the CPRE Program requirement may be satisfied through projects in which Duke Energy or its affiliates have an ownership interest at the time of bidding. Duke Energy Renewables was awarded approximately 20% of the capacity selected in the first tranche of CPRE. NC HB 589 does not stipulate a limit for DEP's option to acquire projects from third parties that are specifically proposed in the CPRE Request for Proposals (RFP) as acquisition projects, though any such project will not be procured unless determined to be among the most cost-effective projects submitted.

ADDITIONAL FACTORS IMPACTING FUTURE SOLAR GROWTH

According to BloombergNEF and the Solar Energy Industries Association (SEIA), the solar industry has not been immune to the impacts of COVID-19[5][6]. The industry has experienced a significant loss in employment in the United States with most of the job losses and impacts associated with distributed generation. The pandemic has certainly introduced supply chain risks, and anecdotal evidence suggests that project financing is becoming more challenging, especially with the likely contraction of tax equity markets. Offsetting these concerns is a more diversified supply chain, especially in the United States, which helps to mitigate some of the supply chain risks. In addition, the U.S. Congress has passed several bills to help provide stimulus and liquidity in the markets, and there are various infrastructure legislative proposals that contain incentives to help the solar industry to continue to move forward. Taken together, the prevailing consensus seems to be that utility scale projects may be delayed, but it is unlikely that there will be large scale cancellations.

[5] https://www.powerengineeringint.com/renewables/bnef-predicts-slow-down-in-clean-energy-economy-due-to-covid-19/
[6] https://www.seia.org/sites/default/files/2020-05/SEIA-COVID-Impacts-National-Factsheet.pdf

Beyond the immediate COVID-19 concerns, there are numerous other factors that impact the Company's forecast of future solar growth in the Carolinas. Key among these is potential changes in the Company's avoided cost in either NC or SC, as these may impact the development of projects under PURPA, NC HB 589, and SC Act 62. Avoided cost forecasts are subject to variability due to changes in factors such as natural gas and coal commodity prices, system energy and demand requirements, the level and cost of generation ancillary service requirements, and interconnection costs. PURPA requires utilities to purchase power from QFs at or below the utility's avoided cost rates. NC HB 589 requires that competitive bids are priced below utility's avoided cost rates, as approved by the NCUC, in order to be selected. Given the potential for changes in the avoided cost rates, the installed cost of solar remains a critical input for forecasting how much solar will materialize in the future. This stems from the fact that the actual cost of solar is not related to the PURPA avoided cost rates, even though solar investment was possible in the past at those avoided cost rates.

Installed solar costs encompass many variables, including physical components such as PV modules, inverters, electrical, and structural equipment, as well as engineering design, O&M and interconnection charges, to name a few. Solar panel prices have been declining at a fairly significant rate over the last decade and are expected to continue this decline into the future, although the Section 201 tariffs that were enacted in 2018 will continue to impact module costs at least through 2021. The tariff is related to solar modules and cells and is set at 20% for the remainder of 2020 and dropping to 15% in 2021, which would be the last year the tariffs are in effect. Additional factors that could put upward pressure on solar costs include direct interconnection costs, as well as costs incurred to maintain the appropriate operational control of the facilities. Finally, as panel prices have decreased, there has been more interest in installing single-axis tracking (SAT) systems (as demonstrated in CPRE tranches 1 and 2) and/or systems with higher inverter load ratios (ILR) which change the hourly profile of solar output and increase expected capacity factors. DEC models fixed tilt and SAT system hourly profiles with a range of ILRs as high as 1.6 (DC/AC ratio).

In summary, there is a great deal of uncertainty in both the future avoided costs applied to solar and the expected price of solar installations in the years to come. As a result, the Company will continue to closely monitor and report on these changing factors in future IRP and competitive procurement filings.

NC HB 589 CUSTOMER PROGRAMS

In addition to the CPRE program, NC HB 589 offers direct renewable energy procurement for major military installations, public universities, and other large customers, as well as a community.

solar program. These programs are in addition to the existing SC Act 236 Programs and upcoming SC Act 62 programs.

As part of NC HB 589, the renewable energy procurement program enables large customers to procure renewable energy attributes from new renewable energy resources and receive a bill credit for the energy and capacity provided to DEC's system. The program allows for up to 600 MW of total capacity, with set asides for military installations (100 MW of the 600 MW) and the University of North Carolina (UNC) system (250 MW of the 600 MW). The 2020 IRP base case assumes all 600 MW of this program materialize, with the DEC/DEP split expected to be roughly 65/35. If all 600 MW are not utilized, the remainder will roll back to the competitive procurement, increasing its volume.

The community solar portion of NC HB 589 calls for up to 20 MW of shared solar in DEP. This program is similar to the SC Act 236 Shared Solar program in that it allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. A key difference between the SC Act 236 Shared Solar program and the NC HB 589 Shared Solar program is that HB 589 does not allow the program to be subsidized. Customers must be credited at avoided cost and projects cannot be greater than 5MW. An RFP issued in 2019 with these parameters resulted in no bids. The 2020 IRP Base Cases assume that all 20 MW of the NC HB 589 shared solar program materializes starting in 2022.

NC HB 589 also established a rebate program for rooftop solar, limited to 10 MW of installed capacity per utility per year over 2018 through 2022. There are rules governing residential and non- residential customers, along with set asides for nonprofit organizations. Any set asides not used by year end 2022 will be reallocated for use by any customer type who meets the necessary qualifications. Since its inception in 2018, the rebate program has spurred greater interest in solar installations and therefore, more net metered customers in NC. Residential and non-residential capacity limits were quickly fully subscribed in 2018, 2019 and 2020. DEC NC installed approximately 13 MW of rooftop solar in 2018 and approximately 23 MW of rooftop solar in 2019. Through May of 2020, installed rooftop solar capacity is approximately 11 MW. For further discussion of rooftop solar projections, see below, as well as Appendix C.

SC ACT 236 AND SC ACT 62

Steady progress continues to be made with the first two tiers of the SC DER Program summarized below, completion of which would unlock the third tier:

- **Tier I:** 13 MW of solar capacity from facilities each >1 MW and < 10 MW in size.

- **Tier II:** 13 MW of behind-the-meter solar facilities for residential, commercial and industrial customers, each ≤1 MW, 25% of which must be ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.

- **Tier III:** Investment by the utility in 13 MW of solar capacity from facilities each >1 MW and <10 MW in size. Upon completion of Tiers I and II (to occur no later than 2021), the Company may directly invest in additional solar generation to complete Tier III.

DEP has executed two PPAs to complete Tier I, resulting in 15 MW which are currently operational. Tier II incentives have resulted in growth in private solar in DEP, as nearly 18 MW of rooftop solar has been installed in DEP SC.

The Company launched its first Shared Solar program as part of Tier I. Duke Energy designed its initial SC Shared Solar program to have appeal to residential and commercial customers who rent or lease their premises, residential customers who reside in multifamily housing units or shaded housing or for whom the relatively high up-front costs of solar PV make net metering unattainable, and non-profits who cannot monetize the ITC. To make the program financially feasible, the subscription fee is subsidized by the ratebase. The program capacity is 1 MW including 200 kW set aside for low to moderate income (LMI) customers earning less than 200% of the federal poverty level. The unreserved 800 kW of capacity sold out within 10 months due to the program's strong economic proposition. As of the end of June 2020, low to moderate income customers have subscribed to 336 kW.

TABLE E-1

DEP SHARED SOLAR PROGRAM

<table>
<tr><th></th><th>AVERAGE SUBSCRIPTION KW PER PARTICIPANT</th><th>CUSTOMERS</th><th>CAPACITY (KW)</th></tr>
<tr><td>Residential LMI</td><td>2</td><td>168</td><td>400</td></tr>
<tr><td>Residential Non-LMI</td><td>7.19</td><td>82</td><td rowspan="2">600</td></tr>
<tr><td>Non-Residential</td><td>18</td><td>1</td></tr>
</table>

SC Act 62 passed in South Carolina on May 16, 2019. SC Act 62 will likely drive additional PURPA solar as DEP must offer fixed price PPAs to certain small power producers at avoided cost for a minimum contract term of 10 years. The 10-year rate is applicable for projects located in SC until DEP has executed IAs and PPAs with aggregated nameplate capacity equal to 20 percent of the previous 5-year average of DEP's SC retail peak load, or roughly 260 MW. After 260 MW have executed IAs and PPAs the Commission will determine conditions, rates, and terms of length for future contracts. Given there is roughly 2,400 MW of solar pending in DEP SC, the Company expects to meet 260 MW within the IRP planning period. The Company intends to closely monitor the capacity with executed IAs and PPAs, evaluate impacts on the NC HB 589 Transition MW and corresponding reduction in CPRE volume. Once the 260 MW threshold is reached, the PSCSC will determine the term limit for PURPA contracts in its sole discretion.

SC Act 62 also called for additional customer programs, requiring the utilities to file voluntary renewable energy programs within 120 days of SC Act 62 passing, and encouraging additional community solar. The Company has a proposed voluntary renewable energy program pending before the Commission, which would create a 150 MW program for DEC and DEP SC combined (37 MW in DEP) offering up to 20-year PPAs. The Companies are considering whether additional community solar should be pursued.

Finally, SC Act 62 lifted the cap on net metering, requiring the Company to offer full retail rate net metering through June 1, 2021, as approved through proceedings under Act 236. As required by the legislation, the Public Service Commission of South Carolina opened a docket in May 2019 to establish a solar choice metering tariff to go into effect for customer applications received after May 31, 2021 which would replace the meting tariff for new installations.[7] The Company expects net metering adoption to pick up to comparable levels of adoption observed in DEP-SC in 2017/2018 through June 2021. Future adoption after that date will be determined based upon the solar choice tariff terms approved by the SC PSC.

WIND

DEP considers wind a potential energy resource in the short and long term to support increased renewable portfolio diversity, an important resource for achieving the Company's 2050 net-zero carbon emission goal, as well as long-term general compliance need. However, sourcing wind remains challenging, whether the wind is imported from other states, sited within the Carolinas, or sited offshore.

In 2020, offshore wind energy is becoming a more viable alternative, but only one project near the Carolinas, the Avangrid Kitty Hawk project off the coast of North Carolina, has the necessary Bureau of Ocean Energy Management (BOEM) offshore lease to begin construction. Several call areas began the process of evaluation along the North and South Carolina border but stalled out in recent years as BOEM refocused their efforts to areas with higher demand. These call areas could eventually become new leasing areas, but first BOEM's Task Force will need a representative from South Carolina to restart the permitting and approvals process.

The Company continues to evaluate options for increasing access to offshore wind energy into the Carolinas, however the cost to transport wind energy from the coast to the load centers located in central North Carolina and South Carolina is significant. In 2012, the North Carolina Transmission Planning Collaborative (NCTPC) released a study that estimated transmission upgrade costs for moving wind into the Carolinas in a few different scenarios: the costs ranged from approximately $930M to $1,730M. While the Company continues working with the NCTPC to update estimates for integrating offshore wind into the DEP and DEC territories, the Company expects those costs to increase significantly as the costs to site and build new transmission infrastructure has increased over the last decade. For further discussion of the transmission costs associated with moving offshore wind from the coast to load centers in the Carolinas, see Chapter 7.

[7] PSCSC Docket 2019-182E.

Wind energy generated onshore in the Carolinas presents other challenges. The wind capacity (speeds and duration) are generally best in the mountains and along the coast of the Carolinas, but these locations also have hurdles. While the moratorium on building land-based wind in NC has recently expired, the Mountain Ridge Protection Act prevents building wind on ridgetops, and coastal tourism often deters siting on land along the coast. Aside from the policy barriers, there is a significant need for meteorological towers to collect wind speed history in key areas across the Carolinas to gain confidence in predicted capacity factors. The Carolinas onshore wind profiles used in this IRP were provided by a third party and may not be based on wind speeds measured near the expected hub heights.

While the Company is working to improve the quality of Carolinas onshore wind profiles for use in future IRPs it is expected that wind generation located in the central portion of the Carolinas would generally have much lower output than sites located on the coast or mountains, but the benefit of these sites would likely be lower transmission costs. These lower costs could potentially outweigh effects of lower output, particularly since their wind profiles are generally complementary to solar generation.

On-shore wind located outside of the Carolinas presents both economic and logistical challenges associated with constructing significant transmission infrastructure. In August 2017, DEC issued an RFP for delivered energy, capacity, and associated RECs from wind projects up to 500 MW. While bids received were not economically valuable enough to pursue, the Company has continued to evaluate potential projects. Out-of-state transmission costs and availability are one of the complicating factors for importing wind from out of state.

While wind energy continues to face challenges, the Company believes wind energy can become a viable resource by the end of the planning horizon. For this reason, Central Carolinas wind was included as an available resource in the base case, and the high renewable case includes both offshore and central US located wind as resources in the 2030 to 2035 timeframe. Additionally, the Company included higher levels of offshore wind in the 70% CO_2 Reduction: High Wind and No New Gas Generation portfolios to demonstrate how diversifying the Company's resource mix can help achieve aggressive carbon emission reduction goals. While the majority of offshore wind was allocated to DEP in the No New Gas Generation case, it is possible that future policy may provide for cost and benefit sharing of emerging carbon free resources, such as offshore wind, across all customers in both DEP and DEC in order to equitably advance such technologies. For a more detailed summary of these portfolios, see Chapter 12 and Appendix A.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS:

BASE WITH CARBON POLICY

The 2020 IRP Base with Carbon Policy case incorporates the projected and economically selected renewable capacities shown below. This case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre-HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including opportunities for growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

However, it is the Company's belief that continued declines in the installation cost of solar and storage will enable coupled "solar plus storage" systems, to contribute to energy and capacity needs. Additionally, the inclusion of a CO2 emissions tax, or some other carbon emissions reduction policy, would further incentivize expansion of solar resources in the Carolinas. In the 2020 IRP, the capacity expansion model selected additional solar coupled with storage averaging 200 MW annually beginning in 2029 if a CO2 tax were implemented in the 2025 timeframe.

Unlike the first tranche of CPRE, the second tranche of CPRE did not yield any solar plus storage projects. The Company continues to believe that the combination of falling storage costs in addition to the most recent avoided cost rate structures proposed in both NC and SC provide strong price incentives for QFs to shift energy from lower priced energy-only hours to hours that have higher energy and capacity prices. This rate design provides incentives to encourage storage additions to solar projects. The Company this year is also projecting that a significant amount of incremental solar beyond NC HB 589 will be coupled with storage. The 2020 base case assumes storage is DC coupled with solar, has a four-hour duration, and the capacity of the battery storage is 25% of the capacity of the solar. In total, DEP expects approximately 1,514 MW of solar coupled with approximately 380 MW of storage by the end of 2035.

Additionally, Phase 1 of NREL's Integration of Carbon Free Resources Study, highlighted the benefit storage provides by reducing the curtailment of solar resources as significant levels of solar are added to the DEP system and create more excess energy conditions. In fact, at current levels of solar investment in DEP, curtailment is becoming a more likely outcome, particularly during periods of low load and high solar output. For modeling purposes, the Company assumes that, beginning in 2026, incremental solar additions in DEP must include storage to limit marginal curtailment of new solar resources to less than 20% of solar energy produced. This constraint will be evaluated in future IRPs as storage becomes more integrated on the DEP system.

Finally, as solar generation is expected to continue its expansion in DEP, interconnecting several thousand MW of new solar generation will likely require new transmission projects and could create logistical constraints due to limited transmission outage windows as these projects are implemented. For the last five years, DEP and DEC have interconnected approximately 500 MW of solar combined annually. While interconnections may potentially exceed those levels in the short-term, over the planning horizon, for base case planning purposes, the Company assumed interconnections were limited to 500 MW on an annual average basis. Since the majority of growth is expected in DEC, the DEP specific interconnection constraint was assumed to be 200 MW annually. The Company will continue to monitor interconnections, and should new, larger projects request interconnection to the DEP system or other efficiencies be realized, the level of interconnections may increase.

The Company anticipates a diverse renewable portfolio including solar, biomass, hydro, storage fed by solar, wind and other resources. Actual results could vary substantially for the reasons discussed in this appendix, as well as, other potential changes to legislative requirements, tax policies, technology costs, carbon prices, ancillary costs, interconnection costs, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table E-2 below.

TABLE E-2

DEP BASE WITH CARBON POLICY TOTAL RENEWABLES

DEP BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	3	131	0	1,301	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	3	131	0	1,324	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	3	120	0	1,341	41	3	120	0	165
2027	4,184	88	120	0	4,392	1,223	22	120	0	1,365	42	22	120	0	184
2028	4,239	163	116	0	4,518	1,229	41	116	0	1,386	42	41	116	0	199
2029	4,294	237	60	0	4,591	1,234	59	60	0	1,354	43	59	60	0	162
2030	4,323	436	43	0	4,802	1,237	109	43	0	1,389	43	109	43	0	195
2031	4,352	634	43	0	5,029	1,240	158	43	0	1,441	44	158	43	0	245
2032	4,331	856	42	0	5,228	1,238	214	42	0	1,494	43	214	42	0	299
2033	4,311	1,076	42	150	5,579	1,236	269	42	12	1,559	43	269	42	53	406
2034	4,290	1,296	41	300	5,928	1,234	324	41	24	1,623	43	324	41	105	513
2035	4,270	1,514	41	450	6,276	1,232	379	41	36	1,688	43	379	41	158	620

Data presented on a year beginning basis

Solar includes 0.5% per year degradation

Capacity listed excludes REC Only Contracts

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study

While solar is not at its maximum output at the time of DEP's expected peak load in the summer, solar's contribution to summer peak load is large enough that it will likely push the time of summer peak to a later hour if solar generation levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to little solar output in the morning hours. Solar capacity contribution percentages to summer and winter peak demands are assumed to be the same as those used in the 2019 IRP. Note, however the solar contribution to peak values now also include additional contributions provided by storage coupled with solar, assumed to be 100% of the storage capacity installed based on the results of the Capacity Value of Battery Storage study discussed in Appendix H.

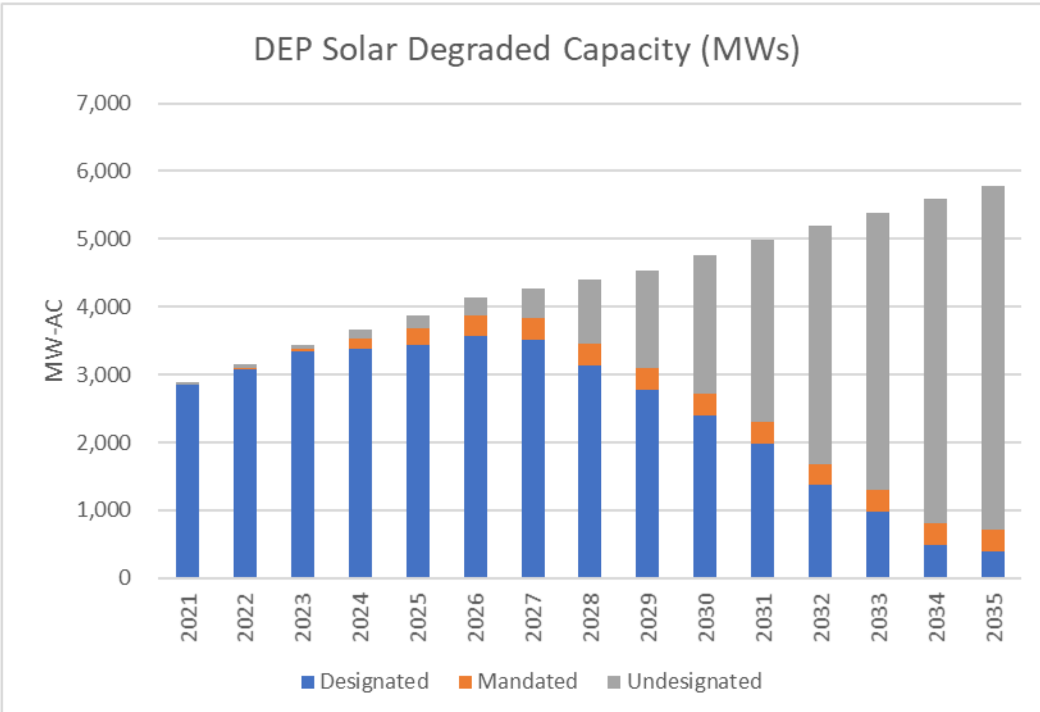
As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

- **Designated**: Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.
- **Mandated**: Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236)
- **Undesignated**: Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed.

The figure below shows DEP's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case. For determining the cost cap pricing in the second tranche of CPRE, the Company includes the Designated bucket only.

FIGURE E-1

DEP SOLAR DEGRADED CAPACITY (MW)



HIGH & LOW RENEWABLE CASES

Given the significant volume and uncertainty around solar investment, high and low solar portfolios were compared to the Base Case described above. The portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed.

Tables 5-B and 5-C below provide the high and low solar nameplate capacity summaries, as well as, their corresponding expected contributions to summer and winter peaks. For more details on these sensitivities see Appendix A.

TABLE E-3

DEP HIGH RENEWABLES SENSITIVITY

DEP BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	3	131	0	1,301	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	3	131	0	1,324	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	3	120	0	1,341	41	3	120	0	165
2027	4,109	229	120	0	4,458	1,216	57	120	0	1,393	41	57	120	0	218
2028	4,089	446	116	0	4,652	1,214	112	116	0	1,442	41	112	116	0	269
2029	4,070	677	60	0	4,807	1,212	169	60	0	1,441	41	169	60	0	270
2030	4,051	904	43	0	4,997	1,210	226	43	0	1,479	41	226	43	0	309
2031	4,031	1,138	43	60	5,272	1,208	285	43	14	1,550	40	285	43	37	405
2032	4,011	1,383	42	120	5,556	1,206	346	42	29	1,622	40	346	42	74	501
2033	3,992	1,647	42	180	5,861	1,204	412	42	43	1,701	40	412	42	111	604
2034	3,974	2,084	41	390	6,489	1,202	521	41	70	1,834	40	521	41	200	802
2035	3,955	2,533	41	615	7,144	1,201	633	41	100	1,975	40	633	41	299	1,013

Data presented on a year beginning basis

Solar includes 0.5% per year degradation

Capacity listed excludes REC Only Contracts

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study

TABLE E-4

DEP LOW RENEWABLES SENSITIVITY

DEP BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	3	131	0	1,301	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	3	131	0	1,324	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	3	120	0	1,341	41	3	120	0	165
2027	4,109	13	120	0	4,242	1,216	3	120	0	1,339	41	3	120	0	164
2028	4,089	13	116	0	4,219	1,214	3	116	0	1,333	41	3	116	0	160
2029	4,070	163	60	0	4,293	1,212	41	60	0	1,313	41	41	60	0	141
2030	4,051	312	43	0	4,406	1,210	78	43	0	1,331	41	78	43	0	161
2031	4,031	461	43	0	4,534	1,208	115	43	0	1,366	40	115	43	0	198
2032	4,011	609	42	150	4,811	1,206	152	42	12	1,412	40	152	42	53	286
2033	3,992	756	42	300	5,090	1,204	189	42	24	1,459	40	189	42	105	375
2034	3,974	902	41	450	5,367	1,202	225	41	36	1,505	40	225	41	158	464
2035	3,955	1,047	41	600	5,644	1,201	262	41	48	1,552	40	262	41	210	553

Data presented on a year beginning basis

Solar includes 0.5% per year degradation

Capacity listed excludes REC Only Contracts

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study

FUEL SUPPLY

APPENDIX F: FUEL SUPPLY

Duke Energy Progress' current fuel usage consists of a mix of coal, natural gas and uranium. Oil is used for peaking generation and natural gas continues to play an increasing role in the fuel mix due to lower pricing and the addition of a significant amount of combined cycle. A brief overview and issues pertaining to each fuel type are discussed below.

NATURAL GAS

During 2019 New York Mercantile Exchange (NYMEX) Henry Hub natural gas prices averaged approximately $2.51 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 92 billion cubic feet per day (BCF/day). Natural gas spot prices at the Henry Hub averaged approximately $2.00 per MMBtu in January 2020, while spot pricing decreased throughout the remaining winter months and averaged $1.75 per MMBtu at the end of March 2020. The lower short-term spot prices in February and March 2020 were driven by both fundamental supply and demand factors as winter temperatures remained mild.

Average daily U.S. net dry production levels of approximately 92 BCF/day in the first quarter of 2020 were 4.2 BCF/day higher than the comparable period in 2019. The U.S. Energy Information Administration (EIA) is forecasting a decrease this year from a reported 93.1 BCF/day in April, to 85.4 BCF/day by December. Most of this decline in production will be seen in the Appalachian region. Prices are discouraging producers from engaging in natural gas-directed drilling, and in the Permian region, where low oil prices reduce associated gas output from oil-directed wells. Current forecasts show dry natural gas production averaging 84.9 BCF/day in 2021, rising in the second half of the year in response to higher prices.

Following this year's winter withdrawal season, U.S. working gas in storage levels were reported to be at approximately 2.3 trillion cubic feet (TCF) as of April 30, 2020, coming in 20% above the five-year average between 2015-2019. Lower-48 U.S. overall demand in the first quarter of 2020 was lower than normal due to the above average temperatures throughout the winter months.

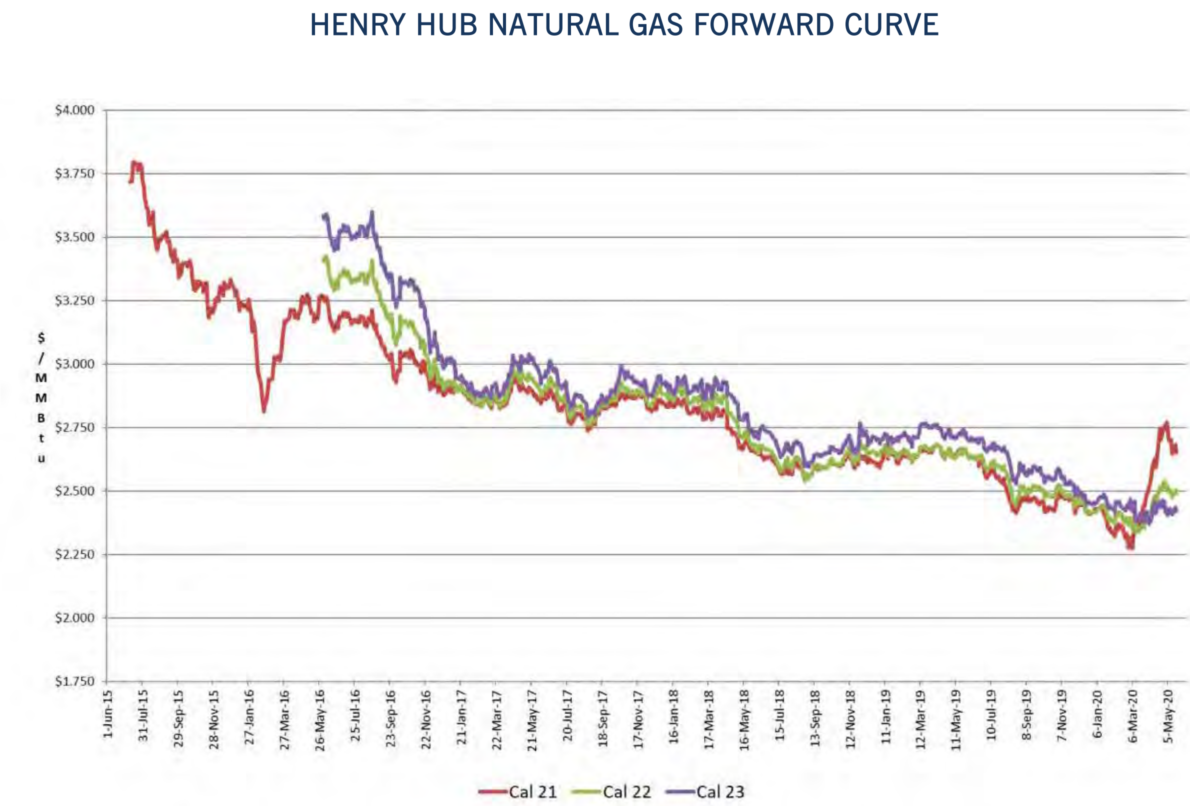
While Henry Hub spot prices averaged $1.63 per MMBtu during the first week of June 2020, the EIA forecasts natural gas prices will generally rise through 2020 as a decline in U.S. production is seen. Spot prices at Henry Hub are being forecasted by the EIA to average $2.14 per MMBtu this year, and then increasing to an annual average of $2.89 in 2021 as a result of lower natural gas production.

The EIA is expecting domestic natural gas consumption to see a 3.4 BCF/day decline compared to 2019. Overall U.S. forecasts for the year are down mainly due to reduced economic activity related to COVID-19, led by a decrease in demand during the first quarter as a result of milder-than-normal temperatures. Per the EIA's short-term energy outlook (STEO) released on May 26, 2020, natural gas consumption in the residential and commercial sectors is forecasted to decrease by 3.7% and 6.9%, respectively. Although those two sectors account for a small fraction of U.S. natural gas consumption outside of winter months when heating demand is high, the EIA expects weaker economic conditions in the coming months to further reduce average consumption in the commercial sector. With the weak economic conditions, the EIA also expects industrial natural gas demand to decline in the U.S. from an average of 21.4 BCF/day in 2019, to an average of 19.9 BCF/day in 2020, which will be at its lowest point since the summer of 2016.

Following the first half of 2020 short-term energy outlook, which expected natural gas used for electric power to grow 1.6 BCF/day compared to the first half of 2019 as a result of low natural gas prices, and lower-than- expected natural gas capacity additions, the EIA forecasts to see a decline during the second half of 2020. With natural gas prices forecasted to rise during that time, the STEO shows a reduction of natural gas consumption for electric power by 2.2BCF/day compared to the second half of 2019. The EIA's most recent short-term energy outlook also reports an expected rise in the May Henry Hub spot price from $1.88/MMBtu to $2.94/MMBtu by December 2020. These higher natural gas prices will result in some coal-fired generation units to become more economical to dispatch versus natural gas-fired units. EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 37% in 2019 to 39% in 2020. As a result, coal's forecast share of electricity generation falls from 24% in 2019 to 19% in 2020. According to Baker Hughes, as of June 5, 2020, the U.S. rig count was at 284. This is 691 less than this time last year.

FIGURE F-1

HENRY HUB NATURAL GAS PRICE FORWARD CURVE



Looking forward, the forward 5 and 10-year observable market curves are at $2.39 and $2.53 per MMBtu, respectively, as of the June 5, 2020 close. In addition, as of the close of business on June 5, 2020, the one (1), three (3) and five (5) years strips averaged approximately $2.48 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is relatively flat with the periods of 2022 and 2023 currently trading at discounts to 2021 prices. The gas market is expected to remain relatively stable due to the recent balancing act of lower production to account for the lack of demand during the COVID-19 pandemic. Demand for natural gas from the power sector for 2020 is expected to be higher than coal generation due to coal retirements, which are tied to the implementation of the EPA's MATS rule covering mercury and acid gasses. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for approximately 97% of net natural gas production today. As noted earlier, per the EIA's short-term outlook dated May 12, 2020, the EIA expects dry gas production to average 89.8 BCF/day by the end of 2020 and fall by 5 BCF/day in 2021 to 84.9 BCF/day. The United States is a net exporter of natural gas, with net exports expected to average 7.3 BCF/day in 2020. According to the EIA forecast, US Liquified Natural Gas (LNG) is forecasted to be 8.9 BCF/day by the end of 2021.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to commodity price relationships and growth in renewable generation. Looking forward, economic dispatch competition is expected to continue between gas and coal, although forward natural gas prices have continued to decline and there has been permanent loss in overall coal generation due to the number of coal unit retirements.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic Request for Proposals (RFPs), market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply and transportation portfolio that supports DEP's generation facilities. With respect to storage and transportation needs, the company continues to add incremental firm pipeline capacity and gas storage as the gas generation fleet has grown. The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

The Atlantic Coast Pipeline (ACP) project was an approximately 600-mile greenfield natural gas pipeline project originating in West Virginia with ultimate delivery into Piedmont's system in Robeson County, North Carolina providing pipeline diversity for the state of NC as well as pipeline diversity for the DEP and DEC electric systems. ACP had an initial capacity of 1.5 BCF/day and would have provided direct upstream access to natural gas production in the Marcellus and Utica shale basins of West Virginia, Pennsylvania and Ohio. On July 5th, 2020 Dominion Energy and Duke Energy announced the cancellation of ACP due to on-going legal uncertainty, anticipated delays and increasing cost uncertainty. DEP and DEC still need additional upstream firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. Given this change in planned interstate natural gas transportation infrastructure coming into the eastern part of NC, the 2020 IRP no longer includes direct access to interstate Marcellus and Utica shale basins coming into the eastern portions of NC.

To reliably and cost effectively support both the existing natural gas generation fleet and future combined cycle natural gas generation growth the 2020 IRP assumes incremental firm transportation service is obtained, as contemplated in the ACP project, with the exception of coming from alternate pipeline providers. While such incremental firm transportation service may not produce the additional geographic pipeline transportation diversity of the original ACP project it will look to provide needed supply diversity, improve supply reliability and provide greater price stability for customers by reducing reliance on increasingly constrained delivered Transco Zone 5 natural gas supply. In this IRP, firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this plan along with estimates of the cost of this firm transportation service. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented.

Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are assumed to be constructed as dual fuel units that are ultimately connected to Transcontinental Pipeline (Transco) Zone 5. Simple cycle CTs will rely on delivered Zone 5 gas supply or, if needed, ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or if gas is higher priced than the cost to operate on fuel oil. The Company will continue to refine transportation volume and cost assumptions over time as future developments in interstate delivery options in the Carolinas are more fully known.

COAL

The main determinants for power sector coal demand are electricity demand growth and non-coal electric generation, namely nuclear, gas, hydro and renewables. With electricity demand growth remaining very low, continued steady nuclear and hydro generation, and increasing gas-fired and renewable generation, coal-fired generation continues to be the marginal fuel experiencing declines. According to the EIA, electric power sector demand has been steadily dropping and accounted for 539 million tons (90%) of total demand for coal in 2019. Additionally, projections show continued strong supply and fluctuating prices for natural gas which, when combined with the addition of new gas-fired combined cycle generating capacity continues to result in more volatile coal burns.

Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental

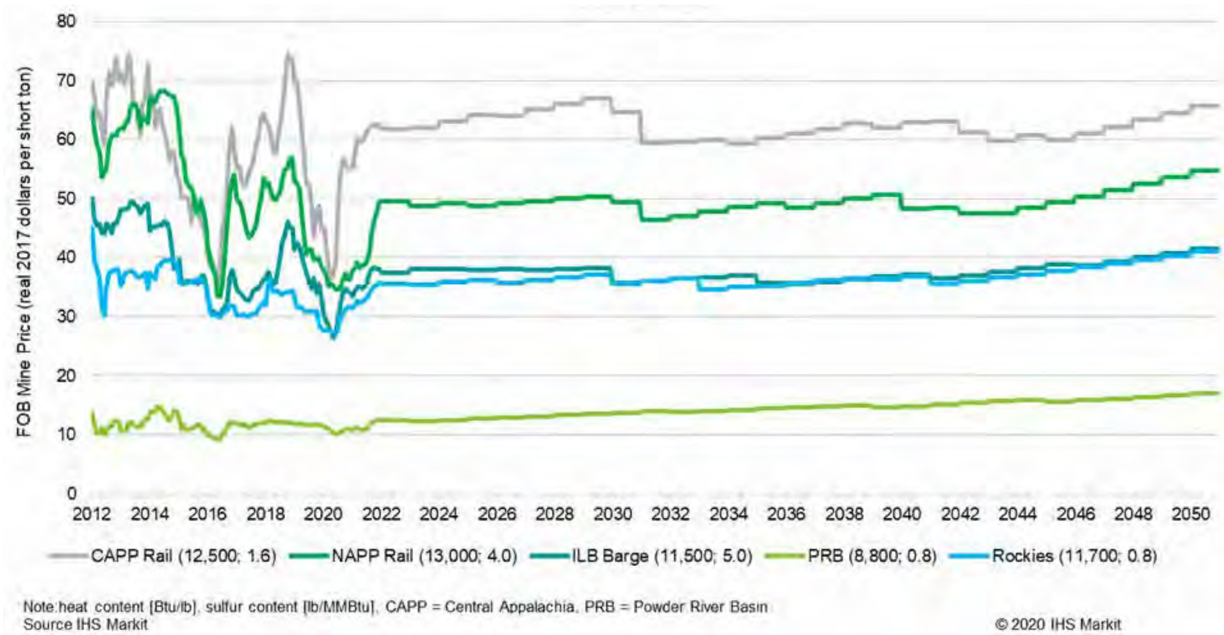
Protection Agency (EPA) regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

According to IHS Markit, future coal prices for the Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB) and Powder River Basin (PRB) coals are expected to be in a steady downward trend until 2020 when they see a modest rebound, flatten and begin to modestly and steadily rise. Future pricing for Rockies coal is expected to be steadily rise for the next 20 years.

FIGURE F-2

MINEMOUTH COAL PRICE FORWARD CURVE

COAL PRICES



With the issuance of the Affordable Clean Energy (ACE) rule in 2019, the fundamental industry outlook now anticipates that less efficient higher cost coal unit retirements will accelerate, with only the lowest-cost production surviving long term. IHS Markit expects 80 GW of coal plant retirements from 2020 to 2025, followed by 42 GW from 2026 to 2030, and 68 GW from 2031 to 2050.

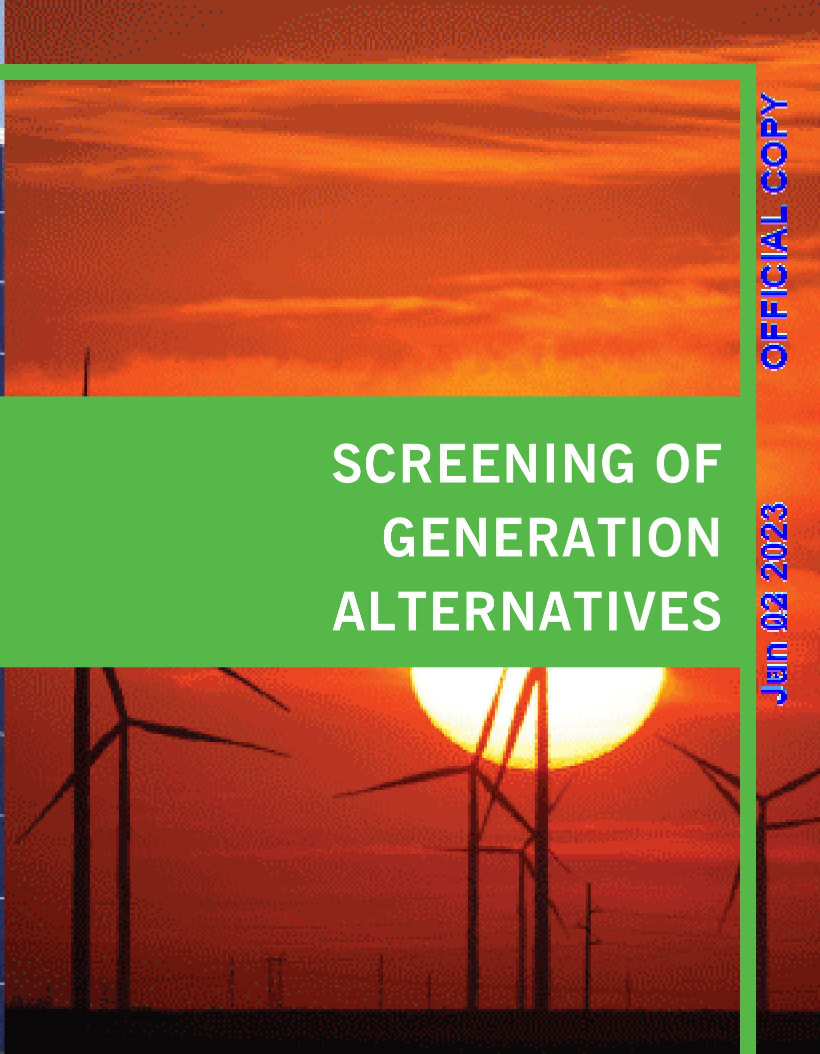
Coal exports have not been immune to global market pressures as total coal exports declined 20% in 2019 from historically high levels in 2018. IHS Markit expects US exports to be curtailed in the short-term due to the economic impacts of COVID-19, but projects that exports, especially for metallurgical coal, should stabilize over the long-term horizon. Lower cost thermal export demand is projected to be mostly limited to NAPP and ILB longwall mine operations, while higher cost production mines are expected to struggle during weaker market years.

The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts.

NUCLEAR FUEL

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, DEP staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

Due to the technical complexities of changing suppliers of fuel fabrication services, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts. As fuel with a low-cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear generation costs are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.



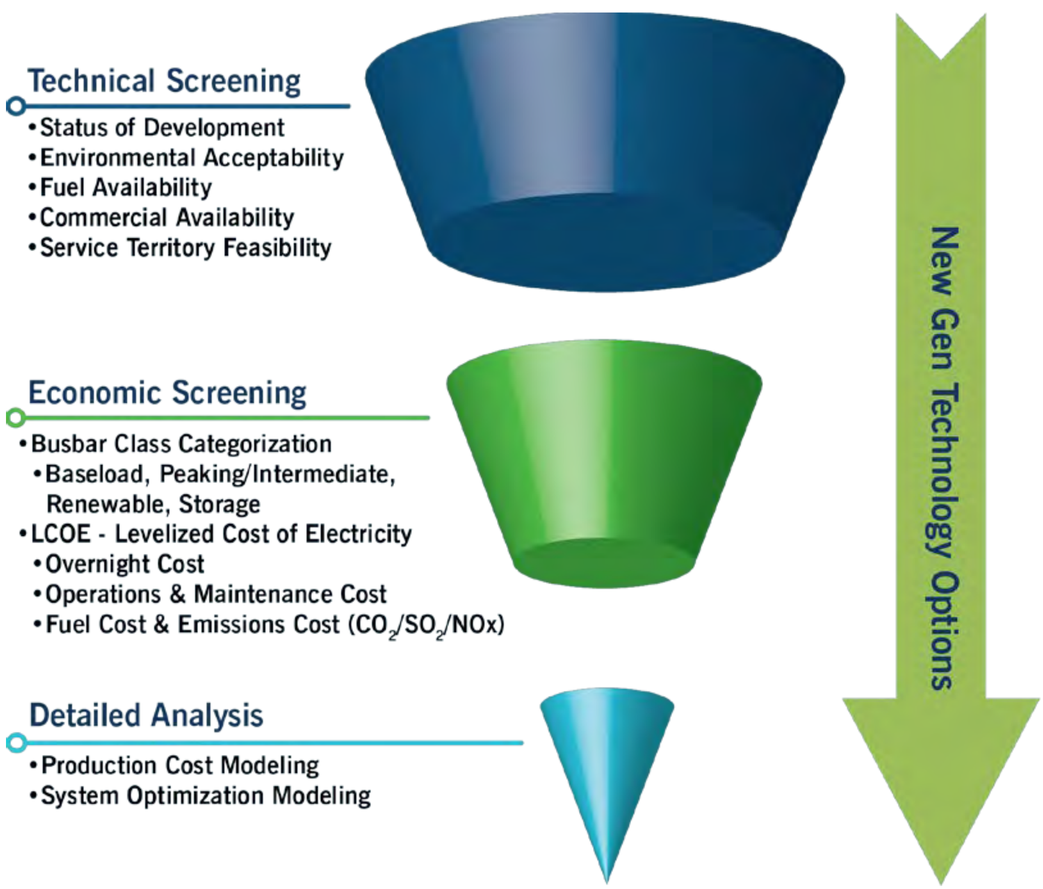
SCREENING OF GENERATION ALTERNATIVES

APPENDIX G: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues, and feasibility in the Duke Energy service territory.

Economic screening is performed using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

FIGURE G-1
NEW GENERATION TECHNOLOGIES SCREENING PROCESS



TECHNICAL SCREENING

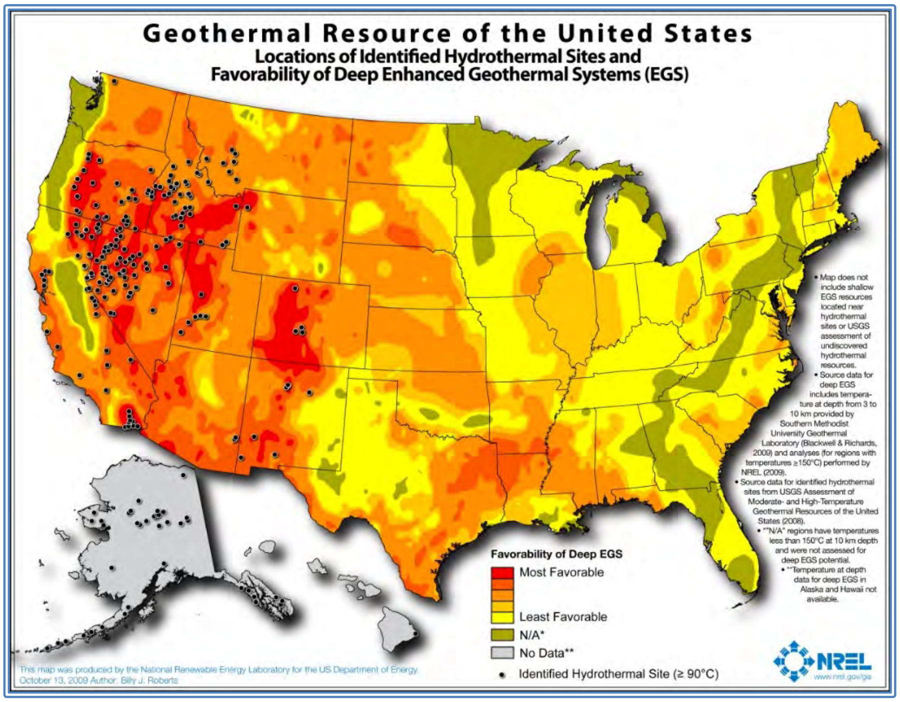
The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially viable/available for utility-scale application. However, fuel cells have the potential to provide carbon-free energy if they utilize hydrogen as a fuel source and therefore continue to be reviewed to determine their applicability for future carbon reductions.

Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project – see Figure G-2, below. However, advanced geothermal is under development and is performing demonstration projects. Recent developments in deep direct-use geothermal may expand geothermal's applicability into some of the least favorable geological formations as seen in Figure G-2. Although these technologies have not yet reached commercial status, Duke Energy will continue to follow the technology as it may present geothermal energy capability within its service territory in the future.

FIGURE G-2

NREL GEOTHERMAL RESOURCE MAP OF THE U.S.



Small Modular Nuclear Reactors (SMR) are generally defined as having a power output of less than 300 MW per reactor and utilizing water as the coolant. They typically have the capability of grouping a number of reactors in the same location to achieve the desired power generating capacity for a plant. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." SMRs continue to gain interest as they contribute no emissions to the atmosphere and, unlike their predecessors, provide flexible operating capabilities alongside inherently safer designs.

NuScale Power is the leader in SMR design and licensing in the US. A NuScale power module is expected to output 60 MW each, and a standard plant offering is expected to contain 12 modules. The NuScale design is expected to receive a certification from the Nuclear Regulatory Committee (NRC) in 2021, which would allow utilities to pursue the design as a new commercial asset. The first NuScale module is expected to reach commercial status in the late 2020s timeframe.

Two additional SMR designs are under development domestically including the GE Hitachi BWRX-300 and the Holtec SMR-160. The BWRX-300 design utilizes design features from the NRC-certified ESBWR, so although GE began their licensing process with the NRC after NuScale, they are expected to reach commercial availability in a similar timeframe. Holtec has not yet submitted a formal design certification request to the NRC and therefore there is no estimated commercialization timeframe in the US.

Similar to 2018, while SMRs were "screened out" in the Technical Screening phase of the technology evaluations due to commercial availability, they were allowed to be selected as a resource in the System Optimizer (SO) model in order to allow the model to meet the high CO_2 emission constraints in the sensitivity analysis. As a result, SMRs have been depicted on the busbar screening curves as an informative item. Duke Energy will be monitoring the progress of the SMR projects for potential consideration and evaluation for future resource plans as they provide an emission-free, diverse, flexible source of generation.

Advanced Nuclear Reactors are typically defined as nuclear power reactors employing fuel and/or coolant significantly different from that of current light water reactors (LWRs) and offering advantages related to safety, cost, proliferation resistance, waste management and/or fuel utilization. These reactors are characteristically typed by coolant with the main groups including liquid-metal cooled, gas cooled, and molten-salt fueled/cooled. There are at least 25 domestic companies working on one or multiple advanced reactor designs funded primarily by venture capital investment, and even more designs are being considered at universities and national labs across the country. There is also significant interest internationally with at least as many international companies pursuing their own advanced reactor designs in several countries across the world.

Specifics of the reactor vary significantly by both coolant type and individual designs. The reactors are projected to range in size from the single MW scale to over 1000 MW, with the majority of the designs proposing a modular approach that can scale capacity based on demand. Designs are typically exploring a flexible deployment approach which could scale power outputs to align with renewable/variable outputs. The first commercially available advanced reactors are targeting the late 2020s for deployment, although most designs are projected to be available in the 2030s. Significant legislative efforts are currently being made to further the development of advanced reactors in both the house and senate at the national level, and new bills continue to be introduced.

Duke Energy has been part of an overall industry effort to further the development of advanced reactors since joining the Nuclear Energy Institute Advanced Reactor Working Group at its formation in early 2015. Additionally, Duke Energy participates on three Advanced Reactor companies' industry boards and has hosted several reactor developers for early design discussions. Duke Energy has also participated in other industry efforts such as EPRI's Owner-Operator Requirements Document, which outlines requirements and recommendations for Advanced Reactor designs. Duke Energy will continue to allot resources to follow the progress of the advanced reactor community and will provide input to the proper internal constituents as additional information becomes available.

Poultry waste and swine waste digesters remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies. See Appendix E for more information regarding current and planned Duke Energy poultry and swine waste projects.

Solar Steam Augmentation systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. As the price of solar panels continues to drop, solar steam augmentation's economics compared to photovoltaic solar likely prevent this technology from moving forward. However, Duke Energy will continue to monitor developments in the area of steam augmentation.

Supercritical CO_2 Brayton Cycle is of increasing interest; however, the technology is still in the demonstration process. NET Power is the leading developer of the technology and is working on a pilot project. The early issues with the pilot show that the technology has not yet reached commercial status. Duke Energy will continue to monitor pilot and early commercial Supercritical CO_2 Brayton Cycle projects to determine if the technology passes the technical screening in future years.

Hydrogen as a fuel offers an advantage over traditional fossil fuels in not emitting carbon dioxide when burned. There has been substantial renewed interest by the industry in pursuing hydrogen as a replacement fuel for natural gas. Although promising, hydrogen as a utility fuel is still in the early stages from both a production and generation standpoint. Turbine manufacturers have proven successful with hydrogen/natural gas cofiring of up to 30% hydrogen by volume without significant gas turbine alterations in many of the combined cycle and combustion turbine plants currently in operation, dependent on gas turbine type. However, to move to 100% hydrogen-fueled turbines substantial improvements in turbine technology are required. Additionally, hydrogen production would have to increase by many orders of magnitude to have ample supply to match the current production output of natural gas-fueled turbines. Duke Energy will continue to monitor hydrogen technology, both production and generation, to prepare for its potential future use as a natural gas fuel substitute.

Additional Storage technologies continue to be developed and pursued by a variety of companies. The range of technologies is vast and include non-lithium-ion batteries, mechanical storage, thermal storage, and variants of pumped hydro storage. Although some storage technologies passed the technology screening, the majority are still in a pre-commercial status. These technologies continued to be studied as future options for generation and include lead acid batteries, sodium-sulfur batteries, metal-air batteries, subterranean pumped storage, gravitational energy, hydrogen, flywheel energy, liquid air energy, chilled water, molten salt, silicon, concrete, sand, and phase change storage. Duke Energy will continue to monitor the developments and pilots of the various storage options to determine which designs have reached commercial status.

A brief explanation of the technology additions for 2020 compared to the 2018 Integrated Resource Plan submittal and the basis for their inclusion follows:

Compressed Air Energy Storage (CAES) offers an additional method of storage over longer durations than typically found in batteries. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. CAES has two primary application methods: diabatic and adiabatic. To utilize CAES, the project needs a suitable storage site, which is typically either a salt cavern or mined hard-rock cavern. Salt caverns have been preferred due to the low cavern construction costs. However, mined hard-rock caverns are now a viable option in areas that do not have salt formations with the use of hydrostatic compensation to increase energy storage density and reduce the cavern volume required. This change to allow mined hard-rock caverns created the potential for CAES in the Carolinas. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir. Energy is then recaptured by releasing the compressed air, heating it, and generating power as the heated air travels through an expander.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

Although flow batteries' capital costs project to be higher than Li-Ion batteries, flow batteries project to become most effective as the duration of the battery is increased due to energy capacity being dictated primarily by the size of the tanks. Therefore, flow batteries have been included in the technology options as a longer duration storage option.

Offshore Wind is a developing technology in the United States but internationally has become a mature technology. Offshore wind farms have been installed in the oceans off European shores since the 1990s and continue to be an important source of energy in that market. There are several projects in various phases of development in U.S. coastal waters, and more are anticipated as technology and construction advancements allow for installation in deeper waters farther offshore. The Block Island project developed by Deepwater Wind is the first to reach commercial operation, and Duke Energy Renewables is performing remote monitoring and control services for the project. This 30 MW project is located about 3 miles off the coast of Rhode Island.

Duke Energy and NREL studied the potential for offshore integration off the coast of the Carolinas in March 2013. In 2015, the U.S. Bureau of Ocean Energy Management (BOEM) completed environmental assessments at three potential Outer Continental Shelf (OCS) sites off the coast of North Carolina. In March 2017, BOEM administered a competitive lease auction for wind energy in federal waters and awarded Avangrid Renewables the rights to develop an area off the shores of Kitty Hawk. Avangrid has plans for a project that may be as large as 2,400 MW.

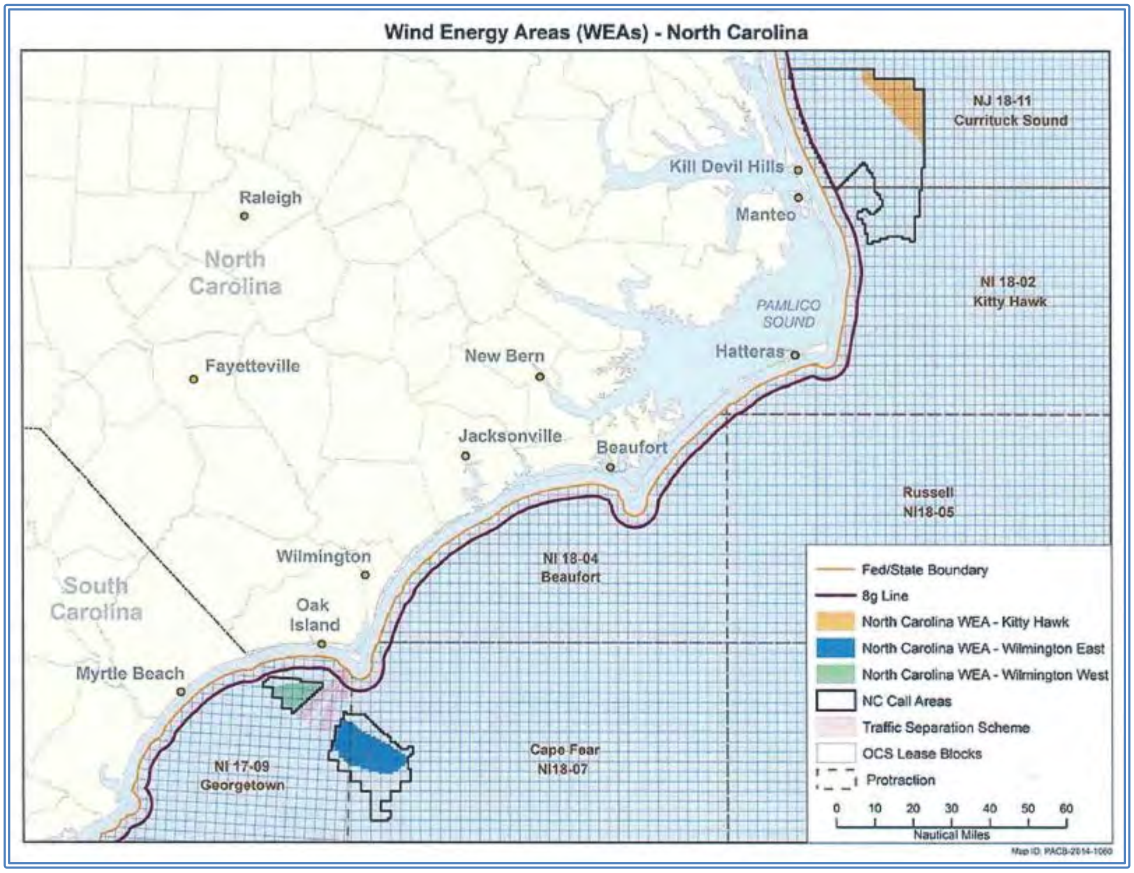
Several coastal states including New York, New Jersey, Maryland, Massachusetts, Connecticut, California, Rhode Island, Delaware, and Virginia have been forecasted to have projects developed. New York has an Offshore Wind Master Plan aimed at 2,400 MW of offshore projects by 2030, and Statoil is developing the 1,500 MW Empire Wind project near New York City, aiming for completion in 2025.

The unique constraints of the industry and the increasingly competitive global market are driving R&D improvements that allow wind farms to be sited farther offshore. Installation and siting require careful consideration to bathymetry and offshore construction concerns, but siting is further complicated by shipping lanes, fishing rights, wildlife migration patterns, military operations, and other environmental concerns. Plus, coastal residents and tourists prefer an unobstructed ocean view, so the larger turbines require longer distances to keep them out of sight.

Although technology costs still remain high for offshore wind, the technology is being evaluated as an additional renewable option. The profile of offshore wind allows for a higher capacity factor in the Carolinas than onshore wind, and the profile also compliments solar energy.

FIGURE G-3

NC WIND ENERGY AREAS (WEAS) (DEVELOPED IN JOINT VENTURE BY DUKE ENERGY AND NREL)



GENERATION FLEXIBILITY AND DUKE ENERGY CLIMATE PLAN

As more intermittent generation becomes associated with Duke’s system there is a greater need for generation that has rapid load shifting and ancillary support capabilities. This generation would need to be dispatchable, possess desirable capacity, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or may do so in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.

Additionally, in 2020 Duke Energy released a revision to its previous Climate Report with aggressive goals to reduce output from its generating facilities by 2030 and even deeper reductions by 2050. Duke Energy concluded that it would need new technologies that have not yet reached commercialization status that performed as Zero-Emitting Load-Following Resources (ZELFR). The load-following requirement comes from the flexibility need described above, and the zero-emission portion is to help Duke Energy meet its future climate goals.

Duke Energy is evaluating several generation technologies that are considered pre-commercial to meet the ZELFR need. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and sequestration, fuel cells, hydrogen, long duration energy storage, and supercritical CO2 Brayton Cycle. All of these technologies are expected to help Duke Energy meet future carbon reduction goals if they reach commercial status and are economically competitive.

Duke Energy expects multiple technologies to be required to meet its carbon reduction goals, and therefore Duke Energy is considering potential paths to help move these technologies towards commercialization. One such effort Duke Energy is pursing is the recently announced partnership with two advanced reactor developers on DOE's Advanced Reactor Deployment Program to deploy one of the first two advanced nuclear reactors. Another effort underway is the collaborative work with Siemens as part of DOE's Energy Storage for Fossil Generation Program to evaluate the possibility of hydrogen co-firing at the Combined Heat and Power Plant on Clemson's campus. Duke Energy recognizes the potentially long commercialization timeframe for some of these technologies and will continue to pursue efforts to move these important technologies forward.

Although these technologies all screen out in the process due to their commercial status, Duke Energy will continue to follow a wider range of technologies to meet these future generation needs.

ECONOMIC SCREENING

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves, also referred to as *busbar* curves. By definition, the *Busbar* curve estimates the revenue requirement (i.e. life-cycle cost) of power from a supply option at the "busbar," the point at which electricity leaves the plant (i.e. the high side of the step-up transformer). Duke Energy provides some additional evaluation of a generic transmission and/or interconnection cost adder associated with each technology.

The screening within each general class of busbar (Baseload, Peaking/Intermediate, Renewables and Storage), as well as the final screening across the general classes, uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy. Again, for the 2020 IRP year, Duke Energy has provided an additional set of busbar curves to represent Storage technology comparisons. As Storage technologies are not traditional generating resource options, they should be compared independently from generating resources. In addition, there has been no *charging* cost associated with the storage busbar buildup. This charging cost is excluded as it is dependent upon what the next marginal unit is in the dispatch stack as to what would be utilized to "charge" the storage resource. For resource options inclusive of or coupled with storage, it is assumed that the storage resource is being directly charged by the generating resource (i.e. Solar PV plus Battery Storage option).

This screening (busbar) curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

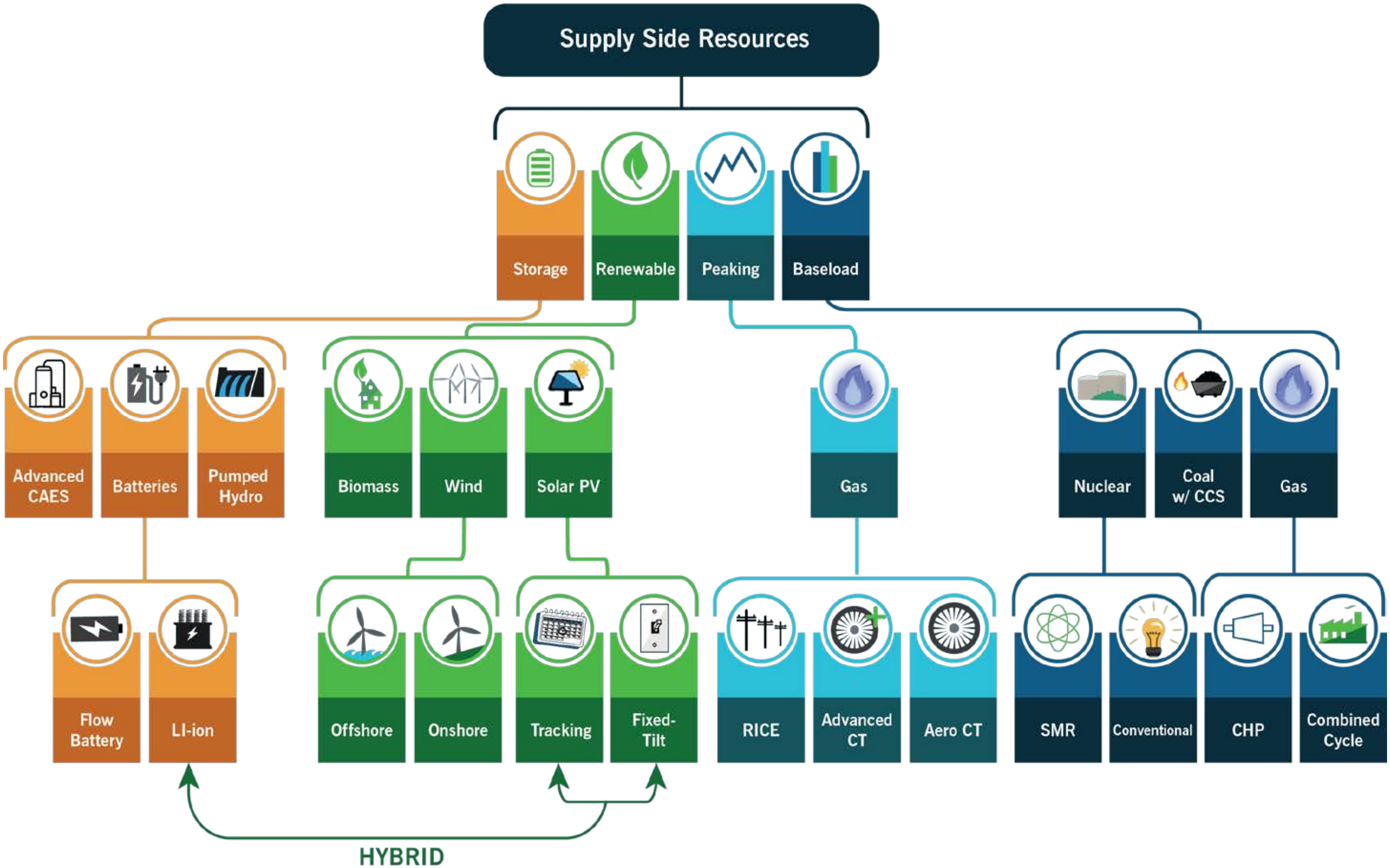
The Company selected the technologies listed below for the screening curve analysis. While future carbon emission constraints may effectively preclude new coal-fired generation, Duke Energy has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for baseload analysis. 2020 additions include Offshore wind, additional Lithium Ion Battery Storage options, Flow Battery Storage, and Advanced Compressed Air Energy Storage.

DISPATCHABLE (WINTER RATINGS)

BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	**NON- DISPATCHABLE (WINTER RATINGS)**
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

FIGURE G-4

DUKE ENERGY, SCREENED-IN SUPPLY SIDE RESOURCE ALTERNATIVES



INFORMATION SOURCES

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include a variety of internal departments at Duke Energy. In additional to the internal expertise, the following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No CO_2, With CO_2) in the four major categories defined (Baseload, Peaking/Intermediate, Renewables, Storage).

CAPITAL COST FORECAST

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs but the costs of all resource technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides cost projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2020 as a base year, an " annual cost factor is calculated based on the change from a base year for the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2018, April 2019)

From *NEMS Model Documentation 2018, April 2019*:

> *"Uncertainty about investment costs for new technologies is captured in the ECP [Electricity Planning Submodule] using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*
>
> *Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table G-1.

TABLE G-1

SNAPSHOT FROM FORECAST FACTOR TABLE BY TECHNOLOGY (EIA - AEO 2020)

YEAR	FRAME CT	AERO CT	NUCLEAR	BATTERY STORAGE	1X1 COMBINED CYCLE	ONSHORE WIND
2020	1.000	1.000	1.000	1.000	1.000	1.000
2021	0.985	0.987	0.984	0.812	0.987	0.987
2022	0.970	0.973	0.967	0.718	0.973	0.973
2023	0.950	0.961	0.950	0.640	0.961	0.961
2024	0.901	0.953	0.920	0.625	0.953	0.953
2025	0.873	0.945	0.909	0.609	0.945	0.945
2026	0.852	0.937	0.898	0.594	0.937	0.937
2027	0.831	0.928	0.886	0.579	0.927	0.928
2028	0.815	0.918	0.874	0.563	0.918	0.918
2029	0.803	0.907	0.861	0.546	0.907	0.907
2030	0.789	0.896	0.847	0.530	0.896	0.896

SCREENING RESULTS

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost baseload resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No CO_2 and With CO_2). Although CHP can be competitive with CC, it is site specific and requires a local steam and electrical load. Carbon capture systems have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology in Duke Energy territories.

The peaking technology screening included F-frame and J-Frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. Simple cycle aeroderivative gas turbines remain in close contention with reciprocating engines. Should a need be identified for one of these two types of resources, a more in-depth analysis would be performed.

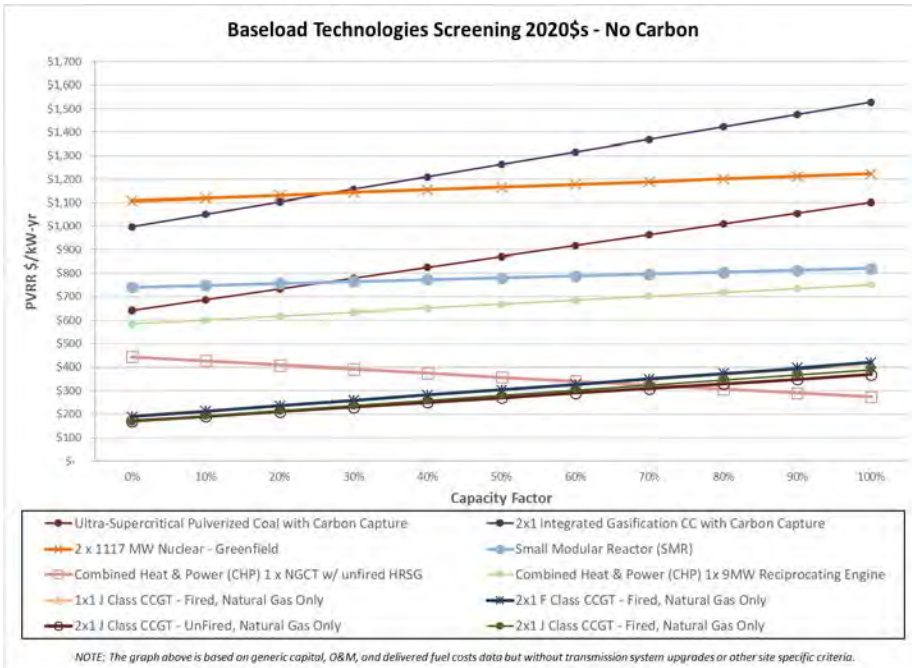
The renewable screening curves show solar continues to be a more economical alternative than other renewable resource options. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas and biomass projects are limited based on site availability but are dispatchable. Landfill gas is not shown in the busbar curve for renewables as the options are limited since most sites have already been transacted with. Although solar PV prices have become competitive with conventional generators, the lack of dispatchability and low capacity factor does not allow it to be a baseload resource.

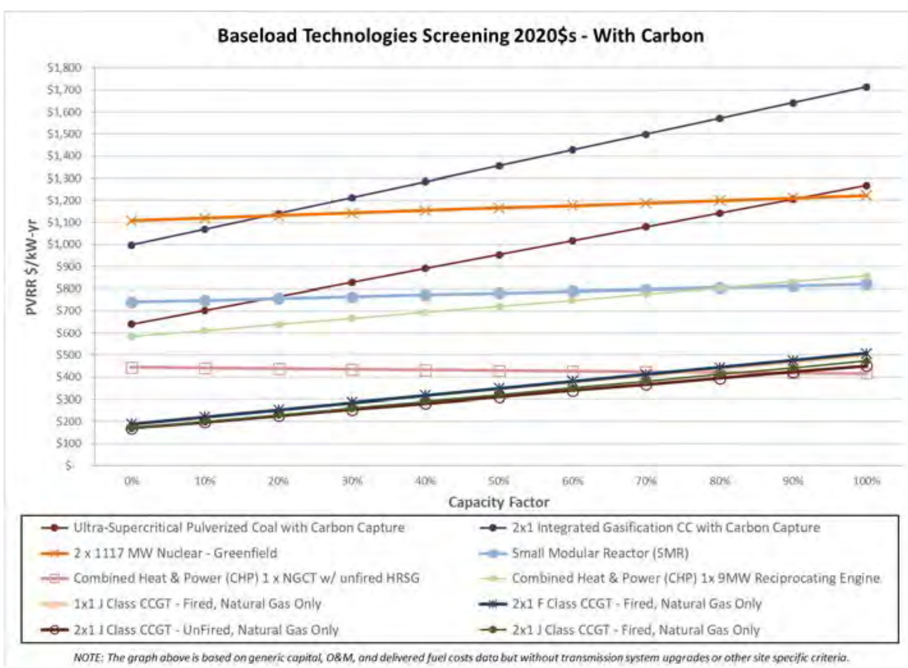
Energy storage has become an increasingly important asset as companies add more variable resources to their portfolio. Energy storage can provide a variety of benefits to the grid and overall resource portfolio. Additional information on energy storage can be found in Appendix H. For the screening results, the lowest $/kW option for energy storage was 1-hour duration Li-Ion storage as expected. However, batteries have a variety of use cases and longer duration storage can be more useful than shorter duration storage in certain cases. Additionally, the $/kWh decreases as the duration of the storage increases. So, although the 1-hour duration Li-Ion battery storage asset had the lowest screening cost, the specific application of the storage option will determine which storage option is the best fit for its use case.

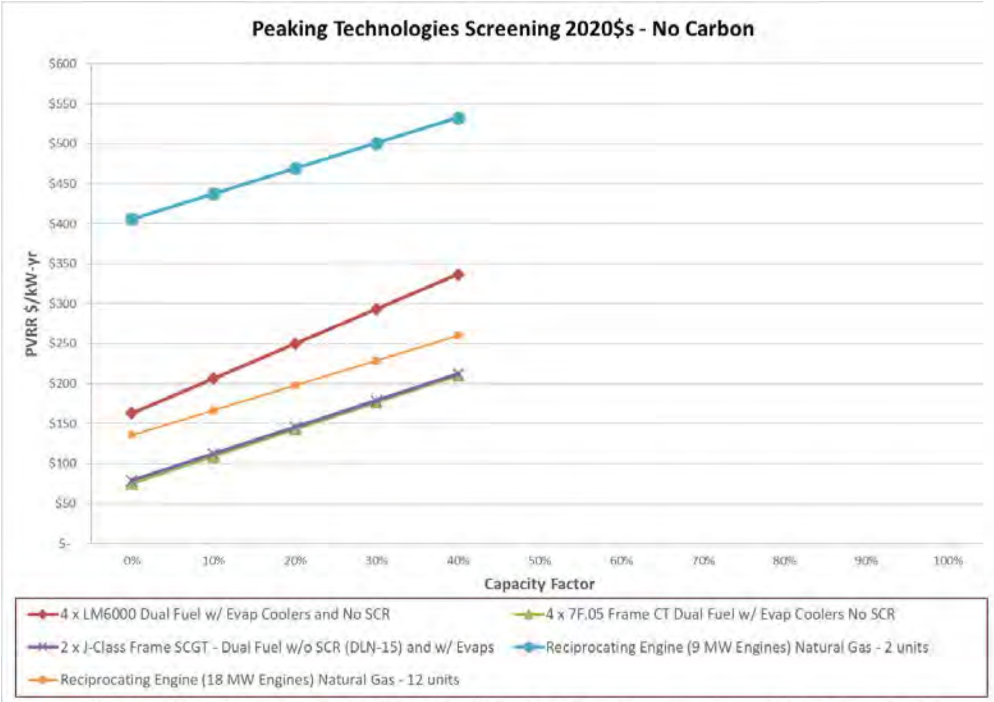
The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

SCREENING CURVES

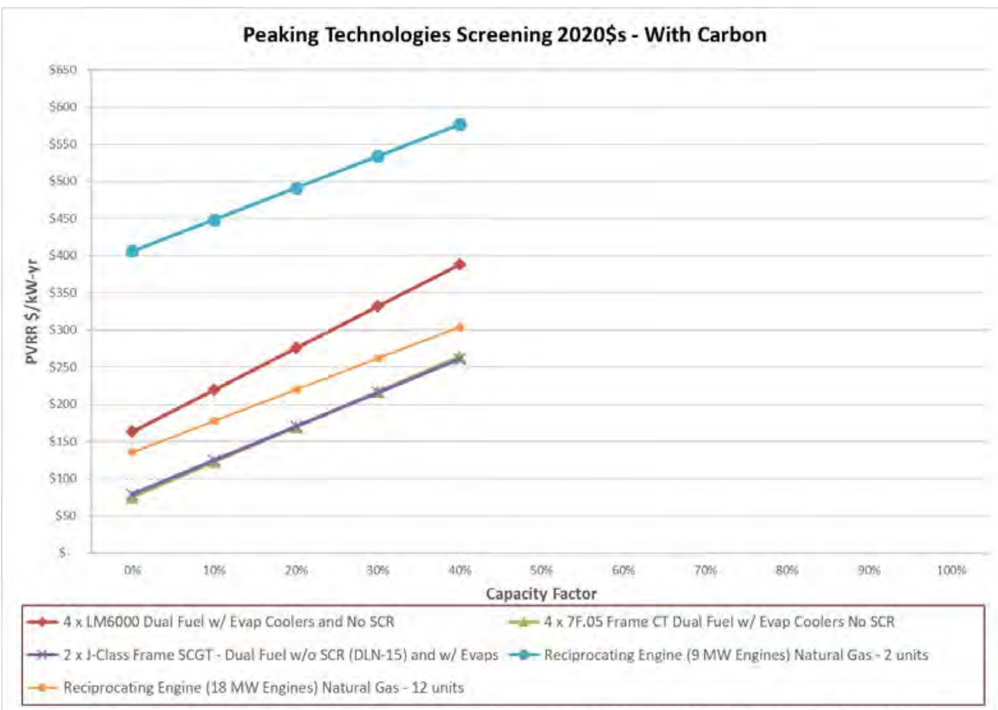
The following pages contains the technology screening curves for baseload, peaking/intermediate, renewable and storage technologies.



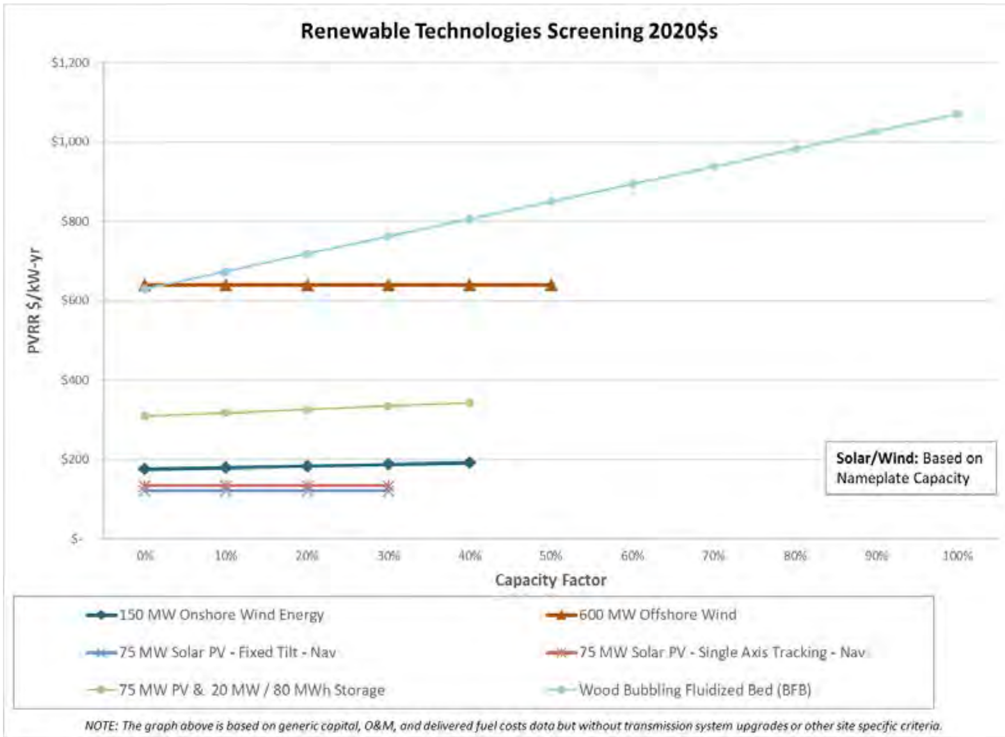




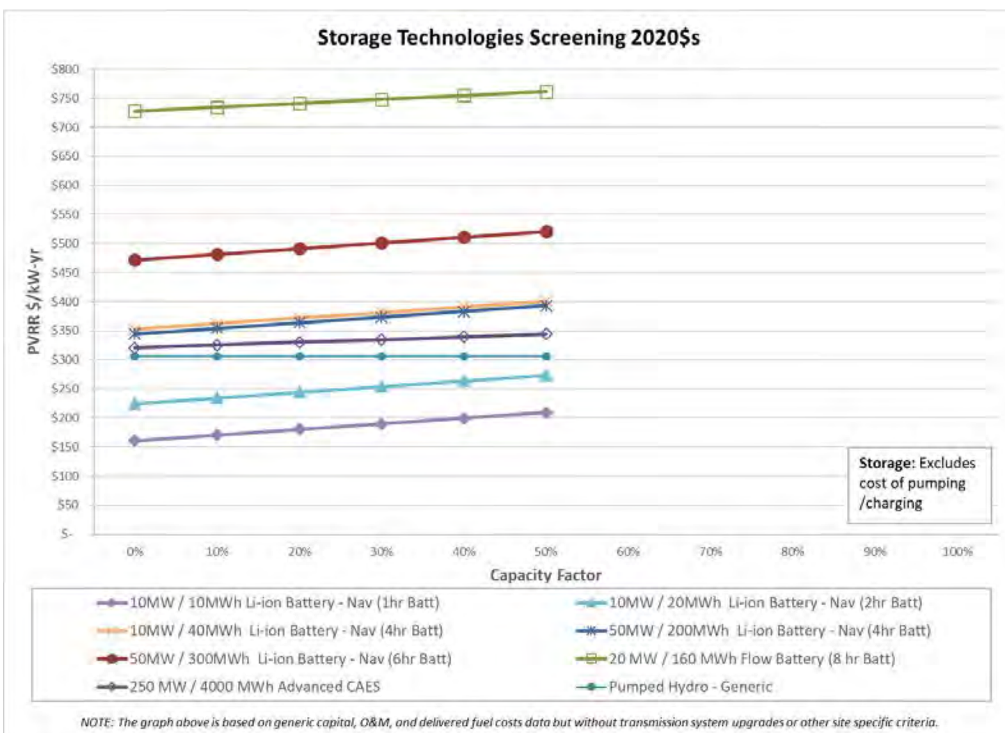
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



Renewable Technologies Screening 2020$s
PVRR $/kW-yr
Capacity Factor
Solar/Wind: Based on Nameplate Capacity
150 MW Onshore Wind Energy
600 MW Offshore Wind
75 MW Solar PV - Fixed Tilt - Nav
75 MW Solar PV - Single Axis Tracking - Nav
75 MW PV & 20 MW / 80 MWh Storage
Wood Bubbling Fluidized Bed (BFB)
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



Storage Technologies Screening 2020$s
PVRR $/kW-yr
Capacity Factor
Storage: Excludes cost of pumping /charging
10MW / 10MWh Li-ion Battery - Nav (1hr Batt)
10MW / 20MWh Li-ion Battery - Nav (2hr Batt)
10MW / 40MWh Li-ion Battery - Nav (4hr Batt)
50MW / 200MWh Li-ion Battery - Nav (4hr Batt)
50MW / 300MWh Li-ion Battery - Nav (6hr Batt)
20 MW / 160 MWh Flow Battery (8 hr Batt)
250 MW / 4000 MWh Advanced CAES
Pumped Hydro - Generic
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.

ENERGY STORAGE

APPENDIX H: ENERGY STORAGE

Battery storage is expected to play an important role in meeting future needs on the DEP system. As discussed in Chapter 6, battery storage can provide multiple services. For purposes of the 2020 IRP, the Company considered capacity, energy arbitrage, and ancillary service benefits when valuing battery storage. Additionally, the Company conducted a thorough review of battery cost and operating assumptions modeled in the 2020 IRP. Benchmarking battery storage costs across publications is difficult, and oftentimes not possible, due to disparate definitions and incomplete documentation. Some publications do not include the full cost that would be needed to construct a battery storage system that would meet the requirements of a manufacturer's warranty and the needs of the Utility over the life of the asset. For this reason and to provide transparency of the cost estimating process, the Company is detailing the battery storage assumptions used in the 2020 IRP below.

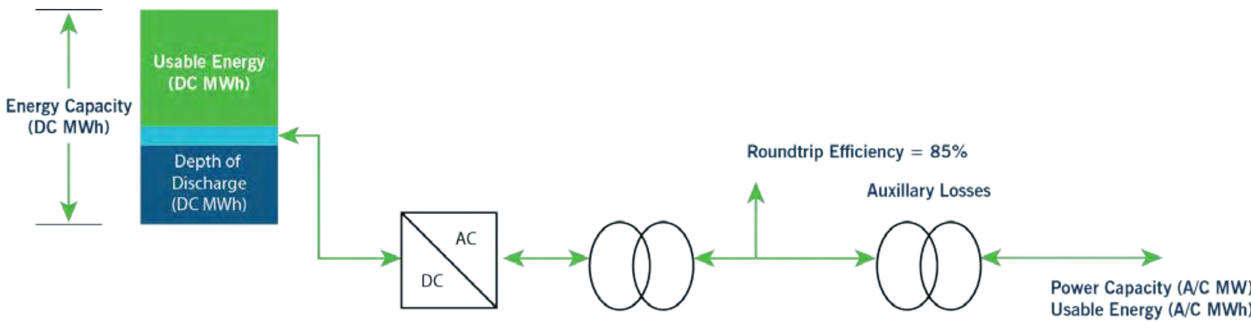
Finally, in order to appropriately estimate the capacity value battery storage can provide, the Company hired a third-party consultant to conduct an Effective Load Carrying Capability (ELCC) study to quantify the contribution to winter peak demand that battery storage could provide in DEP. The results of the ELCC study are described in the following sections and the Battery Storage ELCC study has been filed along with the IRP filing.

BATTERY STORAGE TERMINOLOGY AND OPERATING ASSUMPTIONS

Some of the terminology that the Company uses to describe batteries in the IRP is detailed below. Importantly, while many of the terms and definitions below are standard across the industry, some of the terms are specific to how battery storage is described in this IRP and may not match what is described in other publications. Where appropriate, definitions that are taken directly from outside publications are cited. The following is a diagram of a standalone battery storage system that is modeled in the 2020 IRP.

FIGURE H-1

SIMPLIFIED BATTERY STORAGE SYSTEM MODELED IN 2020 DEP IRP



- **Battery size –** Battery sizing is generally provided in capacity and energy values or capacity value and duration. The terms “capacity”, “energy”, and “duration” are discussed below. An example of battery size nomenclature is “50 MW / 200 MWh” which represents a 50 MW battery with a 4-hour duration.

- **Capacity –** Generally referred to as “power capacity” in the industry and represents the total possible instantaneous discharge capability of the battery storage system, or the maximum rate of discharge the battery can achieve starting from a fully charged state.[1] The Company measures power capacity at the point of interconnect to the transmission system and the units are “MW AC.” The IRP represents the cost of a battery in $/MW where the numerator, or dollars, is the total cost of the battery system and the denominator is the power capacity in MW AC of the system. The components of the total cost of the battery system are described in further detail below.

- **Energy –** The energy that a battery can hold can be represented differently between publications which can make comparing costs between sources of data difficult. For the purposes of this IRP, the Company considers energy in the following manners:

    - **Usable Energy –** Refers to the amount of energy that can be discharged at the point of interconnection over the duration of the battery. Usable energy can be described in units of “MWh AC” or “MWh DC.” When the Company discusses the cost of a

[1] https://www.nrel.gov/docs/fy19osti/74426.pdf.

battery on a $/MWh basis, the numerator is the total cost of the battery system and the denominator is the usable energy in units of MWh AC.

- **Depth of Discharge (DoD) –** "Indicates the percentage of the battery that has been discharged relative to the overall [energy] capacity of the battery."[2] In the 2020 IRP, this number represents the amount of energy that must remain, unused, in the battery to satisfy the warranty of the battery and/or allow the battery to complete the expected number of cycles over the life of the asset. For instance, the Company uses a 20% depth of discharge limit which simply means the battery cannot discharge more than 80% of its energy capacity. Some publications only provide battery costs based on the usable energy of the battery thereby ignoring the DoD; however, the Company calculates the cost of a battery based on the energy capacity, which includes the DoD limitation.

- **Energy Capacity –** The total amount of energy that can be stored or discharged by the battery storage system.[3] In the diagram above, energy capacity is the sum of the usable energy and the depth of discharge limit. Energy capacity is defined in units of "MWh DC." The Company did not include additional costs for other "unused" energy required to maintain the contracted usable energy of the battery, such as additional energy capacity to account for DC or AC losses that occur during charge and discharge of the battery. However, within the production cost model, the Company does account for the production cost impacts of losses on roundtrip efficiency of the battery as discussed below.

- **Duration –** "Amount of time storage can discharge at its power capacity. "[4] For example, a battery with 50 MW of power capacity and 200 MWh of usable energy capacity will have a storage duration of 4 hours.

- **Roundtrip Efficiency –** "Measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It can represent the total DC-DC or AC-AC efficiency of the battery system, including losses from self-discharge and other electrical

[2] https://news.energysage.com/depth-discharge-dod-mean-battery-important/#:~:text=A%20battery's%20depth%20of%20discharge,DoD%20is%20approximately%2096%20percent.
[3] U.S. Battery Storage Trends, U.S. Energy Information Administration, May 2018
[4] https://www.nrel.gov/docs/fy19osti/74426.pdf

losses."[5] The Company uses A/C - A/C efficiency as the production cost models only consider the charging/discharging at the point of interconnect to the power system. The Company assumed a roundtrip efficiency of 85% for all lithium-ion (Li-ion) batteries modeled in the 2020 IRP.

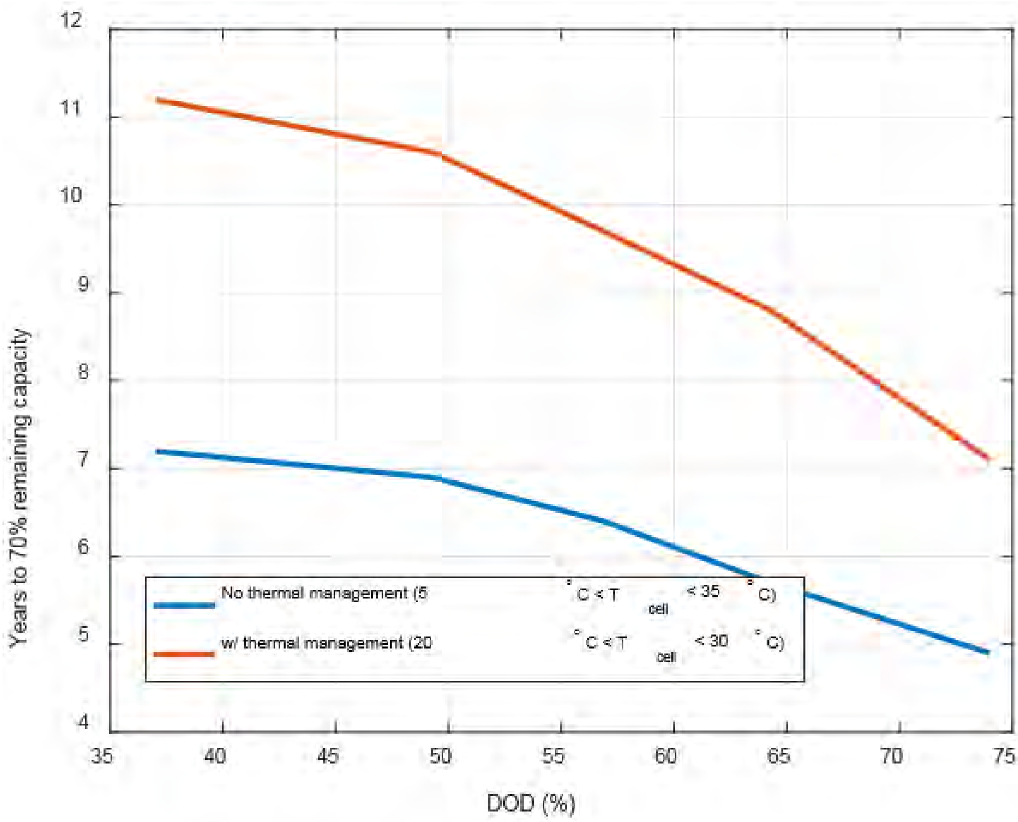
- **Auxiliary Losses -** Included as part of other electrical losses in the calculation of round-trip efficiency and can include power required for HVAC systems associated with the battery storage system.

- **Degradation –** The loss of energy capacity of a battery storage system overtime. "Degradation of lithium-ion batteries is impacted by several variables. Known drivers of degradation include: temperature of operation, average state of charge over its lifetime, and depth of charge-discharge cycles."[6] Figure 2, sourced from NREL's "Life Prediction Model for Grid Connected Li-ion Battery Energy Storage System" demonstrates the effects that DoD and temperature management of the battery storage system can have on degradation.

[5] https://www.nrel.gov/docs/fy19osti/74426.pdf
[6] https://www.energy-storage.news/blogs/is-that-battery-cycle-worth-it-maximising-energy-storage-lifecycle-value-wi#:~:text=Battery%20storage%20degradation%20typically%20manifests,need%20for%20replacement%20of%20batteries.

FIGURE H-2

IMPACT OF BATTERY OVERSIZING AND THERMAL MANAGEMENT ON LIFETIME FROM NREL [7]



- **Battery Augmentation –** As a battery storage system experiences degradation, battery cells can be replenished on a regular, or semi-regular, basis to maintain the usable energy of the battery storage system. This strategy to counteract degradation leads to lower initial capital costs but incurs higher on-going costs throughout the life of the asset. For IRP purposes, the Company assumes a Battery Augmentation strategy to minimize total costs over the 15-year assumed life of the battery asset, while recognizing that this approach does present some challenges with maintaining stable performance of the system.

- **Overbuild –** Refers to an increase in the nameplate energy capacity to account for expected degradation. As an alternative strategy to augmentation, the battery storage system can

[7] https://www.nrel.gov/docs/fy17osti/67102.pdf.

initially be physically oversized beyond depth of discharge limits to account for degradation. This strategy yields higher initial capital costs but lower on-going costs versus an augmentation strategy.

BATTERY STORAGE COST ASSUMPTIONS

Battery storage costs have been declining rapidly over the last several years, and they are expected to continue declining for the foreseeable future. In fact, the Company assumes that battery prices will drop by nearly 50% over the next 9 years.[8]

The Company's capital cost assumptions are developed by a third party and are benchmarked against both internal and external sources. Often, the Company's prices appear higher than published numbers. As discussed above, there are several factors that can drive this difference including:

- The Company calculates the cost of a battery storage device assuming a 20% DoD limit while other publications likely only calculate the cost of the battery based on the rated energy of the battery from their information sources, which often do not specify whether their energy rating factors in DoD. In cases where the energy rating does not account for DoD, the cost of the battery can differ by over 10%.

- The Company assumes interconnection costs based on historical costs on the DEP system. Other publications may include lower interconnection costs or may not account for interconnection costs altogether.

- Because the Company expects to rely on these assets for at least 15-years to provide reliable capacity and energy to its customers on a real-time basis, some of the Company's assumptions of software and controls may lead to higher capital costs than a device that is designed to provide capacity and energy with lower reliability standards or on a more standard schedule.

- Similarly, the Company may be including more expensive HVAC and fire detection and suppression assumptions when calculating the cost of the battery storage system. It is the Company's belief that this cost is warranted for safety and protection of employees as well as the assets.

[8] Real 2020$; prices drop by 34% in nominal terms assuming 2.5% inflation rate.

- Due to low installed capacity and limited operational experience with battery storage on the DEP system, the Company assumes that system integration costs of a battery would be on the level of a custom application rather than a basic, or turnkey, level of cost. It is likely however, that as battery storage becomes more pervasive on the DEP system, system integration costs will decline, and battery storage costs could decline further than the near 50% decline already assumed in the IRP. The Company will monitor developments in this area and adjust as appropriate in future IRPs.

As stated previously, it is very difficult to determine what is included in the cost assumptions for battery storage in publications, particularly with regards to software and controls, HVAC, fire detection and suppression, and system integration costs. The following are the assumptions the Company includes for the percent contribution of costs from various components of a battery storage system along with the projected cost trend through 2029 in nominal terms assuming 2.5% inflation.[9]

TABLE H-1

COST COMPONENTS OF BATTERY STORAGE IN 2020 IRP

COMPONENT	% OF TOTAL COST [10]	PROJECTED COST TREND THROUGH 2029
Battery Pack	53%	-51%
Power Electronics	3%	-40%
Software and Controls	1%	-8%
Balance of Plant	9%	-15%
Systems Integration	15%	-30%
Site Installation	8%	3%
Project Development Fees	6%	-24%
Interconnection Fees	5%	25%

As further context to the above cost allocations and assumptions, EPRI recently conducted a survey of its members regarding cost assumptions of battery storage. Many members use public sources such as NREL, Lazard, and EPRI, in addition to commercial third-party forecasts and in-house SME

[9] Initial value based on 2020 cost of a 50 MW / 200 MWh battery storage system in the 2020 IRP.
[10] Values based on total cost without owner's costs. Owner's costs are consistent with the costs incurred during the development of the Company's previous storage projects.

input, when developing battery storage price forecasts. Importantly, members do not simply rely on published numbers without making some adjustments. Members identified adding costs for items such as interconnection, A/C balance of plant, substation, land, and civic infrastructure. Nearly half of respondents factor in costs associated with a state of charge (SOC) window or depth of discharge limitation when developing cost estimates. Finally, one cost that DEP does not account for are end-of-life costs for disposal and recycling of battery storage components. Just over half of respondents account for these costs and the Company will evaluate adding end-of-life costs in future IRPs.

EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) OF BATTERY STORAGE

The Company commissioned Astrape Consulting, a nationally recognized expert in the field, to conduct a Storage Effective Load Carrying Capability (ELCC) Study of battery storage to determine the capacity value that short-duration storage can provide towards meeting DEP's winter peak demand. The ELCC study evaluated both standalone storage, as well as DC coupled solar plus storage over a range of storage penetrations, durations, and solar levels. The results of the study are highlighted below, and the full report is filed with the IRP as Attachment IV. Importantly, the study confirmed that initial additions of storage can provide nearly 100% contribution to winter peak, however the ELCC contribution of energy storage decreases rapidly with increasing penetration of battery storage as is the case with any energy limited resource.

STANDALONE STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study under a base level of solar (4,000 MW) and a high level of solar (5,500 MW).

TABLE H-2
STANDALONE STORAGE RUN MATRIX FOR ELCC STUDY

Duration / Cumulative Battery Capacity	STANDALONE BATTERY DURATION (HRS)		
	2	4	6
800 MW			
1,600 MW (incr 800)			
2,400 MW (incr 800)			
3,200 MW (incr 800)			

The sensitivities analyzed in the matrix above were conducted separately for each battery duration. For example, 6-hour batteries were studied as if there were no 4-hour or 2-hour batteries on the DEP system. In this manner, the ELCC represents the value of a 6-hour battery without the impacts of other incremental storage on the system. An additional sensitivity was analyzed which studied the impacts of 6-hour storage if up to 1,600 MWs of 6-hour storage were placed on the system *after* 3,200 MWs of 4-hour storage were already operating in DEP.

The ELCC of standalone storage was determined separately under the following three conditions:

- Preserve Reliability – Assumes full control of the battery and only dispatches the battery during emergency events to avoid firm load shed, maintains charge at all times possible. Results in highest possible capacity value but low economic value.

- Economic Arbitrage – Assumes DEP maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- Fixed Dispatch – Assumes DEP has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEP did not have dispatch rights to the storage asset.

The following three charts depict the capacity value of 2-hour, 4-hour, and 6-hour storage under the three operating conditions described above.

FIGURE H-3

AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN PRESERVE RELIABILITY MODE

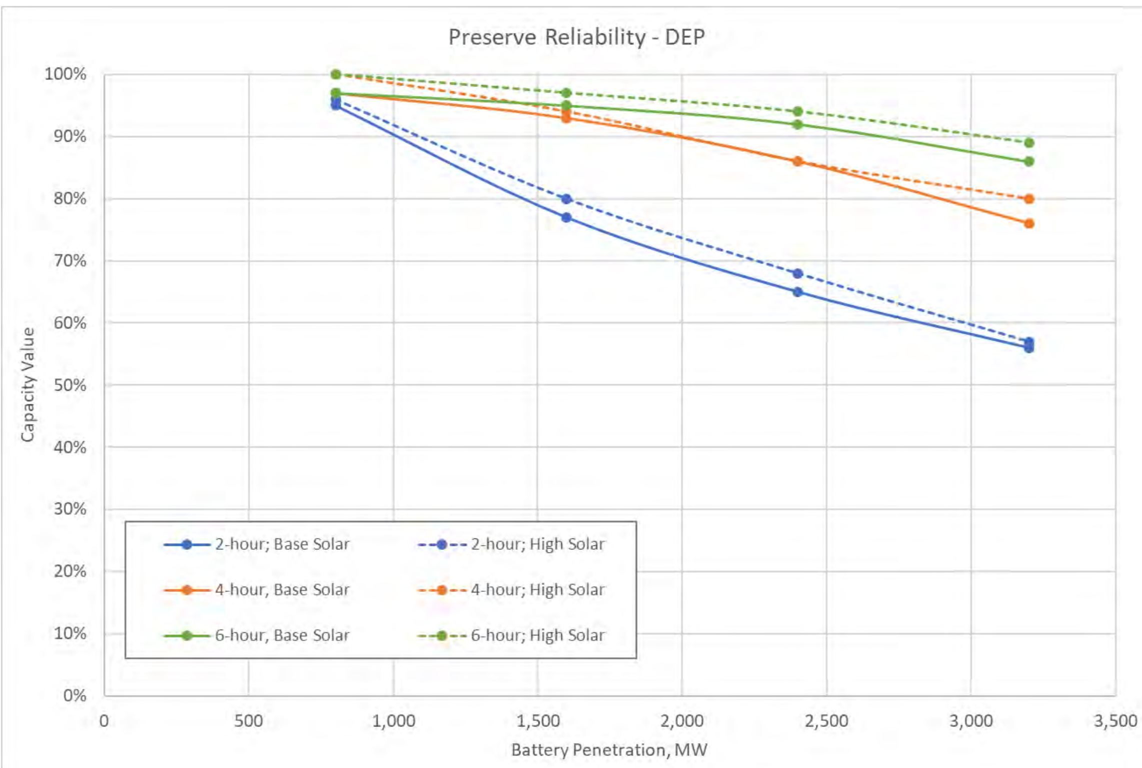


FIGURE H-4

AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN ECONOMIC DISPATCH MODE

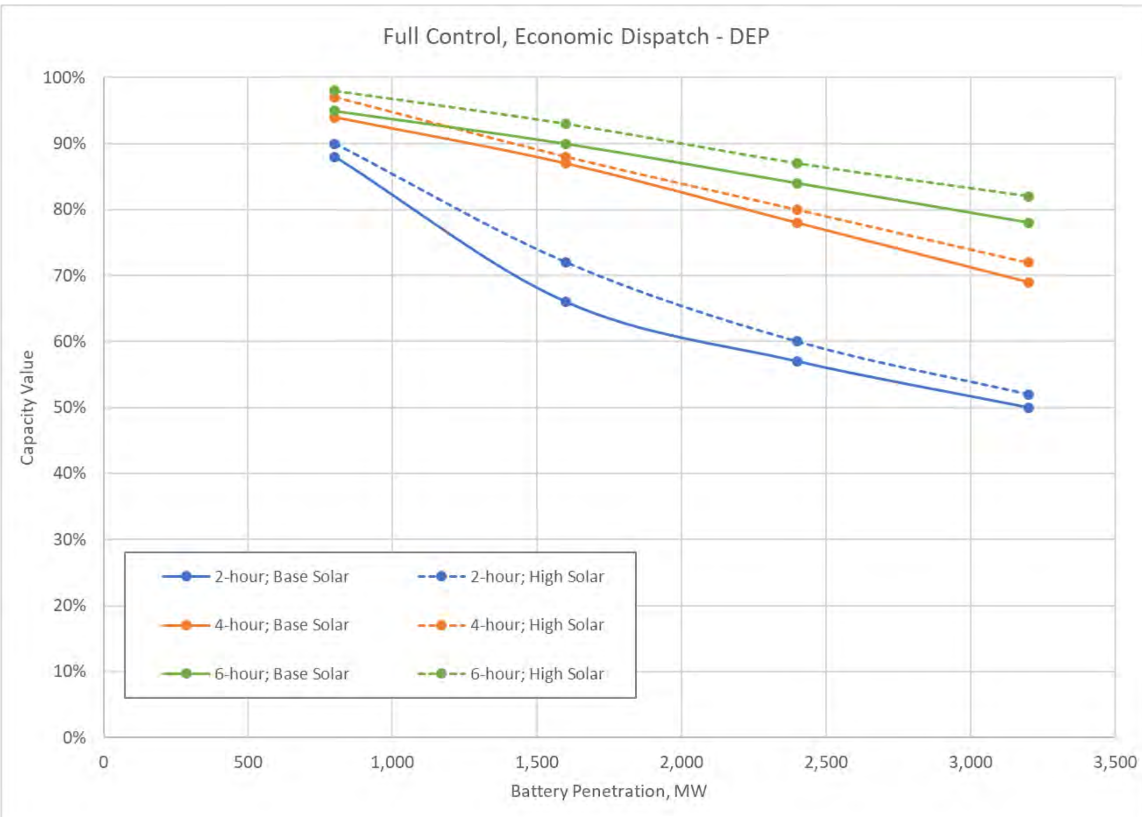
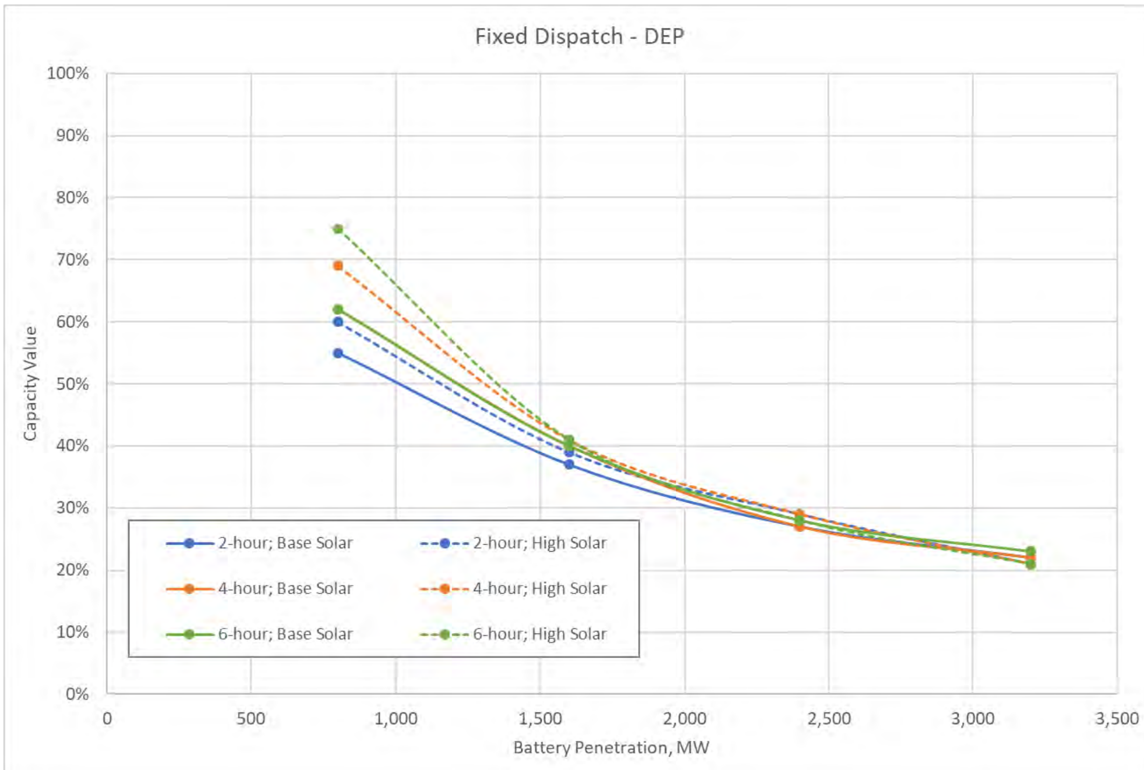


FIGURE H-5

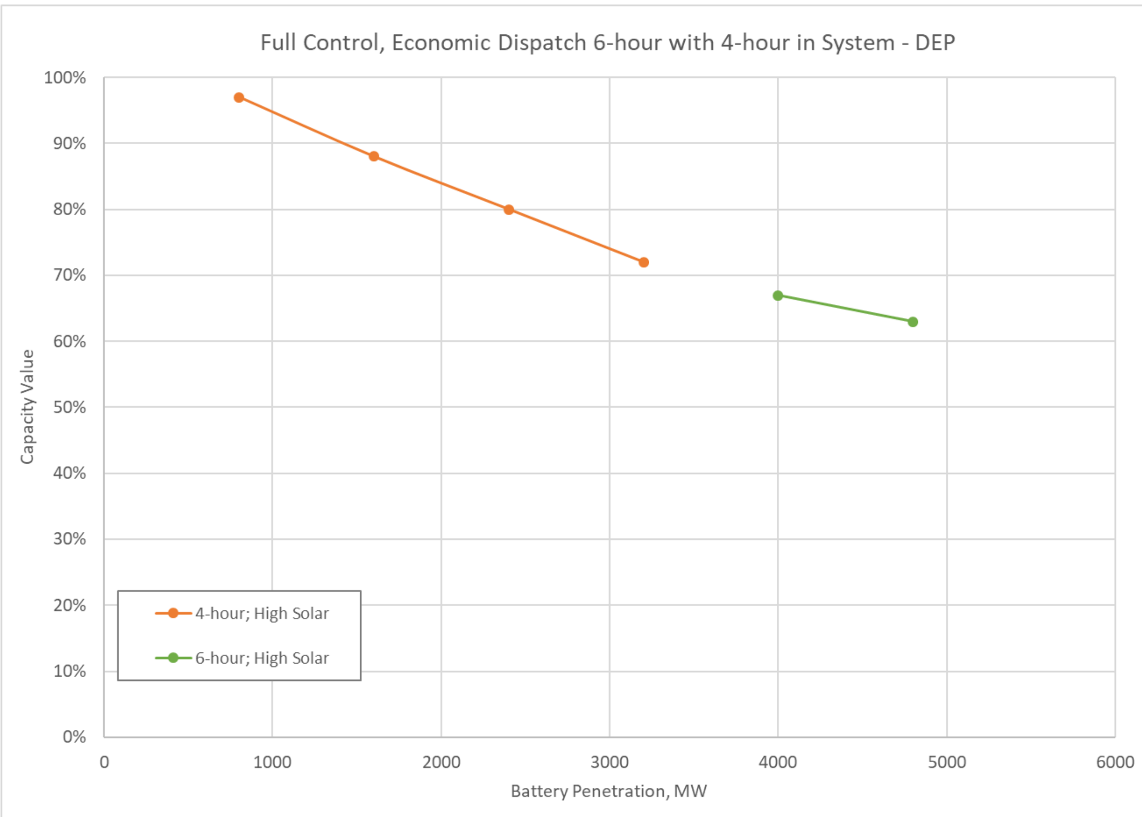
AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN FIXED DISPATCH MODE



The results of the sensitivity of 6-hour storage added after 3,200 MW of 4-hour storage are shown in the following chart.

FIGURE H-6

AVERAGE CONTRIBUTION TO DEP WINTER PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM



Based on the results of the study, DEP made the following assumptions in development of the 2020 IRP:

- All storage capacity values based on Economic Dispatch – The IRP model maximizes the value of battery storage by charging the battery with lower cost energy and discharging the stored energy during periods where energy has more value. The model does not maintain full charge in all hours and forego economic benefit to customers to ensure the battery is available to meet demand if a generator on the system experiences an unplanned outage. Similarly, in practice, a board operator does not have perfect foresight of forced outages and would likely use the battery when it is economically prudent based on what they see at the time. Alternatively, as demonstrated in the results above, the value of battery storage for DEP's customers is maximized when the utility maintains dispatch rights for the battery asset. For these reasons, the Company relied on the ELCC results modeled under Economic Arbitrage conditions.

- Only 4-hour and 6-hour storage considered for standalone storage – Under all dispatch options, the value of 2-hour storage quickly diminishes as their penetration increases on the system. As shown in the Resource Adequacy discussion in Chapter 9, even though most of the LOLH occurs in the hour beginning 7AM, DEP has LOLH over a range of hours in the morning and evening which limits the value that 2-hour storage can provide to the system. Additionally, Two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish.

While the above results show the average capacity value attributed to varying levels of storage on the DEP system, the incremental value of adding 800 MW blocks of storage can be calculated from the results. The incremental values are useful when determining the capacity value of the next block of energy storage, particularly when evaluating replacing a CT with a 4-hour battery as discussed in Appendix A and the economic coal retirement discussion Chapter 11. The incremental capacity value of storage assumed in the IRP is shown in the following table.

TABLE H-3

INCREMENTAL CONTRIBUTION TO PEAK FOR 4- AND 6-HOUR STORAGE IN DEP

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
Base Renew	4-hour	0 - 800	95%
		800 - 1,600	80%
		1,600 - 2,000	70%
	6-hour	0 - 800	95%
		800 - 1,600	85%
		1,600 - 2,600	70%
High Renew	4-hour	0 - 800	100%
		800 - 1,600	80%
		1,600 - 2,100	70%
	6-hour	0 - 800	100%
		800 - 1,600	90%
		1,600 - 2,400	75%

For planning purposes, the Company installed a lower limit of 70% incremental contribution to winter peak before moving to 6-hour storage. In that case, DEP assumed the following incremental contribution to winter peak for 4- and 6-hour storage.

TABLE H-4

INCREMENTAL CONTRIBUTION TO PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
High Renew	4-hour	0 - 800	100%
		800 - 1,600	80%
		1,600 - 2,100	70%
	6-hour	2,100 - 3,000	65%
		3,000 - 3,800	55%
		3,800 - 4,800	45%

SOLAR PLUS STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study assuming a 2-hour or 4-hour battery were coupled with solar.

TABLE H-5

SOLAR PLUS STORAGE RUN MATRIX FOR ELCC STUDY

PROJECT MAX CAPACITY (MW)	SOLAR CAPACITY (MW)	TOTAL BATTERY (MW/% OF SOLAR)	REGION EXISTING SOLAR BEFORE ADDING COMBINED PLUS STORAGE PROJECT (MW)
800	800	80 (10%)	3,200
800	800	240 (30%)	3,200
800	800	400 (50%)	3,200
1,600	1,600	160 (10%)	3,900
1,600	1,600	480 (30%)	3,900
1,600	1,600	800 (50%)	3,900

Solar plus storage capacity value was analyzed with 2- and 4-hour battery storage representing 10%, 30%, and 50% of the nameplate solar MW. This evaluation was conducted with 800 and 1,600 MW of solar paired with storage out of 4,000 MW to 5,500 MW of total solar on the DEP system. The ELCC of standalone storage was determined separately under the following two conditions:

- **Economic Arbitrage –** Assumes DEP maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- **Fixed Dispatch –** Assumes DEP has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEP did not have dispatch rights to the storage asset.

The following chart depicts the contribution to winter peak of solar plus storage under the two dispatch modes. The contribution to peak is the contribution of the solar MWs (i.e. a 100 MW solar facility with 25 MW of storage that provides 25% contribution to peak provides 25 MW towards meeting winter peak demand).

FIGURE H-7

AVERAGE CONTRIBUTION TO DEP WINTER PEAK OF SOLAR PLUS 2-HOUR DURATION STORAGE

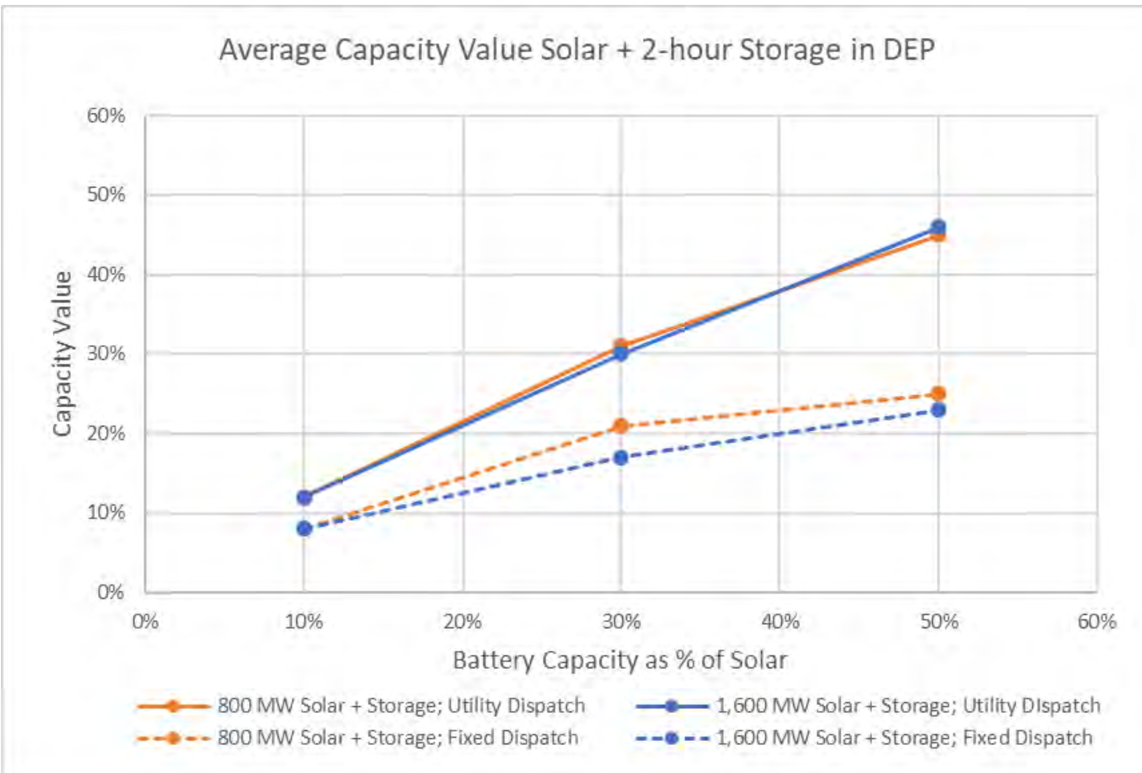
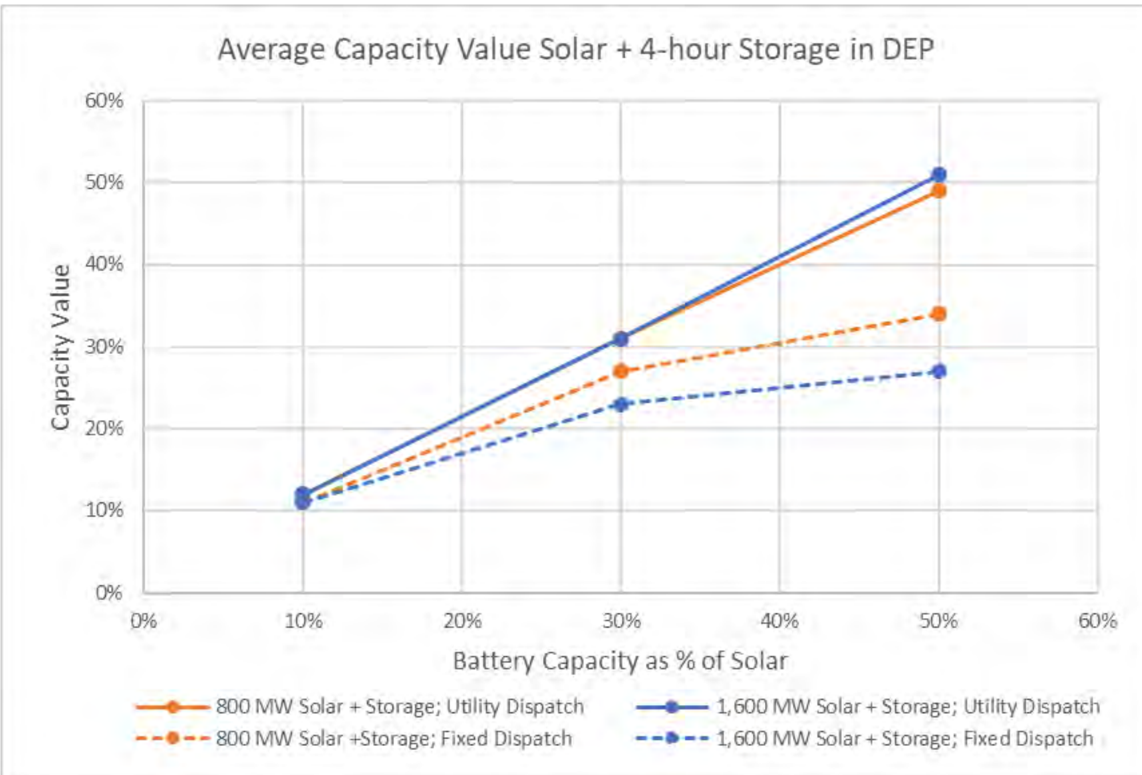


FIGURE H-8

AVERAGE CONTRIBUTION TO DEP WINTER PEAK OF SOLAR PLUS 4-HOUR DURATION STORAGE



Based on the results of the study, and for the same reasons as discussed in the standalone section above, DEP made the following assumptions in development of the 2020 IRP for solar plus storage:

- All solar plus storage capacity values based on Economic Dispatch. The Company will monitor how solar plus storage assets materialize on the system and will adjust this assumption in future IRPs if necessary.

- Only 4-hour considered for storage paired with solar

Additionally, for solar paired with storage in DEP, the Company assumed that the capacity of storage was 25% of the nameplate capacity of the solar the storage was paired with. Based on the results of the ELCC study, the Company assumed that this solar plus storage provided 25% of the solar nameplate capacity towards meeting winter peak demand. Also, the solar plus storage projects were capped at the solar capacity, so a 400 MW solar facility paired with 100 MW of battery storage provided a maximum output of 400 MW and was ascribed 100 MW of capacity value.

CONSIDERATIONS FOR FUTURE STUDIES

For some of the portfolios presented in the IRP, specifically the No New Gas Portfolio (Pathway F), and to a lesser extent, the 70% carbon reduction portfolios (Pathways D and E), the level of solar plus storage exceeded the penetration of storage evaluated in the ELCC study. Additionally, in the no new gas portfolios, significant levels of standalone storage would likely deteriorate the capacity value of solar plus storage resources. The combination of standalone storage and solar plus storage was also not evaluated in the ELCC. In all cases, the contribution to winter peak for solar plus storage was assumed to equal the percentage of storage paired with solar. For these reasons, the contribution to winter peak demand of solar plus storage later in the planning horizon is likely overstated. Future storage ELCC studies should evaluate:

- Higher penetrations of solar plus storage
- The impacts of standalone storage on the value of solar plus storage

I

ENVIRONMENTAL COMPLIANCE

APPENDIX I: ENVIRONMENTAL COMPLIANCE

Duke Energy Progress, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission, EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Progress is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

AIR QUALITY

Duke Energy Progress is required to comply with numerous State and Federal air emission regulations, including the federal Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR) NO_X and SO_2 cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with these regulations, Duke Energy Progress reduced SO_2 emissions by approximately 97% from 2000 to 2019 and reduced NOx emissions by approximately 92% from 1996 to 2019. While the NC CSA was instrumental in achieving significant emission reductions to benefit air quality in North Carolina, recent federal regulations now impose more stringent requirements, as noted below.

The following is a summary of the major air related federal regulatory programs that are currently impacting, or that could impact, Duke Energy Progress operations in North Carolina.

CROSS-STATE AIR POLLUTION RULE (CSAPR)

The "good neighbor" provision of the Clean Air Act requires states in their State Implementation Plans (SIPs) to address interstate transport of air pollution that affects downwind states' ability to attain and maintain National Ambient Air Quality Standards (NAAQS). If states do not submit SIPs or EPA does not approve them, EPA must issue Federal Implementation Plans (FIPs) as a backstop. EPA has created several regulatory programs via the FIP process to address these emissions, including the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR), and most recently, the CSAPR Update Rule. These programs establish state emission budgets for SO_2 and NOx on an annual basis, and NOx during ozone season (May 1-September 30.)

On September 7, 2016, EPA finalized the CSAPR Update Rule which reduces the ozone season NOx emission budgets from those promulgated in the original CSAPR Rule. The rule also removed North Carolina from CSAPR's ozone season NOx program beginning in 2017. However, Duke Energy units in North Carolina remain subject to annual NOx and SO_2 emission limits.

The Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) recently decided environmental and industry challenges to the 2016 CSAPR Update Rule. The Court remanded the rule back to EPA for revision, and DEP expects EPA to issue a proposal addressing the Court's ruling by October 2020. However, EPA's determination that North Carolina sources should be excluded from the CSAPR Update Rule because they do not significantly contribute to downwind ozone non-attainment was not challenged and was not included in the remand from the D.C. Circuit Court.

MERCURY AND AIR TOXICS STANDARDS (MATS) RULE

On February 16, 2012, EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which established emission limits for hazardous air pollutants (HAP) from new and existing coal-fired and oil-fired steam electric generating units. The rule required sources to comply with emission limits by April 16, 2015, or by April 16, 2016 with an approved extension. Duke Energy Progress is complying with all rule requirements.

In June 2015, the Supreme Court determined that EPA had unreasonably refused to consider costs when it determined that it was appropriate and necessary to regulate hazardous air pollutants from coal-fired and oil-fired steam electric generating units and remanded the case to the D.C. Circuit Court for further proceedings.

On May 22, 2020, EPA published a final rule and concluded that it is not "appropriate and necessary" to regulate power plant HAP emissions. However, EPA declined to rescind the 2012 MATS rule. In addition, EPA issued the results of its statutorily required Residual Risk and Technology Review (RTR) and determined that no changes to the MATS emission standards are needed.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

8-HOUR OZONE NAAQS

In October 2015, EPA finalized revisions to the primary (health-based) and secondary (welfare-based) 8-Hour ozone national ambient air quality standard (NAAQS), lowering them from 75 to 70 parts per billion (ppb.) EPA finalized area designations for the 2015 ozone standard and did not designate any nonattainment areas in North Carolina.

In August 2019, the D.C. Circuit decided challenges from state, environmental, and industry challengers to the 2015 standard. The Court upheld the primary standard but remanded the secondary standard to EPA for "further explanation and reconsideration."

SO_2 NAAQS

On June 22, 2010, EPA finalized revisions to the sulfur dioxide (SO_2) NAAQS, establishing a 1-hour standard of 75 ppb.

To demonstrate attainment of the NAAQS, the North Carolina Department of Environmental Quality was required to assess the air quality near large industrial sources of SO_2 emissions, including coal-fired power plants. Based on air quality modeling, NC DEQ provided a demonstration to EPA that the area surrounding the Mayo Station was in attainment. NC DEQ required Duke Energy Progress to conduct ambient air quality monitoring near the Asheville and Roxboro Stations for the period 2017 to 2019 to determine whether those areas were in attainment. Data collected during the period supports an attainment determination, and NC DEQ has submitted its recommendation for classification as attainment to EPA along with a request to discontinue the monitoring at those sites. EPA has a legal obligation to issue a final determination of the attainment classification by December 31, 2020.

On March 8, 2019, after the periodic review required under the Clean Air Act, EPA issued a final rule retaining the SO_2 NAAQS standards, without revision.

FINE PARTICULATE MATTER ($PM_{2.5}$) NAAQS

On December 14, 2012, the EPA finalized revisions to the $PM_{2.5}$ (fine particle) NAAQS, establishing an annual average standard of 12 micrograms per cubic meter and a 24-hour standard of 35 micrograms per cubic meter. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in North Carolina being designated nonattainment. On April 30, 2020, EPA proposed to retain the standards, without revision.

GREENHOUSE GAS REGULATION

On October 23, 2015, the EPA published a final rule establishing carbon dioxide (CO_2) emissions limits for new, modified and reconstructed power plants. The requirements for new plants apply to plants that commenced construction after January 8, 2014. EPA set an emission standard for new coal units of 1,400 pounds of CO_2 per gross MWh, which would require the application of partial carbon capture and storage (CCS) technology for a coal unit to be able to meet the limit. The EPA set a final standard of 1,000 pounds of CO_2 per gross MWh for new natural gas combined cycle (NGCC) units. Duke Energy Progress considers the standard for NGCC units to be achievable.

On December 20, 2018, EPA proposed revised NSPS standards. The proposed emission limit for new and reconstructed coal units is 1,900 pounds of CO_2/MWh, which is intended to reflect what has been demonstrated by the most efficient coal units without the use of CCS. The requirements apply to plants that commenced construction after December 20, 2018. EPA did not propose to change the standard established in 2015 for new or reconstructed natural gas combined-cycle units.
On October 23, 2015, the EPA published the Clean Power Plan (CPP) final rule, regulating CO_2 emissions from existing coal and natural gas units. The CPP established CO_2 emission rates and mass cap goals that apply to existing fossil fuel-fired Electric Generating Units (EGUs). Petitions challenging the rule were filed by numerous groups, and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting its implementation.

On July 8, 2019, EPA finalized the Affordable Clean Energy (ACE) rule, and in a separate but related rule repealed the Clean Power Plan and established CO_2 emission standards for existing coal-fired power plants only. EPA declined to set standards for existing natural gas plants. States have until July 8, 2022, to submit plans based on application of efficiency improvements at existing coal-fired power plants to EPA for approval. Various environmental groups, states, and industry groups have filed petitions for review in the D.C. Circuit challenging the ACE rule, whereas many states and industry groups have intervened on behalf of EPA to defend the rule.

WATER QUALITY AND BY-PRODUCTS ISSUES

CWA 316(B) COOLING WATER INTAKE STRUCTURES

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014, with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All DEP nuclear fueled, coal-fired and combined cycle stations in South Carolina and North Carolina are affected sources.

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a continuous 24-month period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw greater than 125 MGD are required to submit information to characterize entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities to submit all necessary 316(b) reports in accordance with its Clean Water Act (CWA) discharge permit and schedule developed by the state permitting agency. The Company expects the state permitting authority to determine necessary controls for the affected DEP facilities in the 2022 to 2024 timeframe and intake modifications, if necessary, to be required in the 2023 to 2026 timeframe.

STEAM ELECTRIC EFFLUENT GUIDELINES

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("ELG Rule") were published in the Federal Register on November 3, 2015, with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEP's existing coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology-based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual (CCR) landfills and impoundments. The rule also establishes technology-based limits on gasification wastewater, but this waste stream is not generated at any of the DEP facilities. Affected facilities must comply between 2018 and 2023, depending on timing of its Clean Water Act (CWA) discharge permit.[1]

[1] On September 12, 2017, EPA finalized a rule ("the Postponement Rule") to postpone the earliest compliance date for bottom ash transport water and FGD wastewater for a period of two years (i.e. November 1, 2020), but this rule did not extend the latest compliance date of Dec. 31, 2023 and did not revise the earliest compliance date for fly ash transport water. The Postponement Rule was subsequently upheld by the Fifth Circuit Court of Appeals on August 28, 2019.

Petitions challenging the rule were filed by several groups and all challenges to the rule were consolidated in the Fifth Circuit Court of Appeals. On August 11, 2017, the EPA Administrator signed a letter announcing his decision to conduct a rulemaking to consider revising the new, more stringent effluent limitations and pretreatment standards for existing sources in the final rule that apply only to bottom ash transport water and FGD wastewater. On August 22, 2017, the Fifth Circuit Court of Appeals granted EPA's Motion to Govern Further Proceedings, thereby severing and suspending the claims related to flue gas desulfurization wastewater, bottom ash transport water and gasification wastewater. Subsequently, challenges to the limits for fly ash transport water and gasification wastewater were voluntarily dismissed while litigation on the limits for legacy wastewater and CCR leachate continued.

On April 12, 2019, the Fifth Circuit vacated and remanded portions of the rule dealing with legacy wastewater and CCR leachate. It is unknown when EPA will propose new limits for these waste streams.

The proposed rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater was published on November 22, 2019. The public comment period ended on January 21, 2020. The rule is anticipated to be finalized in 3rd quarter 2020.

All DEP coal-fired units have technologies installed to meet the requirements in the 2015 ELG Rule. The anticipated final rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater is not expected to require the installation of any additional technology.

COAL COMBUSTION RESIDUALS

In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure, Congress issued a mandate to EPA to develop federal regulations for the disposal of coal combustion residuals (CCR). CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. On April 17, 2015, EPA finalized the first federal regulations for the disposal of CCR. The 2015 CCR rule regulates CCR as a nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) and allows for beneficial use of CCR with some restrictions.

The 2015 CCR rule applies to all new and existing landfills, new and existing surface impoundments that were still receiving CCR as of the effective date of the rule, and existing surface impoundments that were no longer receiving CCR but contained liquids as of the effective date of the rule, provided these units were located at stations generating electricity (regardless of fuel source) as of the effective date of the rule. The rule establishes national minimum criteria that include location restrictions, design standards, structural integrity criteria, groundwater monitoring and corrective action, closure and post-closure care requirements, and recordkeeping, reporting, and other operational procedures to ensure the safe management and disposal of CCR.

The 2015 CCR rule was challenged in litigation by industry and environmental petitioners. In August 2018, the D.C. Circuit Court vacated provisions that allowed unlined and clay-lined impoundments to continue to operate, finding those provisions violated the RCRA protectiveness standard. In response to the D.C. Circuit decision, EPA proposed two rulemakings to address unlined impoundments. The “Part A” rule, which was proposed on December 2, 2019, would establish an August 31, 2020 deadline to cease placement of CCR and non-CCR wastestreams into unlined ash basins and initiate closure (although that date is expected to be moved back in the final rule.)

The “Part B” rule, which was proposed on March 3, 2020, would establish a process for owners/operators to make an alternate liner demonstration. The proposal also included other significant provisions, including EPA’s reiteration of its view that the use of CCR in units subject to forced closure is prohibited under the current CCR regulations. However, EPA proposed two options for allowing the use of CCR in surface impoundments and landfills for the purpose of supporting closure. In addition, EPA proposed a new closure-by-removal option, which would allow owners/operators to complete groundwater corrective action during the post-closure care period.

In February 2020, EPA published a proposed rule to establish a federal permitting program for CCR surface impoundments and landfills in states that do not have approved state permit programs, as provided under the 2016 WIIN Act. Only Oklahoma and Georgia currently have approved state programs, so this rule would apply in North Carolina until such a time that a state CCR permit program is approved by EPA.

In August 2019, EPA proposed amendments addressing CCR storage and criteria for unencapsulated beneficial uses that would require CCR storage piles to be completely enclosed (four walls and a roof), or would require control of releases and demonstration that the accumulation is “temporary” and that all CCR will be removed at some point in the future. EPA also proposed replacing the mass-based threshold for unencapsulated non-roadway beneficial uses to location-based criteria based on landfill location restrictions.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by North Carolina. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on July 14, 2016.

CAMA establishes requirements regarding the beneficial use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA required eight "high-priority" CCR surface impoundments in North Carolina to be closed no later than December 31, 2019 (although that date was subsequently extended to August 1, 2022, for the two Asheville Station impoundments.) CAMA also required state regulators to provide risk-ranking classifications to determine the method and timing for closure of the remaining CCR surface impoundments. The North Carolina Department of Environmental Quality (NCDEQ) categorized all remaining CCR surface impoundments as low-risk after Duke Energy completed required dam safety repairs and established alternate permanent replacement water supplies for landowners with drinking water supply wells within a one-half-mile radius of CCR surface impoundments. Despite Duke Energy having taken these measures, on April 1, 2019, NCDEQ ordered that all remaining CCR surface impoundments in the state be closed by removal of CCR.

The impact from both state and federal CCR regulations to Duke Energy Progress is significant.

J

NON-UTILITY GENERATION AND WHOLESALE

APPENDIX J: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts, firm wholesale purchased power contracts and non-utility generation contracts.

TABLE J-1

WHOLESALE SALES CONTRACTS

DEP AGGREGATED WHOLESALE SALES CONTRACTS COMMITMENT (MW)									
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
3,386	4,113	4,130	4,151	4,203	4,085	4,129	4,170	4,213	4,237

NOTES:

- For wholesale contracts, Duke Energy Carolinas/Duke Energy Progress assumes all wholesale contracts will renew unless there is an indication that the contract will not be renewed.
- For the period that the wholesale load is undesignated, contract volumes are projected using the same methodology as was assumed in the original contract (e.g. econometric modeling, past volumes with weather normalization and growth rates, etc.).

TABLE J-2

FIRM WHOLESALE PURCHASED POWER CONTRACTS

PURCHASED POWER CONTRACT	WINTER CAPACITY (MW)	LOCATION	VOLUME OF PURCHASES (MWH) JUL '19 – JUN '20
Peaking	850	SC	310,015
Peaking	800	NC	160,700
Intermediate	373	NC	N/A
Intermediate	415	NC	113,643

NOTES: Data represented above represents contractual agreements. These resources may be modeled differently in the IRP.

NON-UTILITY GENERATION FACILITIES – NORTH CAROLINA

Please refer to DEC and DEP Small Generator Interconnection Consolidated Annual Reports filed on March 12, 2020 in NCUC Docket No. E-100, Sub 113B for details on the DEP North Carolina NUGS. The DEP NUG facilities are comprised of 99% intermediate facilities while the remaining 1% represents baseload facilities. Currently, hydro is considered baseload, solar and other renewables are considered intermediate.

Please refer to Table J-3 DEP Non-Utility Generator Listing – North Carolina Facilities.

NON-UTILITY GENERATION FACILITIES – SOUTH CAROLINA

Table J-4 contains non-utility generation contracts for facilities located in South Carolina.

Please refer to the attachment, Table J-4 DEP Non-Utility Generator Listing – South Carolina Facilities.

QF INTERCONNECTION QUEUE

APPENDIX K: QF INTERCONNECTION QUEUE

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition; however, the current queue clearly supports solar generation's central role in DEP's NC REPS compliance plan and HB 589.

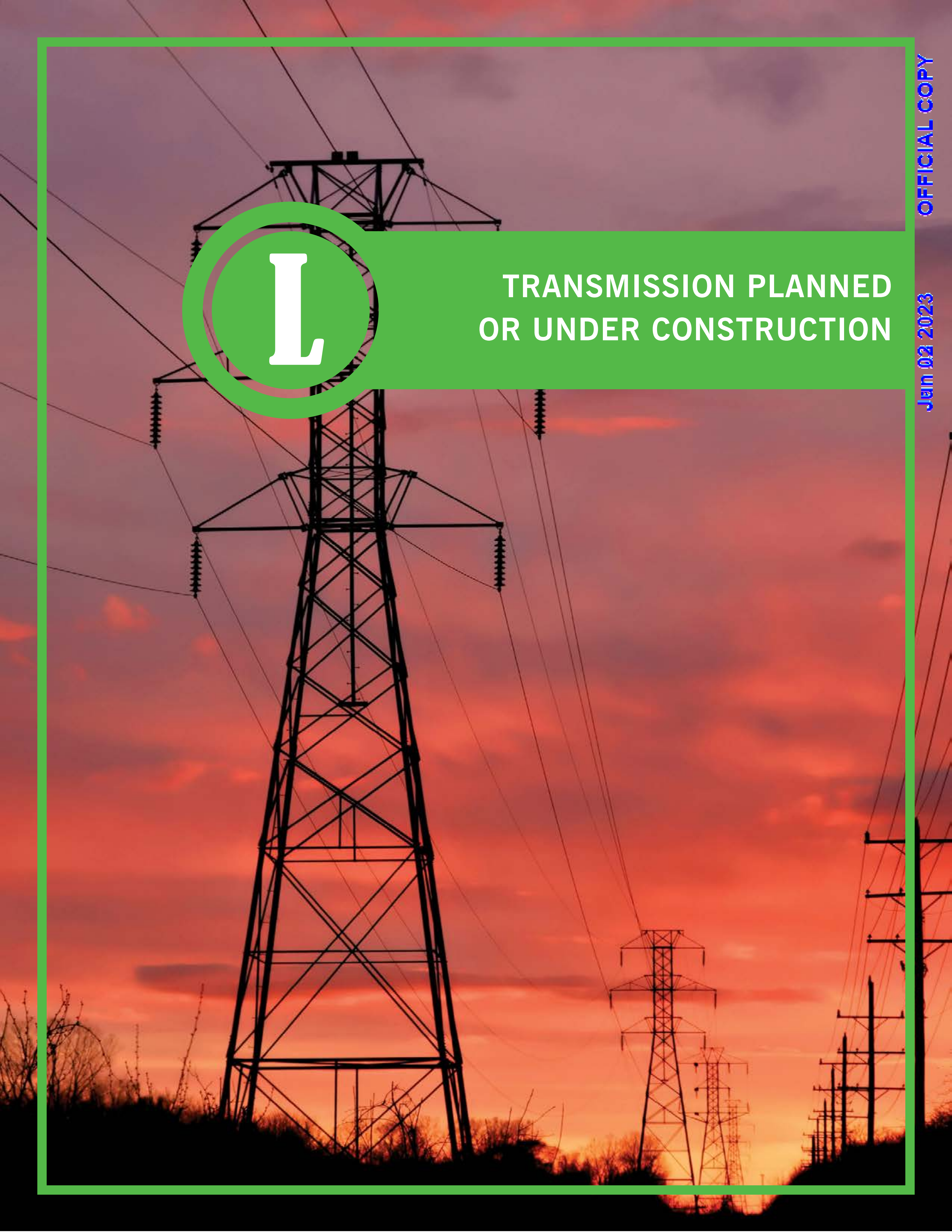
Below is a summary of the interconnection queue as of July 31, 2020:

TABLE K-1
DEP QF INTERCONNECTION QUEUE

UTILITY	FACILITY STATE	ENERGY SOURCE TYPE	NUMBER OF PENDING PROJECTS	PENDING CAPACITY (MW AC)
DEP	NC	Battery	5	153
		Solar	188	4,612
	NC Total		193	4,765
	SC	Solar	140	2,332
	SC Total		140	2,332
	DEP Total		333	7,097

NOTE: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.

(2) Table does not include net metering interconnection requests.



L

TRANSMISSION PLANNED OR UNDER CONSTRUCTION

APPENDIX L: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

In this section, DEP provide details on transmission projects planned or under construction, as well as how DEP ensures transmission system adequacy.

DEP IN-SERVICE TRANSMISSION

Table L-1 below reflects Duke Energy Progress installed transmission circuit miles at each voltage class.

TABLE L-1

DEP INSTALLED TRANSMISSION CIRCUIT MILES BY VOLTAGE CLASS

CIRCUIT VOLTAGE	44 KV	66-69 KV	100 -199 KV	230 KV	345 KV	500+ KV
Duke Energy Progress		12	2,551	3,390		292

DEP TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This section lists the planned transmission line additions. A discussion of the adequacy of DEP's transmission system is also included. Table L-2 lists the transmission line projects planned to meet reliability needs. This section also provides other information pursuant to the North Carolina and South Carolina rules.

TABLE L-2

DEP TRANSMISSION LINE ADDITIONS

	LOCATION		CAPACITY	VOLTAGE	
YEAR	FROM	TO	MVA	KV	COMMENTS
2020	Cleveland Matthews Rd. Tap	Cleveland Matthews Rd	621	230	New
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New
2023	Porters Neck Tap	Porters Neck	442	230	New
2024	Brunswick #1	Folkstone Tap Line	594	230	New
2024	Folkstone Tap Line	Jacksonville	594	230	New

CECPCN / CPCN

Certificates of environmental compatibility and public convenience and necessity (CECPCN) for the construction of electric transmission lines in South Carolina and Certificates of Public Convenience and Necessity (CPCN) in North Carolina

(p) Plans for the construction of transmission lines in North Carolina and South Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with FERC in April 2020.

(p) Plans for the construction of transmission lines in North Carolina and South

Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

a. Commission docket number;
b. Location of end point(s);
c. Length;
d. Range of right-of-way width;
e. Range of tower heights;
f. Number of circuits;
g. Operating voltage;
h. Design capacity;
i. Date construction started;
j. Projected in-service date;

CLEVELAND MATTHEWS ROAD 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line from the Erwin-Selma 230 kV Line in Johnston County to the Cleveland Matthews Road 230 kV Substation in Johnston County.

a. NC Docket number: E-2, Sub 1150
b. County location of end point(s); Johnston County
c. Approximate length; 11.5 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 621 MVA
i. Date construction started; March 2019

j. Projected in-service date; December 2020

JACKSONVILLE – GRANTS CREEK 230 KV LINE

Project Description: Construct new 230 kV transmission line from the Jacksonville 230 kV Substation in Onslow County to the Grants Creek 230 kV Substation in Onslow County.

a. NC Docket number: E-2, Sub 1102
b. County location of end point(s); Onslow County
c. Approximate length; 15 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 1195 MVA
i. Date construction started; September 2018
j. In-service date; June 2020

NEWPORT – HARLOWE 230 KV LINE

Project Description: Construct new 230 kV transmission line from the Newport 230 kV Substation in Carteret County to the Harlowe 230 kV Substation in Carteret County.

a. NC Docket number: E-2, Sub 1113
b. County location of end point(s); Carteret County
c. Approximate length; 8 miles
d. Typical right-of-way width for proposed type of line; 125 feet
e. Typical tower height for proposed type of line; 80 – 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV

h. Design capacity; 681 MVA
i. Date construction started; October 2018
j. In-service date; June 2020

The following pages represent those projects in response to NC Rule R8-62 part (3).

PORTERS NECK 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line from the Castle Hayne-Folkstone 230 kV Line to the Porters Neck 230 kV Substation in New Hanover County.

a. County location of end point(s); New Hanover County
b. Approximate length; 4.5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 442 MVA
h. Estimated date for starting construction; January 2022
i. Estimated in-service date; June 2023

BRUNSWICK #1-FOLKSTONE 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line segment from the Brunswick- Jacksonville 230 kV Line (Brunswick #1 side) to the Folkstone 230 kV Substation in Onslow County.

a. County location of end point(s); Onslow County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet

d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 594 MVA
h. Estimated date for starting construction; January 2023
i. Estimated in-service date; June 2024

FOLKSTONE-JACKSONVILLE 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line segment from the Brunswick- Jacksonville 230 kV Line (Jacksonville side) to the Folkstone 230 kV Substation in Onslow County.

a. County location of end point(s); Onslow County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 125 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 594 MVA
h. Estimated date for starting construction; January 2023
i. Estimated in-service date; June 2024

DEP TRANSMISSION SYSTEM ADEQUACY

DEP monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at projected generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, North Carolina Electric Membership Corporation (NCEMC) and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC systems in both North and South Carolina. In addition, transmission planning coordinates with neighboring systems including Dominion Energy South Carolina Inc. (DESC; formerly SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between DESC, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEP's Transmission Planning Summary guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (NERC) Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that there are no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at projected peak load with selected equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT and the North Carolina and South Carolina Interconnection Procedures. It should be noted that location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to approve the interconnection request. In addition, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

SERC audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEP in 2019 and DEP received "No Findings" from the audit team.

DEP participates in several regional reliability groups to coordinate analysis of regional, sub- regional and inter-balancing authority area transfer capability and interconnection reliability. Each reliability group's reliability purposes are to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;

- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and

- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year future periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above ensures that DEP's transmission system continues to provide reliable service to its native load and firm transmission customers.

ECONOMIC DEVELOPMENT

APPENDIX M: ECONOMIC DEVELOPMENT

CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT:

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2020 is:

RIDER EC

14 MW for North Carolina
8 MW for South Carolina

RIDER ER

0.3 MW for North Carolina
0 MW for South Carolina

DEP WESTERN REGION PROJECT UPDATE

APPENDIX N: WESTERN CAROLINAS MODERNIZATION PLAN (WCMP)

The Western Carolinas Modernization Plan (WCMP) is often viewed as a collection of investments:

- New combined cycle power plant (in-service)
- Retirement of existing coal-fired power plant (demolition is underway)
- Transmission improvements (many improvements complete)
- At least 15 megawatts of solar (progress made)
- At least 5 megawatts storage (significant progress made)

These investments are critical to ensuring a cleaner and smarter energy future for Duke Energy Progress – West Region (DEP-West). But, the cornerstone of the WCMP's success is its community and stakeholder engagement.

This deliberate and purposeful engagement began in 2016 when a group of local leaders, representing the City of Asheville, Buncombe County and Duke Energy, attended the Rocky Mountain Institute's eLab Accelerator. This immersive experience started to create a foundation of trust and helped outline a wholistic community engagement effort to increase demand-side management, energy efficiency and distributed energy resources locally.

From this grew the Energy Innovation Task Force (EITF). The EITF was formed in 2016 and comprised of a diverse group of community leaders to:

- Avoid or delay the construction of the planned contingent combustion turbine (CT).
- Transition DEP-West to a smarter, cleaner and affordable energy future.

The co-conveners (City of Asheville, Buncombe County and Duke Energy Progress) then engaged Rocky Mountain Institute as a key partner early in the process to provide analytical support. Because of their participation and expertise, the company knows more about how customers in DEP-West use electricity than ever before. Their work also narrowed the focus on areas for the group to focus – primarily heating system efficiency. This work extended through 2017.

The research of Rocky Mountain Institute also identified the current lack of automated-metering infrastructure (AMI) in the region as a barrier to the effort's overall success. AMI deployment is now complete in DEP-West.

2018 was a pivotal year for the work of the Energy Innovation Task Force. This was when the group's 18-months of planning and analysis were put into action.

A critical milestone for the Energy Innovation Task Force was the launch of the Blue Horizons Project in March of 2018. This brand was created through community conversations facilitated by the Knoxville-based Sustainability marketing firm – The Shelton Group.

The Blue Horizons Project[1] is the brand associated with the community movement around energy efficiency, demand-side management, renewables and low-income weatherization locally. The primary gateway for customers to interact with Blue Horizons Project is a user-friendly website that directs customers to Duke Energy programs, local governmental initiatives and/or non-profit energy efficiency and weatherization opportunities.

Their work, along with canvassing by Duke Energy, helped expand the DSM program, EnergyWise^{SM}. In 2016, when the Energy Innovation Task Force was formed, 7,183 DEP-West customers were enrolled in the program. As of August 13, 2018, 11,329 customers are enrolled in winter EnergyWise^{SM} programs. Customer participation in this goal specifically addresses reductions in peak demand. In 2019, the focus was to grow participation in multi-family participation in EnergyWise^{SM}.

Both the City of Asheville and Buncombe County have made sizable investments to advance the work of the Blue Horizons Project for building audits, staff support and other direct investments in low-income weatherization.

Through this community collaboration in DEP-West, specifically Buncombe County, the contingent CT has been pushed out beyond the horizon of this 15-year planning analysis. This was a significant and celebrated milestone in the community's work.

In 2019, the initial work of the EITF and Blue Horizons Project started to shift from defining the problem, to enabling broader support for larger, community-driven goals. The co-conveners of the EITF worked to redefine the future goal and purpose of the task force. To that end, the EITF has been

[1] https://www.bluehorizonsproject.com.

recast as the Blue Horizons Project Community Council (BHPCC). The purpose of this council will be to drive behavior and investments that help achieve the community renewable-energy goal.

In late 2018, both the City of Asheville and Buncombe County passed 100 percent clean/renewable energy goals. The goals require that both the City and County achieve the 100 percent targets for operations by 2030, and for all homes and businesses by 2042. The original conveners all agree that a continued commitment and partnership among the City, County, and Duke Energy is critical to enable success of these very ambitious local goals.

One area of focus is to fully leverage purposeful and deliberate investments in advanced and evolving technologies to help advance these lofty community goals. The Technology Working Group, a subcommittee of the Energy Innovation Task Force, has been meeting regularly for more than three years to look for cost-effective options for deployment of solar, battery storage, AMI, cold-climate heat pumps and other technologies. Their work has resulted in efforts to:

- Support and enable DEP-West's first ever microgrid (solar and battery) on Mt. Sterling in the Great Smoky Mountains National Park. (complete and in service)

- Advocate for and support a grid connected microgrid (solar and battery) to serve the Town of Hot Springs, should their radial feed go out. (initial construction is underway)

- Commit to at least 19 MW of battery storage in the region. A list of project updates is below:

  - Mt. Sterling Microgrid (Docket No. E-2, Sub 1127)
    - Haywood County
    - Approximate Capacity – 10 kW Solar PV and 95 kWh Battery Storage Facility
    - NCUC Order Granting CPCN – April 2017
    - Completion Date – May 2017

  - Asheville – Rock Hill Battery
    - Buncombe County
    - Sited at utility-owned substation
    - Approximate Capacity – 9 MW Battery Storage Facility
    - Completion Date – June 2020

- Hot Springs Microgrid (Docket No. E-2, Sub 1185)
  - Madison County
  - Approximate Capacity – 2 MW Solar PV and 4 MW Battery Storage Facility
  - NCUC Order Granting CPCN – May 2019
  - Anticipated In-Service Date – 2020

- Woodfin Solar
  - Buncombe County
  - Approximate Capacity – 4 to 5 MW Solar PV
  - CPCN Filed – July 2020
  - Anticipated In-Service Date – 2021

- Riverside Battery
  - Buncombe County
  - Sited at utility-owned substation
  - Approximate Capacity – 5 MW Battery Storage Facility
  - Anticipated In-Service Date – 2021

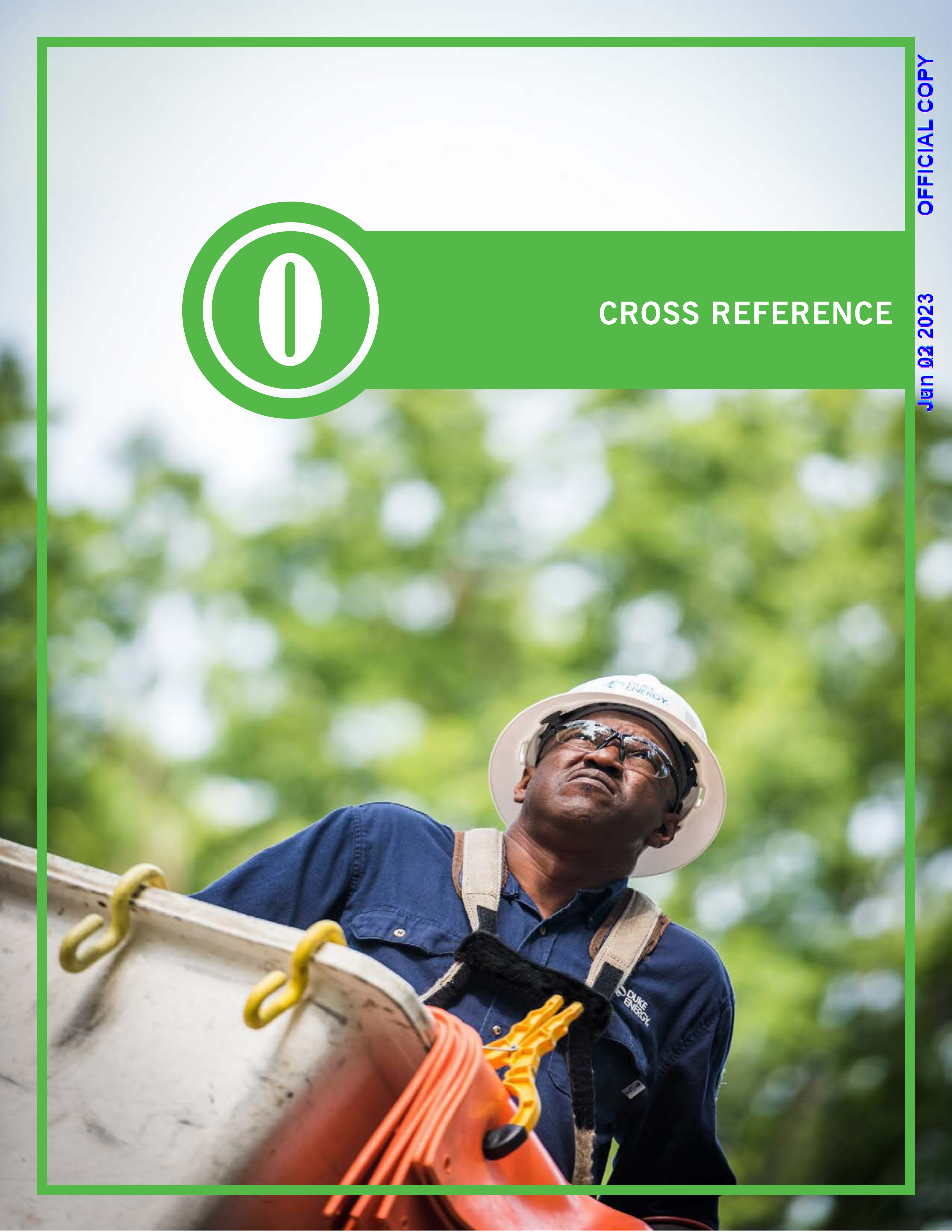
- Asheville Plant Solar and Battery
  - Buncombe County
  - Sited at utility-owned CC plant
  - Approximate Capacity – 9 to 10 MW Solar PV and 17 to 18 MW Battery Storage Facility
  - Anticipated In-Service Date – 2024

- Develop a pilot for cold-climate heat pump. This technology would operate more efficiently in the DEP-West region than other heat pump technologies.

- Partner with Buncombe County to site, design and build a large solar farm at the retired Buncombe County Landfill. (CPCN filed in July 2020)

- Enable an external pilot group for the real-time AMI usage app.

What makes the WCMP special is the engagement and community-centered approach to increasing participation in EE/DSM, making deliberate and strategic investments in technology, and supporting low-income customers with weatherization. Although collaboration with the DEP-West community has yielded strong results, the efforts to transition the region to a smarter, cleaner and affordable energy future for customers continues.



O

CROSS REFERENCE

TABLE O-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS

REQUIREMENT	REFERENCE	LOCATION
15-year Forecast of Load, Capacity and Reserves	NC R8-60 (c) 1	Chapter 3 Appendix C
Comprehensive analysis of all resource options	NC R8-60 (c) 2	Chapter 8 Chapter 12 Appendix A Appendix G
Assessment of Purchased Power	NC R8-60 (d)	Chapter 12 Appendix A Appendix J Attachment II
Assessment of Alternative Supply-Side Energy Resources	NC R8-60 (e)	Chapter 8 Appendix G
Assessment of Demand-Side Management	NC R8-60 (f)	Chapter 4 Appendix D Attachment V
Evaluation of Resource Options	NC R8-60 (g)	Chapter 5 Chapter 8 Appendix A Appendix D Appendix G
Short-Term Action Plan	NC R8-60 (h) 3	Chapter 14
REPS Compliance Plan	NC R8-60 (h) 4	Attachment I
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources * 10-year History of Customers and Energy Sales * 15-year Forecast w & w/o Energy Efficiency * Description of Supply-Side Resources	NC R8-60 (i) 1(i) NC R8-60 (i) 1(ii) NC R8-60 (i) 1(iii)	Chapter 3 Chapter 4 Appendix C Appendix D Attachment V

TABLE O-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS (CONT.)

REQUIREMENT	REFERENCE	LOCATION
Generating Facilities * Existing Generation * Planned Generation * Non-Utility Generation	 NC R8-60 (i) 2(i) NC R8-60 (i) 2(ii) NC R8-60 (i) 2(iii)	 Chapter 2 Chapter 12 Appendix B Appendix J
Reserve Margins	NC R8-60 (i) 3	Chapter 9 Chapter 12 Attachment III
Wholesale Contracts for the Purchase and Sale of Power * Wholesale Purchased Power Contracts * Request for Proposal * Wholesale Power Sales Contracts	 NC R8-60 (i) 4(i) NC R8-60 (i) 4(ii) NC R8-60 (i) 4(iii)	Chapter 12 Chapter 14 Appendix A Appendix J
Transmission Facilities	NC R8-60 (i) 5	Chapter 7 Appendix L
Energy Efficiency and Demand-Side Management * Existing Programs * Future Programs * Rejected Programs * Consumer Education Programs	 NC R8-60 (i) 6(i) NC R8-60 (i) 6(ii) NC R8-60 (i) 4(iii) NC R8-60 (i) 4(iv)	Chapter 4 Appendix D Attachment V
Assessment of Alternative Supply-Side Energy Resources * Current and Future Alternative Supply-Side Resources * Rejected Alternative Supply-Side Resources	NC R8-60 (i) 7(i) NC R8-60 (i) 7(ii)	Chapter 8 Appendix A Appendix G
Evaluation of Resource Options (Quantitative Analysis)	NC R8-60 (i) 8	Appendix A
Levelized Bus-bar Costs	NC R8-60 (i) 9	Appendix G
Smart Grid Impacts	NC R8-60 (i) 10	Appendix D
Legislative and Regulatory Issues		Appendix I
Greenhouse Gas Reduction Compliance Plan		Chapter 16 Appendix A
Other Information (Economic Development)		Appendix M
NCUC Subsequent Orders		Table O-3

TABLE O-2

CROSS REFERENCE – SC ACT 62 REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each electrical utility must submit its integrated resource plan to the commission. The integrated resource plan must be posted on the electrical utility's website and on the commission's website.	Part (C)(2)	Post - filing
a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Part (C)(2)	Chapter 3 Appendix A Appendix C
The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Part (C)(2)	Chapter 8 Appendix A Appendix F Appendix G
projected energy purchased or produced by the utility from a renewable energy resource;	Part (C)(2)	Chapter 5 Chapter 12 Appendix A Appendix E Appendix J Appendix N (DEP)
a summary of the electrical transmission investments planned by the utility;	Part (C)(2)	Chapter 7 Appendix A Appendix L

TABLE O-2

CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i)customer energy efficiency and demand response programs; (ii)facility retirement assumptions; and (iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Part (C)(2)	Chapter 3 Chapter 4 Chapter 12 Appendix A Appendix B Appendix C Appendix D Appendix I
data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Part (C)(2)	Chapter 2 Appendix B
plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan	Part (C)(2)	Chapter 7 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A

TABLE O-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs	Part (C)(2)	Chapter 7 Chapter 8 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A Appendix G
a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Part (C)(2)	Chapter 3 Chapter 4 Appendix C Appendix D
An integrated resource plan may include distribution resource plans or integrated system operation plans.	Part (C)(2)	Chapter 7 Chapter 11 Chapter 15 Appendix A Appendix L

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The two Base Case Plans (i.e. Base CO2 Future and Base No CO2 Future) … encourages the Companies to carry forward both alternatives for their next IRPs due for 2020.”	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 12 Appendix A
DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company’s existing coal-fired generating units are retired by the earliest practicable date. The “earliest practicable date” shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified. In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A Appendix I

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Commission expects that the "earliest practicable date" chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 7 Chapter 11 Appendix A Appendix L
The Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20 E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	IRP Filing Letters Chapter 9 Attachment III
In documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission will direct DEC and DEP to more fully explain and detail the study results.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The updated Resource Adequacy Study should provide additional clarity around outputs… At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR).	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Executive Summary Chapter 15
The 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 15
The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 13
Demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 3 Chapter 4 Chapter 8 Chapter 12 Appendix A Appendix D Appendix G Appendix J

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 12 Chapter 14 Appendix A Appendix J
A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans."	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Chapter 12 Chapter 16 Appendix A
A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Appendix A Appendix D

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Include information, analyses, and modeling regarding economic retirement of coal-fired units	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Model continued operation under least cost principles in competition with alternative new resources	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
If continued operation until fully depreciated is least cost alternative, shall separately model an alternative scenario premised on advanced retirement of one or more of such units (including an analysis of the difference in cost from the base case and preferred case scenarios.)	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Chapter 9 Attachment III
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Filed Under Seal
Future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 6 E-100, Sub 1118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Chapter 3 Appendix C
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7	Appendix D

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Appendix D Attachment V
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Chapter 3 Appendix C

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 14 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14	Chapter 5 Appendix E Appendix K
Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 10

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Duke will include Li-ion battery storage technology in the economic supply-side screening process as part of the IRP.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 19) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 6 Chapter 8 Chapter 12 Appendix A Appendix G Appendix H
DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.	E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	Appendix D

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	Chapter 8 Appendix A Appendix F Appendix G
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Chapter 5 Appendix A Appendix E Appendix N (DEP)
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret.	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Attachment I

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program.	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program)	Appendix D
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Chapter 14 Appendix D

GLOSSARY OF TERMS

10 CFR	Title 10 of the Code of Federal Regulations
AC or A/C	Alternating Current
ACE	Affordable Clean Energy
ACP	Atlantic Coast Pipeline
ACT 62	South Carolina Act 62
ADP	Advanced Distribution Planning
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
ARP	Acid Rain Program
ASOS	National Weather Service Automated Surface Observing System
BHPCC	Blue Horizons Project Community Council (DEP)
BCFD	Billion Cubic Feet Per Day
BFD	Bubbling Fluidized Bed
BOEM	Bureau of Ocean Energy Management
BYOT	Bring Your Own Thermostat
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMA	North Carolina Coal Ash Management Act of 2014
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals Rule
CCS	Carbon Capture and Sequestration (Carbon Capture and Storage)
CCUS	Carbon Capture, Utilization and Storage
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
CEP	Comprehensive Energy Planning
CES	Clean Electricity Standard
CFL	Compact Fluorescent Light bulbs
CO2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COVID-19	Coronavirus 2019

GLOSSARY OF TERMS (CONT.)

COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity (NC)
CPP	Clean Power Plan
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DER	Duke Energy Renewables
DESC	Dominion Energy South Carolina, Inc. (formerly SCE&G)
DIY	Do It Yourself
DMS	Distribution Management System
DoD	Depth of Discharge
DOE	Department of Energy
DOJ	Department of Justice
DOM	Dominion Zone within PJM RTO
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSDR	Distribution System Demand Response Program
DSM	Demand-Side Management
EC or Rider EC	Receiving Credits under Economic Development Rates and/or Self-Generation deferral rate
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration

GLOSSARY OF TERMS (CONT.)

EITF	Energy Innovation Task Force
ELCC	Effective Load Carrying Capability
ELG Rule	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction Contractors
EPRI	Electric Power Research Institute
ER or Rider ER	Receiving Credits under Economic Re-Development Rates
ESG	Environmental, Social and Corporate Governance
ET	Electric Transportation
EVs	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLG	Federal Loan Guarantee
FPS	Feet Per Second
FSO	Fuels and System Optimization
FT Solar	Fixed-tilt Solar
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GA-AL-SC	Georgia-Alabama-South Carolina
GHG	Greenhouse Gas
GIP	Grid Improvement Plan
GTI	Gas Technology Institute
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HB 589	North Carolina House Bill 589
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ILR	Inverter Load Ratios

GLOSSARY OF TERMS (CONT.)

IPI	Industrial Production Index
IRP	Integrated Resource Plan
IS	Interruptible Service
ISOP	Integrated Systems and Operations Planning
IT	Information Technologies
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LCR Table	Load, Capacity, and Reserves Table
LED	Light Emitting Diodes
LEED	Leadership in Energy and Environmental Design
LEO	Legally Enforceable Obligation
LFE	Load Forecast Error
Li-ION	Lithium Ion
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
M&V	Measurement and Verification
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MGD	Million Gallons Per Day
MISO	Midcontinent Independent Operator
MPS	Market Potential Study
MMBtu	Million British Thermal Units
MW	Megawatt
MW AC	Megawatt-Alternating Current
MW DC	Megawatt-Direct Current
MWh	Megawatt-hour
MWh AC	Megawatt-hour-Alternating Current

GLOSSARY OF TERMS (CONT.)

MWh DC	Megawatt-hour-Direct Current
MyHER	My Home Energy Report
NAAQS	National Ambient Air Quality Standards
NAPP	Northern Appalachian Coal
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC REPS or REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCDEQ	North Carolina Division of Environmental Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NEM	Net Energy Metering
NEMS	National Energy Modeling Systems
NERC	North American Electric Reliability Corporation
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
NUG	Non-Utility Generator
NUREG	Nuclear Regulatory Commission Regulation
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
OATT	Open Access Transmission Tariff

GLOSSARY OF TERMS (CONT.)

PC	Participant Cost Test
PD	Power Delivery
PEV	Plug-In Electric Vehicles
PHS	Pumped Hydro Storage
PJM	PJM Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PRB	Powder River Basin
PROSYM	Production Cost Model
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PSH	Pumped Storage Hydro
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificate
REPS or NC REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engines
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
RRP	Refrigerator Replacement Program
RTO	Regional Transmission Organization
RTR	Residential Risk and Technology Review
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar

GLOSSARY OF TERMS (CONT.)

SB 3 or NC SB 3	North Carolina Senate Bill 3
SC	South Carolina
SC Act 62	South Carolina Energy Freedom Act of 2018
SC DER or SC ACT 236	South Carolina Distributed Energy Resource Program
SC DER	South Carolina Distributed Energy Resources
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SEIA	Solar Energy Industries Association
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SG	Standby Generation or Standby Generator Control
SIP	State Implementation Plan
SISC	Solar Integration Services Charge
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SO	System Optimizer
SO2	Sulfur Dioxide
SOC	State of Charge
SOG	Self-Optimizing Grid
SPM	Sequential Peaker Method
SRP – SLR	Standard Review Plan for the Review of Subsequent License Renewal
STAP	Short-Term Action Plan
STEO	Short-Term Energy Outlook
T&D	Transmission & Distribution
TAG	Technology Assessment Guide
TCFD	Trillion Cubic Feet per Day
Transco	Transcontinental Pipeline
The Company	Duke Energy Progress
The Plan	Duke Energy Progress Annual Plan

GLOSSARY OF TERMS (CONT.)

TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
UNC	University of North Carolina
USCPC	Ultra-Supercritical Pulverized Coal
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive
VCEA	Virginia Clean Economy Act
VVO	Volt-Var Optimization
WCMP	Western Carolinas Modernization Project (DEP)
WERP	Weatherization and Equipment Replacement Program
WIIN	Water Infrastructure Improvement for the Nation Act
ZELFR	Zero – Emitting Load Following Resource

BUILDING A **SMARTER** ENERGY FUTURE ®

E Quantitative Analysis

Introduction to Quantitative Analysis

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

As will be discussed in more detail for each subject below, the Carbon Plan quantitative analysis involved extensive evaluation of input assumptions, modeling, and analysis of results. This included identifying base assumptions and sensitivities to these assumptions to further quantify risks and opportunities of how parameters affecting the resource portfolio could change over time, economic analysis of DEC's and DEP's coal unit retirement dates, and portfolio and sensitivity analyses to evaluate the robustness of portfolios. Operational and financial analysis of the modeling was used to derive observations and planning approaches for execution. Maintaining affordability and reliability for customers along the path to CO_2 reduction for the Carolinas system is a core focus of the Carbon Plan analysis.

Overview of Analytical Process

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

Analytical Process Steps:

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

2. Portfolio Development Modeling

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

    b. Preliminary Capacity Expansion Results

3. Portfolio Verification Modeling

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

    b. Bad Creek Powerhouse II Validation

    c. Resource Adequacy and Reliability Verification

4. Portfolio Performance Analysis

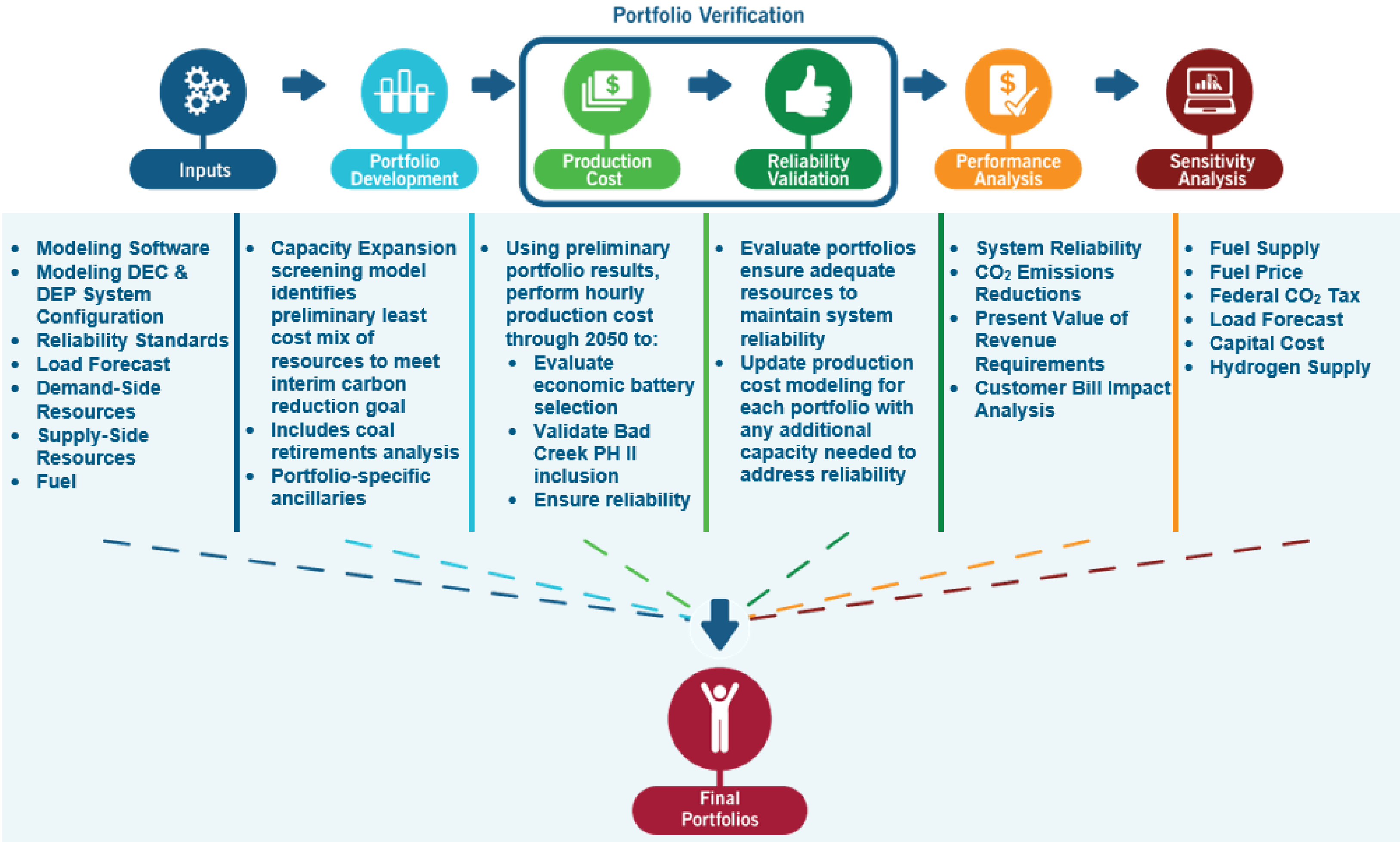
    a. CO_2 Reduction Analysis

    b. Present Value Revenue Requirement Analysis

    c. Customer Bill Impact Analysis

5. Sensitivity Modeling and Analysis

Figure E-1: Carbon Plan Analytical Process Flow Chart



Modeling Software and Development of Modeling Assumptions

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

Carbon Plan Modeling Software

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

Capacity Expansion Model

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

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

Production Cost Model

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

Modeling Pathways

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

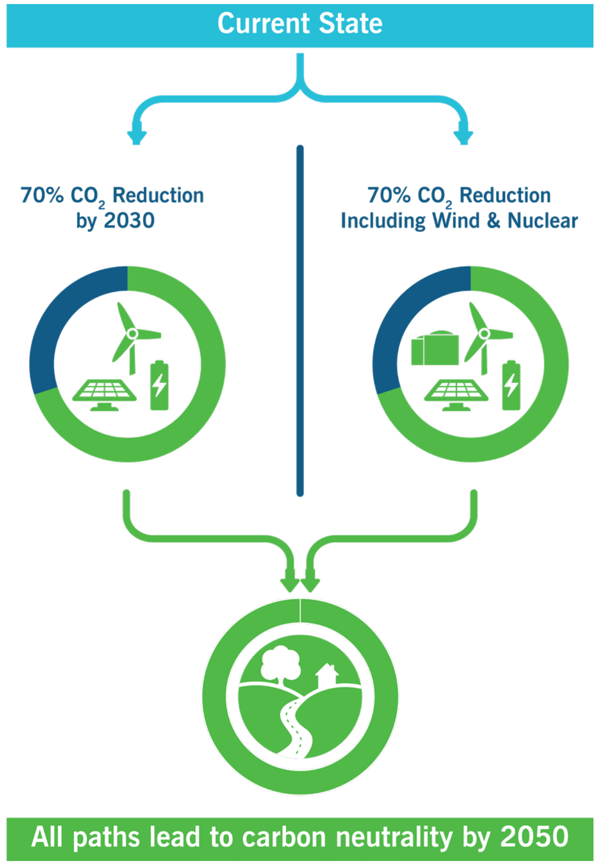
- Where optimal timing of generation and resource-mix to achieve the least cost path to compliance requires more time, up to two years;

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

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

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

Figure E-2: Two Pathways to Carbon Neutrality



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

Mass Cap Modeling

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

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

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

For purposes of modeling the Carbon Plan, DEC and DEP used a system mass cap approach; that is, when the system mass cap is achieved, it simultaneously results in achieving the the 70% interim target. The system mass cap is applied to the combined emissions of both DEC and DEP for all units regardless of location. Modeling the mass cap at the system level maintains balanced economic dispatch across all units within the geographic footprint of the system irrespective of where existing generation units are located.

Consistent with integrated resource planning principles, Carbon Plan modeling does not identify locations for generic resource additions. Siting will be determined based on an evaluation of the most cost-effective option when considering resources during the siting and execution phase as further detailed in Chapter 4 (Execution Plan). As described in Appendix A (Carbon Baseline and Accounting), the Carbon Plan does not use location of resources as a method for achieving the CO_2 emissions target and the Carbon Plan modeling assumed that any new CO_2-emitting resources would be sited in North Carolina. That is, for purposes of the analysis, the Carbon Plan assumes all future emissions of unspecified generic resources, whether in-state or out-of-state, count against the HB 951 CO_2 emissions target. The Companies have also requested the Commission opine on the appropriateness of this approach under HB 951.

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

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

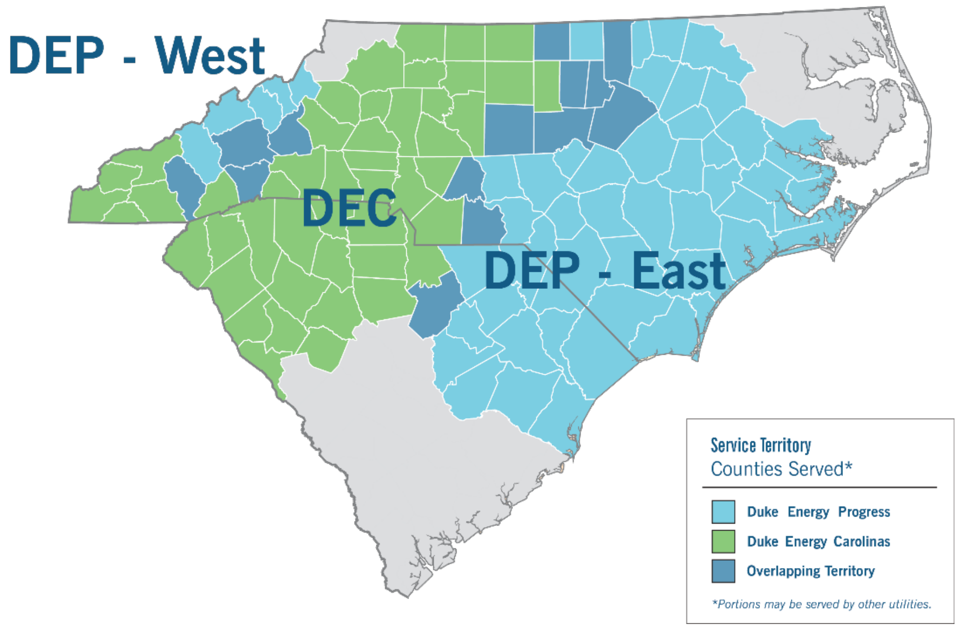
	Interim 70% Reduction Target	2050 Carbon Neutrality Target
System Mass Cap	24,908,603	0

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

Modeling the Carolinas Systems: DEC/DEP System Configuration

In capacity expansion and production cost modeling of the Carolinas system for the Carbon Plan, DEC and DEP remain two separate utilities and legal entities, operating across three areas (DEP-West, DEC and DEP-East, as depicted in Figure E-3), each with its own load, resources, and transmission limits between them. DEC and DEP continue to utilize joint dispatch, which allows for the utilities to optimize the dispatch of the system to provide cost savings to customers.

Figure E-3: DEC and DEP Service Territories and Balancing Authorities



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

As discussed in Appendix R (Consolidated System Operations), the Carbon Plan analysis assumes the implementation of a Consolidated System Operations model where the NERC Balancing Authority ("BA"), Transmission Service Provider ("TSP") and Transmission Operator ("TOP") functions are consolidated for DEC and DEP. This consolidated approach allows for economically dispatching the system, and furthermore, allows for optimization of meeting operating services requirements, such as balancing and regulating reserves. In the current operations of the DEC and DEP systems, each utility must meet its own operating requirements with its own units to meet the system operational needs of its balancing authority area. The Consolidated System Operations model allows the collective operating requirements to be aggregated at the combined system level, which reduces the requirement as compared with the separate Balancing Authority scenario. The two utilities do, however, retain responsibility for independently committing resources for meeting forecasted demand and maintaining long-term capacity planning requirements in the Carbon Plan modeling.

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

Assessing Resource Needs

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

Resource Adequacy and Planning Reserve Margin

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

2020 Resource Adequacy Study

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

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

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

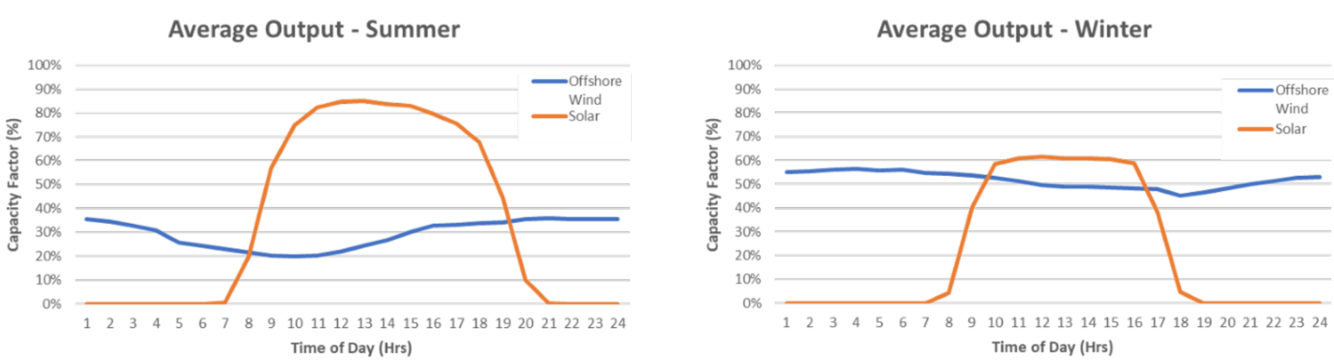
[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé has conducted several Resource Adequacy Studies and Effective Load Carrying Capability Studies for DEC and DEP in recent years.

Astrapé examined resource adequacy for a number of scenarios: an island scenario which assumes no market assistance is available from neighbor utilities; a base case, which reflects the reliability benefits of the interconnected system including the diversity in load and generator outages across the region; a combined case, which allowed preferential support between DEC and DEP to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority; and numerous sensitivities to understand which assumptions and inputs impact study results. Based on these simulations, Astrapé recommended that DEC and DEP continue to maintain a minimum 17% winter reserve margin for IRP planning purposes. The Companies used a minimum 17% winter reserve margin in the development of the Carbon Plan portfolios. The 2020 Resource Adequacy Study Reports for DEC and DEP are being provided as Attachments I and II to the Carbon Plan.

Effective Load Carrying Capability of Renewable and Storage Resources

Meeting HB 951 CO_2 reduction targets requires the addition of significant levels of variable renewable resources and energy-limited storage resources to the system. Conventional thermal resources are typically dispatchable and available to meet load when not in forced outage or planned maintenance. However, due to the variable nature of solar and wind resources and the energy-limited nature of storage resources, it is critical to understand the reliable capacity contributions of these resources in the generation planning process. For example, winter peak loads for DEC and DEP occur in the early morning and late evening when the solar output is low, while peak loads in the summer occur across the afternoon and early evening, which is more coincident with solar output. Like solar, onshore and offshore wind resources are also variable energy resources. However, deployment of wind resources can complement solar resources by providing energy to the system during overnight hours or winter months when solar energy is low or not available. Average summer and winter solar and offshore wind profiles are illustrated in Figure E-4 below, which shows the availability of wind generation during hours when solar generation is not available.

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



ELCC Study

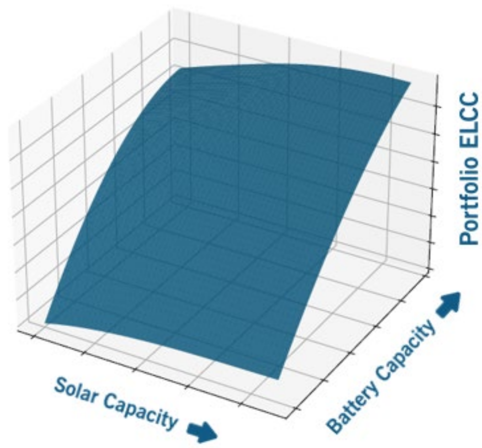
The Companies worked with Astrapé to conduct a new Effective Load Carrying Capability ("ELCC") study to understand the reliable capacity contributions of solar, onshore wind, offshore wind, and storage for use in the Carbon Plan. The ELCC or "capacity value" of a resource can be thought of as a measure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

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

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

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

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



Application of ELCC Study in Carbon Plan Model

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

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

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

Solar ELCC

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

Table E-2: DEC Winter Solar Incremental ELCC Values

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

Table E-3: DEP Winter Solar Incremental ELCC Values

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

Storage ELCC

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

Table E-4: DEC Standalone Storage Incremental ELCC Values

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

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

Table E-5: DEP Standalone Storage Incremental ELCC Values

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

Solar Paired with Storage ("SPS") ELCC

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

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

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

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

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

Wind ELCC

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

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

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

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

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

Table E-10: Winter Offshore Wind Incremental ELCC Values

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

Load Forecast

The load forecast is an important factor in planning the system. The primary target of resource planning is matching resource requirements with load projections. The load forecast can influence how many resources are added over time, what types of resources are added, and the load can have a significant impact on a portfolio's ability to achieve carbon emissions targets. Below are brief descriptions of the basic components included in the load forecast in the Carbon Plan, and what assumptions are made for base planning and sensitivity analysis for each component. More discussion on Load Forecasting included in Appendix F (Electric Load Forecast).

Base Economic Forecast

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

Utility Energy Efficiency Forecast

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

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

In keeping with this aspirational target, the Companies developed two additional UEE forecasts for the Carbon Plan. The first, used as the base Carbon Plan planning assumption, grows UEE savings at a minimum of 1% of eligible retail load in each year of the Carbon Plan. This continues to assume that certain customers are eligible to opt-out of Companies-sponsored UEE programs and the associated rider. The second forecast takes an increasingly aggressive approach to UEE and assumes a minimum savings of 1% of *all* retail load in every year of the Carbon Plan. This high UEE assumption for the Carbon Plan is only used in the low load sensitivity and carries significant execution risk, as it would require legislative and procedural changes to customer opt-outs of UEE.

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

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

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

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

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

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

Net Energy Metering forecast

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

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

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

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

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

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

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

Integrated Voltage/VAR Control - Conservation Voltage Reduction Forecast

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

In July 2014, DEP completed the installation of the Distribution System Demand Response ("DSDR") peak-shaving program across 97% of eligible circuits in its service territory. Therefore, the only program upgrade required in DEP is to implement CVR mode across the eligible circuits that will allow a centralized Distribution Management System ("DMS") to control voltage by circuit. DEC's current state IVVC program planning assumption is for implementation across approximately 60% of the eligible circuits on the DEC system. The Carbon Plan recognizes that the energy conservation potential of expanding IVVC to a higher level of circuits can reduce the load the utility needs to serve. Modeling assumptions for the Carbon Plan assumes the DEC IVVC program will be expanded to approximately 96% of the eligible circuits across the system, an increase from base resource planning assumptions and currently approved programs.

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

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

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

Electric Vehicle Forecast

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

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

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

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

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

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

Net Load Forecast

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

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

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

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

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

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

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

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

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

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

Existing Resources

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

Existing Resource Capacity Uprates

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

Table E-21: Planned Unit Uprates

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

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

Existing Generation Retirements

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

With respect to non-coal generating assets, the Carbon Plan assumes the retirement dates of owned generation resources. While most of the generating resources on the system today are expected to retire by 2050, a select few are assumed in the Carbon Plan to continue service to the system in 2050 or beyond.

This includes all of DEC's and DEP's existing nuclear fleet, representing 11 units and over 9,000 MW of owned capacity, which in 2021 generated approximately 50% of the energy used to serve DEC and DEP customers. Subsequent License Renewal, which will extend the potential operating life for these units to 2050 and beyond, for most of the Companies' existing nuclear units, will keep the option open for these resources to operate affordably and reliably for up to 80 years. While not directly impacting the Carbon Plan analysis, after the 2050 planning horizon, additional planning of the system will have to account for the retirement of this significant source of carbon-free energy.

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

Conversions to Hydrogen

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

Capacity PPA Expiry

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

Forecasted Demand-Side Management

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

Utility Energy Efficiency

The Carbon Plan utilizes an aggressive UEE forecast well above the Companies' most recent IRP planning assumptions for UEE growth as described in the load forecast section above. UEE is factored into the net load forecast, but UEE also reduces peak energy consumption, impacting the net load forecast.

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

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

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

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

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

Demand Response

DR customer programs reduce system peak load requirements by modifying customer consumption. DR consists of two types of customer programs: mechanical/manual reduction programs and rate programs. Mechanical and manual reduction programs consist of controlling specific equipment, such as thermostats and hot water heaters, and can be called upon by the system operators to reduce the load of the system. Customers are compensated monthly for opting into programs to reduce demand when needed by the system. Rate programs are price signals sent to customers to incentivize a reduction in their energy consumption through different energy rates.

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

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

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

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

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

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

	DEC	DEP
2030 Projection	229	131
2040 Projection	514	298

Integrated Voltage-VAR Control - Peak Shaving

IVVC is described above in the load forecast section of this Appendix. The CVR mode of IVVC is captured in the load forecast, but the Peak Shaving capacity is modeled as a DR program in the Carbon Plan modeling. As stated above DEP represents deployment across 100% of circuits, while DEC represents an increase over the base planning assumption of 60% of circuits to approximately 96% of circuits at full implementation.

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

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

	DEC	DEP
2025 Projection	175	161
2035 Projection	212	175

Forecasted Supply-Side Resources

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

Forecasted Solar

Solar is an important part of the DEC and DEP systems today and the Carolinas region is considered a leader in solar in the United States. Supportive policies to-date have aided the integration of solar into the Companies service territories. Solar that is currently installed on the system and the near-term expected growth due to these supportive policies are included as forecasted solar in the Carbon Plan. While the majority of the solar included in the portfolios of the Carbon Plan is economically selected in the modeling, forecasted solar represents existing solar capacity as well as projects in various stages of the interconnection process including HB 589 Green Source Advantage ("GSA") and Competitive Procurement of Renewable Energy ("CPRE") Tranches 1 and 2 projects. The Carbon Plan modeling also anticipate that current uncontracted projects under CPRE Tranche 3 would be connected prior to 2026, and the remaining uncontracted HB 589 GSA solar would connect throughout the remainder of the decade. The existing, incrementally forecasted, and total forecasted solar assumed in the Carbon Plan is included in Table E-27 below.

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

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

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

Forecasted Batteries

Battery development remains an important planning consideration for the Companies. Near-term deployments are important for finding cost-effective and reliable solutions to meet Duke Energy's customers' energy needs. The forecasted batteries in the Carbon Plan represents a limited amount of grid-connected battery storage projects that will allow for a more complete evaluation of potential benefits to the distribution, transmission, and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale. The experience gained in these early installations will support the acceleration of storage additions toward meeting the clean energy targets in this decade.

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

Lincoln CT17 Integration

Lincoln County CT17 is a collaboration with Siemens Energy to bring online an industry leading advanced turbine technology. The project, still under control and operation of Siemens Energy, successfully achieved first fire in 2020 and is currently in its extensive testing and extended commissioning phase as this is a first-of-its-generation combustion turbine. The Carbon Plan assumes DEC will take care, custody, and control of the completed 402 MW (winter capacity) unit in 2024.

Bad Creek Powerhouse II

Pumped storage hydro ("PSH") is the use of two water reservoirs at different elevations to store and release energy by running water between the two. When there is excess low-cost energy available to the system, water can be pumped from the lower reservoir to the upper reservoir by consuming electricity from the grid. At times of high-cost energy or demand, the water can be released from the upper reservoir and run through a turbine generator to produce electricity.

DEC currently owns and operates two pumped storage hydro facilities located in western South Carolina: Bad Creek and Jocassee. With the competition of the Bad Creek Runner Upgrade project in 2025, the two plants have a combined generating capacity of over 2,400 MW. The long-duration storage aspect of these stations continues to provide valuable dispatchable generation or load to the system to provide peak energy to customers or time shift excess energy from renewables to be available during times of greater demand.

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

Bad Creek PH II was prescribed into all portfolios. As discussed later in this Appendix, the capacity expansion model alone is not sufficient for evaluating energy storage resources. For this reason, the Companies performed a separate comparative economic analysis for Bad Creek PH II utilizing the production cost model to validate inclusion in the modeling was economic against other long-duration storage options. More discussion on this analysis is included in the portfolio verification section of this Appendix. The Companies will continue to evaluate the value of long-duration storage on the system and its ability to provide significant power capacity in addition to facilitating reliable retirement of coal capacity.

Selectable Supply-Side Resources

This section discusses each of the supply-side resources that the capacity expansion model can economically select to develop a portfolio. The model is designed to select "least cost" portfolios of supply-side resource that minimize the cost of the system, subject to meeting constraints such as CO_2 emissions reductions, capacity planning reserve margins and operating reserve requirements. Each resource's unique characteristics present valuable tradeoffs for the model to weigh. Carbon-free energy production, dispatchability, operating flexibility such as ramp rates, minimum loads, cycle times, efficiency, availability (both when and how much of a resource can be integrated to the portfolio), and capacity value are all important factors that can influence the optimal set of resources to meet future energy and capacity needs. Modeling parameters are discussed for each resource in more detail below, including how they are applied throughout the Carbon Plan modeling.

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

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

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

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

Mature Technologies in DEC/DEP Service Territories

Solar

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

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

- Standalone Solar – 75 MW Single-axis tracking bi-facial solar
- Solar paired with Storage (50% Battery Ratio) – 75 MW Single-axis tracking bi-facial solar with 40 MW / 80 MWh ("megawatt-hour") battery
- Solar paired with Storage (25% Battery Ratio) – 75 MW Single-axis tracking bi-facial solar with 20 MW / 80 MWh battery

Costs for these resources generally align with industry standards and base assumptions include technology maturity over the short-term, which results in cost declines. Table E-28 through Table E-30 below describe the assumptions for each solar resource in the Carbon Plan modeling.

Table E-28: Standalone Solar Modeling Assumptions

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

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

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

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

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

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

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

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

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

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

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

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

Simple Cycle Combustion Turbines

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

Table E-33: CT Modeling Assumptions

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

DEC and DEP each has its own cost assumption for intrastate natural gas firm transportation (“FT”) service. Peaking units do not assume interstate natural gas transportation service, but instead rely on ULSD back up fuel to ensure fuel supply. CTs that are selected in the Carbon Plan before 2040 are assumed to be converted to 100% operations on Hydrogen by 2050 to comply with the 2050 carbon neutrality target.

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

Combined Cycle Power Blocks

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

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

Table E-34: CC-J Modeling Assumptions

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

Table E-35: CC-F Modeling Assumptions

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

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

New-to-the-Carolinas Technologies

Standalone Batteries

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

While batteries can also be introduced to the system via solar paired with storage (and such resources are described earlier in this Appendix), the resources described here and shown in Table E-36 are standalone batteries. Standalone storage resources can charge from and dispatch to the grid, whereas storage paired with solar is assumed in the Carbon Plan to be DC-tied, and thus, only able to charge from the solar facility and dispatch to the grid when solar is not already using all of the interconnection limit.

Table E-36: Standalone Battery Modeling Assumptions

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

Small Modular Nuclear and Advanced Nuclear

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

The second nuclear technology assumed for the Carbon Plan is Advanced Nuclear with Integrated Storage, as shown in Table E-38. These advanced reactors use a moderator other than water, which allows for efficiency gains compared to light water reactors. Furthermore, the integrated thermal storage allows for increased peaking capacity and flexibility to reduce the output of the site without changes to the reactor output, providing flexibility and longer-duration and more efficient storage options for the system.

Table E-37: SMR Modeling Assumptions

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

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

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

Due to the different stages of research, development, demonstration, and large-scale deployment, the availability of these resources for future integration into the DEC and DEP systems differ. SMRs are modeled as first available for selection starting in 2033 and Advanced Nuclear with Integrated Storage starting in 2038. The generic SMR unit assumed in the Carbon Plan is constant throughout the planning horizon, but the gap in availability for the model to select SMRs between the 2030s and the 2040s (as shown in Table E-39 and Table E-40 below) represents the potential for this technology to become an advanced reactor SMR with improved efficiencies and potential for large scale hydrogen production, while leveraging its modular scale.

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

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

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

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

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

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

Onshore Wind

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

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

Table E-41: Onshore Wind Modeling Assumptions

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

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

Offshore Wind

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

Table E-42: Offshore Wind Modeling Assumptions

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

The Carbon Plan assumes an aggressive integration timeline of offshore wind availability for the Carolinas. While there are potential offshore wind lease areas and wind energy areas in the Carolinas, development of the project and the necessary transmission system upgrades prevent earlier integration. A unique challenge of the Carolinas prospect of integrating Offshore Wind, compared to those of the Northeast and Mid-Atlantic, is that the major load centers in the Carolinas are much further inland, which requires adequate transmission to transport the energy from the coast to where customers' energy needs are most significant. As described in Appendix J (Wind), these projects can take many years to permit and construct, making earlier integration a challenge.

Due to uncertainty with future development of offshore wind, and availability of offshore wind lease areas, the Companies assume a limited amount of offshore wind is available starting in 2030 with additional offshore wind capacity available beginning in the early 2040s. Table E-43 provides the maximum cumulative availability of offshore wind available for economic selection.

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

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

Transmission Costs

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

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

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

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

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

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

Transmission costs are applied to each supply-side resource in the capacity expansion model. For the capacity expansion model to select any resource it must incur the transmission network upgrade proxy costs in addition to the interconnection facilities costs included in the generation resource cost for each resource type. All selectable resources included transmission costs to ensure all resources were evaluated on an equitable basis. Costs were inflated to reflect the generation resource's in-service year and are levelized over the life of the transmission asset.

Each of these proxy transmission related costs require additional study for actual implementation and will be further updated for each Carbon Plan update cycle. Furthermore, based on recent transmission-related material and labor cost trends, the transmission interconnection and associated network upgrade costs may experience inflation rates higher than represented in Table E-44 in future years.

Fuel Supply and Commodity Pricing

Natural Gas

Natural Gas Price Forecast

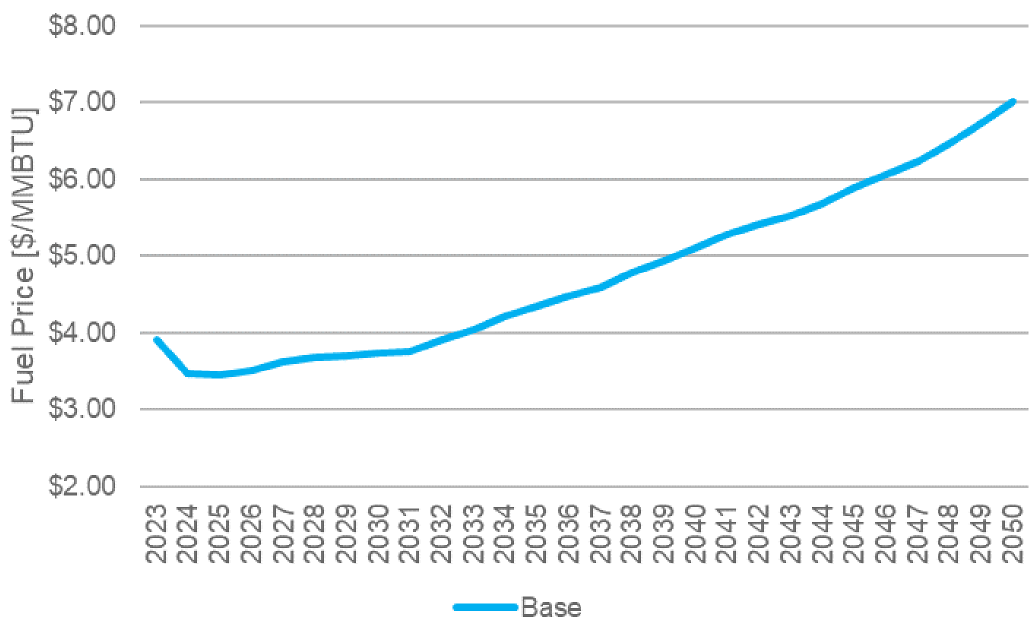
The natural gas price forecast methodology used for the Carbon Plan utilized both short-term market-based price forecasts and longer-term fundamentals-based price forecasts, as well as a transition period from market-based pricing to fundamental based pricing. The Companies natural gas price forecast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

Recent natural gas price forecasts have also varied among fundamentals providers and can be significantly impacted by the assumptions made in each provider's forecast and timing of issuance. The use of a single fundamental-based natural gas price forecast has inherently more reliance on the specific assumptions used in the development of that forecast. This uncertainty of any single set of assumptions can be somewhat offset by looking at fundamental forecasts from multiple reputable fundamental forecast providers. For the purposes of the Carbon Plan, the Companies' developed their fundamentals-based natural gas price forecast by averaging four recent natural gas prices forecasts:

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

The resulting Henry Hub natural gas price forecast utilized in the Carbon Plan modeling, consisting of the near-term market-based price forecast, the three-year transition to fundamentals-based price forecast, and finally the full fundamentals-based price forecast (an average of the price forecast of the four different fundamentals providers discussed above) is shown below in Figure E-6.

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

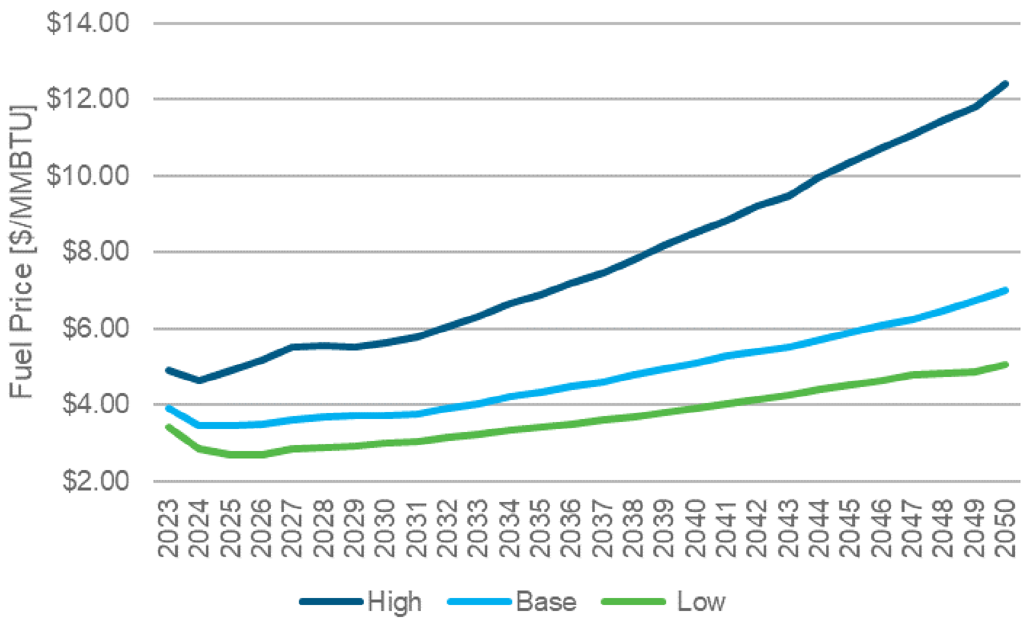


High and Low Natural Gas Price Forecast Sensitivities

To further quantify the impacts on resource selection, cost to the system, and achievement of reduction targets, the Carbon Plan also uses high natural gas price forecasts and low natural gas price forecasts as sensitivities in the modeling. These high and low natural gas price forecasts were developed starting with the Companies' base natural gas price forecast. From there, the Companies utilized the

EIA's AEO "side cases." As part of the AEO, the EIA also develops side cases to capture uncertainty of specific impactful variables on the energy consumption and commodity prices in its forecast. The Companies applied the ratio between Low Oil and Gas Supply and High Oil and Gas Supply side cases, respectively, to the AEO Reference Case, to its base natural gas price forecast to develop its high and low natural gas price forecasts for the Carbon Plan. High and low natural gas price forecasts were developed for each fuel supply case according to the specific fuel supply and commodity pricing assumptions and impacts used in each case. Figure E-7 below shows the resulting high and low natural gas prices forecasts compared to the Companies' base forecast.

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



Natural Gas Fuel Supply Assumptions

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

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

Base Fuel Supply Assumption - Limited Appalachian Gas Supply

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

Alternate Fuel Supply Sensitivity - No Appalachian Gas Supply

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

Coal Price Forecast

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

Hydrogen

As a base planning assumption, the Carbon Plan includes hydrogen as a fuel used to generate electricity for the system. Hydrogen fuel is assumed to be used in two ways. First, starting in 2035, a small amount of hydrogen (1% by heat content, ~3% by volume) is assumed to be blended into the natural gas supply for all resources. Though in relatively small volumes, the blending of hydrogen into natural gas supply impacts both the price of the now blended fuel, and the carbon content, even if minimally impactful to overall price and carbon emissions. This is to represent the likelihood of hydrogen or other low carbon fuels being introduced into the gas supply of the system over the next two decades. Over time the amount of hydrogen blended into the natural gas fuel supply grows moderately (to 3% by heat content or approximately 10% by volume by 2038 and to 5% by heat content or approximately 15% by volume by 2041) but remains a small fraction of total fuel supply in the pipelines.

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

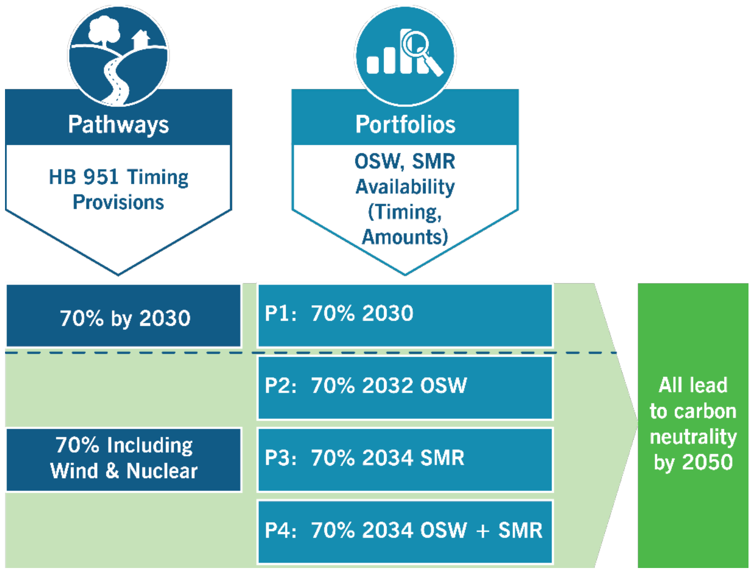
Supply of hydrogen carries a significant uncertainty. There are initiatives and funding for the development of hydrogen supply hubs across the United States. While the ultimate realization of a hydrogen hub in the Carolinas is uncertain, the hydrogen economy is viewed by the Companies as a potential breakthrough technology that can contribute to achieving national economy-wide CO_2 emissions reductions. Resource portfolios that are robust enough to produce hydrogen in times of excess electricity supply could be an added benefit and risk mitigation factor. To identify potential for the Companies to self-supply a significant portion of hydrogen used by 2050, the Companies performed a Hydrogen Supply Analysis, which is discussed later in this Appendix.

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

Portfolio Development

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

Figure E-8: Portfolio Development Overview



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

Determining Economic Retirement of Coal Generating Capacity

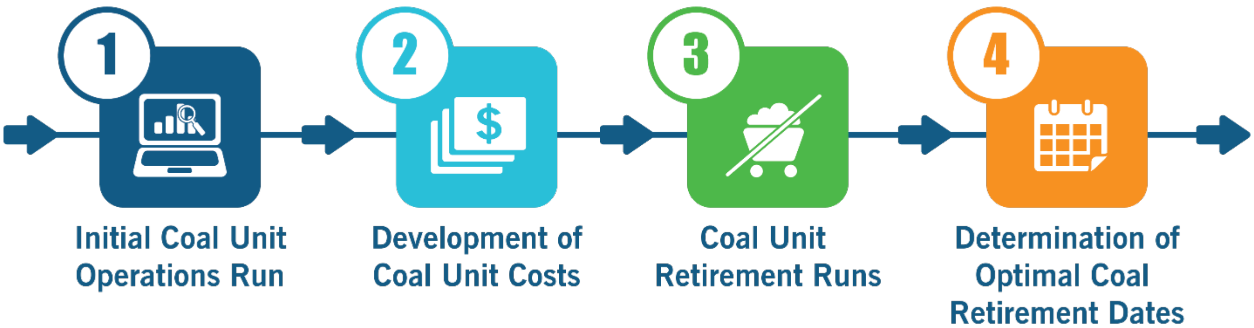
The Carbon Plan identifies the timing of future coal retirements endogenously within the capacity expansion model.[4] The capacity expansion model weighed the continued operational benefits to the system and costs to operate and maintain the coal units over time against the retirement and potential replacement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

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

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

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

Figure E-9: Coal Retirement Analysis Process



Initial Coal Unit Operations Runs

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

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

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

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

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

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

Development of Coal Unit Costs

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

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

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

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

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

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

Coal Unit Retirement Runs

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

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

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

Determination of Optimal Coal Retirement Dates

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

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

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

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

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

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

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

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

Preliminary Capacity Expansion Results

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

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

Portfolio Development Scenario 1

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

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

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

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

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

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

To support these variable energy resources, 3.2 GW of batteries, combined between standalone batteries and batteries paired with solar, are selected by 2030. In addition to the battery capacity supporting variable energy renewables, 2.4 GW of CC capacity is also selected, proving additional firm capacity and overall system flexibility to backstand the variable energy renewables. These capacity resources also support the retirement of 4.9 GW of coal capacity. The coal retirements represent all subcritical coal remaining on the Carolinas system, with the only remaining coal capacity on the system being able to be co-fired with natural gas to increase flexibility and lower carbon emissions. No new CT capacity is selected in the preliminary resource identification by the capacity expansion model for Portfolio 1.

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

Portfolio Development Scenario 2

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

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

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

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

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

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

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

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

Portfolio Development Scenario 3

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

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

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

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

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

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

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

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

Portfolio Development Scenario 4

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

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

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

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

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

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

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

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

Portfolio Results Summary through 2035

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

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

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

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

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

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

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

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

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

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

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

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

Portfolio Verification

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

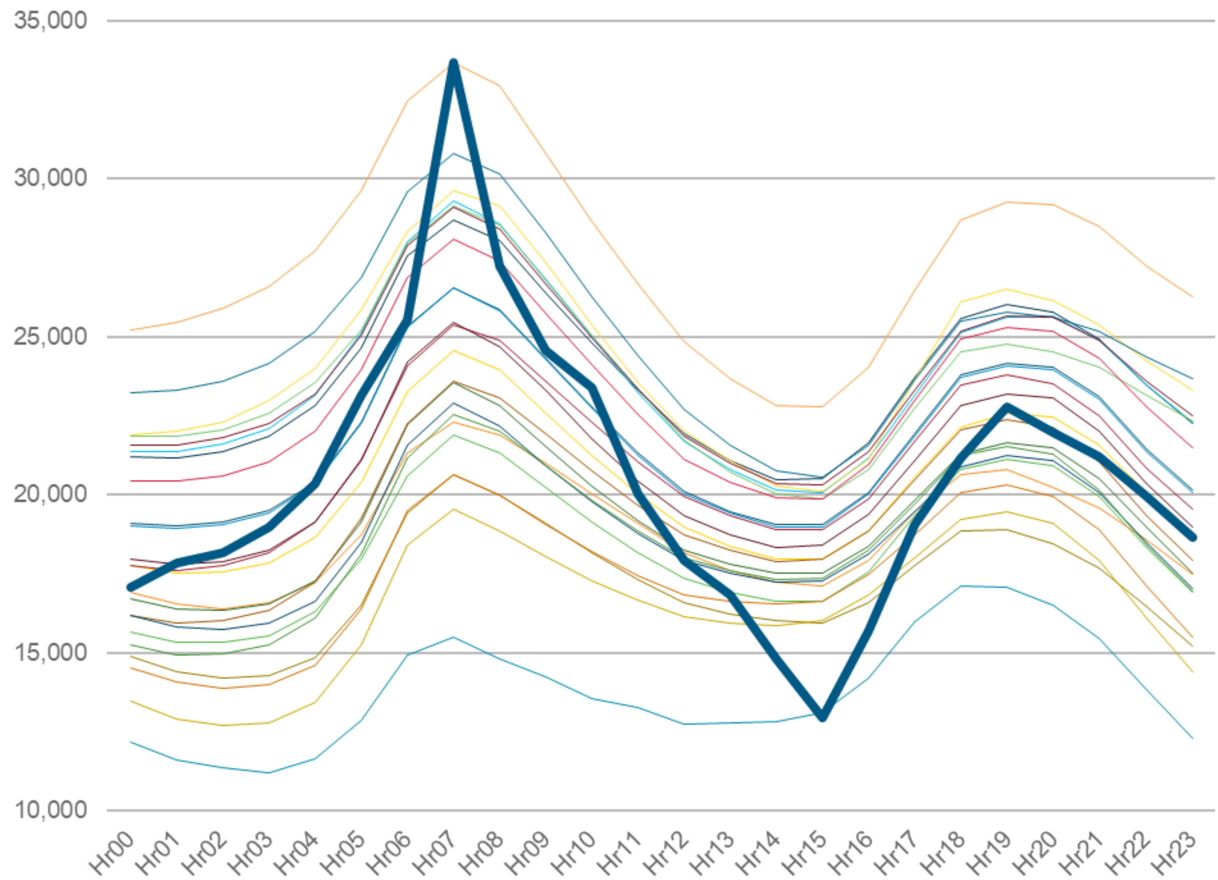
Battery-CT Optimization

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

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

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

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



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

Battery-CT Optimization Modeling

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

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

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

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

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

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

Bad Creek Powerhouse II Validation

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

Due to the limitations of the capacity model with evaluating energy storage, as discussed in the Battery-CT Optimization step, the Companies performed additional comparative economic analysis of this long-duration storage to confirm Bad Creek PH II as an economic inclusion in the portfolios.

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

The project will continue to be evaluated over the coming years as a potential to help integrate renewables, provide significant capacity additions, and have an impact on the Carolinas energy system for decades to come while leveraging existing infrastructure.

Resource Adequacy and Reliability Verification

Overall Portfolio Reliability and 2050 CO_2 Reduction Verification

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

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

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

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

Solar Levelization

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

Portfolio LOLE and Resource Adequacy Validation

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

As previously noted, ELCC values are dependent on many factors including the load and load shape to be served, the existing resource mix, as well as the adoption level of different resource technologies. An overstatement of ELCC value in the modeling process can result in a system that has insufficient capacity planning reserves. Since it is not practical to determine ELCC values for infinite combinations of resources, nor are such inputs easily integrated into the resource planning models, the Companies conducted LOLE analysis for each of the Carbon Plan portfolios. This process utilized the Strategic Energy Risk Valuation Model ("SERVM")[8] to evaluate the LOLE of each portfolio for the years 2030 and 2035 to ensure that the portfolios satisfy the LOLE target in later years with higher levels of renewables and energy storage resources.

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

[7] LOLE is the expected number of days in a year for which there is loss of load at least once per day (units are in days). LOLE counts the days having loss of load events, regardless of the number of consecutive or nonconsecutive loss of load hours in the day.

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

[9] 2020 Resource Adequacy Study Report, at 7, filed as Attachment I (DEC) and Attachment II (DEP) to the Companies' 2020 IRPs in Docket No. E-2, Sub 165.

transition to variable energy and energy limited resources to achieve CO_2 reduction targets. It is expected that if current trends hold, as neighboring systems continue to install solar and storage resources, the neighbors' LOLE risk may shift to the winter months as it has for Duke Energy. This could potentially lower the amount of neighbor assistance available in the future since there may be fewer capacity reserves available during winter peak periods. Thus, it is difficult to project the level of firm market resources and available transmission for providing reliability assistance in the next decade and beyond.

Rather than speculate and buildout an assistance area for 2030 and 2035 in SERVM, the Companies assumed that the level of market assistance would neither improve nor decline from the level of assistance modeled in the 2020 Resource Adequacy Study. For the reasons noted above, the Companies believe that this assumption may overestimate their ability to rely on neighbors in the next decade; however, this simplifying assumption was undertaken to facilitate the LOLE validation step providing a general representation of how the transition of Duke Energy's system could impact resource adequacy. This approach allows the Companies to observe how reliability of the combined islanded system changes with resource transition across time without speculation about future market assistance.

To establish a threshold LOLE metric for an island scenario, the Companies utilized modeling data from the 2020 Resource Adequacy Study Combined Case. The Combined Case from the 2020 Resource Adequacy Study allowed preferential support between DEC and DEP to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority. The SERVM model was used to rerun the 17% reserve margin Combined Case, except as an island with no market assistance. The LOLE result was then compared against the interconnected study as shown in Table E-56:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Energy Adequacy

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

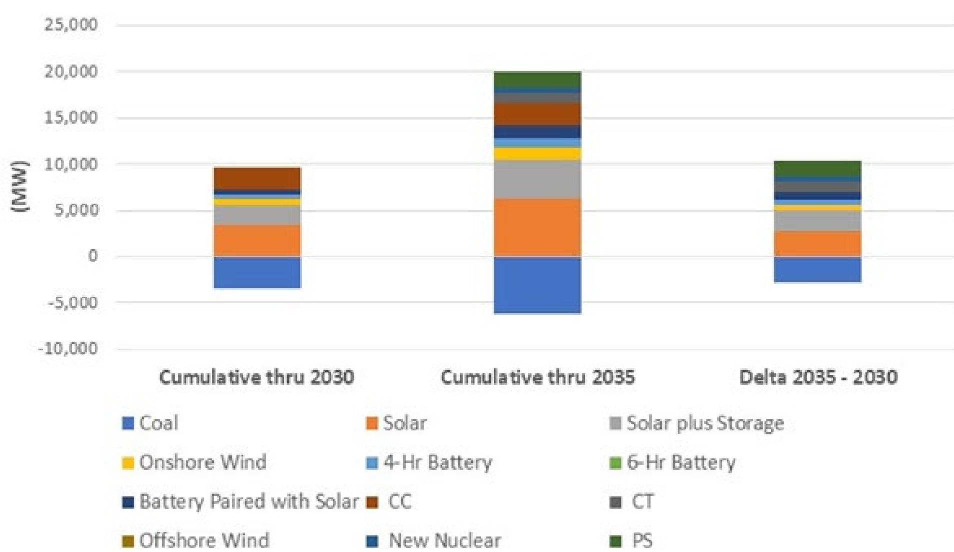
As an example, Table E-60 compares reliability metrics for Portfolio 3 for the years 2030 and 2035, along with the combined island threshold values. The table shows that the reserve margin for P3 is approximately the same in 2030 (22.1%) and 2035 (22.0%) and is approximately 5% above the minimum winter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

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

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

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

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



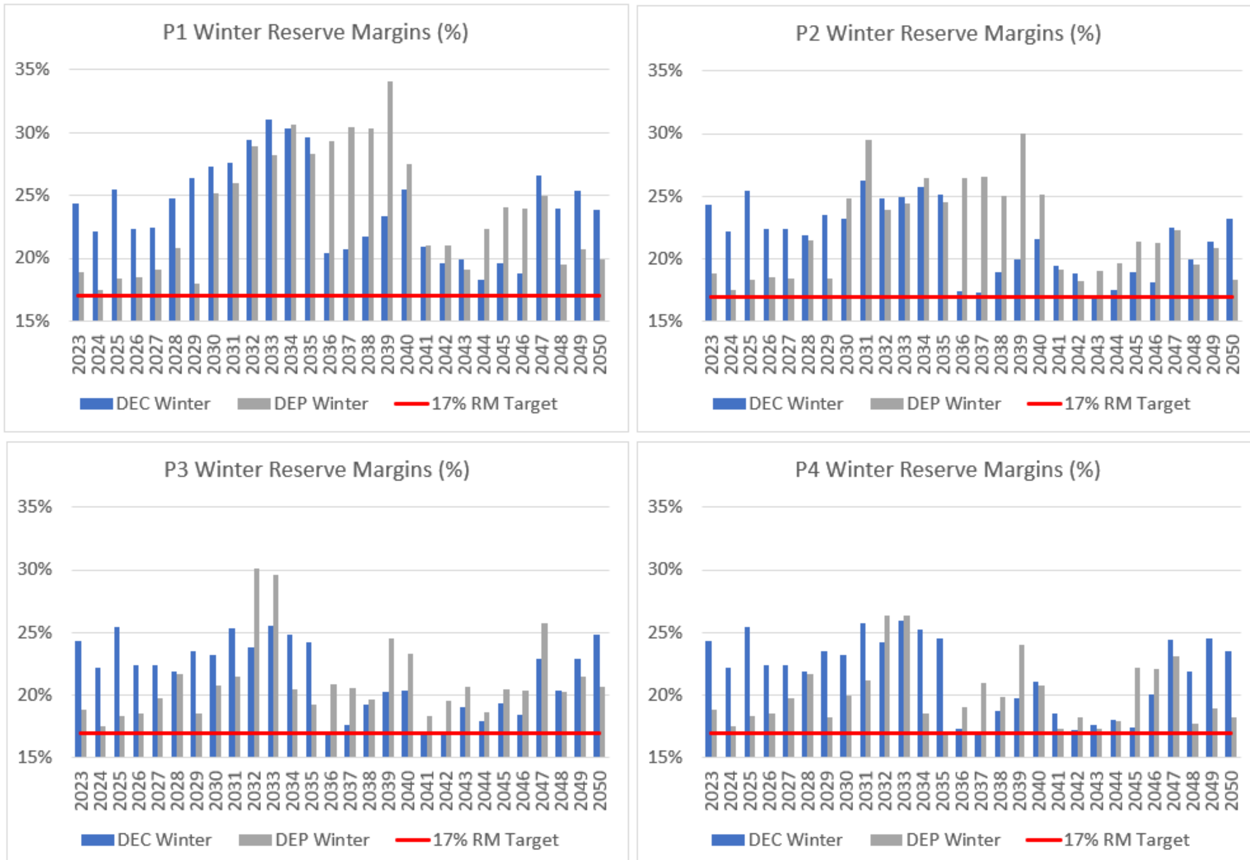
This analysis of P3 shows that higher reserve margins may be needed to maintain the same customer reliability, especially from an EUE perspective, with higher adoption of renewables and storage resources. The 0.1 event-days / year LOLE standard is currently widely used in the electric industry for measuring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

Adequacy of Projected Reserves

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

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

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



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

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

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

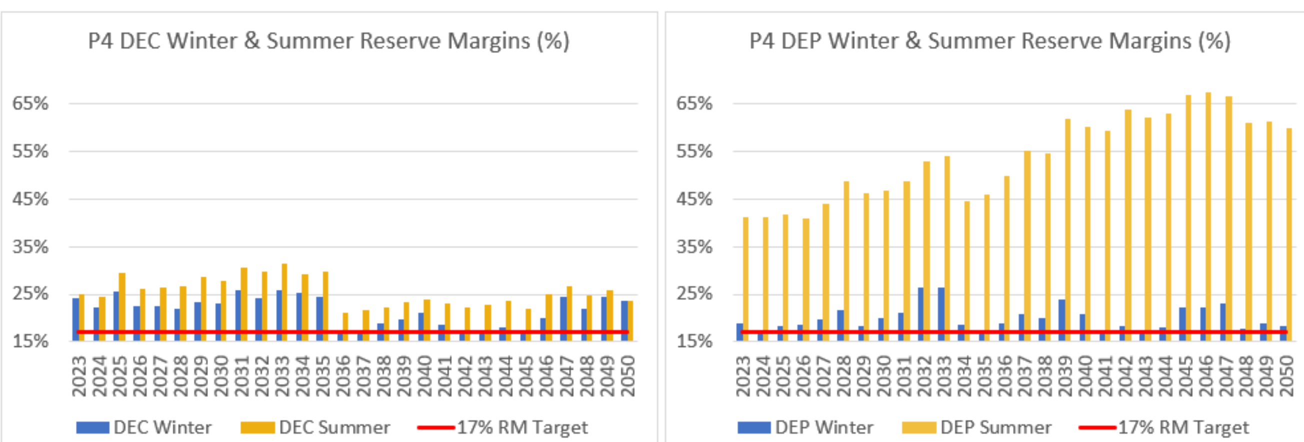
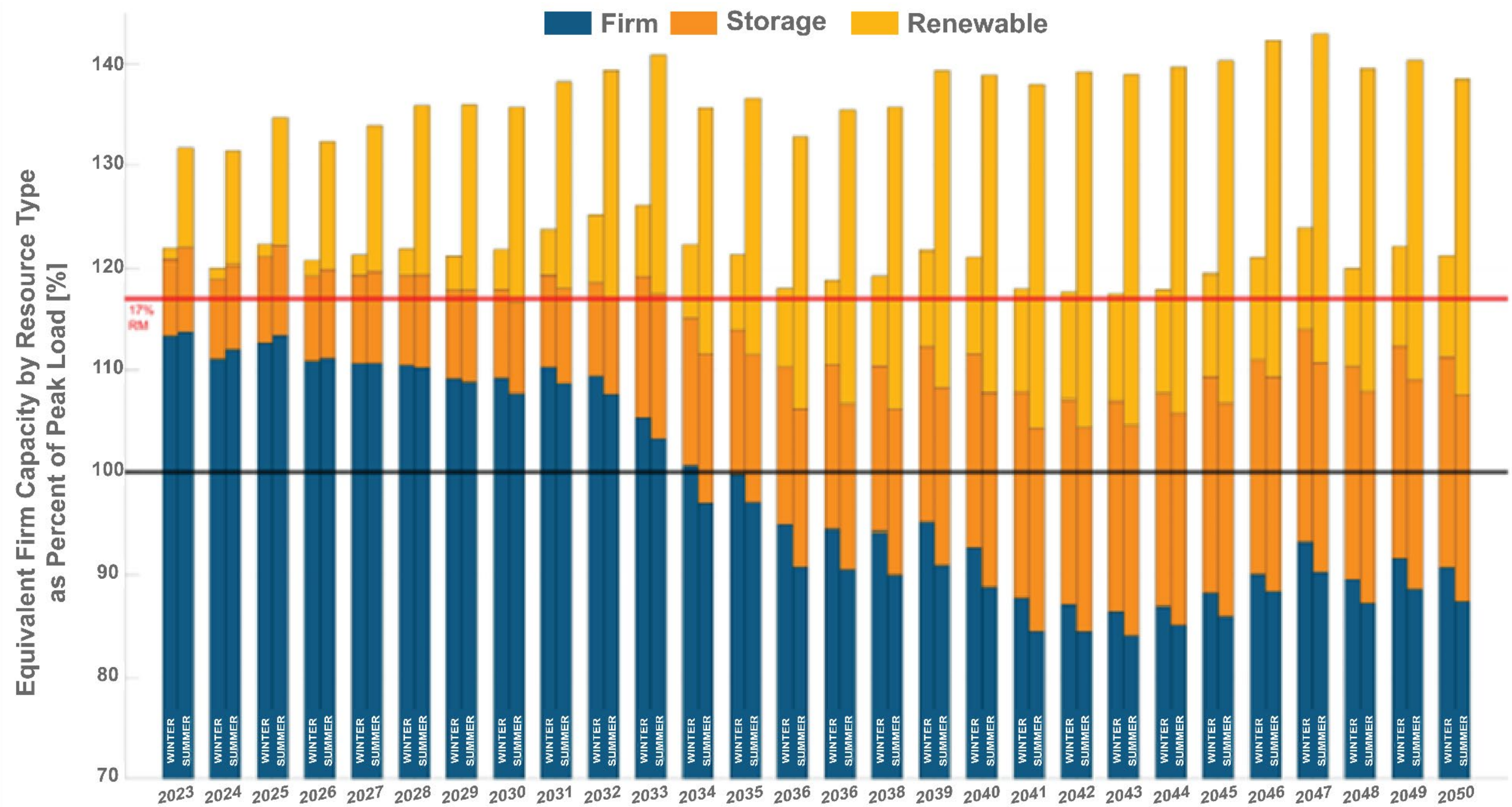


Figure E-14 provides another view of reserve margins by season and year for Portfolio 4. In this figure, DEC and DEP firm capacity and peak loads are combined to create reserve margin projections for the combined Carolinas' systems. Three types of resources are represented: Firm (gas, coal, oil, nuclear,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

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



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

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

Final Carbon Plan Portfolios

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Portfolio Performance

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

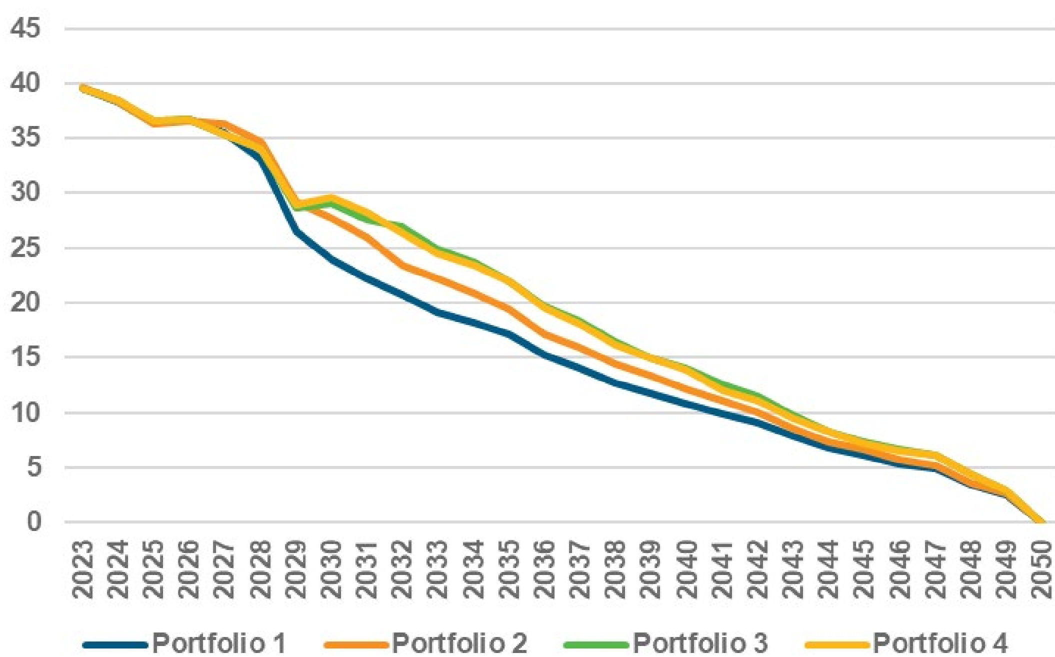
This section highlights the relative performance of each of the final portfolios in terms of CO_2 reductions and cost, both in terms of overall PVRR and customer bill impacts. The results in this section were developed based on detailed production cost modeling runs of the final portfolios, including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

CO_2 Reduction Analysis

The primary objective of the Carbon Plan is to present portfolios that comply with the CO_2 emissions reductions targets in a least cost manner, while maintaining or improving Duke Energy's compliance with reliability standards. This includes assessing the trade-off between interim target achievement dates and resources used to achieve the CO_2 emissions reductions targets. The projected emissions are outputs of the production cost model, which occur through economically dispatching the specific set of resources in each portfolio to meet the energy needs of the system. For the detailed production cost runs, no mass cap, environmental dispatch adder, or price on carbon is used to influence the operation of the system. The system mass cap was only utilized in the development of portoflios and selection of resources. As mentioned previously throughout this Appendix, the DEC and DEP system are jointly dispatched. For this reason, emissions are shown for the combined systems.

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

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



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

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

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

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

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

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

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

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

Present Value of Revenue Requirements

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

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

Resource planning PVRR analysis is typically limited to costs associated with projected resources and operations of the generation system to serve customer load, but the analysis for the Carbon Plan includes additional projected transmission network upgrade costs associated with adding new resources, as discussed in the Selectable Supply-side Resource section of this Appendix and retiring existing ones. Also included in the PVRR are costs associated with UEE, DR, IVVC, and costs for maintaining coal units through their projected lives.

Each of the costs described above varies from portfolio to portfolio as the resource mix in each portfolio changes with the targeted year. Shown below in Table E-75 are the annual revenue requirements of these costs, discounted to present value at DEC's and DEP's Company specific discount rate. A combined DEC and DEP PVRR is also shown.

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

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

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

Customer Bill Impact Analysis

As previously noted, the PVRR of a portfolio is a common and useful financial metric in resource planning to measure the cost of the plan over a long period of time. This metric captures the costs and benefits of accelerating retirements, building new generation and associated transmission, and changing fuel prices and operation costs over time. While PVRR is an important metric for the long run costs of a portfolio, the Companies are also concerned with the immediate cost to customers and emphasize the ability to provide affordable energy to customers as a core target of this Carbon Plan.

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

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

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

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

	2030	2035
P4	$5	$28

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

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

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

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

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

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

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

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

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

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

Portfolio, Production Cost, and Capital Cost Sensitivity Analysis

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

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

Alternate Fuel Supply Sensitivity Analysis

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

Alternate Fuel Supply Sensitivity Portfolio Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Alternate Fuel Supply Portfolio Sensitivity Performance

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

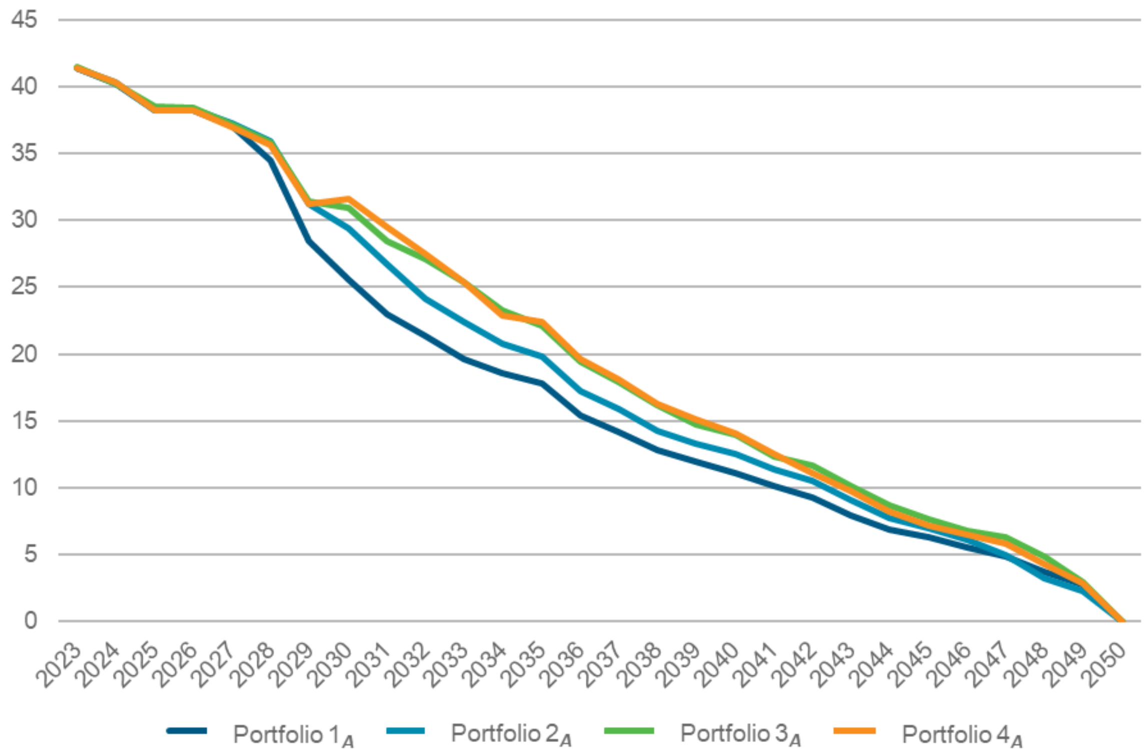
CO_2 Reduction Analysis

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

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

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

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



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

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

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

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

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

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

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

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

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

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

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

*Present Value of Re*venue Requirements

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

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

	DEC	DEP	DEC + DEP
P1$_A$	$60.0	$44.1	$104.1
P2$_A$	$57.8	$43.5	$101.3
P3$_A$	$58.7	$39.9	$98.6
P4$_A$	$58.1	$40.9	$98.9

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

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

Customer Bill Impact Analysis

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

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

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

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

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

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

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

	2030	2035
P4$_A$	$19	$34

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

	2030	2035
P1$_A$	4.1%	2.7%
P2$_A$	3.3%	2.7%
P3$_A$	2.4%	1.9%
P4$_A$	2.2%	2.2%

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

Fuel Price Forecast Portfolio Sensitivity Analysis

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

Selection of CC resources in High Natural Gas Price Forecast

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

Economic Replacement of Battery Capacity with CT capacity

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

Fuel Price Forecast Production Cost Sensitivity Analysis

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

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

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

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

	High Gas Price Forecast	Low Gas Price Forecast
P1$_A$	$7.2	-$3.4
P2$_A$	$7.6	-$3.6
P3$_A$	$7.9	-$3.7
P4$_A$	$8.0	-$3.7

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

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

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

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

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

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

Effects of an Environmental Dispatch Shadow Price

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

Federal CO_2 Tax Production Cost Sensitivity Analysis

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

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

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

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

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

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

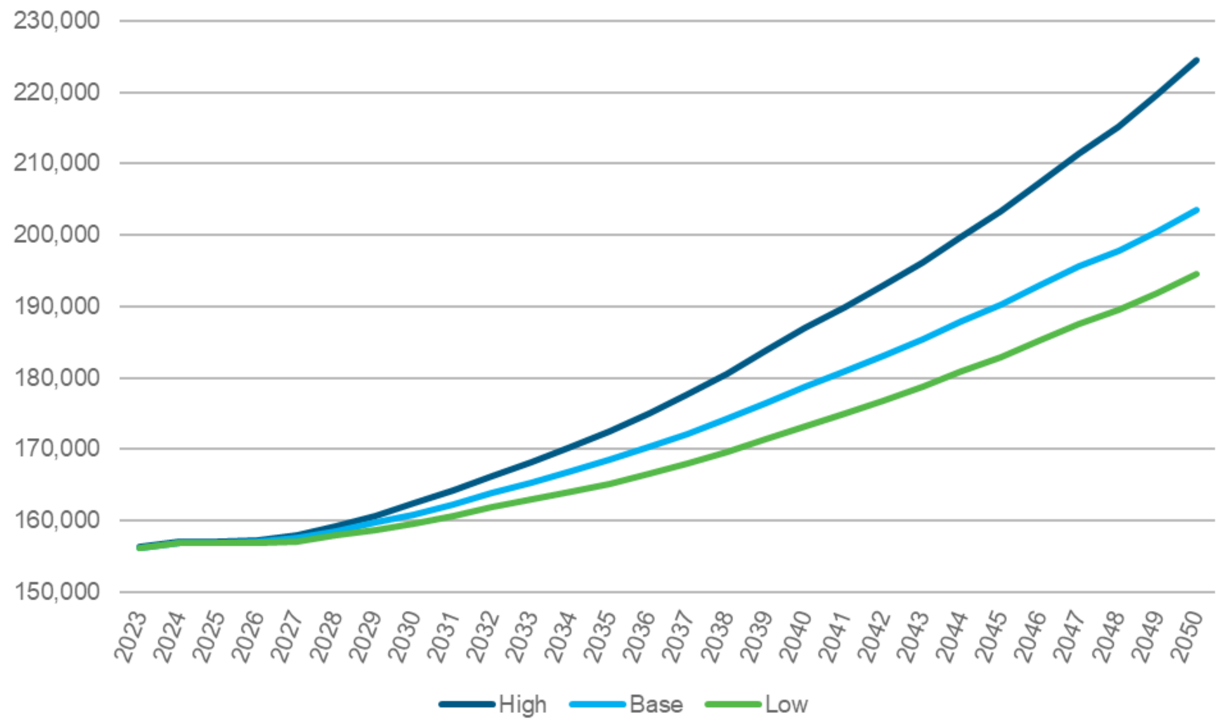
As shown in Table E-98 above, the incremental cumulative CO_2 emissions reductions between Portfolio 1 and Portfolio 4 do not fully close the PVRR cost differential between the portfolios with this CO_2 emissions price. This means that the earlier incremental cost to enable CO_2 emission reductions is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

Load Forecast Sensitivity Analysis

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

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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

New Supply-Side Resource Capital Cost Sensitivity Analysis

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

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

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

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

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

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

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

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

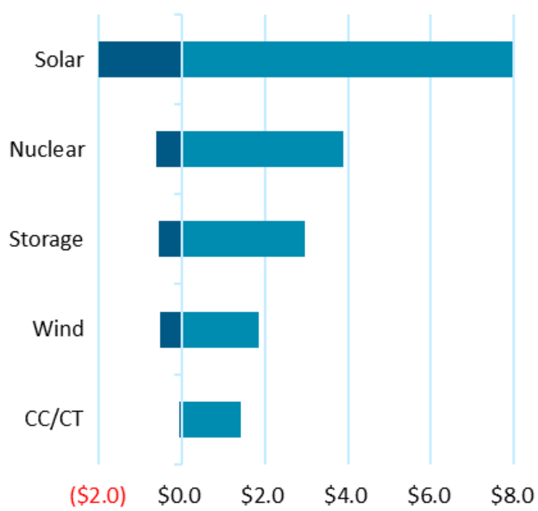
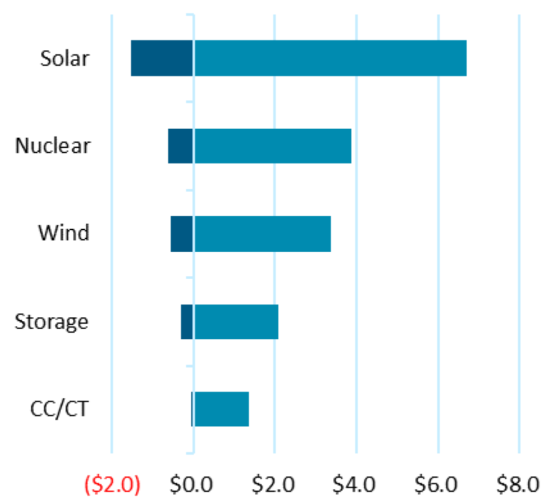


Figure E-19: Portfolio 2 Capital Sensitivity Analysis Results, Technology-Specific PVRR Impacts [2022, $B]



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

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

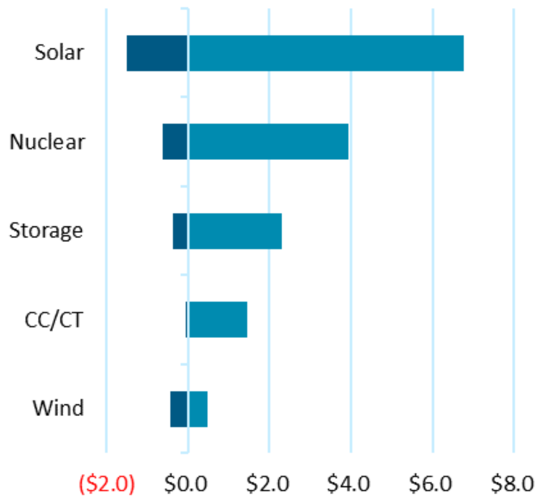
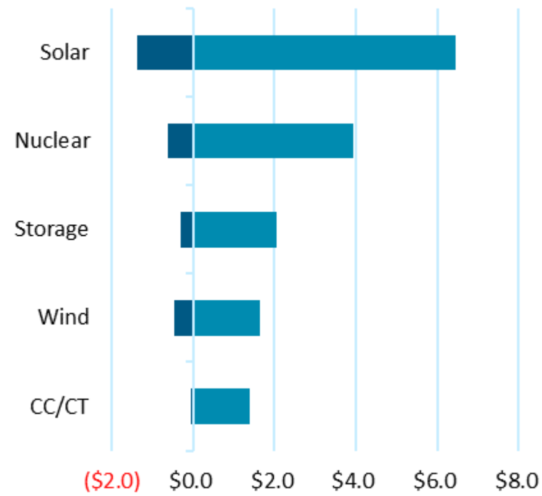


Figure E-21: Portfolio 4 Capital Sensitivity Analysis Results, Technology-Specific PVRR Impacts [2022, $B]



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

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

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

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

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

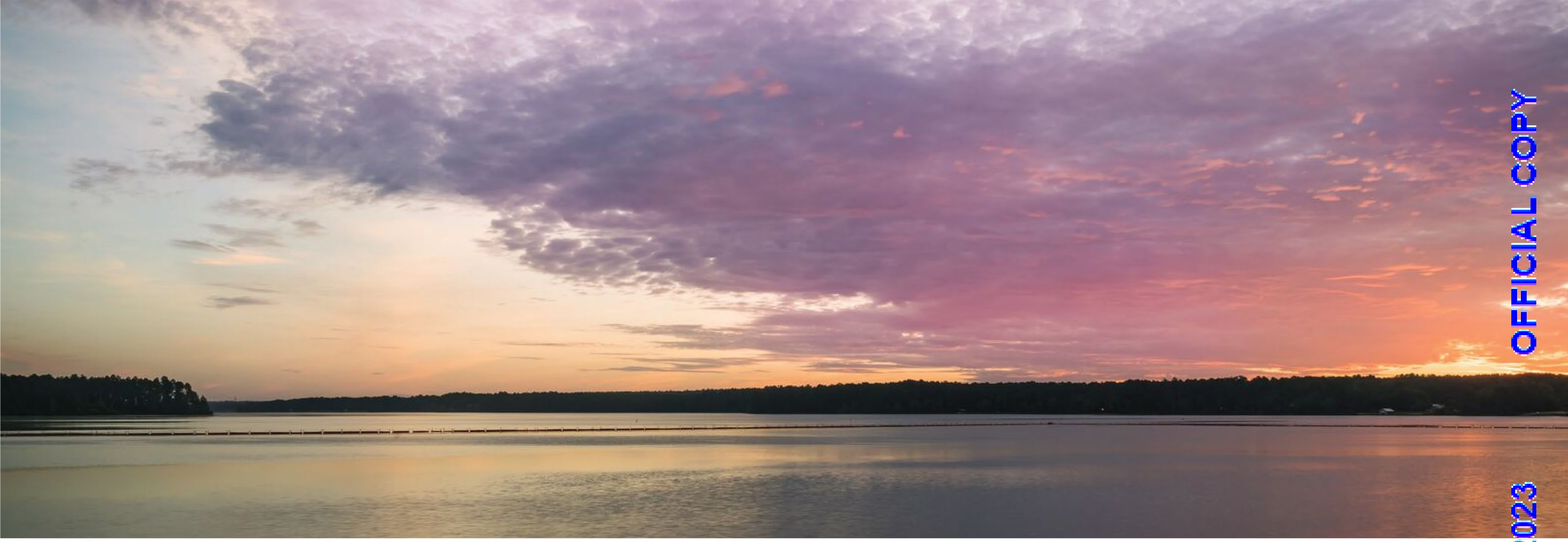
As seen in the individual technology impacts, the high price risk is much higher than the potential benefit opportunity of costs coming in lower than the Companies' projected price forecasts. Portfolio 1 represents the highest impacts in both the high and low capital price forecast sensitivities. This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

Hydrogen Supply Sensitivity Analysis

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

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

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



1 Introduction and Background

For more than a century, Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP” and, together with DEC, “Duke Energy” or the “Companies”) have delivered on their commitment to provide affordable, reliable electricity to customers and communities in the Carolinas. The Companies’ two dual-state electricity systems serving North Carolina and South Carolina (that is, North Carolina customers are served, in part, by South Carolina-sited generation and South Carolina customers are served, in part, by North Carolina-sited generation) provide electric service to 4.2 million customers over a 56,000-square-mile area, with more than 30,000 megawatts (“MW”) of electric generating capacity. Appendix C (System Overview) provides an overview of the dual-state systems.

Through constructive regulation, prudent investment, and efficient operation, the dual-state systems have delivered tremendous economies of scale, resiliency, and savings to customers and communities in both states. The dual-state systems have created competitive advantages for both states’ economies and have fueled job creation through the reliable and safe supply of electricity at rates consistently below the nation’s average. To continue to deliver these results, mitigate known risks posed by continued reliance on emissions-intensive resources, and meet the requirements of Session Law 2021-165 (“HB 951”), the Companies have prepared their proposed Carolinas Carbon Plan (the “Plan” or “Carbon Plan”).

Like the Companies’ Integrated Resource Plans (“IRP”) and associated IRP updates submitted to the North Carolina Utilities Commission (“Commission”) and the Public Service Commission of South Carolina (“PSCSC”) in 2020, the Plan presents multiple potential portfolios for the Companies to meet future energy and demand requirements and assesses the associated risks, benefits, and costs to customers of the portfolios. Like the IRPs, the Plan identifies multiple supply- and demand-side resource combinations needed to meet the Companies’ projected demand over time to ensure reliable service to customers.

Also like the 2020 IRPs, the Plan targets further reductions in carbon emissions. While directionally similar to Portfolio C in the 2020 IRPs, which accomplished a 66% reduction in CO_2 by 2030, the Plan represents a more updated resource analysis that would achieve 70% CO_2 emissions reductions by 2030, 2032 or 2034 with wind and nuclear. Importantly, the Plan is a product of a series of robust stakeholder engagement sessions conducted in early 2022 with a diverse group of hundreds of stakeholders, as well as numerous other issue-specific collaboratives and task forces the Companies' subject matter experts have routinely attended, conducted, and/or hosted in the Carolinas.

Finally, the Companies continue to believe that supportive state policies in both North Carolina and South Carolina that allow for continuation of the Companies' dual-state systems are in the best interests of customers. The Companies also affirm that subsequent regulatory processes will be needed in South Carolina (as discussed in more detail below), along with continued engagement with South Carolina stakeholders, in order to ensure continued dual-state alignment. Continued alignment in both states will provide immense benefits to both North Carolina and South Carolina, and the alternative would necessitate a different model for serving customers, potentially increasing costs by inefficiently serving North Carolina and South Carolina customers separately. The Companies are hopeful that this outcome will be avoided and that the Plan will ultimately be accepted in both states.

Orderly Energy Transition Began Two Decades Ago

The Companies' orderly transition away from continued reliance upon emissions-intensive resources began in the early 2000s. Since 2010, DEP and DEC, collectively, have retired approximately 4,400 MW of aging, inefficient coal-fired generation, consisting of 35 units, and converted approximately 3,150 MW of coal capacity, consisting of eight units, such that they can use natural gas as a fuel. The Companies' existing emissions-free resources are significant. The six nuclear plants, 26 hydro-electric facilities, and almost 1,000 solar facilities that are now online and serving customers are foundational to the Companies' orderly transition of its dual-state systems. With winter capacities of the Companies' nuclear and hydro fleet reaching over 11,000 MW and 3,400 MW, respectively, continued operation of these emissions-free resources is essential to meeting the interim 70% CO_2 emissions reductions target outlined in this Plan. Relicensing of the nuclear fleet, which began this year, provides the Companies the option to operate these plants for an additional 20 years. Relicensing of the Companies' hydro units began nearly two decades ago and has been largely successful. In 2022, DEC began the multi-year process of relicensing the Bad Creek Hydroelectric Project, one of the largest energy storage assets in the world, for another 40-50 years. If successful, the resource would continue to provide customers with 1,400 MW of storage capacity with the potential to approximately double the capacity through investment in expansion of the existing Bad Creek facility subsequent to relicensing. Furthermore, in the last decade, the Companies' solar resources have grown to approximately 4,350 MW of installed solar in the Carolinas, ranking Duke Energy among national leaders in solar energy.

Orderly Energy Transition Is Reasonable and Prudent

The orderly transition away from reliance upon emissions-intensive resources is a reasonable action and the Plan's portfolios are reasonable, prudent, and consistent with risk mitigation practices throughout the electric power industry. Irrespective of the many attempts to regulate the electric power sector's carbon emissions at the federal level,[1] numerous electric utilities' integrated resource planning

[1] Congressional Research Service, U.S. Climate Change Policy (Oct. 28, 2021), *available at* https://crsreports.congress.gov/product/pdf/R/R46947.

now includes a focus, preference or requirement that a utility's long-term plans incorporate CO_2 reduction goals, targets or compliance obligations,[2] driven by a range of factors including stringent environmental regulatory requirements. The latest research indicates that approximately 300 individual electric utilities are preparing to meet "100 percent" carbon reduction targets.[3] Stated simply, the orderly transition away from reliance on emissions-intensive resources is occurring even in the absence of direct mandates. The Companies, along with other peer utilities in the Southeast and across the country, have been and continue to reduce reliance on coal resources.

Continued planned reduction in reliance on emissions-intensive resources will not only deliver on environmental benefits of clean energy, but will also deliver the following tangible benefits to customers, communities and the Companies (as is described in further detail below):

- Reduced exposure to financial and operational risks associated with reliance on coal generation and coal suppliers;

- Enhanced economic development competitiveness of the Carolinas region, enabling the states to recruit, retain, and grow leading manufacturers, back-office operations, corporate headquarters, defense organizations, technology firms, etc.;

- Opportunities for substantial capital investment, including through growth of the states' renewable energy industries, resulting in job growth and economic stimulation of the states (including rural communities); and

- Continued access to financing to fund operations and growth at reasonable rates.

Transition Reduces Risk Exposure to Coal Generation and Fuel Supply

Reductions in the use of carbon-intensive generation across the Companies' dual-state systems not only reflect the Companies' commitment to the economic development and prosperity of the Carolinas, but also reflect a risk-informed determination to ensure long-term reliability and resiliency, fuel supply assurance, and continued access to capital for utility infrastructure investments at competitive rates.

Coal is an increasingly risky fuel source. With more retirements planned for the nation's aging coal fleet, the businesses that supply coal are increasingly distressed, and coal market volatility has increased due to a number of factors, including deteriorated financial health of coal suppliers due to declining domestic demand for coal; uncertainty around proposed, imposed and stayed regulations for power plants; and increasing financing costs for coal producers. These issues are compounded by rail transportation providers' limited and diminishing operational flexibility. This lack of transportation flexibility results in increased difficulty in adapting to changes in scheduling demand needed due to changes in coal's generation burn. Although the Companies continue to manage coal supply

[2] Nat'l Reg. Research Institute, State Clean Energy Policy Tracker, at 2, https://www.naruc.org/nrri/nrri-activities/clean-energy-tracker/ (last visited May 3, 2022).

[3] Smart Elec. Power Ass'n, Utility Carbon-Reduction Tracker, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/ (last visited May 3, 2022).

assurance risks, the supply chain is expected to further deteriorate over time. These long-term declines in supply uncertainty and operational flexibility ultimately create long-term fuel supply assurance risks for customers.

Increases Economic Development Competitiveness

The Plan supports the Companies' commitment to the prosperity of communities they serve. In 2021, the Companies were instrumental in helping attract more than $2.4 billion in capital investment and 5,310 new jobs to North Carolina, and $712 million in capital investment and 1,038 new jobs to South Carolina.[4] As active partners in economic development, the Companies are acutely aware of the fact that commercial and industrial businesses are increasingly citing the emissions-intensity of electricity generation as a selection criterion in the search for future sites for operations.[5] This Plan provides for enhanced economic development competitiveness of the Carolinas region, enabling the states to recruit, retain and grow leading manufacturers, back-office operations, corporate headquarters, defense, and technology firms, among others.

Leading North Carolina and South Carolina employers have clear mandates or targets to reduce the carbon intensity of their operations. In the Companies' own recent experience, nearly every North Carolina and South Carolina economic development prospect has specifically requested information regarding the Companies' generation mix, plans for the future, and renewable investment, and nearly all ask whether they can be served exclusively with carbon-free resources. Carbon emissions are clearly top-of-mind for businesses choosing whether to locate in a particular state, and the Carolinas stand to become an even more prosperous, even more attractive destination for facility relocation and expansion. While industry leaders are looking for utility partners with increasingly emissions-free systems, investors who purchase utility stocks and lend to utilities are – at the same time – demanding that the companies they invest in hold themselves accountable for long-term, sustainable operations. Investing with an eye toward environmental, social, and governance ("ESG") principles, or ESG-focused investing, has grown in recent years.[6]

Investment Opportunities in a Transitioning Energy Industry

The Companies' remaining coal facilities are nearing the end of their technical and economic life and becoming riskier to operate; thus, retirement is increasingly inevitable. What will replace the substantial amount of firm, dispatchable capacity, and where those resources will be located, will be determined

[4] Duke Energy 2021 ESG Report at 44, https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/esg/2021-esg-report-full.pdf?la=en&rev=39232657c7f74bf48fb0360adffd0bb7.

[5] Publicly traded commercial and/or industrial customers are under increasing pressure to "decarbonize" their supply chains by reducing Scope 1, 2 and 3 emissions. As providers of an essential input, electricity, the Companies are considered "suppliers" and the Companies' Greenhouse Gas ("GHG") emissions are accounted for in the firm's GHG inventory because they are a result of the organization's energy use. Enabling a customer to reach a Scope 2 emissions goal, increases the likelihood of expanding operations at that site.

[6] U.S. Securities and Exchange Commission, Environmental, Social and Governance (ESG) Funds – Investor Bulletin (February 26, 2021), https://www.investor.gov/introduction-investing/general-resources/news-alerts/alerts-bulletins/investor-bulletins-1.

by informed decisions made within the respective regulatory constructs of North Carolina and South Carolina. Significant transmission development, new investment in pumped storage hydro, advanced nuclear projects, solar and battery storage investments, and other large projects and jobs investments will be at play as part of the implementation of resource planning outcomes in the Carolinas. These investments will mean substantial investment for the tax base and jobs in the Carolinas, not to mention opportunities for all energy industry participants. Decisions by the Commission and the PSCSC between now and when the Companies begin to site replacement resources will be critical in influencing the "what" and the "where" of resource development and the associated capital investment and long-term economic impact.

All Plan portfolios significantly reduce reliance upon coal resources and outline a path to replacing those resources, such as through new investment in pumped storage hydro, advanced nuclear projects, solar and battery storage. Undoubtedly, large project and jobs investments will be at play as an input to resource planning in the Carolinas. These investments could mean significant levels of investment for the Carolinas' tax base and jobs in the state. The Plan will also result in continued strength of the renewable energy industry in the Carolinas through continued growth in solar generation and potentially wind generation throughout both North Carolina and South Carolina.

Enables Continued Access to Financing

The transition away from reliance upon emissions-intensive resources is necessary to mitigate potential increases in costs of debt and equity due to growing preference of institutional investors in reducing their portfolios' exposure to carbon and climate risks. This impacts access to, and the cost of, equity and debt securities, and has also become a material consideration among the credit rating agencies. An example of this is the Glasgow Financial Alliance for Net-Zero, which launched in April 2021. Within its first year, the membership to this consortium grew to 450 firms from 45 countries, representing approximately $130 trillion in total investments[7] – 40% of all globally banked assets. The primary purpose of the alliance is to align lending and investment activities of large financial institutions with the net-zero targets of the Paris Agreement to limit global temperature increases to 1.5 degrees Celsius. Many of the largest equity and debt investors have joined this initiative and are taking a more proactive role in evaluating each utilities' approach toward a clean energy future.

For many investors, the evaluation of a company's decarbonization plan is not just to meet the investors' own climate targets and expectations, but it is part of the investors' overall risk assessment of a company. For example, BlackRock, one of the largest investment firms in the world, and Duke Energy Corporation's second-largest shareholder, notes that "[c]limate risk presents significant investment risk – it carries financial impacts that will reverberate across all industries and global markets, affecting long-term shareholder returns, as well as economic stability."[8] As investors evaluate their portfolios and make decisions on where to allocate capital, the pace of companies' decarbonization plans is becoming more critical. Investors have a variety of investment opportunities

[7] Glasgow Financial Alliance for Net Zero, https://www.gfanzero.com/about.

[8] BlackRock, Climate Risk and the Global Energy Transition at 1, https://www.blackrock.com/corporate/literature/publication/blk-commentary-climate-risk-and-energy-transition.pdf (February 2022).

available to them, and they require a return commensurate with the risk they incur. If a utility's climate risk is deemed to be elevated, it can directly impact customers in several ways. First, investors will require a higher return, increasing the cost of capital and customer rates. Second, investors may allocate less capital to certain companies or ultimately choose not to invest. This further impairs a company's access to capital, which could limit its ability to execute capital projects for the benefit of its customers.

An assessment of DEC's and DEP's creditworthiness is performed by two major credit rating agencies, Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), and results in their credit rating. The credit rating agencies consider both qualitative and quantitative factors, and they are increasingly focused on environmental issues. In ratings released by S&P in November 2021, DEC and DEP were both rated "negative" on environmental issues, indicating that environmental factors are having a materially negative impact on the creditworthiness of the Companies.[9] Included among the negative risk factors was "climate transition risks," with S&P stating that decarbonization will "rapidly modify the economics of [] projects and hence their future cash flows, cost of capital, and access to financing."[10] As risk increases, credit quality declines and ratings can come under pressure. As credit quality declines, investor requirements for higher returns increase, meaning customers will pay more for capital. To ensure reliable and cost-effective service for customers, access to capital at reasonable rates is critical. This requires utilities to consider how their decarbonization plans impact debt and equity investors' evaluation of them. Carbon reduction targets that address investor concerns over longer term risk increase a utility's ability to access capital through various market conditions. As investors and credit rating agencies have expanded their assessment criteria to include climate and environmental issues, the Securities and Exchange Commission has proposed rule changes that would require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including information about climate-related risks that are reasonably likely to have a material impact on their business, results of operations, or financial condition, and certain climate-related financial statement metrics in a note to their audited financial statements. The required information about climate-related risks also would include disclosure of a registrant's greenhouse gas emissions, which have become a commonly used metric to assess a registrant's exposure to such risks.[11]

Need for Continued State Alignment

Duke Energy has operated dual-state systems across North Carolina and South Carolina for over a century, and the Companies believe that this model is the most optimal and efficient way to provide reliable, efficient and increasingly clean energy to its customers at affordable rates. For example, North Carolina customers have received the benefits of (and paid rates that incorporate an allocated cost to

[9] S&P Global, ESG Credit Indicator Report Card: Power Generators, https://www.spglobal.com/_assets/documents/ratings/research/esg-rc-for-public-site-power-generators.pdf (November 19, 2021).

[10] *Id.* at 4.

[11] U.S. Securities and Exchange Commission, *SEC Proposes Rules to Enhance and Standardize Climate-Related Disclosures for Investors* (March 21, 2022), https://www.sec.gov/news/press-release/2022-46.

build and operate) significant carbon-free generation located in South Carolina. Six of the Companies' combined 11 carbon-free baseload nuclear units totaling over 5,600 MW are located in South Carolina. The 1,400 MW Bad Creek pumped storage hydroelectric station located in Oconee County, South Carolina, provides essential energy storage capabilities to the system allowing for more reliable and economic system operations.

As explained in the Executive Summary, the benefits of these dual-state systems speak for themselves: reliable and safe electric service; rates below national averages; and a relatively low carbon intensity fleet – including nation-leading amounts of nuclear and solar generation located in North Carolina and South Carolina. Together, these features constitute a strong foundation upon which to continue providing increasingly clean energy to customers in the Carolinas and to attract new customers with clean energy targets, thereby maintaining the region's competitive advantage in economic development. There can be no doubt that the energy transition supported by the Companies and many of their customers will be more effectively and efficiently achieved through continued dual-state planning and coordination.

Therefore, because the DEC and DEP systems operate across state lines, Duke Energy necessarily must plan its systems for a single future under the joint oversight of the Commission and the PSCSC. As this Commission is aware, the Companies initially pursued a joint proceeding with the PSCSC as described in their petition in Docket Nos. E-2, Sub 1259 and E-7, Sub 1283. Although the requested joint proceeding was a unique and novel procedural path, the intended outcome was that both state commissions could hear the same evidence and make independent decisions regarding – dual-state planning for the Companies' customers in North Carolina and South Carolina – a path that would continue the dual-state system planning and operation that has benefited customers in the Carolinas for generations. However, because the procedural complexities presented by the potential joint proceeding, in some cases, prevented stakeholders from focusing on the important resource planning issues that the Companies sought to address through the joint proceeding, it became apparent to the Companies that the potential benefits of the joint proceeding were unlikely to be realized. Therefore, the Companies requested, and the Commission allowed for the withdrawal of the petition. In doing so, the Commission observed

> "The DEP and DEC systems, each of which operates as a single integrated system across both North Carolina and South Carolina, for many generations have provided reliable, efficient, and affordable electricity to the residents of both states. As the electric industry continues its transition, if the benefits of the dual-state systems are to be maintained, then coordination in planning would seem to be an important step. For these reasons, engagement with the PSCSC to consider and examine the benefits of continued system-wide planning and operation for Duke's customers in both States, in a manner that is consistent with applicable South Carolina law and North Carolina law and respectful of the jurisdiction and sovereignty of each State could be worth exploring."[12]

[12] Order Accepting Withdrawal of Petition for Joint Proceeding, Docket Nos. E-2, Sub 1259 and E-7, Sub 1283, at 2.

The Companies agree with this perspective and are committed to continuing to work to achieve continued alignment through a future South Carolina IRP. More specifically, the Companies' comprehensive South Carolina IRPs are targeted for filing in 2023 and will reflect the Carbon Plan approved by this Commission on or before December 31, 2022 (see Chapter 4 (Execution Plan) for a summary of proposed future Carbon Plan and IRP proceedings).

As is also explained above, the energy transition that will occur in the context of HB 951 is a continuation of a transition already underway and approved by the PSCSC, and the Companies are hopeful that the PSCSC will ultimately similarly find the continued energy transition to be in the public interest under South Carolina law. If continued alignment cannot be achieved and the PSCSC ultimately determines that it desires a future resource mix that is fundamentally different than the future resource mix approved by the NCUC, it will raise questions about whether the states will need to separately plan to meet the respective customers' needs, which could result in the ultimate separation of the utilities. This approach could increase costs and will, in general, make the energy transition less efficient.

Nevertheless, in such an extreme scenario in which a transition to separate state planning is required, the Companies will continue to diligently pursue compliance with HB 951's targets and believe that such targets are achievable even in a scenario in which the Companies are prescribed to pursue compliance on a North Carolina-only basis. Importantly, the near-term procurement and development activities proposed in this Carbon Plan are "no-regrets" resources – meaning that such investments will be needed in both a scenario in which dual-state planning continues and one in which dual-state planning is modified. In summary, the continuation of the energy transition that will be facilitated through the Carbon Plan is prudent, reasonable and in the best interest of customers. Continuation of a dual-state system will deliver benefits for customers, including by providing the most efficient pathway for the continued energy transition, and the Companies will pursue all available avenues to ensure continued alignment.

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.

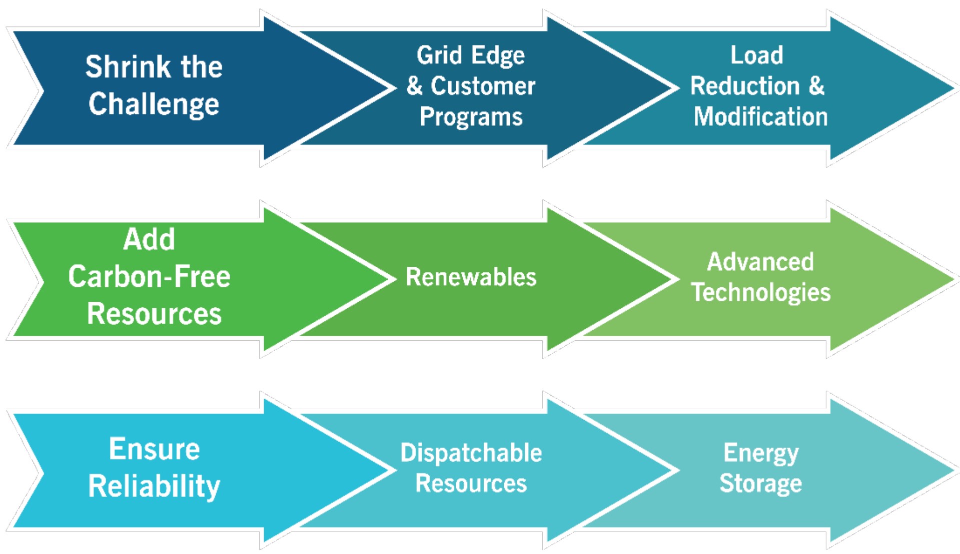
Of note, the inputs, assumptions, and modeling framework utilized to develop the Plan represent a snapshot in time as of late 2021 to early 2022 and are subject to change in future Plan updates given the extremely dynamic nature of the energy industry and supply chain both domestically and globally. 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

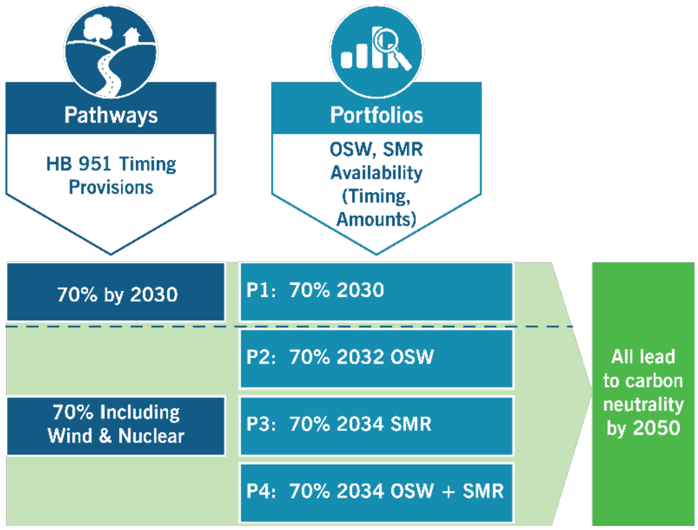


In preparing the Carbon Plan, the Companies utilized the three-pronged approach presented in Figure 2-1 and designed resource planning pathways and portfolios for the Commission's consideration to achieve core Carbon Plan objectives (CO_2 reduction, affordability, reliability and executability) at the 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

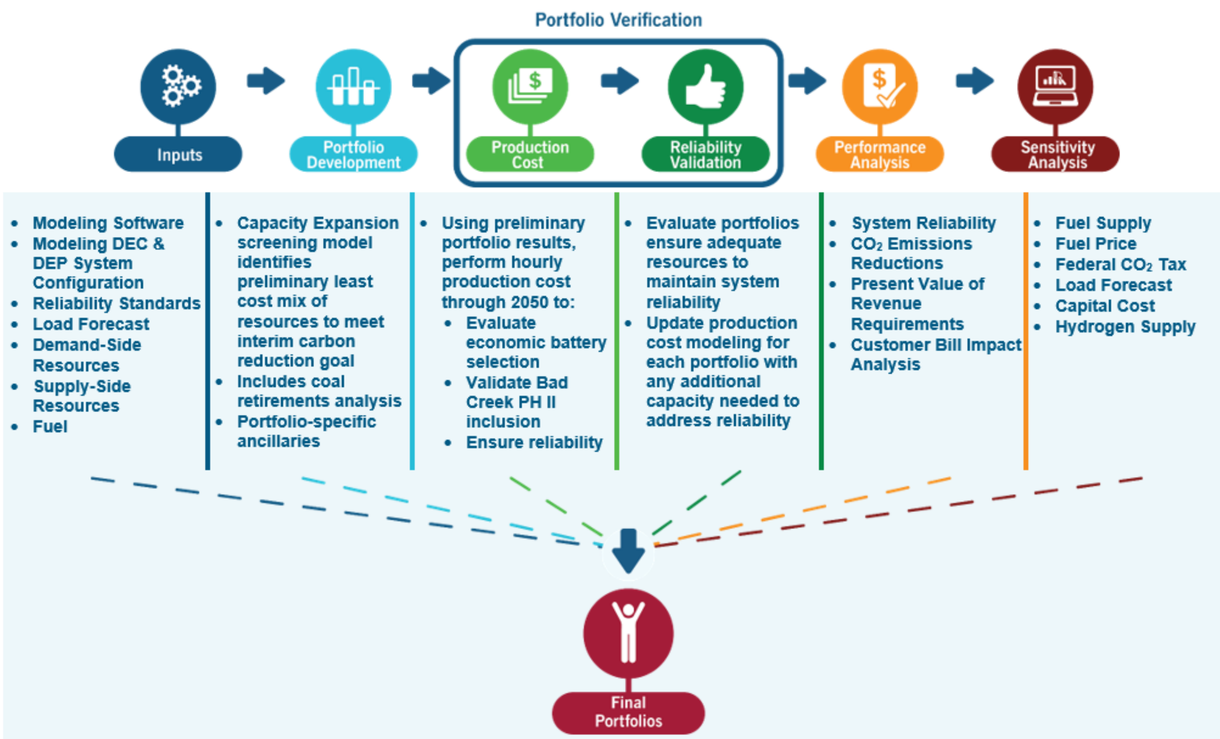
The Companies used the EnCompass capacity expansion and production cost simulation software package ("EnCompass") as the primary modeling tool for the development and analysis of the Carbon Plan portfolios.[5] The capacity expansion model and the production cost model are separate modules within Encompass 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	
H2	• 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.

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>EE 1% of eligible retail sales</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 rowspan="2">IVVC growing to 96% (DEC) and 97% (DEP) circuits</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>Winter DR & CPP</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>EE 1% of eligible retail sales</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">IVVC growing to 96% (DEC) and 97% (DEP) circuits</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>Winter DR & CPP</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)

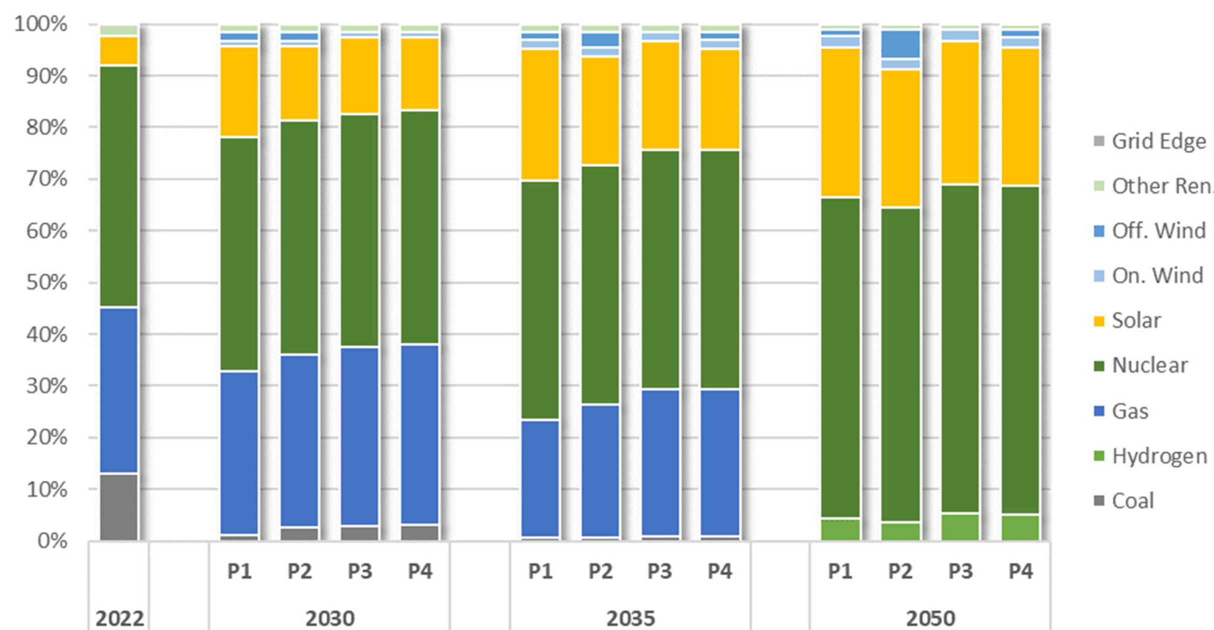
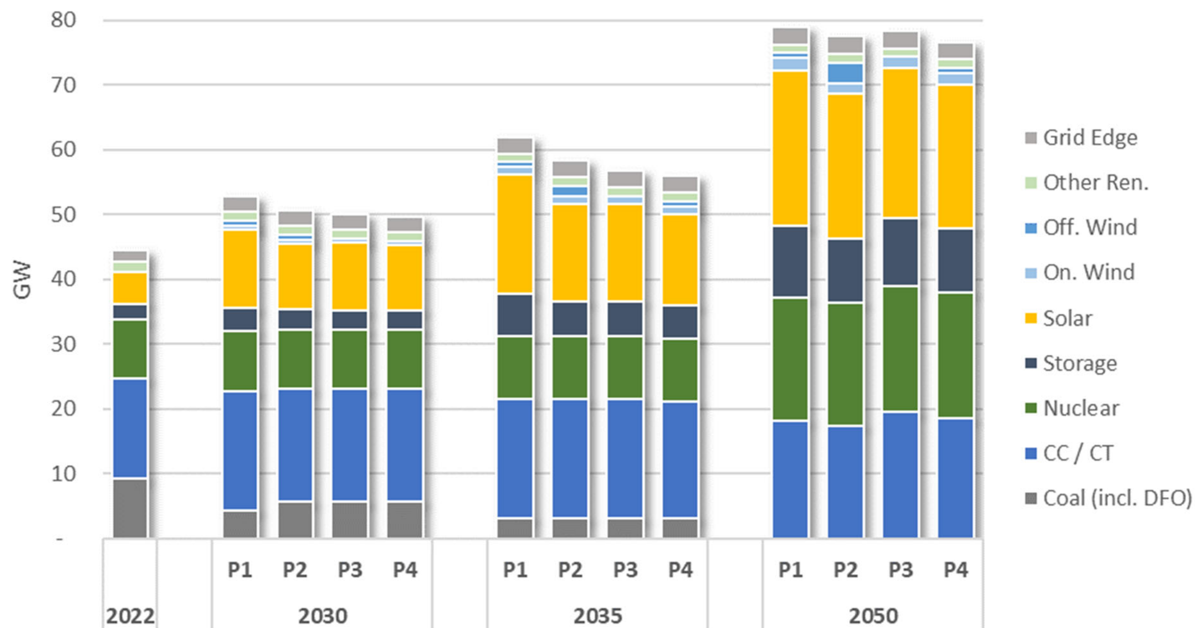


Figure 3-4: Capacity Mix by Portfolio, Combined Carolinas System (GW basis)



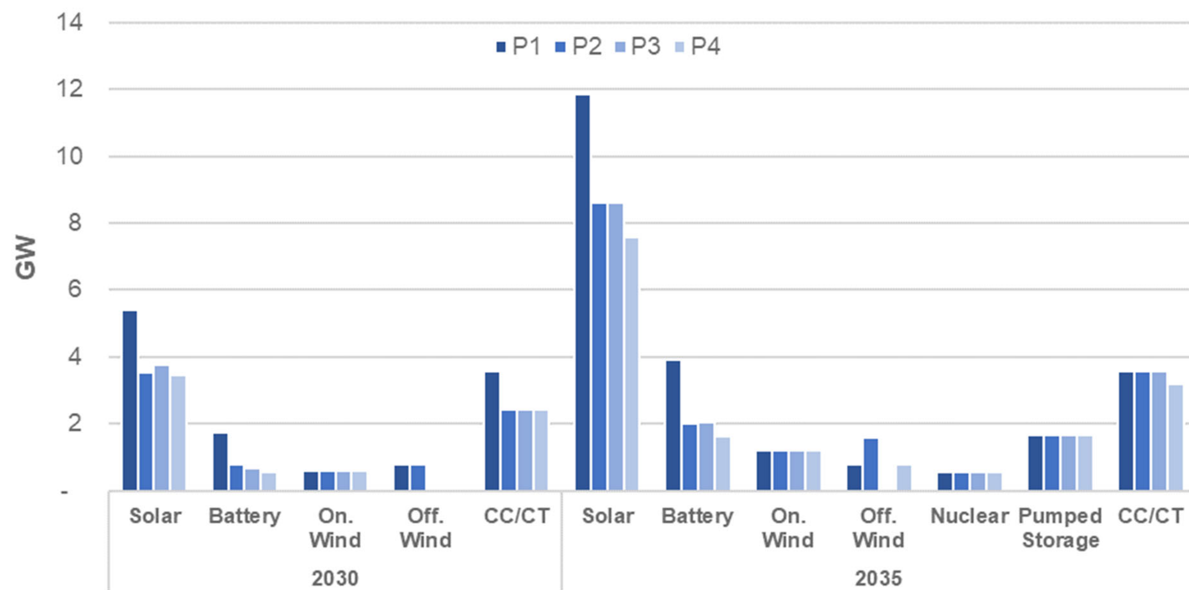
As indicated above, all portfolios result in very similar energy and capacity mixes over the long-term. By 2050, all portfolios call for an extensive expansion of solar and solar plus storage resources on the system (22,200 MW to 24,000 MW total), as well as the introduction of wind energy into the Carolinas' 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

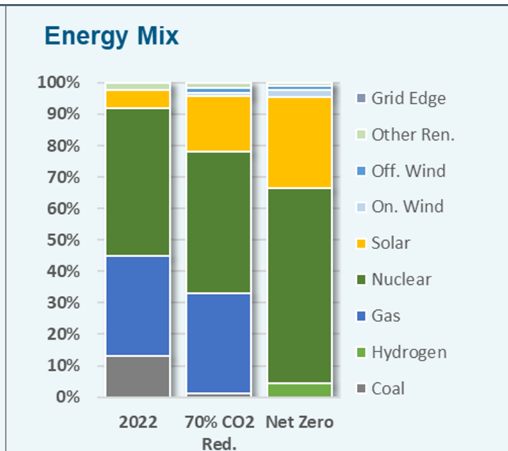
This section includes summary descriptions of modeling results for each of the four Carbon Plan portfolios. Appendix E (Quantitative Analysis) provides additional detail on development of the portfolios and portfolio-specific results. A portfolio summary table is presented for each portfolio identifying (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.

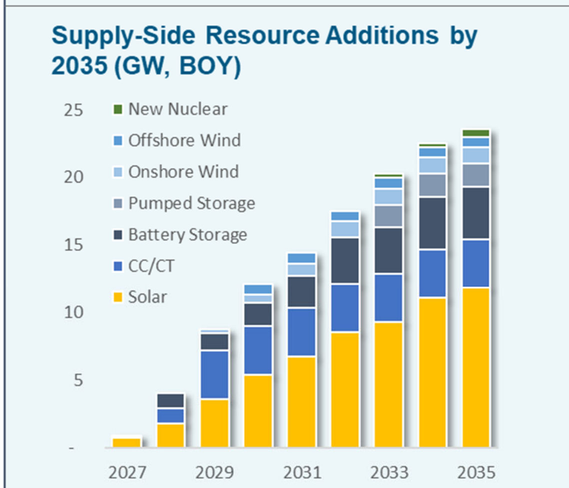
Portfolio 1: "70% by 2030"

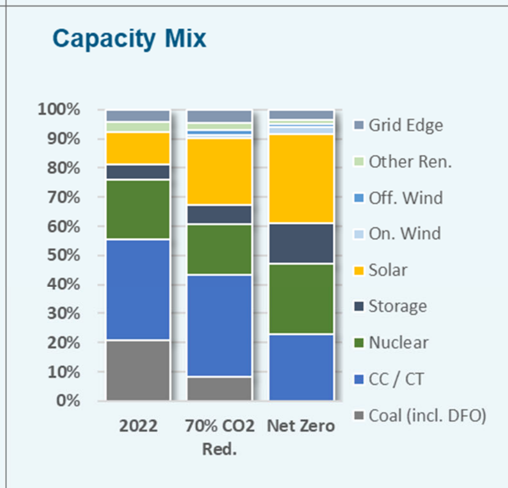
Portfolio 1 targets achieving the 70% CO_2 emissions reductions by 2030. To meet this aggressive target, P1 requires 800 MW (one 800 MW block) of offshore wind to be placed in service by year-end 2029, new solar interconnections ramping up to 1,800 MW/year by year-end 2028 (approximately 2.5 times the 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	







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

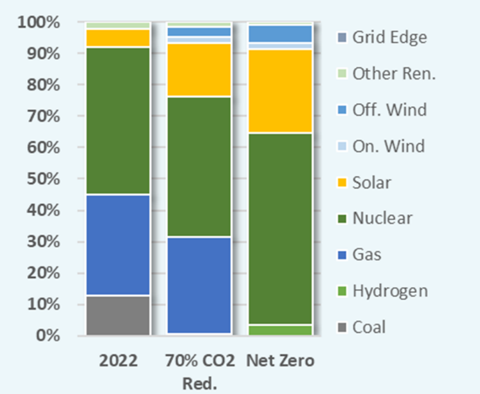
Portfolio 2: "70% by 2032 OSW"

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.

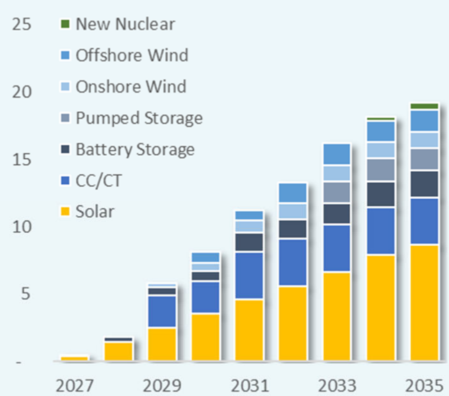
Figure 3-7: Portfolio 2 Summary

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	

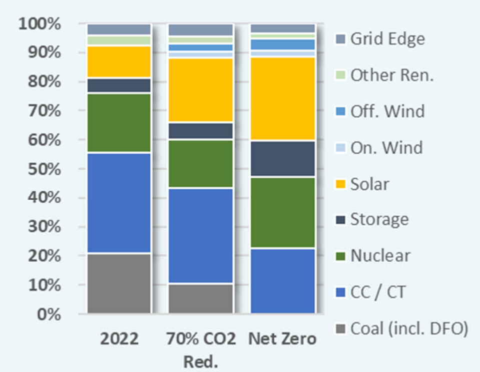
Energy Mix



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	--	--	1,409	1,318	--	--	2,220

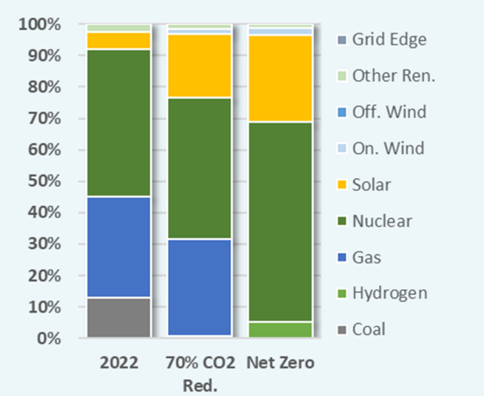
Portfolio 3: "70% by 2034 SMR"

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.

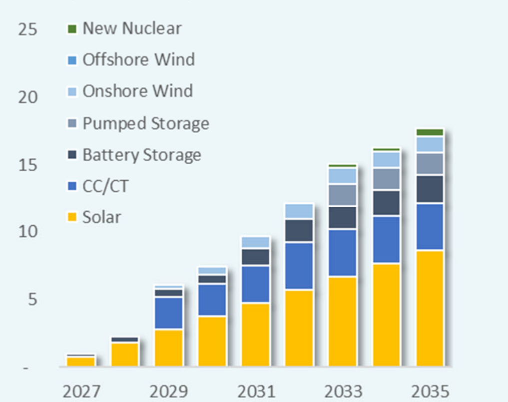
Figure 3-8: Portfolio 3 Summary

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	

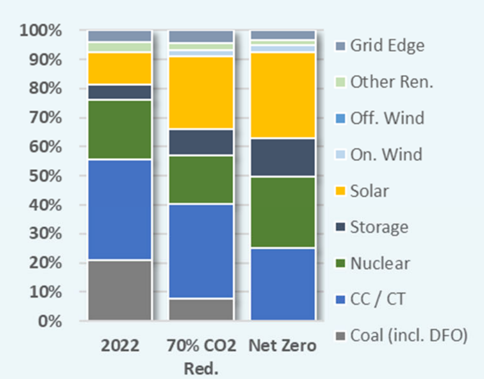
Energy Mix



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

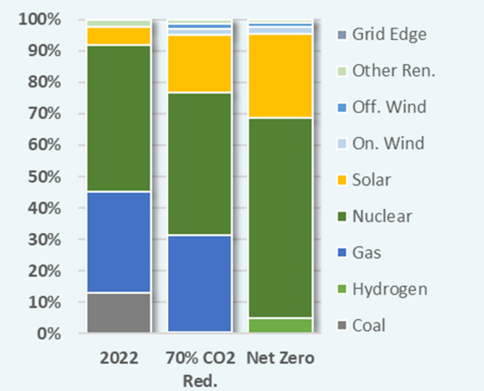
Portfolio 4: "70% by 2034 OSW+SMR"

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.

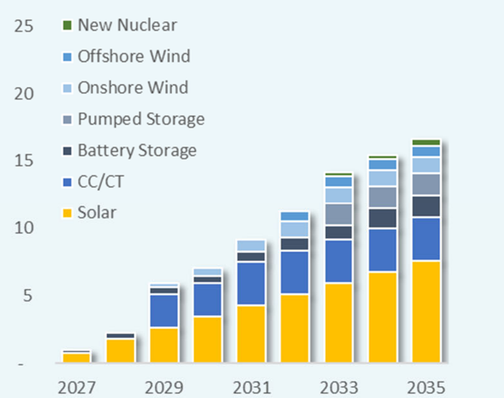
Figure 3-9: Portfolio 4 Summary

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	

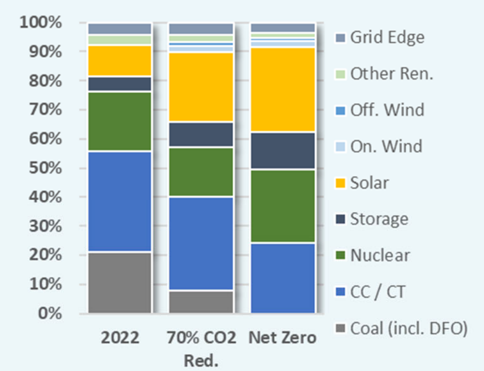
Energy Mix



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:

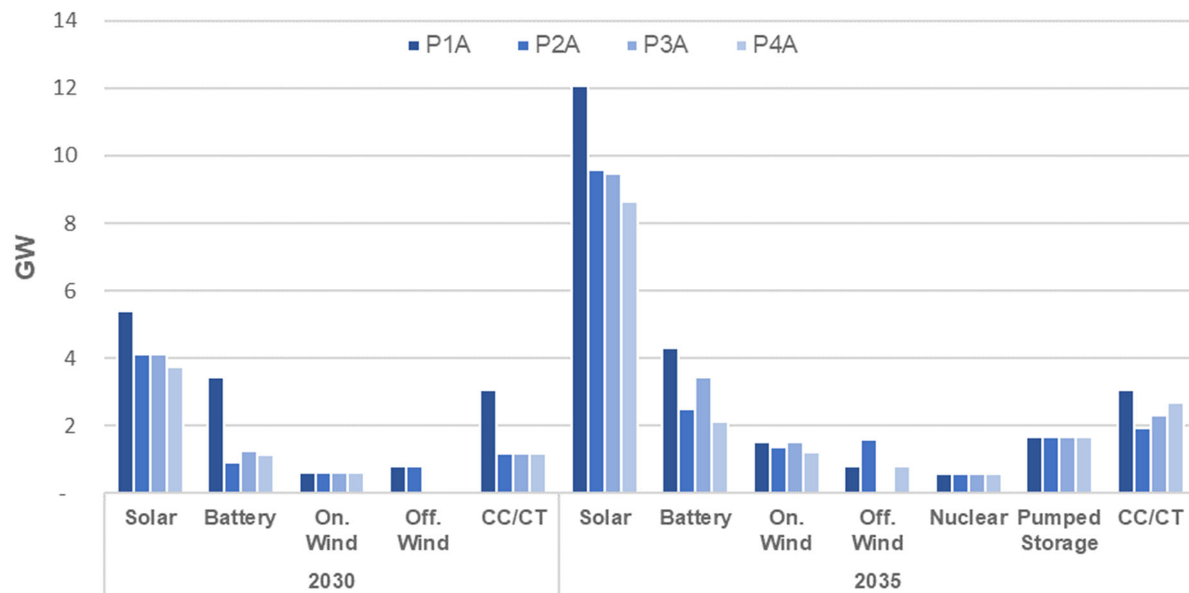
- Adjusted load forecast (portfolio sensitivity);
- Adjusted natural gas price (production cost sensitivity);
- Potential federal carbon tax policy (production cost sensitivity); and
- Hydrogen fuel supply sensitivity analysis.

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.

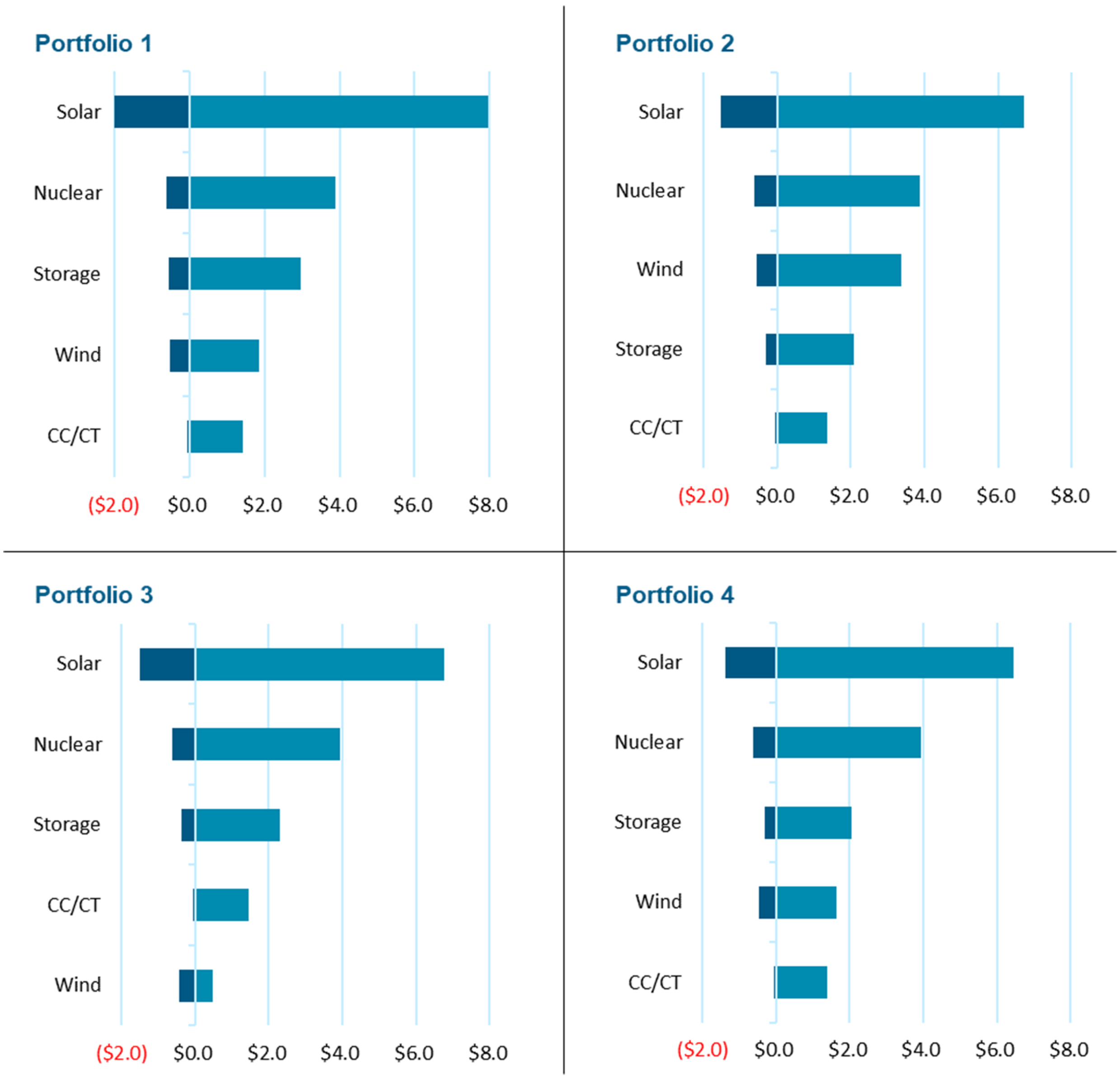
The Companies developed high capital cost forecasts for each technology using the greater of the Companies' internal estimates and EIA's 2022 projected technology costs[1] as starting points. The EIA costs are higher than the Companies' internal cost estimates for all technologies except solar and battery 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

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[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

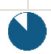
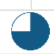
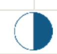
The following sections provide a comparative summary of results across portfolios followed by an evaluation of portfolio performance and tradeoffs with respect to the established core Carbon Plan objectives.

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

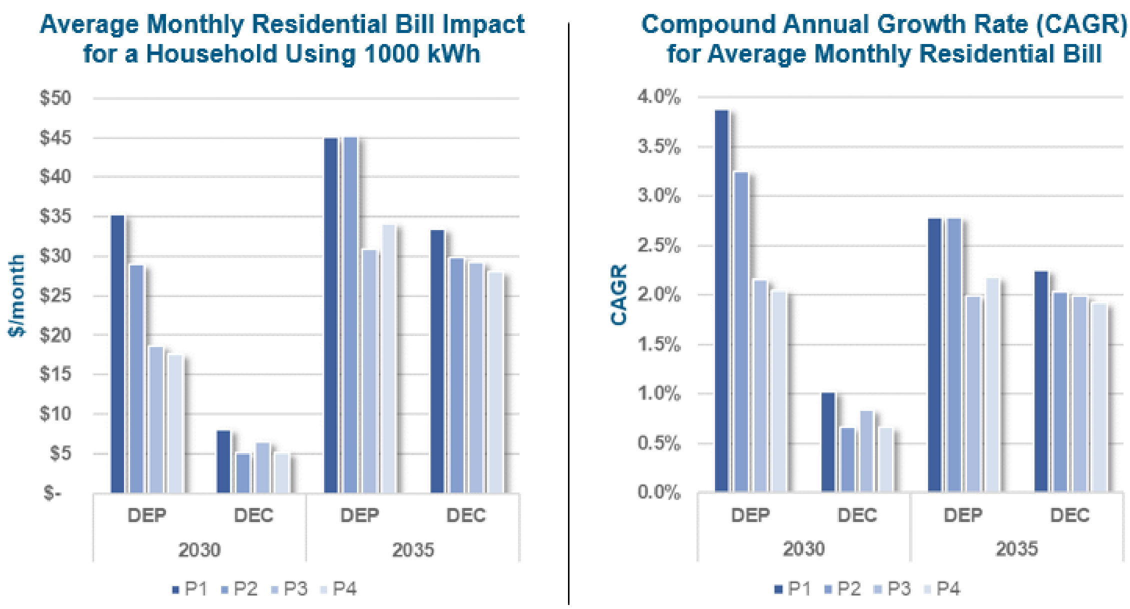
CARBON PLAN PORTFOLIOS	P1		P2		P3		P4	
RESOURCES [MW] START OF YEAR (2030 | 2035)								
Total Contribution from Grid Edge and Customer Programs[1]	3,486	4,230	3,486	4,230	3,486	4,230	3,486	4,230
Total System Solar[2, 3]	12,307	18,829	10,432	15,604	10,657	15,604	10,357	14,554
Incremental System Solar (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

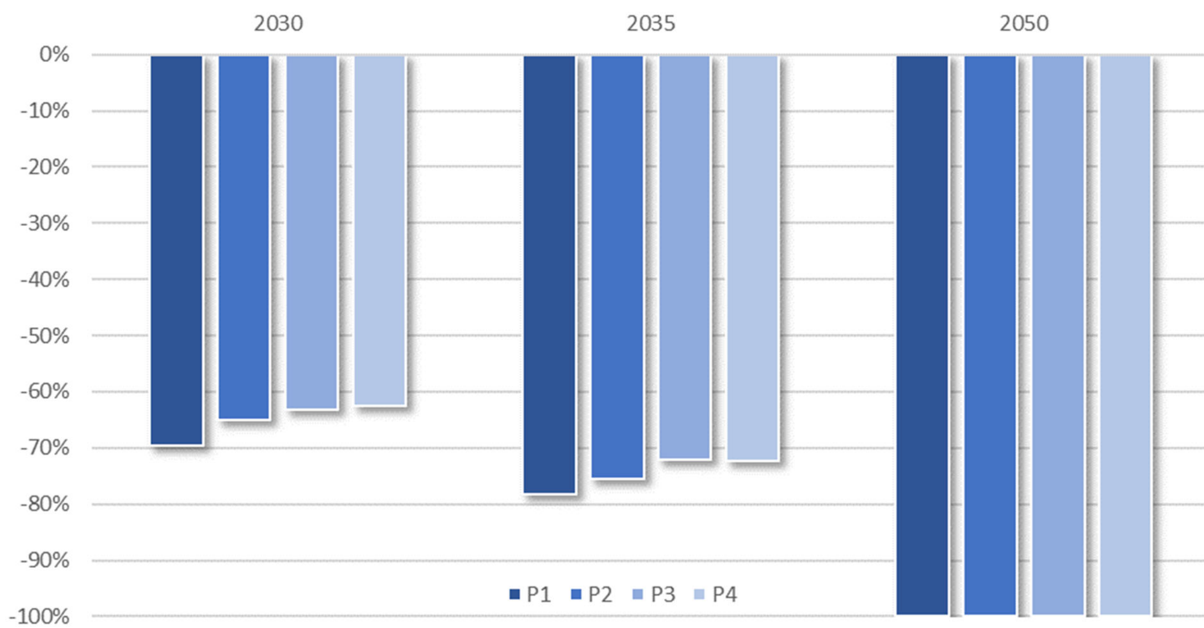


The benefit of accelerated emissions reductions achieved in Portfolio 1 requires very aggressive pre-2030 deployment (and increased levels of investment) for battery energy storage, incremental annual solar, as well as the pre-2030 siting, development and interconnection of offshore wind resources. Figure 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



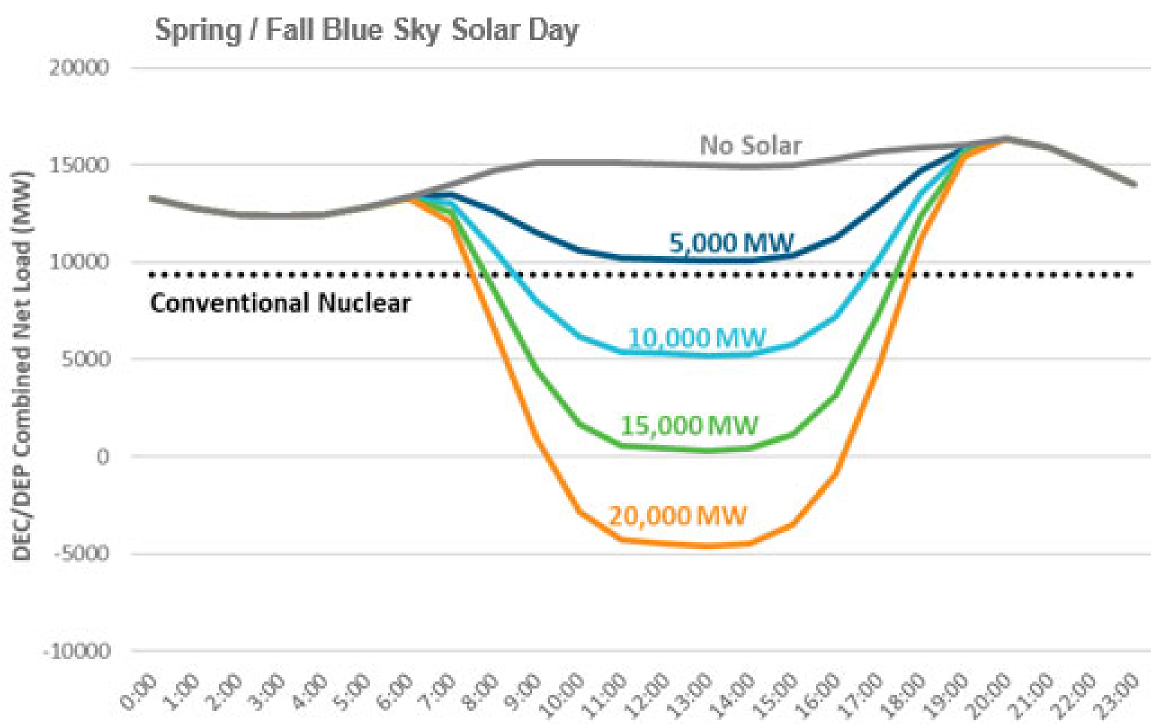
As shown in Figure 3-13, Portfolio 1, which targets 70% CO_2 reduction by 2030 and includes more aggressive near-term adoption of new, carbon-free generation, achieves somewhat greater emissions reductions than Portfolios 2 through 4 in 2035. Notably, all four portfolios exceed the 70% interim target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

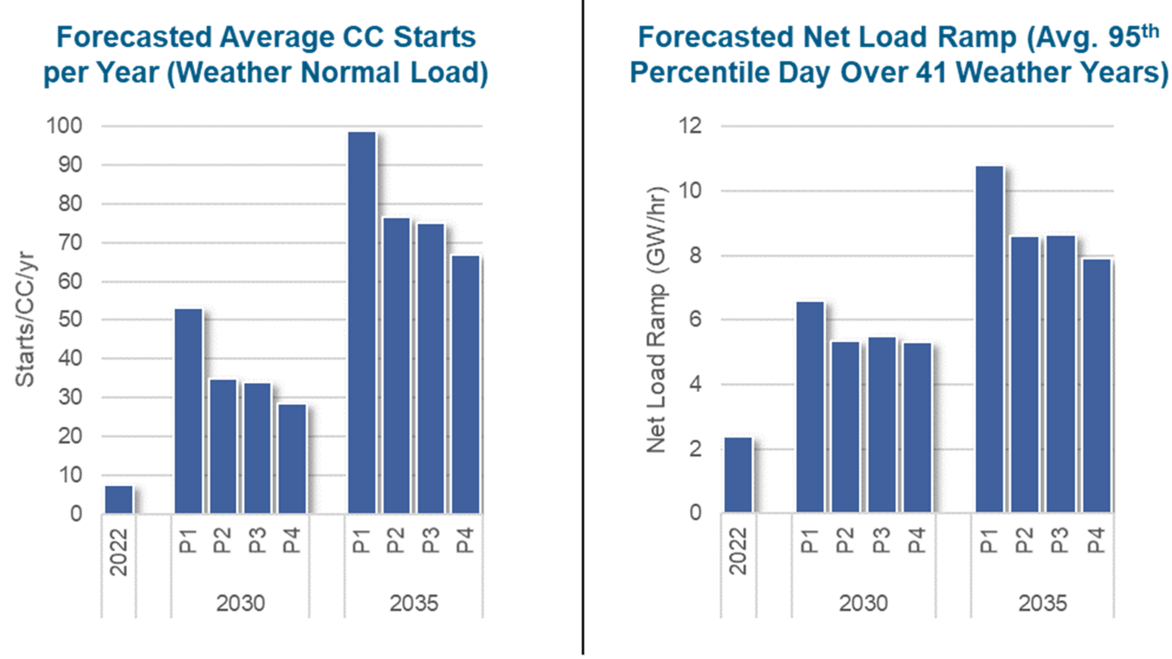
Figure 3-14: Spring Low Net Load Examples with Different Levels of Installed Solar Capacity



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

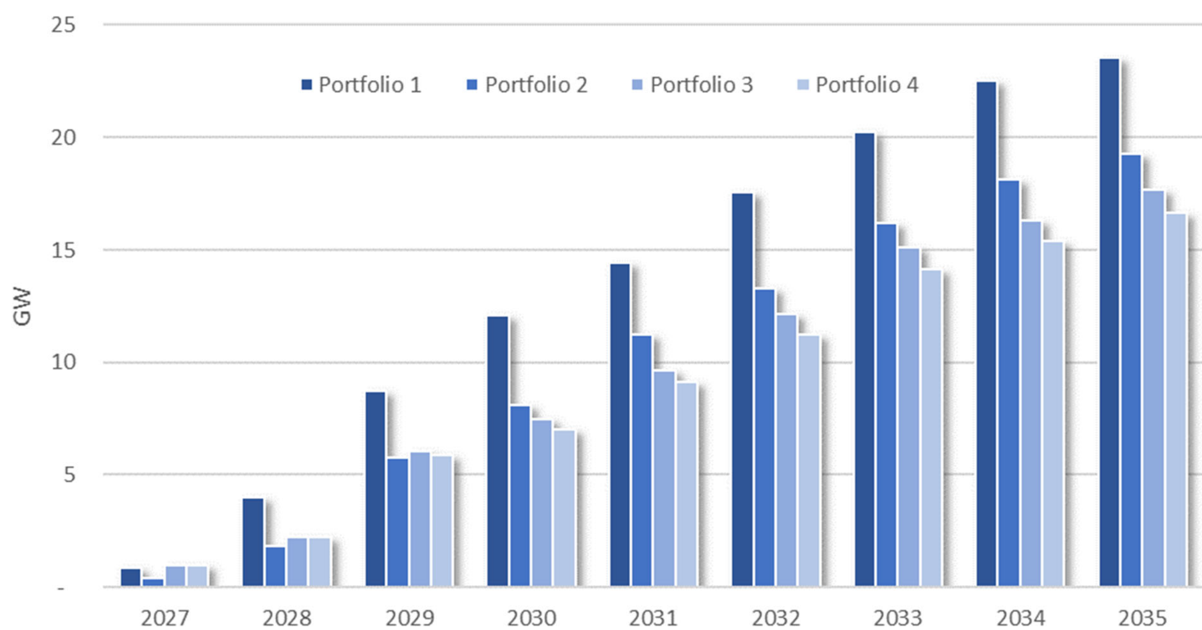


The greater net load ramp and CC starts associated with the more rapid adoption of new renewable energy resources required for Portfolio 1 will create additional flexibility challenges and operational risk. This correlation in the pace of renewable adoption and the increase in both system hourly ramping 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)

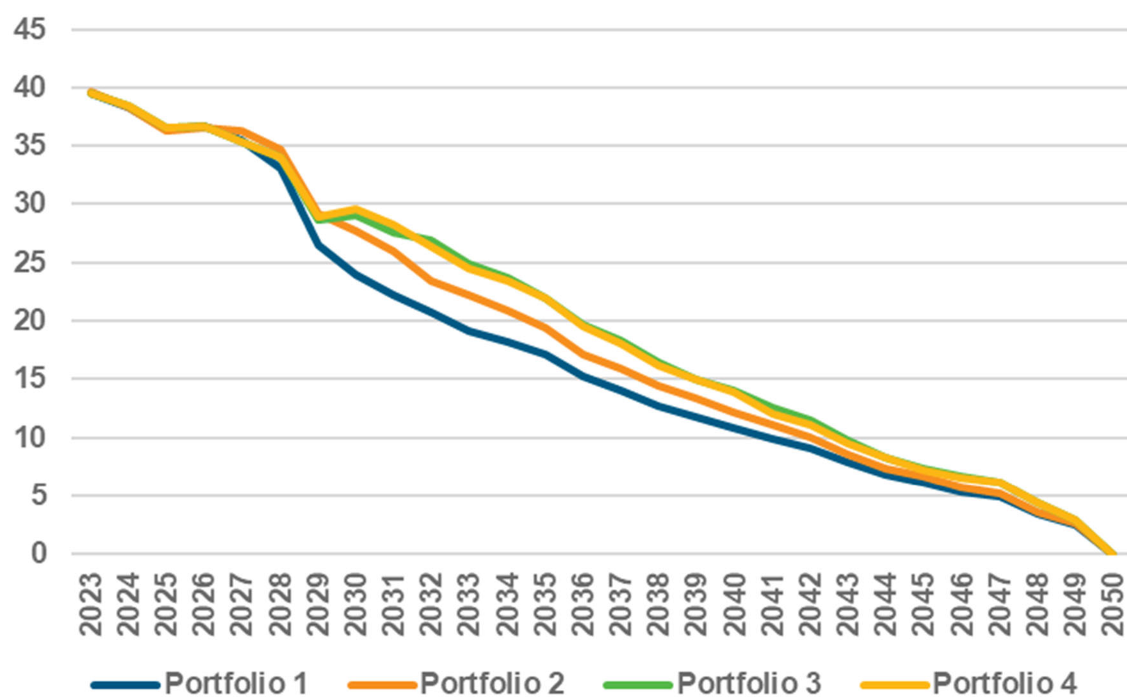


As Figure 3-16 shows, Portfolio 1 requires a significantly more rapid pace of new supply-side resource acquisition and deployment than is contemplated under any of Portfolios 2 through 4. As discussed in more depth in Chapter 4 (Execution Plan), this compressed timetable paired with significant development 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

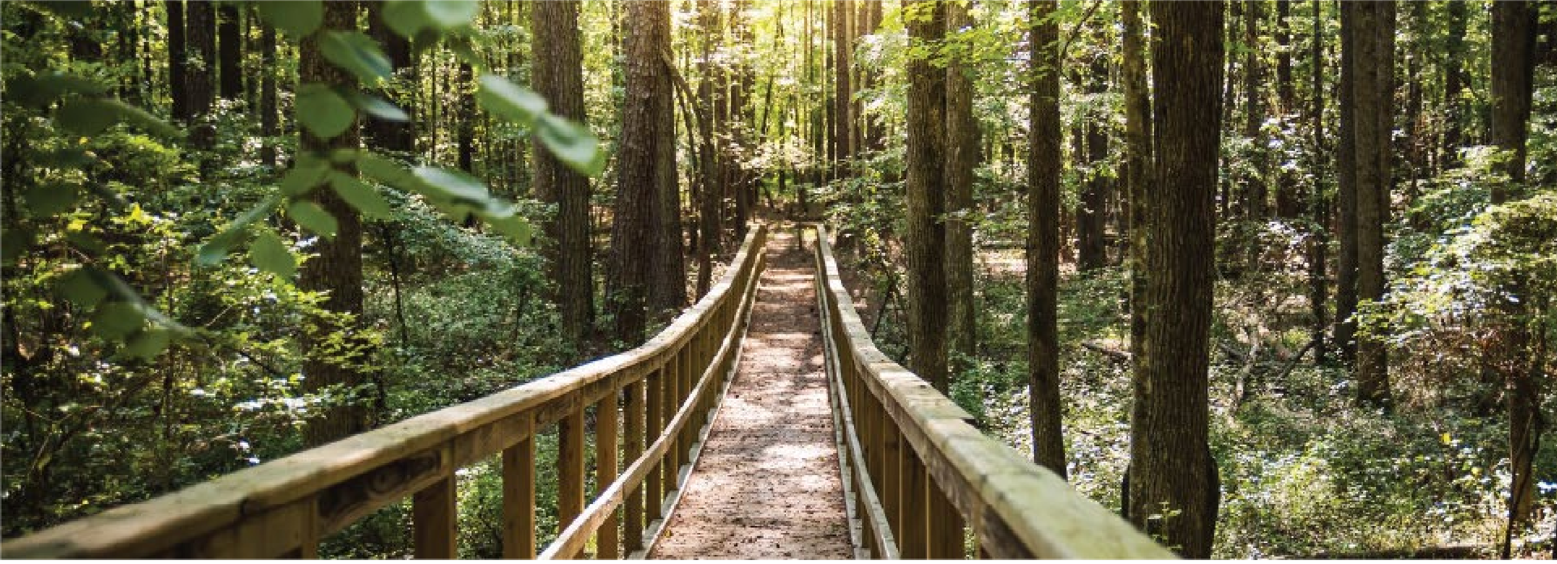
As discussed throughout this Chapter and in Appendix E (Quantitative Analysis), all portfolios across both CO_2 emissions reductions pathways require deployment of a diverse range of lower carbon intensity resources, including grid-edge resources and customer programs, renewables, energy storage, new 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.



4 Execution Plan

This Execution Plan identifies the actions and enablers that Duke Energy has identified as necessary to achieve the CO_2 emissions reductions and energy transition targets identified in the Carbon Plan, along with potential challenges. Successful execution of the Carbon Plan requires Commission approval of a defined set of near-term activities that are needed to affordably and reliably continue the energy transition and pursue HB 951's CO_2 emissions reductions targets.

This Execution Plan addresses a number of important implementation-related issues. First, the Execution Plan introduces the planning horizons for Carbon Plan execution, with information on monitoring risks and signposts to navigate uncertainty. Second, the Companies describe their approach to developing the near-term Execution Plan that is generally consistent with all pathways and portfolios. Third, the Execution Plan outlines near-term and intermediate-term actions, enablers and challenges across each of the following major components of the Carbon Plan:

1. Existing Supply-Side Resource Optimization
2. New Supply-Side Resources
3. Transmission System Planning and Grid Transformation
4. Consolidated System Operations
5. Grid Edge and Customer Programs

Finally, the Execution Plan addresses the Companies' plans for a longer-term planning strategy toward 2050 and concludes by proposing a strategy for future Carbon Plan updates to be filed biennially starting in 2024 with the Companies' next comprehensive IRPs.

Execution Planning Horizons and Navigating Uncertainty

This Execution Plan represents an evolution from the short-term action plan framework presented in past IRPs. More specifically, the Execution Plan provides the Commission and stakeholders a more detailed overview of the Companies' near-term, all-of-the-above, energy transition strategy for executing the Carbon Plan, as well as intermediate- and longer-term strategies to meet the interim CO_2 emissions reductions target and to achieve carbon neutrality by 2050. Through the sections that follow, the Companies describe the Carbon Plan execution actions and procurement strategies by resource type (supply-side resources, grid resources and demand-side resources) across three horizons:

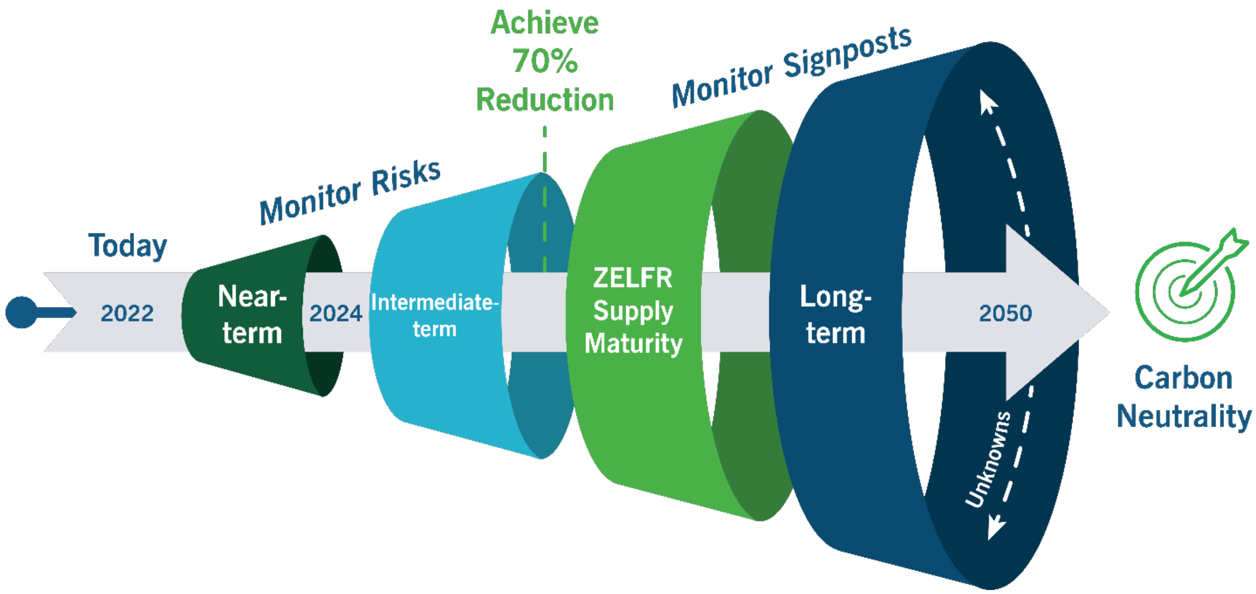
1. **Near-Term Actions** are those plans and legal/regulatory actions required in the 2022-2024 time frame to enable the development, procurement and integration of the resources identified as needed and in the best interest of customers across all pathways and portfolios. The Companies view these near-term actions as prudent and necessary to execute all pathways and portfolios and to stay on track to meet the Carbon Plan's intermediate and long-term CO_2 emissions reductions targets.

2. **Intermediate-Term Actions** reflect actions the Companies are planning to achieve the initial 70% interim CO_2 emissions reductions target under the Carbon Plan. For this planning period, this execution plan presents an intermediate-level view of the Companies' business planning and assessment of risks and legal/regulatory execution strategy for the Carbon Plan.

3. **Long-Term Planning** addresses strategies, considerations and signposts that the Companies are actively monitoring and plan to explore over time to help ensure the Carbon Plan achieves the least-cost path to 2050 carbon neutrality. For this long-term planning period, the Execution Plan presents high-level qualitative business planning and sign-post monitoring to ensure the Companies are on the least cost path to providing affordable, reliable emissions-free electricity to the Carolinas by 2050 and beyond.

The need to execute on the Carbon Plan to continue the energy transition and meet CO_2 emissions reductions targets requires the Companies to implement near-term activities while monitoring risks and signposts across all planning horizons, as illustrated in Figure 4-1 below and discussed in more detail later in this Chapter. While the long-term planning and modeling processes are able to assess many of these risks to make informed planning decisions, such modeling presents a resource planning "snapshot in time" and relies on numerous assumptions that become increasingly difficult to predict out into future years as the band of uncertainty widens with regard to technology, cost, policy, consumer trends and economic conditions. Risk and signpost monitoring will provide key information that will be used to check and adjust plans during future biennial updates of the Carbon Plan.

Figure 4-1: Execution Plan Time Horizons and Navigating Uncertainty



Overview of Near-Term Actions Supported by Pathways and Portfolios

Central to the Companies' Execution Plan are activities that are required in the near term and for which the Companies request approval under HB 951.[1] The near-term execution activities identified by the Companies are those that are generally consistent with all portfolios.

Due to the long lead times of new supply-side resources and their associated grid upgrade requirements, Commission approval of this near-term action plan and public policy support for needed transmission system upgrades are critically important for executing activities in the near-term that advance the deployment of resources in the 2026 through 2029 timeframe, and into the early part of the 2030s. The accelerated time frame to deliver new resources, along with the interdependencies between generation and transmission needed to achieve the target in service dates presented in the Carbon Plan, underscores the importance of Commission approval and support for near-term Execution Plan activities in this initial Carbon Plan.

Importantly, many of these actions are interdependent on one another to achieve the CO_2 emissions reductions targets while maintaining or improving upon the adequacy and reliability of the system. For example, coal facilities cannot be retired independent of the timely in-service of adequate replacement capacity, along with any needed upgrades to the transmission system to ensure bulk power system reliability is maintained. Though near-term Execution Plan activities can be organized in independent categories, many are interrelated to fully achieve Plan targets. Finally, the Carbon Plan is a long-term plan, so the dates and quantities in the portfolios should be considered directional and not exact. The specific resources (technology, design, capacity) to be developed and optimal in-service dates will be

[1] HB 951, Section 1(1) (directing that "new generation facilities or other resources [shall be] selected by the Commission in order to achieve the authorized reduction goals . . .")

refined through the development and siting processes as Plan components are executed, considering a multitude of practical factors that are beyond the scope of the long-term planning process presented in the Carbon Plan. As more information is gathered through execution, the Companies will keep the Commission apprised of material developments through future biennial Carbon Plan updates, as well as through seeking resource-specific regulatory processes or approvals (e.g., a CPCN proceeding).

Optimizing Existing Supply-Side Resources

All portfolios require retiring coal units, expanding the flexibility of existing gas units, and subsequent license renewals ("SLR") for existing nuclear generation units that provide over 10,000 MW of zero-carbon, cost-competitive capacity through 2050 to achieve CO_2 emissions reductions targets. Importantly, coal unit retirements are dependent upon the replacement of their capacity that maintains or improves system reliability.

New Supply-Side Resources

As explained in the Executive Summary and re-introduced above, the Companies have identified a proposed set of near-term activities for supply-side resources as part of the Carbon Plan for which the Companies request Commission approval. Table 4-1 below provides a summary of the proposed near-term actions with respect to these supply-side resources and delineates the supply-side resources that the Companies request to be selected by the Commission and the project development activities proposed by the Companies for Commission approval.

Table 4-1: Supply-Side Resources Requiring Actions in Near Term

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2029		
Carbon Plan Solar	3,100 MW	• Begin Public Policy Transmission projects in 2022[6] • Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage
Battery Storage	1,600 MW	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar
Onshore Wind	600 MW	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024
New CT[1]	800 MW	• Submit CPCN for 2 CTs totaling 800 MW in 2023
New CC[2]	1,200 MW	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability
Proposed Resource Development: Options for 70% Interim Target		
Offshore Wind[3]	800 MW	• Secure lease • Initiate development and permitting activities for 800 MW[7] • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission
New Nuclear[4]	570 MW	• Begin new nuclear early site permit ("ESP") for one site • Begin development activities for the first of two SMR units
Pumped Storage Hydro[5]	1,700 MW	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing

Notes:
1 – CPCN for two CTs (800 MW) estimated for in-service 2027-2028.
2 - CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
3 – Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
4 – New nuclear capacity represents first two SMR units, planned in-service date through 2034.
5 – Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
6 – Projects subject to North Carolina Transmission Planning Collaborative ("NCTPC") approval.
7 – Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan ("SAP"); or ii) a combined SAP and Commercial Operation Plan.

Achievement of the 70% interim target will require decisive near-term procurement and development actions across various new supply resources.

In the case of those supply side resources with potentially shorter or more defined lead times—solar, energy storage, natural gas, and onshore wind—the Companies are requesting the Commission to “select” a defined amount of such resources, and have proposed substantial near-term development and procurement activities consistent with such defined amounts. The Commission will have further opportunity to assess such projects through future CPCNs, or through other regulatory processes as deemed necessary.

In the case of supply-side resources with longer lead times and greater external dependencies – offshore wind, SMRs, and pumped storage hydro – substantial development work will be needed in the near-term to maintain optionality and the in-service dates contemplated in the Plan. However, the Companies are not requesting the Commission to “select” such resources at this time. Initial development work is needed both to gather information to provide a more refined cost estimate to the Commission, as well as to be positioned to implement such resources on a timeline consistent with the portfolios. Stated simply, if the Companies do not undertake development activities in the near-term for these long-lead-time resources, these new resources will not be available on the timelines contemplated by the portfolios. But it is also important to note that all three resources are likely to be needed to achieve carbon neutrality by 2050, and therefore, the development work performed in the near term is likely to be needed as the Companies progress the energy transition towards carbon neutrality.

The nature and scope of the development activities needed in the near term with respect to each of these three longer-lead time resources varies and is described in greater detail in this Execution Plan, as well as the respective technology appendices. In the case of SMRs, near term action is needed, primarily to perform a new nuclear siting study (or studies), conduct final technology evaluations, and prepare and submit a nuclear early site permit (“ESP”) application for one site. In the case of pumped storage hydro, near-term action is needed to complete the Bad Creek II feasibility study and determine and refine the potential EPC strategy.

While the assumed timelines for all the longer-lead time items are aggressive, the timelines for offshore wind assumed in the Plan, informed by stakeholder input, are extremely aggressive, particularly under P1. Achievement of such timelines will require the immediate commencement of more substantial development activities in the near term. Substantial development work is needed both for the offshore wind site and for the associated onshore transmission and interconnection facilities. Furthermore, due to the limited number of potential wind energy areas (“WEA”) available, it will be necessary for the Companies to secure a WEA lease in the near term (assuming consistency with the estimated costs in the Carbon Plan modeling). Without securing a WEA lease in the near-term and initiating key project development activities, it will be impossible to even have the potential to achieve the offshore wind timelines assumed in the modeling.

Once again, all of these near-term development activities are needed if the Commission desires to preserve the potential for these resources to be utilized in achieving the 70% interim target on the targeted timelines. Approval of such development work does not mean that the Commission is thereby "selecting" these long-lead time resources for purposes of this initial Plan. Instead, such activity will allow the Companies to take additional critical steps toward refining the final cost estimates and then to present such information to the Commission in the biennial 2024 Carbon Plan update. Importantly, if the Commission ultimately determines that one or more of these resources is not part of the least cost path to achieve the 70% interim target, such resources will nevertheless likely still play a role on the pathway to carbon neutrality by 2050.

As stated in the Executive Summary, the Companies request that the Commission make the following three findings with respect to the proposed near-term project development activities and associated costs relating to long-lead-time new supply side resources:

(1) engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;

(2) to the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs[2] for recovery in a future rate case (including a return on the unamortized balance at the applicable Company's then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and

(3) that in the event such long-lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time.

This forward-looking approval is necessary and appropriate in this unique context where substantial development activities are needed in advance of final selection by the Commission in order to ensure that such resources can achieve commercial operation on a timeline consistent with the Companies' proposed portfolios and HB 951's targeted timelines. Such forward-looking approval is also consistent with N.C. Gen. Stat. § 62-110.7, which contemplates the Commission's preapproval of project development costs in connection with a potential nuclear electric generating facility.

With respect to (1), the Companies believe that the development activities proposed are reasonable and prudent because they are necessary to keep such long-lead time resources on a timeline that is consistent with the portfolios and HB 951, as explained in this Execution Plan and the related technology appendices. With respect to (2), while many of the project development costs to be incurred are capitalizable under applicable accounting rules, the Companies believe that it is appropriate to

[2] Duke Energy's use of the term "project development costs" is informed by N.C. Gen. Stat. § 62-110.7(a) and is intended to include all "costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs."

ensure full clarity that any such project development costs that are not capitalizable will be deferred for future recovery. Finally, with respect to (3), the Companies believe that it is appropriate for the Commission to find that, in the event such long-lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time. This outcome is also consistent with N.C. Gen. Stat. § 62-110.7(d), which mandates that, after preapproval of the incurrence of project development costs, the utility is entitled to recover such project development costs in the event such project is ultimately not required.

In summary, the Companies proposed initial procurement and development for new supply-side resources are “reasonable steps” that are generally consistent with pace of deployment contemplated across all portfolios but will also allow for subsequent adjustment based on Commission direction and other factors such as improvement in the current supply chain for key components such as solar panels, batteries, and offshore wind components; support for proactive transmission investments; reduction in inflationary pressures on key commodities required for the generation transition; and progress in permitting, engineering, and public acceptance for offshore and onshore wind development (including associated right of way for new high-voltage transmission). The Companies believe that this set of proposed near-term supply-side activities represent reasonable and prudent steps and a balanced approach that commits the Companies to procuring a meaningful amount of those resources while minimizing near-term cost and risk exposure for customers, as a more complete picture of the Carbon Plan forms over the next two years.

Transmission System Planning and Grid Transformation, Consolidated System Operations

Pursuing proactive transmission investments is a common critical path component to all portfolios necessary to integrate renewables and allow for the accelerated retirement of coal, as further described in Appendix P (Transmission System Planning and Grid Transformation). Additionally, the Companies plan to initiate regulatory proceedings in the near-term to implement a generation replacement queue process and to consolidate the Companies’ system operations functions to facilitate a more cost-effective and efficient energy transition for customers across all portfolios, as further described in Appendix R (Consolidated System Operations).

Grid Edge and Customer Programs

Commission support of the Companies’ planned near-term activities in the first prong of the planning approach, “shrinking the challenge” is critically important to achieving Carbon Plan targets through advancing available tools to reduce demand and modify load through enhanced and new Grid Edge and Customer Programs outlined in Appendix G (Grid Edge and Customer Programs). As highlighted earlier in this Carbon Plan and addressed in more detail in Appendix G (Grid Edge and Customer Programs), the Companies’ Carbon Plan modeling assumes nation-leading amounts of EE and DSM (targeting 4,230 MW of contribution by 2035 in all scenarios). These important enablers to CO_2 emissions reductions do not change across portfolios.

Detailed Execution Plan: Existing Supply-Side Resources

Retiring Existing Coal

Reducing risk for customers and achieving CO_2 emissions reductions targets will require continued retirement of the Companies' remaining coal units across North Carolina. As discussed in Chapter 3 (Portfolios), there is very little difference in the projected coal retirement dates across the portfolios, with all portfolios resulting in a full exit from coal-fueled generation by 2035 (retiring over 8,400 MW of coal capacity). Executing on these coal unit retirements must be coordinated with the development of new low-carbon and zero-carbon resources and transmission system improvements to maintain resource adequacy and reliability for customers.

In the near term, the Companies will work with existing coal and railroad suppliers to maintain service reliability and fuel assurance needed to maintain reliability as the Companies continue to plan their intermediate and longer-term coal unit retirement strategy. The Companies will also perform transmission evaluations, outlined in Appendix P (Transmission System Planning and Grid Transformation), to identify any necessary system improvements that are needed to allow coal unit retirement while ensuring bulk power system reliability is maintained. If transmission improvements are necessary, they must be factored into the retirement schedule.

Table 4-2 below describes the Companies' near-term and intermediate-term Execution Plan for coal retirements and additional information on how coal retirements were evaluated in Plan modeling is provided in Appendix E (Quantitative Analysis).

Table 4-2: Execution Plan – Coal Retirements

Near-Term Actions (2022-2024)	

2023	• Retire Allen Units 1 & 5
	  • DEC will retire Allen units 1 and 5 by the end of 2023, including completion of all regulatory notices and filings.
	  • Final retirement date is contingent upon completion of South Point switching station transmission project, already under construction

Intermediate-Term Actions (Achieve 70% Target)	

2025-2026	• Retire Cliffside Unit 5
	  • Planning analysis does not identify any major transmission upgrades to be required to retire Cliffside Unit 5
	• Complete environmental/operational projects necessary for coal unit retirements
	  • Marshall Station (DEC) - complete auxiliary steam boiler needed for Units 3 and 4 startup to allow Units 1 and 2 to retire;
	  • Roxboro/Mayo Stations (DEP) – complete auto-load tap changer enabled transformers at Harris Nuclear Plant to reduce necessary voltage support runs at Roxboro and Mayo plants

Intermediate-Term Actions (Achieve 70% Target)	
2027-2033	• Retire subcritical coal units (Marshall, Roxboro and Mayo) when replacement generation and supporting electric and/or gas transmission are in service

Expanding Flexibility of the Existing Gas Fleet

As coal units are retired and the integration of renewable resources increases, the flexibility of dispatchable gas-fired resources becomes an increasingly important resource for maintaining system reliability in a least-cost manner. Today, the Companies' gas-fired generation fleet consists of 55 CTs, nine CC units, and one combined heat and power ("CHP") unit, having a combined total capacity of 11,991 MW. To increase the flexibility of the existing gas-fired fleet, the Companies will need to equip a number of its CC/CT stations to support more flexible operational capabilities, such as lower load operations, increased ramp rates, and the ability to cycle more often to respond to increased variability in the output of renewable resources. In the near and intermediate term, the Companies will plan and implement gas unit control upgrades and equipment changes and seek regulatory approvals for operational and air permit changes.

Table 4-3 below outlines the Companies' near-term and intermediate-term Execution Plan to increase the flexibility of the existing gas fleet and additional information on the existing CT/CC fleet is provided in Appendix M (Natural Gas).

Table 4-3: Execution Plan – Existing Gas Fleet

Near-Term Actions (2022-2024)	
2022-2023	• Perform engineering studies and model impacts of heavy renewables integration on existing CC fleet • Submit air permit revisions to allow for increased flexibility of select CTs/CCs (run hours, turndown, etc.)
2022-2024	• Ensure long-term fuel security for existing CC and dual fuel optionality fleet • Implement smaller unit flexibility projects on existing CCs
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• Verify need and then implement larger Unit Flexibility projects on existing CCs

Extending the Life of Existing Nuclear Fleet with Subsequent License Renewal

Extending the life of the Companies' existing nuclear fleet is a bedrock assumption for the Plan, providing for the continuation of a major source of reliable, zero-carbon, cost-competitive power through 2050 in every portfolio. Accomplishing this important Carbon Plan objective requires federal regulatory approval of 20-year subsequent license renewals ("SLRs") for the 11 existing nuclear generation units operating at six nuclear stations across the Carolinas, totaling 10,773 MW of generation. The current operating licenses will begin to expire in the 2030s, and the regulatory process may take up to 4 years per SLR application. The Nuclear Regulatory Commission ("NRC") accepted the Companies' first SLR application for review in mid-2021 and is currently in the process requesting additional information to support its review. The Companies plan to develop and submit an SLR application for each nuclear station approximately every three years, with the remaining submittals tentatively planned for 2024, 2027, 2030, 2033 and 2036.

In addition to extending the operating licenses at each site, Duke Energy continues to optimize the use of power uprates where cost-effective. Several of the nuclear facilities (e.g., Harris, Robinson and Brunswick) have already been uprated extensively while the remaining facilities (e.g., Oconee, McGuire and Catawba) are at the early stages of being evaluated for major modifications to increase their power output. Uprates to the Oconee Nuclear Station for Measurement Uncertainty Recapture are included in the modeling for the Carbon Plan, which results in an additional 15 MW per unit over the 2022-2023 period. The remaining potential uprates would require extensive component replacement; therefore, more investigation is needed into the cost and timing of the potential projects. If implemented, these power uprates would provide additional zero-carbon capacity and energy to Duke Energy's customers in the Carolinas.

Table 4-4 below outlines the Companies' near-term and intermediate-term Execution Plan to extend the life of the existing zero-carbon nuclear fleet and additional information is provided in Appendix L (Nuclear).

Table 4-4: Execution Plan – Existing Nuclear

Near-Term Actions (2022-2024)	
2021	• SLR Application for Oconee Nuclear Station submitted to NRC
2022-2023	• Implement Oconee Measurement Uncertainty Recapture
2023 – into intermediate-term	• Explore other potential uprates for Catawba and McGuire
Intermediate-Term Actions (Achieve 70% Target)	
2024-2025	• SLR Application for second nuclear plant to be submitted to NRC
2027-2028	• SLR Application for third nuclear plant to be submitted to NRC

Detailed Execution Plan: New Supply-Side Resources

The Carbon Plan identifies the need for a diverse portfolio of new zero- and low-carbon emitting generating assets across both pathways and all four portfolios. This section addresses the actions that the Companies intend to commence immediately in the near term and to continue over the intermediate term relating to the development and procurement of new supply-side resources. Note that each of the resources has an associated Appendix that provides further technical background regarding the resource.[3]

General Procurement Approach

The Execution Plan anticipates implementation of the Carbon Plan will include a range of procurement methods. Foundational to the procurement activities outlined below is the need to preserve customer value by pursuing least cost across each procurement action the Companies undertake. Specific categories of procurement include utility self-development, asset acquisitions and, for solar and solar paired with storage, solicitations for controllable purchase power agreements. In all cases, the information gained through the procurement process will be used to inform and refine future Carbon Plan analysis and filings. This iterative process involving subsequent procurement efforts and their associated regulatory proceedings informing future carbon plan updates will provide the Commission and the Companies with opportunities to adjust the pace and volumes of procurement activities in response to changing market conditions relative to planning assumptions at any given point in time.

Self-Development

In some cases, the Companies anticipate leveraging utility self-development for projects that are location specific, long lead-time resources that the Companies have evaluated for the best combination of siting, fuels, transmission and timing to meet their customers' future needs and to achieve CO_2 emissions reduction goals. Self-development will leverage the Companies' existing property, station workforce, electric and/or gas transmission, access to water, permits, etc. to the benefit of customers. For self-development projects, the Companies will be responsible for project siting and development, managing permitting as well as obtaining engineering, procurement and construction ("EPC") services. The Companies have substantial self-development experience with internal processes to competitively bid major equipment and EPC services to ensure the best value for customers considering project specific costs and risks. The Companies may also pursue joint development projects in which a third-party development partner shares in the responsibility for project siting, development, permitting and engineering, but the Companies will have responsibility for procurement and construction activities. The Companies would also competitively bid construction services for joint development projects.

Asset Acquisition

The Execution Plan anticipates the potential for acquisition of resources from third-party developers and potentially existing asset owners. Asset acquisitions can be accomplished through procurements or bilateral negotiations and are generally utilized when there is flexibility as to where the assets are located and the market for development is more mature. Specific types of acquisitions for new assets include asset transfers, asset transfers plus EPC services, Build-Own-Transfers, and acquisition of operating assets. Details of each type of acquisition are further detailed below:

[3] *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.

- **Asset Transfer**: A third-party developer proposes to sell a fully developed project and is responsible for, but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, limited engineering, and all interconnection studies. The developer assigns or transfers all assets, rights, etc. to the Company upon satisfaction of all development and closing conditions, which generally occurs prior to the start of construction. The Utility is responsible for final engineering, procurement and construction of the facility.

- **Asset Transfer plus EPC**: A third-party developer proposes to sell a fully developed project and is responsible for, but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, engineering, all interconnection studies and all procurement and construction of the facility pursuant to an EPC Agreement. The developer and Utility enter into an agreement in which the developed project assigns or transfers all assets, rights, etc. to the Utility upon satisfaction of all development and closing conditions, which generally occurs prior to the start of construction. The parties also enter into an EPC Agreement in which the developer is responsible for final engineering, procurement and construction of the facility.

- **Build, Own, Transfer**: A third-party developer proposes to sell a fully developed and constructed, turn-key, facility. The developer is responsible for all project development activities, including but not limited to, project siting, land control, development, site investigation, surveying, title work, permitting, engineering and all interconnection studies. The developer and utility enter into a Built Transfer Agreement ("BTA") in which the developer is responsible for all development scope, engineering, procurement, and construction of the facility. The facility is assigned to the Utility at BTA closing, which is generally between mechanical completion and placed in-service milestones.

- **Acquisition of current operating facilities**: A third-party asset owner agrees to sell an existing facility already constructed and in operation by the facility owner to the Utility.

Solar Procurements for Controllable PPAs

The Companies will also leverage established and evolving competitive procurement processes to secure controllable PPAs from third-party owners of solar and solar paired with storage resources. Under HB 951, 45% of new solar generation selected by the Commission under the Carbon Plan is required to be owned by third parties and delivered to the Companies under controllable PPAs. The Companies have robust experience with procuring new third-party owned solar resources and have requested Commission approval to implement the 2022 Solar Procurement. Specific procurement actions including the anticipated procurement method are discussed in further detail in their respective resource subsections that follow.

Transitioning with Additional Dispatchable Natural Gas Resources

New dispatchable natural gas-fueled resources are needed under both Carbon Plan pathways and across all four portfolios in order to retire coal, reliably integrate renewables and maintain system reliability, as discussed in Appendix M (Natural Gas) and Appendix Q (Reliability and Operational Resilience Considerations). By 2035, all portfolios identify the need for at least 1,200 MW of new CTs (three advanced class CTs) and 2,400 MW of new CCs (two units). As further discussed in Chapter 3 (Portfolios), future access to Appalachian gas supports the need for developing an additional CC unit and the Companies plan to pursue access to Appalachian fuel supply in the near term as part of the new natural gas resource execution strategy discussed in Appendix N (Fuel Supply).

The Companies' near-term and intermediate-term Execution Plan for dispatchable new hydrogen capable natural gas resources, outlined in Table 4-5 below, presents an aggressive development timeline designed to enable the Companies to achieve commercial operation of two CTs by the end of 2027 and the first CC unit by the end of 2028. A select number of additional units will follow closely to provide dispatchable capacity needed to enable coal unit retirements outlined in the portfolios and provide system flexibility to back stand growing amounts of intermittent renewable resources on the system.

Assuming no material delays in siting and permitting, the timeline for construction of new natural gas-fueled generation is minimally five to six years, thus requiring the Companies to take immediate action to begin developing new CT and CC units to achieve the planned in-service dates. To meet these aggressive target in-service dates for dispatchable new gas assets and to achieve the planned coal unit retirement schedule, the Companies plan to self-develop the initial new CT and CC gas assets to be located on the Companies' existing sites. These initial CT/CC assets would be brownfield additions at existing power stations that can utilize the Companies' existing transmission, infrastructure, and workforce. The new replacement generation will be sized at similar or lower capacity than the existing coal generation to be retired, which would enable the Companies to use existing transmission and to net emissions from existing air permits. Importantly, the Companies are only commencing development activities at this time and will return to the Commission at a later date for a CPCN.

Table 4-5: Execution Plan – Natural Gas Assets

Near-Term Actions (2022-2024)	
2022	• Select Owner's Engineer • Begin preliminary site work • Begin CPCN preparations for two CTs (2027) and first CC (2028) across two sites
2022-2023	• Contract for interstate firm transportation fuel supply
2023	• Submit Interconnection Requests (expedited replacement generator process, if approved) • Begin preparation of air permit applications • Bid turbines • Submit CPCN applications for two sites (two CTs at one & one CC at the other) • Submit air permit applications at two sites

Near-Term Actions (2022-2024)	
	• Receive Facility Studies
2023-2024	• Contract for intrastate firm transportation fuel supply
2024	• Commence construction if CPCN approved • Award turbines- full NTP • EPC- full NTP • Receive Interconnection Agreement • Begin transmission build-out/modifications
Intermediate-Term Actions (Achieve 70% Target)	
2025-2027/2028	• Site construction
2025	• Transmission backfeed available
2027/2028	• Commissioning begins
EOY 2027	• First new CTs in service (brownfield site)
EOY 2028	• First new CC in service (brownfield site)

Intermediate-term actions beyond 2024 are dependent upon issuance of CPCNs to construct the new CT and CC units and other needed regulatory approvals including receipt of air permits. Once necessary regulatory approvals are received, the selected EPC contractor can begin construction. Transmission build-out required to support each facility must be completed in time to support back-feed, which will allow commissioning activities to begin. Once commissioning is complete, each site will be placed in service. The Companies will continue to assess development timelines and resource needs for additional CT/CC units and/or storage builds necessary to maintain system reliability depending on the pathway selected and the success of implementing other generation and non-generation solutions.

Procurement Plan – New Gas Assets

The time frame to meet the aggressive desired in-service dates (2027 for earliest CTs and 2028 for earliest CC) requires self-development activities to begin in 2022, generator interconnection studies and CPCN applications to be pursued in 2023 and likely does not allow sufficient time for bidding of new future sites through a RFP where all sites would need to progress through full DISIS Cluster Study and full transmission studies performed prior to awarding bids. Siting the initial CT/CC builds at brownfield sites will also leverage existing resources and mitigate transmission upgrades to retire existing coal units and to build new dispatchable capacity. For future CT/CCs, Duke Energy will also explore potential acquisitions of available capacity from existing or late stage developed gas generators to the extent such resources are available.

Significantly Expanding Utility-Scale Solar

As of December 31, 2021, approximately 4,350 MW of utility-scale solar (i.e., solar projects that are greater than 1 MW) are connected to the DEC and DEP systems and this level will need to grow to over 12,000 MW of solar capacity to meet the 70% interim target.

Looking beyond the solar resources that are already mandated by existing programs and procurements, the Carbon Plan portfolios identify the need for between 3,450 MW and 5,400 MW of incremental solar between 2026 and the start of 2030. These future solar resources will primarily be larger, transmission-connected projects with higher capacity factors than existing solar facilities, delivering significant zero-carbon electricity to the Companies' combined systems.

Achieving this significant level of solar capacity growth will require an accelerated rate of solar interconnections. Reaching the 70% interim target by 2030 requires a rate of new solar interconnections approximately 2.5 times the maximum amount interconnected in any previous year as further discussed in Chapter 3 (Portfolios) and Appendix I (Solar). This will also drive the need for transmission investments to accommodate increased solar deployment, as discussed in Appendix P (Transmission System Planning and Grid Transformation).

2022 Solar Procurement Target Volume

The Companies have sought Commission approval to enable procurement of needed new solar resources through the 2022 Solar Procurement Program[4] ("2022 SP Program"). The Companies have requested Commission approval to procure a minimum target volume of 700 MW subject to determining a "Carbon Plan-informed" RFP target volume of new solar resources to be procured in the 2022 SP Program. The Companies have begun the pre-solicitation market participant engagement process and are targeting opening the 2022 SP Program RFP on or about May 31, 2022, pending Commission approval.

As presented in Appendix I (Solar), the Companies propose to procure 750 MW of new solar resources through the 2022 SP Program, which reflects the volume of new solar-only resources that the Companies forecast can interconnect in 2026 (which is also referred to as beginning-of-year 2027). The 2022 SP Program design includes a volume adjustment mechanism to mitigate pricing risk if bid prices exceed 110% of the Carbon Plan's assumed solar cost and to enable up to 20% more solar to be procured if bid prices are 10% below the Carbon Plan's assumed solar cost. As discussed further below, additional annual procurements for both solar and solar paired with storage resources are planned in 2023 and beyond to procure needed solar resources to be installed under moderately aggressive to extremely aggressive interconnection timelines that are dependent on the outcome of planned transmission investments as further described in Appendix I (Solar) and Appendix P (Transmission System Planning and Grid Transformation).

[4] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Petition for Authorization of 2022 Solar Procurement Program, Docket Nos. E-2, Sub 1297, E-7, Sub 1268 (filed March 14, 2022).

Table 4-6 below outlines the Companies' near-term actions associated with the 2022 SP Program and preparing for and executing the 2023 solar and solar paired with storage procurement, and intermediate-term actions to advance subsequent procurements.

Table 4-6: Execution Plan – Solar

Near-Term Actions (2022-2024)	
2022	• Finalize and issue 2022 SP Program to align with 2022 DISIS cluster (May 2022) • 2022 Solar Procurement Step 1 bid evaluation process (Q3-Q4 2022) • NCUC approval of final 2022 SP Program target volume (11/1/22) • Stakeholder engagement in preparation for 2023 Solar Procurement ("2023 SP") framework (Q4 2022)
2023	• 2022 SP Program Step 2 bid evaluation process and DISIS cluster Phase 2 study (Q1-Q2 2023) • Finalize 2023 Solar Procurement plan (Q1 2023), targeting procurement of 1,000 MW • Selection and contracting of 2022 SP winners (Q2-Q3 2023) • Finalize and issue 2023 SP to align with DISIS cluster (Q2-Q3 2023) • Stakeholder engagement in preparation for 2024 Solar Procurement, as needed (Q4 2023)
2024	• Selection and contracting of 2023 SP winners (Q2-Q3 2024) • Finalize and issue 2024 Solar Procurement to align with 2024 DISIS cluster (Q2-Q3 2024), targeting procurement of 1,350 MW
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• Issue subsequent solar procurement RFPs in 2025-2030 in alignment with then-approved Carbon Plan

Procurement Plan – Solar

Both pathways and all four portfolios identify the need for significant expansion of new solar and solar paired with storage resources on the DEP and DEC systems in the near- and intermediate-terms.

The Companies anticipate multiple rounds of solar procurements of new solar and solar paired with storage resources between 2022 and 2030. The Companies have requested the Commission approve the final Carbon Plan-informed 2022 SP Program target volume by November 1, 2022.

Future procurements will solicit both utility-owned solar and solar paired with storage resources as well as third-party owned resources that provide the Companies rights to dispatch, operate and control the facilities in the same manner as utility-owned solar resources. The Companies plan to engage with stakeholders in late 2022 and early 2023 to discuss the structure of the next procurement. Subject to further guidance from the Commission, the Companies are targeting 1,000 MW to be procured in the 2023 solar procurement and 1,350 MW to be procured in a potential 2024 solar procurement (totalling 3,100 MW in the near term, including the 750 from 2022 SP Program). Like the 2022 SP Program, Duke Energy plans to utilize an Independent Evaluator to assist with RFP issuance and bid selection. As with the 2022 SP Program, the bid window and RFP dates will be established to align with the annual DISIS Interconnection schedule.

Exploring Advanced Nuclear Resources

The Companies have owned and operated nuclear plants in the Carolinas for over 50 years, generating carbon-free, reliable electricity, as well as supporting well-paying jobs, providing significant tax revenues, and creating many other benefits for their communities. The Companies cannot achieve the energy transition and CO_2 emissions reductions targets without nuclear power – their largest generator of zero-carbon electricity. In fact, all viable portfolios to achieving the 70% CO_2 emissions reductions target rely on existing nuclear facilities continuing to provide zero-carbon energy through 2030 and beyond. In addition, new advanced nuclear plants, such as small modular reactors ("SMRs") and advanced reactors will be critical to achieving carbon neutrality by 2050 as required by HB 951.

The Carbon Plan modeling performed by the Companies identifies the need for at least 570 MW of new nuclear (two SMRs) to be installed by 2035 under both pathways and all portfolios. As further addressed in Appendix L (Nuclear), the earliest date for having a new SMR unit online is mid-2032. The Companies believe it is prudent and necessary to begin development of new nuclear resources to ensure that these zero-carbon load-following resources are viable options to be selected by the Commission in the future. Table 4-7 below outlines the Companies' near-term and intermediate-term Execution Plan to advance new zero-carbon nuclear.

Table 4-7: Execution Plan – New Nuclear

Near-Term Actions (2022-2024)	
2022-2023	• Organize nuclear development staff for new nuclear builds • Perform new nuclear alternative siting study • Perform new nuclear technology selection
2022-2024	• Begin new nuclear early site permit ("ESP") development • Perform new nuclear technology due diligence review • Choose the advanced nuclear technology/company to build the first plant(s)
2023-2025	• Develop new nuclear construction and operating license
Intermediate-Term Actions (Achieve 70% Target)	
2026	• Submit COL application and obtain operating license approval

Intermediate-Term Actions (Achieve 70% Target)	
2027-2028	• Obtain CPCN siting approval to construct new advanced nuclear plant
2029	• Begin construction of new advanced nuclear plant • Determine reactor vendor and schedule for future builds

The actions above support the initial new nuclear SMR unit in-service date of mid-2032. Future units could follow in 18-month intervals as determined to be needed in the Carbon Plan.

Procurement Plan – New Nuclear

A mid-2032 in-service date for an initial new nuclear SMR unit presents an aggressive but currently feasible timeline if Duke Energy takes actions beginning in 2022 to start the licensing process, including potential early site permitting. Based on the unique nature of building new nuclear plants, the competitive selection comes when Duke Energy chooses the advanced nuclear technology/company to build the first plant(s). The ESP would allow Duke Energy to gain NRC approval for the future deployment of one or more reactor technologies at a site, prior to a specific technology/vendor being selected. The ESP allows for finality of the environmental and site safety regulatory issues before the reactor technology is chosen.

Planning for New Wind Energy Resources

Wind, both onshore and offshore, is an important resource to meet the HB 951 interim and long-term CO_2 emissions reductions targets. Meeting the 70% interim reduction target requires the development of between 600 MW (P1) to 1,200 MW (P2, P3 and P4) of onshore wind. In addition, three of the four portfolios identify the development of offshore wind as part of meeting the 70% interim target, 800 MW for P1 and P4 and 1,600 MW for P2.

Today, there are no operational or under-development onshore wind facilities within the Companies' balancing authority areas, as discussed in Appendix J (Wind). As such, the Companies' near-term efforts, outlined in Table 4-8 below, will be directed toward evaluating the establishment of a working group to build the market and strategies to bolster the development of onshore wind resources in achievement of the Carbon Plan onshore wind procurement goals.

Development of offshore wind is restricted to specified offshore wind energy areas ("WEA"), which begin at 3 nautical miles from shore and are under the jurisdiction of the Bureau of Ocean Energy Management ("BOEM"). Developers must win WEAs through competitive auctions, at increasingly rising prices, to gain the right to control the development of offshore wind resources, as discussed in Appendix J (Wind). On May 11, 2022, the Carolina Long Bay auction was held, and Duke Energy Renewables Wind, LLC, an unregulated affiliate of Duke Energy, was the provisional winner of the Carolina Long Bay OCS-A 0546 lease area.[5] Following the results of this lease decision, Duke Energy

[5] Carolinas Long Bay | Bureau of Ocean Energy Management (boem.gov).

will focus on executing the near-term and intermediate-term actions outlined in Table 4-9 below.[6] Maintaining progress toward these near-term actions will be critical, as development of offshore wind resources in the time frame necessary to deliver significant zero-carbon energy to support the HB 951 70% interim target is an aggressive timeline that could be challenged by a number of circumstances, including failure to obtain timely approvals of all required federal and state agency permits.

Table 4-8: Execution Plan – Onshore Wind

Near-Term Actions (2022-2024)	
2023	• Explore development of an onshore wind working group • Develop outreach plan to engage the wind development community and shape the wind industry for the Carolinas • Consider partnership approaches for future onshore wind development • Commence procurement of up to 600 MW onshore wind
2024	• Continue onshore wind development and procurement efforts
Intermediate-Term Actions (Achieve 70% Target)	
2025	• Continue onshore wind development and procurement efforts

Onshore wind activities beyond the near-term actions above would include continued RFP issuance, design, permitting, constructing and commissioning of onshore wind assets. Community outreach will be critical for enabling the development of onshore wind resources to contribute to the achievement of the CO_2 emissions reductions targets in HB 951.

Table 4-9: Execution Plan – Offshore Wind

Near-Term Actions (2022-2024)	

2022 - 2023	• Secure lease
	• Initiate development and permitting activities for 800 MW
	    • Develop and submit Site Assessment Plan and begin engaging stakeholders
	    • Begin developing Construction and Operations Plan
	    • Initiate local and state permitting processes
	• Initiate interconnection study process

2024	• Obtain Site Assessment Plan approval from BOEM

[6] Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan ("SAP"); or ii) a combined SAP and Commercial Operation Plan.

Intermediate-Term Actions (Achieve 70% Target)	
2025	• Launch construction planning activities
2027	• Submit Construction and Operations Plan to BOEM

Procurement Plan – Wind

Onshore Wind: Due to the history of onshore wind in the Carolinas, near-term actions will be needed to bolster the onshore wind market in the Carolinas to ensure wind resources are developed to deliver on the HB 951 CO_2 emissions reduction targets. The Companies are considering engaging with wind developers, trade groups and industry advocates in a working group to develop a comprehensive strategy to bring new onshore wind opportunities to the Carolinas. Duke Energy expects to leverage the working group for defining arrangements with wind developers, issuing RFPs for onshore wind projects, and considering wheeled wind opportunities. The Companies plan to include onshore wind in their 2023 RFP.

Offshore Wind: Developing offshore wind depends on winning very select lease auctions. The Carolinas Long Bay auction was held by BOEM on May 11, 2022, and Duke Energy Renewables Wind, LLC, an unregulated affiliate of Duke Energy, prequalified as an able bidder for the auction. Duke Energy Renewables Wind, LLC is the provisional winner of the Carolina Long Bay OCS-A 0546 lease area and TotalEnergies Renewables USA, LLC, is the provisional winner of Carolina Long Bay OCS-A 0545.[7] In addition, BOEM awarded Avangrid Renewables, LLC, parcel OCS-A 0508 covering an area offshore near Kitty Hawk, North Carolina in 2017.[8]

Increasing System Flexibility and Maintaining Reliability With Energy Storage

Energy storage will play a critical role in the low-carbon future of the power system. With the significant increase of intermittent zero-carbon generation, such as wind and solar, increasing the energy storage capacity in the Carolinas will be critical for managing extreme fluctuations in net load and for matching the generation of zero-carbon energy to when the demand for energy exists. The nature of energy storage allows energy to be injected back onto the grid when it is needed most to increase system reliability. The Companies' Carbon Plan modeling includes 4-hr and 6-hr grid-tied battery energy storage, battery energy storage at solar paired with storage sites and new powerhouse at the Bad Creek Hydroelectric Station ("Bad Creek II").

Today, long duration storage, totalling 2,300 MW of capacity, is currently available via the Jocassee and Bad Creek pumped storage hydro systems. Through a series of upgrade projects that include the installation of four additional pump turbines, three higher-rated step-up transformers, and new generators, the Companies intend to increase the capacity of its Bad Creek facility by approximately se320 MW by 2024. Beyond these planned upgrades, the Companies are exploring the feasibility of

[7] Carolinas Long Bay | Bureau of Ocean Energy Management (boem.gov).

[8] Interior Department Auctions Over 122,000 Acres Offshore Kitty Hawk, North Carolina for Wind Energy Development | U.S. Department of the Interior (doi.gov).

a cond powerhouse (12-hour storage facility) at the Bad Creek Hydroelectric Station, with construction targeted to commence in 2027. Constructing Bad Creek II would add approximately 1,700 MW of baseload capacity with an expected in-service date in 2033. Table 4-10 below outlines the Companies' near-term and intermediate-term Execution Plan to advance pumped storage hydro.

Table 4-10: Execution Plan – Pumped Storage Hydro

Near-Term Actions (2022-2024)	
2022-2023	• Complete Bad Creek II Feasibility Study
2024	• Determine EPC strategy for Bad Creek II
2022 - 2024	• Continued development of FERC application for Bad Creek relicensing
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• File state approvals for Bad Creek II • File final FERC application for Bad Creek relicensing
2027	• Construction of Bad Creek II begins

In addition to the pumped storage hydro systems, the Companies currently have 300 MW of grid-connected battery storage under development as part of inflight projects on the DEP and DEC systems.

While there are various types of storage technologies that may be available in the future to support the Companies plans for stand-alone battery storage and solar paired with storage, in the near-term, the Companies plan to deploy megawatt-scale electrochemical batteries while continuing to partner with diverse suppliers who can provide the latest battery technology expertise and resources. Table 4-11 below outlines the Companies' near-term and intermediate-term Execution Plan to advance 1,600 MW of new battery energy storage to be developed by 2029 (1,000 MW stand-alone storage, 600 MW storage paired with solar).

Table 4-11: Execution Plan – Energy Storage

Near-Term Actions (2022-2024)	
2022-2024	• Submit Interconnection Requests for battery energy storage projects at strategic grid locations supporting Carbon Plan needs through 2029 • Design controls, dispatch and software tools for a fleet of battery energy storage systems • Test and study non-lithium technologies at the R&D scale

Near-Term Actions (2022-2024)	
	• Finalize procurement strategy and initiate procurement activities relative to procurement strategy for 1,600 MW of battery energy storage (1,000 MW stand-alone storage, 600 MW storage paired with solar)
Intermediate-Term Actions (Achieve 70% Target)	
2025-2030	• Procure, construct and interconnect energy storage selected in Carbon Plan • Optimize control and dispatch of the Duke Energy fleet with a variety of energy storage technologies

Procurement Plan – Energy Storage

Bad Creek II Powerhouse: During the near-term period through 2024, Duke Energy will continue engineering work but will not need to commit to any major construction expenses. Beyond 2024, actions include filing for state regulatory approvals and the final FERC application. Once all required regulatory approvals to construct are obtained, which are targeted for 2027, construction of Bad Creek II would begin with an expected in-service date in 2033. To ensure cost competitiveness, Duke Energy will bid out EPC services at the appropriate time.

Standalone Battery Storage: The value of energy storage, specifically batteries, is maximized for the grid and customers if the assets are strategically located on the Companies' system and incorporate operational parameters into the designs. Many of these strategic locations are within or adjacent to Duke Energy-owned land. Due to these factors, the Companies believe the battery storage assets are best served via self-development while working with established component manufacturers and service providers that focus on certain project development activities, such as design, siting, permitting, and environmental due diligence. When cost-effective, the Companies will employ competitive solicitations for EPC services to qualified vendors, ensuring the best value for customers. Timing of EPC solicitations will be specific to the project schedules. Additionally, the Companies will seek to purchase components and services from local providers – to the extent that they provide the required functionality and are cost competitive in relation to other options – so as to promote economic development in the region.

Procurement of Battery Storage Paired with Solar: The Companies will utilize established and evolving procurement practices for battery paired with solar resources that align with the Companies' plans for procuring and self-developing new controllable solar resources, as discussed above.

Assessing the Viability of Hydrogen Resources

While the Carbon Plan does not assume any projected use of hydrogen by 2030, hydrogen supply and use will grow significantly to become an important component of the pathway to achieve carbon neutrality by 2050. The Companies anticipate the capability to use 100% hydrogen for fuelling new zero-carbon generation and as an avenue to decarbonize existing and future natural gas generation facilities. The Companies also envision hydrogen as a way of providing an alternative long-duration storage option for excess energy generated by renewable resources.

Table 4-12 below outlines the Companies' near-term and intermediate-term Execution Plan to participate in the necessary studies and demonstrations to advance the understanding and development of hydrogen production, storage, transportation and generation. Additional information is provided in Appendix O (Low-Carbon Fuels and Hydrogen). With a long-term need for hydrogen technologies anticipated, the Companies will continue to seek opportunities to understand, prepare for and implement hydrogen through government, university and industry partnerships. Hydrogen actions beyond the near term would include completing approved studies and demonstration projects and may include seeing the beginning and build out of hydrogen supply infrastructure and retrofitting selected existing units to high or full hydrogen capability.

Table 4-12: Execution Plan – Hydrogen

Near-Term Actions (2022-2024)	

2022-2024	• Develop clean hydrogen studies and demonstration projects
	    • Submit information and proposals for potential federal funding to offset costs where appropriate
	    • Leverage work to date on Clemson CHP Hydrogen study to implement an operational pilot project
	• Understanding and mapping hydrogen opportunities
	    • Support and develop storage technology research and demonstrations
	    • Collaborate with academic and industry research partners to advance low-carbon hydrogen production technologies
	    • Support of combustion turbine manufacturers development of 100% hydrogen capable dry low-emission combustion
	    • Improve hydrogen production, hydrogen transportation and hydrogen storage cost projections
	• Develop options and regulatory support for hydrogen transport infrastructure

2023-2024	• Commence approved studies and demonstrations • Determine hydrogen readiness scope for new unit builds • Plan for new CT/CC units built with max hydrogen feasibility
Intermediate-Term Actions (Achieve 70% Target)	
2025-2028	• Continue development of clean studies and demonstration projects
2025-2030	• Complete approved studies and demonstrations, incorporate learnings into planning

Transmission System Planning and Grid Transformation

Executing the Carbon Plan requires a transformation of the Companies' transmission system to achieve CO_2 emission reduction targets while ensuring adequate and reliable service is maintained. This transformation includes investments required to retire existing coal-fired generation and interconnect new solar, solar paired with storage, stand-alone storage, wind, SMRs, and gas generation. Additional details on how the Companies prudently plan and reliably operate their transmission systems are addressed in Appendix P (Transmission System Planning and Grid Transformation).

Enabling Coal Unit Retirements

Each of the Carbon Plan pathways and portfolios includes the retirement of existing coal units. Locating replacement generation at the same site of retiring coal-fired generation can provide the grid support necessary to ensure continued system reliability and reduce transmission network upgrade costs. The Execution Plan includes a near-term action to file with FERC in 2022 to establish a replacement generation study process to ensure efficient, timely, and cost-effective interconnection processing of new generation planned to be sited at retiring coal-fired generation locations.

For DEC, a switching station is currently under construction to enable the retirements of Allen Units 1 & 5 in 2023. Transmission planning studies completed to date have not identified major transmission impacts from the retirement of Cliffside Unit 5 scheduled by the end of 2025. Intermediate-term actions include the assessment and construction of additional transmission system upgrades to enable coal-fired generation retirements in the late 2020s and early 2030s. Retirement of the Marshall coal units will require new transmission that will need to be in service by December 2028 unless equivalent replacement capacity is located at the existing Marshall site. DEC plans to evaluate transmission upgrades to enable retirements as the Belews Creek mid-2030s planned retirement date approaches; preliminary analysis suggests that transmission upgrades will be required to retire this capacity if not replaced with new generation on-site and coincident with retirement.

For DEP, the retirement of the Roxboro and Mayo coal units will cause the need for additional transmission projects unless this generation capacity is replaced sufficiently at the Roxboro and/or Mayo sites and coincident with the retirements.

Intermediate-term actions include the continued assessment and construction of additional transmission system upgrades to enable coal unit retirements. Additional detail on transmission planning assessments to support coal unit retirements is addressed in Appendix P (Transmission System Planning and Grid Transformation).

Public Policy Transmission Projects

The Execution Plan also includes a near-term action to initiate, subject to NCTPC approval, public policy transmission projects necessary to allow for substantial incremental solar resource interconnections in existing "Red Zone" areas of DEC and DEP, as further described in Appendix P

(Transmission System Planning and Grid Transformation). The Companies' transmission planning process and recent interconnection planning studies have identified an initial group of projects (see Table P-3 in Appendix P) that the Companies will propose to be added to the NCTPC Local Transmission Plan by midyear 2022. The Companies will also continue to develop their transmission planning processes based on the outcome of the recently established FERC rulemaking proceeding on transmission planning and cost allocation and generator interconnection.[9]

In the intermediate term, more extensive transmission network upgrades will be required to integrate remote interconnected resources and ensure safe and reliable energy delivery to load centers under various grid conditions. Upgrades of existing transmission lines, although very successful with enabling interconnections of the first phase of Carbon Plan resources, will not be sufficient to interconnect later phases of incremental resources associated with Carbon Plan implementation. In addition to the initial upgrades of existing transmission, new transmission infrastructure with new rights of way will be required toward 2030 and through the 2030s to enable Carbon Plan resource implementations.

Offshore Wind-Enabling Transmission Projects

Carbon Plan portfolios P1, P2 and P4 include interconnection of 800 or 1,600 MW of offshore wind between the end of 2029 and the beginning of 2032. Previous screening studies have indicated that 800 MW of offshore wind can be injected at New Bern 230 kV without the addition of major new onshore transmission lines but with some significant upgrades to the existing system in the New Bern area. Studies have also indicated that injection of 1,600 MW of offshore wind into New Bern would likely require construction of a new 500 kV network line. The Execution Plan includes a near-term action to request an interconnection study for offshore wind interconnecting into New Bern Substation in 2023.

Intermediate actions include construction of the network upgrades to support the resource selected in the Carbon Plan. Completing the required transmission to support offshore wind injections in the 2029-to-2032 timeframe will be challenging as siting, permitting and constructing the transmission system upgrades are dependent on public engagement, routing, scoping, and the acquisition of new right of ways.

Table 4-13 below outlines the Companies' near-term and intermediate-term Execution Plan to advance the grid needs critical to the Plan described in this section.

Table 4-13: Execution Plan – Transmission Planning and Grid Transformation

Near-Term Actions (2022-2024)	
2022	• FERC filing to establish generation replacement queue process • Subject to Transmission Advisory Group stakeholder review and NCTPC approval, start public policy transmission projects included in

[9] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022).

Near-Term Actions (2022-2024)	
	Local Transmission Plan • Start preliminary routing, scoping, siting, right-of-way acquisition for OSW transmission projects with point of interconnection at New Bern Substation

2023-2024	**DEC**
	• Marshall Station (Units 1-4) - (Earliest planned retirement date Marshall 1,2 EOY 2028; Marshall 3,4 EOY 2032)
	  • Determine feasibility for upgrading McGuire – Marshall 230kV lines by EOY 2028. Study replacement generation located at brownfield site
	• Belews Creek (Units 1-2) - (Earliest planned retirement date EOY 2035)
	  • Transmission planning to evaluate transmission upgrades and replacement generation requirements to enable retirements by EOY 2035
	DEP
	• Roxboro Station (Units 1-4) and Mayo (Unit 1) (Earliest planned retirement dates Roxboro 3,4 EOY 2027; Roxboro 1,2 EOY 2028; Mayo EOY 2028) Transmission planning to evaluate transmission upgrades and replacement generation requirements to enable retirements by earliest planned dates
	• For contingency purposes, transmission planning to evaluate transmission upgrades needed to site Roxboro/Mayo replacement generation in DEC service area

2023	• Request interconnection studies for needed MW levels of offshore wind being injected into New Bern Substation

Consolidated System Operations

The Companies each currently operate as separate NERC registered Balancing Authorities, Transmission Operators, Transmission Service Providers, and plan as separate NERC registered Transmission Planners. To support implementation of the Carbon Plan and in response to stakeholder feedback, the Companies propose to consolidate these functions and consolidate the Companies' Carolinas' system operations through the appropriate regulatory filings in the near term. Specific benefits include enhancing portfolio flexibility, improving reliability, capturing production cost savings, and simplifying NERC compliance and transmission service provisions. Table 4-14 below provides a summary of system consolidation benefits, and a more detailed discussion of Consolidated System Operations can be found in Appendix R (Consolidated System Operations).

Table 4-14: Consolidated System Operations Benefits

Flexibility	Production	Simplification
• Optimization of existing resources • Less solar curtailment • Reduction in CO_2	• Reduced generation costs • Reduced dump energy • Improved market purchases • Improved storage utilization	• NERC Standard Compliance • One OATT • Single wholesale view
Reserves	**Response**	**Reliability**
• Reduction in day ahead planning reserves • Reduction in planning reserve margin	• Larger balancing area better able to aggregate greater amounts of variable generation and load	• Reserve sharing • Consolidated system operations

The Execution Plan, outlined in Table 4-15 below, includes near-term actions necessary to support a detailed evaluation of consolidated system benefits, stakeholder outreach, and development of North Carolina, South Carolina and FERC regulatory filings. These filings are expected to occur in the first quarter of 2023 and third quarter of 2023, respectively. Also, the Southeastern Reliability Corporation ("SERC"), the Regional Reliability Organization reporting to NERC, will need to certify the consolidated registered NERC entity functions and supporting technical infrastructure relative to their roles in meeting mandatory reliability standards. This certification is expected to occur in late 2024, closer to the effective date of the consolidated system operations.

The Companies estimate consolidated system operations could begin in the 2025 timeframe. However, the timeline for implementation of consolidated system operations by 2025 is aggressive and highly dependent on achieving the necessary regulatory approvals in a timely manner. State regulatory approvals need to be achieved by third quarter of 2023 and FERC approvals need to be achieved by third quarter of 2024 to meet a 2025 implementation date. Any significant delay or insurmountable barrier to implementing consolidated system operations would significantly hinder the ability to manage the variability and intermittency of variable energy resources such as solar and thus hinder the ability to meet the carbon reduction objectives laid out in the Carbon Plan.

Table 4-15: Execution Plan – Consolidated System Operations

Near-Term Actions (2022-2024)	
2022	• Conduct stakeholder outreach
2023	• Develop and submit State regulatory filings in order to receive State approvals by third quarter of 2023

Near-Term Actions (2022-2024)	
	• Develop and submit FERC filings in order to receive FERC approval by third quarter of 2024
2024	• Provide materials for SERC to conduct certification of consolidated NERC functions and achieve certification of the new registered NERC functions for consolidated system operations by year-end 2024

Grid Edge and Customer Programs

Grid Edge and Customer Programs are a foundational component of the Carbon Plan. Customer Programs include energy efficiency ("EE") programs, clean energy customer programs, and net metering programs aimed at helping customers reduce energy usage from the grid and access clean energy resources. Grid Edge programs include customer pricing, demand response, electric vehicle managed charging and system voltage optimization programs designed to allow management of the electric system and shape overall energy loads. Grid Edge and Customer Programs are enabled by the continued implementation of enabling grid improvement programs, such as Self-Optimizing Grid and the modernization of telecommunications infrastructure, which are required to support large-scale distributed energy resource ("DER") deployment.

These programs are discussed in more detail in Appendix G (Grid Edge and Customer Programs) and Appendix F (Electric Load Forecast). This Execution Plan, outlined in Table 4-16 below, addresses near-term and intermediate actions in each of these program areas.

Customer Programs

Energy Efficiency

The Carbon Plan includes the expansion of existing EE programs and the addition of new technologies to achieve a 1% reduction of eligible retail sales. This target reflects an aggressive long-term forecast of EE savings that is more than double the level assumed in the Companies' 2020 IRPs. To achieve this goal, the Execution Plan includes actions to expand the reach of existing programs, accelerate the development of new measures and examine ways to reduce barriers and unlock additional energy efficiency savings. Near-term actions are highlighted below.

On-tariff Financing: To expand program reach, the Companies plan to develop and file for regulatory approval a pilot to provide on-tariff financing targeting multifamily new construction for residential customers that implements savings measures through approved EE programs. Financing costs for improvements are expected to be paid for through reduced monthly energy bills. The Companies have already started work to pilot an on-tariff financing option with residential customers and plan to file for both a pilot approval and a broader five-year implementation plan during 2022. The Companies plan to investigate a non-residential on-tariff financing pilot by 2023 with the potential to seek approval of a full program rollout available to support programs in the 2025 timeframe.

Expansion of Low-Income Programs: As a near-term action, the Companies will seek approval to expand and/or add EE programs that ease the energy burden on income-eligible customers. Program changes include the following recommendations developed in collaboration with stakeholders.

- Work with the EE/DSM Collaborative in coordination with the Low-Income Affordability Collaborative ("LIAC") to redefine the definition of Low-Income and eligibility of customers for income-qualified programs to include what historically had been defined as moderately low-income customers with incomes <300% of the federal poverty level.

- Expanding existing DEC Weatherization program to DEP, including offering (i) weatherization measures and/or (ii) heating system replacement with a 15 or greater seasonal energy efficiency ratio heat pump and/or (iii) refrigerator replacement with an ENERGY STAR® appliance.

- Launching the Energy Burden Reduction Pilot Program that will install deep retrofits at no cost to the customer with an emphasis on low-income neighborhoods with mobile/manufactured homes.

- Expanding the existing Neighborhood Energy Saver Program measure to include additional deep retrofits and replacements including HVAC replacement, heat pump water heater and window improvements.

As Found Baseline for Energy Efficiency Measures*:* The Companies plan to seek approval to offer incentives using the "as found" baseline as a new option for identified measures as described in Appendix G (Grid Edge and Customer Programs). Using an "as found" baseline will allow the Companies to provide higher incentives and estimates that implementation of this recommendation could increase EE savings by approximately 20% on identified measures. The Companies will vet the need for the additional "as found" measures with the EE/DSM Collaborative and seek approval for this near-term action in 2022.

Incentives for Non-Lighting Measures*:* The U.S. Energy Information Administration projects that delivered energy for air conditioning will increase more than any other end use in commercial buildings through 2050. Many customers are not motivated to replace their air conditioner or heat pump units due to the low rebates and the high cost of replacing equipment. This program will seek approval to incentivize customers to replace equipment prior to failure with new units requiring minimum code standards only. The incentive will be offered in combination with a control system, thermostat or other identified measures for bundle. The Companies estimate implementation of this near-term action has the potential to increase participation by 15%.

Advance Codes and Standards Adoption*:* Fast-tracking the state of North Carolina's adoption of commercial building energy codes will ensure EE measures are implemented at the time of construction or retrofit. The Companies plan to seek approval to update the existing Smart $aver® tariff to allow the Companies to improve the market's compliance with existing and future standards through education, outreach and technical support. The Companies estimate this change could account for 5% of program savings.

Clean Energy Customer Programs

The Companies plan to engage stakeholders in the coming months regarding expansion of existing and development of new Clean Energy Customer programs. The Companies anticipate that these potential programs would be focused both on customer self-sourced renewable energy options, whereby customers may directly adopt or support new renewable energy facilities, as well as utility-sourced options, whereby the Companies would participate in transactions that provide customers with access to renewable energy credits or other clean energy opportunities. The Companies will also work with stakeholders to consider programs that help support the adoption of battery storage by customers to support their clean energy goals. The Companies are optimistic that working together with stakeholders, solutions can be identified that can be brought to the Commission for approval later in 2022.

Net Metering

Continued development of the customer-sited solar market is dependent upon customers having some level of price certainty through defined net metering programs. The Companies have worked in collaboration with the rooftop solar industry participants and environmental advocates to design programs that fulfil the needs of customers and industry alike. The Execution Plan includes near-term actions to:

- Offer a Solar Choice Net Metering program that will include dynamic rates that vary based on the time of day and peak demand and integrate with other EE and demand response measures to offer customers additional participation incentives.
- Implement a revised net metering design to more closely reflect the avoided costs associated with behind-the-meter solar generation.
- Secure regulatory approval and implement the proposed “Smart $aver Solar” EE program and expand the program concept to new product bundles and non-residential customers subject to regulatory approval.

The Companies recognize the potential need to bundle behavioural demand response programs, such as Peak Time Rebates, or other load management tools with rate design options to encourage adoption and enable additional responsiveness. As availability and customer interest in DER technologies increase, the Companies will seek ways to harness the usefulness of these various devices through product offerings that work with well-designed rate structures to provide value to both the customer and the overall system. These devices would potentially include in-home storage devices, EVs, load control technology, smart thermostats, and behind-the-meter solar systems with smart inverters. The potential for EVs to provide vehicle-to-home (V2H) or vehicle-to-grid (V2G) services also create opportunities to dynamically manage system load. The Execution Plan includes actions to continue to engage stakeholders and develop subscription concepts that seamlessly bundle these offerings in a manner that provides cost certainty for the customer while providing system benefits. These bundled offerings will also likely lead to a greater adoption of behind-the-meter solar.

Grid Edge Programs

Grid Edge Programs include a mix of customer programs and utility technology applications designed to allow management of the electric system and shape overall loads in a way that defer or eliminate the need for additional generation or system investments. These programs include new rate designs, demand response programs, and voltage optimization.

Rate Design

Rate Design is an important load shaping tool that uses time differentiated rates and other forms of dynamic pricing to encourage customers to change their load profiles in ways that better support the use of low-carbon and zero-carbon resources. A large-scale stakeholder engagement initiative (the Comprehensive Rate Reform Collaborative) has been ongoing to identify new rate designs that provide appropriate pricing structure and encourage behavioral changes that change load shape. Rate Design near-term actions include:

- Updating pricing structures to reflect a change in hourly energy costs due to increased solar penetration. The Companies anticipate offering lower pricing for residential and non-residential during times of high solar production and higher pricing in other time periods.

- Development of new real time pricing tariffs to enable broader, more diverse customer participation by large business customers. Duke Energy's customer research indicates customer interest could result in approximately 10%-30% of the current Large General Service customer class enrolling in an hourly pricing rate and becoming price-responsive loads. Assuming the midpoint of this range and a 65% load factor, the Companies estimate that approximately 790 MW of new price-responsive load.

- Piloting subscription rates and enabling products and services that provide even more attractive pricing options for customers who allow the Companies to actively manage their charging to target times when solar resources may otherwise be curtailed.

Demand Response Programs

Demand Response ("DR") programs are already incentivizing 500,000 Carolinas' customers to reduce peak demand on the electric system when and where needed. The goal is to significantly increase customer participation in the future. Traditional DR programs have historically enabled the Companies to decrease their reliance on older, more expensive generation and spot market power purchases. To support the Carbon Plan, the Companies plan to evolve their use of DR to both reduce peak load and shape load in ways that help the Companies maximize their use of zero-carbon resources. To accomplish this, the Companies intend to incorporate dynamic loads, such as EVs and customer-sited energy storage. Specific near-term actions include:

- Expanding Small and Medium Business (‘SMB”) program to allow additional flexibility in load types that can participate in the program
- Expand existing Heat Strip Program to DEC and DEP East
- Develop a cost-effective Water Heater program
- Pilot Electric Vehicle Charging programs
- Seek approval of Smart $aver Solar EE program
- Seek Commission approval for the need to grow summer capability.

Voltage Optimization (Conservation Voltage Reduction)

The Companies are utilizing systems designed to control distribution grid equipment in both DEC and DEP, as well as deploying new technology to optimize voltage, which results in reduced peak demand and energy usage. Conservation Voltage Reduction (“CVR”) technology allows the Companies to conserve energy at a circuit or system level. CVR coordinates the settings of devices to lower the voltage for an entire circuit. This in turn reduces the load of the system, thereby lowering generation fuel consumption which leads to lower CO_2 emissions. The Companies plan to expand CVR rollout in the DEC service territory and introduce CVR in the DEP service territory to support achieving Carbon Plan targets. Near-term actions to expand CVR include seeking Phase II approval to expand CVR from 67% to 90% of eligible circuits in DEC.

Transportation Electrification

Transportation electrification will lead to a significant increase in the amount of electricity consumed by vehicles as more consumers switch to EVs. It is expected that a collection of rates, deployed assets and customers programs will be needed to support this significant change. Managed EV charging is a valuable solution to support lower CO_2 emissions by reducing existing load peaks and eliminating risks from new ones. Managed charging strategies for residential, fleet and commercial customers vary, but each approach will leverage customer-focused design processes combining usage monitoring and control geared to avoid higher-emission generation and to improve grid stability and efficiency. Near-term actions to effectively manage the impact of EV charging and support broader policy objectives include implementation of the EV programs filed in 2021 and continued engagement with the EV Collaborative to identify and develop additional EV charging programs that enable effective EV integration.

Table 4-16: Execution Plan – Grid Edge and Customer Programs

Near-Term Actions (2022-2024)	
2022	**Energy Efficiency** • Seek and obtain approval of On-tariff Financing Pilot for multi-family new construction

Near-Term Actions (2022-2024)	
	• Seek and obtain approval of On-tariff Financing program (DEC/DEP five-year rollout) • Seek and obtain approval of expansion of low-income EE programs (Weatherization program for DEP, new low-income pilots, and LIAC Report recommendations) • Seek and obtain approval of "as found" Baseline measures for equipment replacement • Seek and obtain approval to update Smart $aver program to include education, outreach and technical support for new construction market • Seek and obtain Commission approval to update the inputs underlying the determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism **Demand Response Programs** • Seek and obtain approval for Load Shaping DR with SMB incentive expansion • Seek and obtain approval for Heat Strip program expansion to DEC and DEP East **Transportation Electrification** • Seek and obtain approval for Electric Vehicle Supply Equipment Tariff • Seek and obtain approval for subscription EV Managed Charging pilot • EV Make-Ready Credit rollout (approved in 2022)
2022 - 2023	**Smart $aver Solar** • Obtain NCUC approval and launch the proposed Residential Smart Saver Solar Program **Clean Energy Customer Programs** • Seek and obtain approval for suite of new Clean Energy Customer Programs **Demand Response Programs** • Expand outreach to increase adoption of existing thermostat programs **Rate Design** • Seek and obtain approval for enhanced Real Time Pricing Pilot program **Transportation Electrification** • Seek and obtain approval for V2X pilots
	Energy Efficiency • Seek and obtain approval of increased incentives for non-lighting measures

Near-Term Actions (2022-2024)	
2023	**Rate Design** • Contingent on Commission approval, rollout new Net Metering Rate (DEC/DEP implementation) • Seek and obtain approval for updated pricing structures to reflect a change in hourly energy costs due to increased solar penetration • Seek and obtain approval for behavioral demand response program and supporting infrastructure to encourage dynamic rate adoption **Grid Edge** • Seek and obtain approval for new locational grid pilots (including regulatory framework) and measures **Electric Transportation** • Complete Park & Plug Pilot Phase 1 (approved in 2021) • Complete EV School Bus Phase 1(approved in 2021) **Voltage Optimization** • Complete DEC IVVC/CVR Phase 1 rollout to 73% of eligible DEC circuits
2024	**Voltage Optimization** • Complete DEP DSDR CVR software implementation
Intermediate Term Actions (Achieve 70% Target)	
2026	**Voltage Optimization** • Seek and obtain approval for Phase 2 expansion of DEC IVVC/CVR to 90% of eligible circuits

Long-Term Grid Edge and Customer Programs Considerations

Achieving the Carbon Plan modeled EE target will require collaboration and commitment from the Companies, customers, stakeholders, regulators, and potentially policy makers. The Companies will build upon their existing region-leading EE portfolio but achieving the new levels of energy efficiency will ultimately depend upon customers investing to reduce energy usage. Feedback from existing program participants have shown that customer awareness and implementation of energy efficiency measures is directly tied to customer awareness, program marketing and incentive levels and recommend modifying program cost-effectiveness tests to appropriately value the cost of CO_2 emissions reductions and avoided demand costs. The Companies estimate that including valuing carbon reduction and demand in a manner that increases the cost-effectiveness threshold by 35% could yield a 12% and 8% increase in total residential and nonresidential kWh savings, respectively.

Similarly, the shift toward flexible demand management will be dependent on customer participation in new rate design and demand response programs enabled by the continued expansion of automated technologies. Subscription and bundled services that allow utility management of loads will be increasing important, especially as EV adoption and load increase significantly over the next decade.

Implementation of building code standards that drive the market toward compliance with existing or greater standards also has the potential to reduce energy usage and demand resulting in reduced carbon emissions. Additionally, building code changes that drive residential customer adoption of Wi-Fi-enabled water heaters, thermostats, smart panels and smart inverters could unlock value for customers and the energy system.

Monitoring Risks in the Near Term and Intermediate Term

Integral to executing the Carbon Plan is the identification and monitoring of risks throughout execution to determine when external factors require the Companies to take mitigating actions, consider alternative strategies, or pivot to alternative options to achieving Carbon Plan targets. Assessment of risks in the near term and intermediate term is also key to the Commission's decision-making regarding the optimal timing and generation and resource mix to accomplish the least-cost path to achieving HB 951's targets.

Risks tend to be related to executable components of the Carbon Plan, such as programs, projects, or resource types; however, some risks are also a result of the interdependencies between Plan components. The Companies have identified initial execution risks and, as activities launch, the Companies will monitor those risks and include appropriate adjustments to biennial Carbon Plan updates or in related regulatory dockets. Execution risks categories are outlined below, and the Appendices provide additional information on risks specific to the planning area or technology.

Supply Chain

Material and equipment supply chain disruptions may lead to construction delays or inability to develop certain types of programs or projects on the timeline identified in this Execution Plan or at the costs or amounts assumed in the modeling. Capacities of vendor supply chains may be challenged as entities compete for limited resources, leading to delays or cost escalations. Inflationary pressures on components, material and equipment may lead to cost escalations.

Siting and Permitting

Inability to site and receive timely permits and environmental reviews for new energy resource facilities and supporting electric transmission and gas pipeline infrastructure may inhibit or slow advancement of execution activities, including:

- Electric transmission system expansion and modification supporting larger volume of renewable resources and the retirement and replacement of generation; and
- Gas infrastructure needed to supply incremental natural gas facilities.

Labor Supply

Shortages in qualified craft and engineering labor may cause delays or increased costs in constructing new energy resource facilities and supporting infrastructure or implementing new programs.

Regulatory Approvals

Ability to receive timely regulatory approvals from all required authorities and jurisdictions for proposed activities may impact progression toward Plan targets. This risk cuts across all prongs of planning, including enhanced existing and new supply-side resources, transmission planning and grid requirements, Customer and Grid Edge programs, and the development and demonstration of breakthrough technologies.

Interdependencies on Transmission System Planning and Interconnection

As detailed in Appendix P (Transmission System Planning and Grid Transformation), coordinated proactive transmission planning and timely construction of the significant transmission that will be needed to interconnect new resources selected in the Carbon Plan presents a key interdependency and timing risk.

Interdependencies on Fuel Supply

As outlined in detail in Appendix N (Fuel Supply), future uncertainty or inability to secure additional interstate pipeline firm transportation causes increased fuel assurance risk, increased customer fuel cost exposure and potentially delayed coal retirements. Also, the inability to secure flexible coal supply through coal unit end of life may accelerate the need for their capacity replacement.

To manage these risks, the Companies near-term and intermediate-term planning strategy focuses on diversification across all three prongs of planning – demand-side and load modification, zero-carbon renewables and nuclear, and flexible and dispatchable supply-side and energy storage resources. Relying on diverse energy resources, rather than only one or two technologies, to achieve the CO_2 emissions reductions targets reduces exposure to execution risks such as labor shortages and supply chain disruptions that may become more pronounced for any one particular technology. Resource diversification also reduces integration challenges, prevents over-reliance on any one single emergent technology, and preserves optionality to achieve the least-cost requirement as technologies mature.

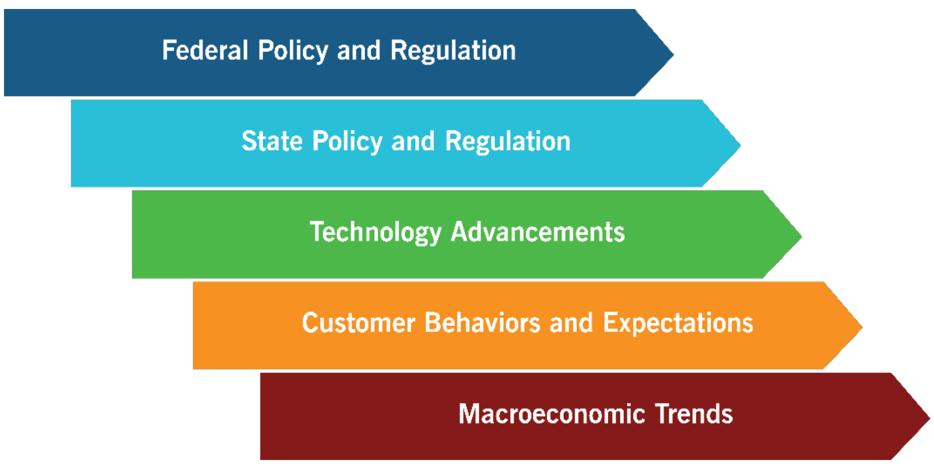
Long-Term Planning and Signpost Monitoring

In addition to executing the near-term and identifying the next phase of intermediate actions required to achieve the interim 70% reduction target, longer-term activities will be necessary to achieve carbon neutrality by 2050. Each of the Carbon Plan portfolios face challenges and uncertainty that may require pivoting as time progresses and the band of uncertainty narrows. Therefore, rather than identifying specific long-term actions in this initial Carbon Plan, the Companies have identified signposts to closely monitor, as illustrated in Figure 4-2 below.

Signpost Monitoring to Guide Planning

To navigate longer-term or disruptive uncertainties such as policy shifts, innovation, or economic trends, the Companies will actively monitor the signposts that could impact plan trajectory toward meeting carbon neutrality to guide their long-term planning assumptions and necessary future adjustments to the Carbon Plan. As these signposts emerge and evolve, the Companies will update planning assumptions, adjust for any new requirements or constraints, and integrate into future Carbon Plan modeling to determine whether modification of the Carbon Plan is required to achieve carbon neutrality reliably and cost-effectively. Signpost categories are shown in Figure 4-2 and described further below.

Figure 4-2: The Key Signpost Categories for Monitoring the Carbon Plan



Federal Policy and Regulation

Federal policies and regulations can influence the timing, costs and technical requirements for achieving carbon reduction targets at least cost. Aspects of this signpost include federal law and regulations of CO_2 emissions or other pollutants, federal trade policy, federal climate and clean energy policy goals, and federal appliance and equipment standards. U.S. Securities and Exchange Commission ("SEC") regulations, including those related to climate disclosures, can also influence the pace of clean energy technology advancement and shifting business customer preferences toward clean energy solutions. Examples under this signpost that could influence the selection and timing of energy resource investments include continuation or expansion of federal tax credits (e.g., production tax credits for wind and solar or tax credits for EV, or EV purchases) for certain technologies and federal incentives and funding for clean energy technology innovation and demonstration. Lastly, policy, regulations, and standards under the purview of FERC, including NERC, the NRC, BOEM, the U.S. Environmental Protection Agency, and U.S. Department of Commerce, among others, can influence aspects of electricity system planning.

State Policy and Regulation

Similar to national policies, state energy law and regulations can influence energy resource planning decisions. In many respects, state policies have a more significant influence than federal policies as North Carolina and South Carolina have jurisdiction over most energy resource planning issues. This includes authority over electric utility rates and other policies and regulations adopted and enforced by the Commission and the PSCSC. Aspects of this signpost are similar to federal policy and regulation and can include state-specific policies or regulations of the environment, state climate policy commitments, policies that influence transportation and building electrification, and building energy standards. Examples within this signpost include state tax credits or funding incentives for clean energy technologies and related infrastructure and special programs. Lastly, state policies can influence where new energy resources can be permitted and sited and impact Plan execution.

Technological Maturity and Cost

The maturity and efficacy of emerging clean energy technologies and grid technologies is critical to meeting the Companies' CO_2 emissions reductions targets. This can be measured by findings from pilots and other demonstration projects, studies that estimate current and future technology costs (reductions or increases), and evaluation of other technological maturity gains (e.g., efficiency). Key technologies include long-duration energy storage systems, renewable energy, advanced nuclear, and hydrogen fuel.

Achieving carbon neutrality will likely require reliance on breakthrough technologies, as is contemplated by HB 951[10], that are still in the development and demonstration phase and have not yet achieved widespread commercial availability and economies of scale. Duke Energy's emerging technology group identifies, prioritizes and tracks future technologies, which could contribute to achieving CO_2 emissions reductions. Prior to full large-scale projects, and consistent with industry best practice, Duke Energy prefers to perform educated pilots and demonstrations to explore the operation and integration of such new technologies on its system. The Companies are engaged throughout the industry in monitoring and assessing potential breakthrough technologies that have the greatest potential for benefit to customers. Ultimately, it may be prudent for the Commission to approve and the Companies to pursue one or more such breakthrough technologies in order to facilitate and even hasten industry and technology evolution. Such initiatives could be particularly beneficial where the Companies are able to leverage partnerships and external funding for the benefit of customers and gain experience in real-world operation on a small scale before large-scale deployment. The Companies are currently evaluating such opportunities involving long-duration storage and hydrogen production, storage, transportation and generation.

Customer Behavior and Expectations

Consumers across all customer classes can be influential in the decarbonization journey and dictate the adoption curve for certain low-carbon or zero-carbon technologies such as electric transportation, distributed solar, electric heat pump conversions, and investment in renewables. Trends in adoption

[10] HB 951 Section 1(1).

of customer-owned distributed generation (e.g., behind-the-meter solar and combined heat and power) and energy storage can inform the potential contribution to CO_2 emissions reductions, particularly when such resources can provide enhanced value to the resiliency of the electricity system.

The adoption of other distributed energy resources, such as EE, DR, and EVs can also influence the timing and costs associated with achieving decarbonization goals and objectives as these resources can either increase or decrease electricity demand. Additionally, consumer interest in electrifying their homes and businesses for space and water heating and cooking, particularly if coupled with financial incentives, could increase electricity demand. The capability and adoption of digital energy technologies could also provide a catalyst for new demand management strategies, including incentives for advanced energy management systems, smart devices with utility control, and virtual power plants.

Macroeconomic Trends

Duke Energy will also monitor macroeconomic trends and indicators that could require adjustments to ensure the Carbon Plan meets the least-cost objective. Macroeconomic indicators are measures that can be influenced by national or global economic conditions, including energy commodity prices, inflation and interest rates, taxes or other added costs, supply chain disruptions, labor shortages and other national or global disruptions due to macro-economic policies or geopolitical influences impacting the energy industry.

Planning for Future Updates to Carbon Plan

Planning for future updates to the Carbon Plan is an important issue to address proactively with the Commission and stakeholders as the Companies begin executing on the initial Carbon Plan. HB 951 provides that the Carbon Plan shall be reviewed every two years and may be adjusted as necessary in the determination of the Commission and the Companies.[11]

The Companies agree with the Commission's stated inclination in the November 19, 2021 scheduling order to sync the Carbon Plan proceedings with future IRP proceedings. While the November 19, 2021 scheduling order deferred the Companies' next comprehensive IRPs to September 2023 to allow the Commission and the Companies to focus on developing the initial Carbon Plan in 2022, the Companies believe the more appropriate step is to reestablish an "even-year" cadence for filing comprehensive IRPs and Carbon Plan updates starting in 2024, as illustrated in Figure 4-3 below. This approach aligns with the schedule required by the General Assembly for biennial Carbon Plan updates and would allow DEC and DEP time to begin executing the near-term execution plan before presenting the next full Carbon Plan update to the Commission. This approach would also allow time in 2023 for review of the Commission's IRP Rule R8-60 and related rules to ensure that the resource planning regulatory framework aligns with the new IRP/Carbon Plan requirements of HB 951.

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

Filing the Companies' next comprehensive IRP/Carbon Plan update in 2024 would also recognize the important role of the PSCSC, as the Companies necessarily must be able to execute on a single systemwide resource planning pathway as explained in more detail in Chapter 1 (Introduction and Background). Deferring the next comprehensive IRP/Carbon Plan Update to 2024 would allow the Companies to more fully focus in 2023 on developing and presenting comprehensive IRPs to the PSCSC, as required by S.C. Code Ann. § 58-37-40. Recognizing the benefits to customers of dual-state systems planning, the Companies strongly believe that regulatory clarity and resource planning alignment between the two jurisdictions will be critically important to obtaining these benefits for customers moving forward.

Figure 4-3: Near-Term Schedule for Carbon Plan Updates

Summary of Near-Term Execution Plan

The Companies' have taken a deliberate approach to near-term planning, developing a proposed set of prudent and necessary actions to initiate the energy transition and meet the CO_2 emissions reduction targets set forth in HB 951. The near-term actions identified for Commission approval in this Execution Plan are reasonable and prudent steps to commence during the near-term 2022-2024 timeframe in advance of the next biennial Carbon Plan update and will facilitate advancement of all three prongs of the Carbon Plan. As discussed earlier, in the context of an interconnected electric system and in support of the multipronged approach to planning, many of these actions are interdependent on one another to achieve the CO_2 emissions reductions targets while maintaining or improving upon the adequacy and reliability of the system, therefore the activities in this Execution Plan should be viewed as a complete plan.

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

CAROLINAS

CARBON PLAN

DUKE ENERGY

BUILDING A SMARTER ENERGY FUTURE ®

Executive Summary

The Carolinas Carbon Plan (the "Carbon Plan" or the "Plan") represents the next major step on the continued energy transition of the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke Energy" or the "Companies") systems. The Companies' continued transition, which relies on a diverse portfolio of technologies with lower carbon intensity, is prudent and necessary to reduce exposure to diminishing coal supply and associated regulatory risks, provides for continued reliability, and ensures continued access to capital at reasonable rates for the benefit of customers. Furthermore, the energy transition is supported by a broad range of the Companies' customers and, when combined with continued affordable and competitive rates, will play a crucial role in retaining existing businesses and attracting new economic development to North Carolina and South Carolina (together, the "Carolinas").

This Plan is built on the foundation of decades of reasonable and prudent utility planning practices and decisions that have been jointly overseen by the North Carolina Utilities Commission ("NCUC" or the "Commission") and the Public Service Commission of South Carolina ("PSCSC"). This dual-state approach to least-cost resource planning has benefited customers in the Companies' service territory across the Carolinas through the provision of reliable and affordable electric service with a decreasing carbon intensity. DEC and DEP have a combined carbon dioxide ("CO_2") emission rate that is lower than the national average among all privately held and investor-owned utilities.[1]

Utilizing well-established planning principles honed through decades of integrated resource planning processes overseen by the NCUC and the PSCSC, the Companies' proposed Carbon Plan assesses a range of portfolios that will facilitate continued modernization of the Companies' systems spanning the Carolinas and result in further CO_2 reductions through a prudent, orderly, and cost-effective energy system transition.

For over a century, Duke Energy has provided affordable, reliable, and increasingly cleaner energy for its customers and communities in the Carolinas.[2] Facilitated in part by the Joint Dispatch

[1] MJ Bradley "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States". July 2021 (www.mjbradley.com).

[2] Duke Energy's Carolinas operations include DEC and DEP service territories. *See* Appendix C (System Overview) for additional information.

Agreement ("JDA"),[3] the Companies' 4.4 million customers in the Carolinas benefit from a diverse and reliable mix of resources and already receive more than half of their energy from nuclear, hydroelectric and solar, making Duke Energy a national leader in carbon-free generation. The dual-state systems provide customers with an expansive portfolio of energy efficiency, demand-side management, and advanced grid technology programs reducing or modifying load to complement the Companies' supply-side generating resources used to reliably serve customer capacity and energy needs. Combined with a very large geographic footprint, the dual-state systems have delivered tremendous economies of scale to customers in the Carolinas, creating competitive advantages for the states' economies and fueling job creation through reliable supply of electricity at rates consistently below the national average.

Duke Energy's CO_2 emissions reductions trajectory represents reasonable and prudent planning for the benefit of customers and aligns with a fundamental energy transformation that is in progress across the U.S. and is changing how energy is produced, delivered and used, as discussed in Chapter 1 (Introduction and Background). Customers, businesses, and communities are expressing a strong desire for emissions-free energy, and many have adopted specific energy-related goals. There is also growing momentum across the country for clean energy through a variety of policies advanced by the federal government, states and communities. Infrastructure investors are also increasingly making decisions based on a company's environmental, social and governance ("ESG") measures, including their CO_2 emissions. Clean energy technologies are advancing and are becoming increasingly cost-effective over time. Finally, reliance on a diminishing coal supply chain with limited transportation flexibility puts additional pressure on aging coal resources. Given all these factors, the Carbon Plan represents prudent long-term electric resource planning that complies with current law and practice with respect to least-cost planning for generation and allows the Companies to further advance the energy transition that is already underway.

North Carolina Session Law 2021-165 ("HB 951") was signed into law on October 13, 2021, and provides a crucial policy framework for the Companies regarding the continued orderly implementation of the energy transition. HB 951 was supported by overwhelming bipartisan majorities in the North Carolina General Assembly and then executed by Governor Roy Cooper. The strong bipartisan support of HB 951 affirms that continuation of the energy transition that Duke Energy has been pursuing under the oversight of the NCUC and PSCSC is sound and prudent energy policy.

Overview of Carbon Plan

The Companies' proposed Plan presents for the Commission's consideration two pathways consisting of four discrete portfolios, all of which further the transition of the Companies' energy systems and achieve the CO_2 emissions reductions targets established under HB 951. The Plan assesses each of the portfolios against four core Carbon Plan objectives (CO_2 reduction, affordability, reliability and executability), all of which are grounded in prudent utility planning and operation.

[3] The Joint Dispatch Agreement provides for combined operational control of DEC's and DEP's respective generating facilities to facilitate the sharing of non-firm economic energy between the two utilities.

As is described in greater detail below, the Plan identifies - and seeks Commission approval of - the reasonable and necessary steps needed in the near term to further the energy transition, and also identifies further actions needed over the intermediate term and key signposts to be monitored over the longer term. The Companies' proposed near-term activities are reflective of a measured, balanced and "all-of-the-above" approach to the energy transition. This approach is built on the bedrock of aggressive, nation-leading goals to continue to "shrink the challenge" of an energy transition by first reducing or modifying energy usage on the system at the customer level, along with plans to evolve customer programs to provide greater access to a zero-emitting energy supply, cutting-edge rate designs to encourage customers to change their load profiles in ways that better support use of carbon-free resources, and implementation of "Grid Edge" technologies that enable Duke Energy to manage the electric system in ways that lower carbon emissions while maintaining reliability.

Under the Plan, the remaining customer demand is then projected to be served through substantial, diversified investments in both technologies mature to the Carolinas and technologies that would be new to the Carolinas' energy system, along with transmission grid investments needed to reliably integrate these new resources onto the Carolinas system. Mature technologies in the Companies' Plan include solar, pumped storage hydro and dispatchable natural gas units, while technologies new to the Carolinas include onshore wind and offshore wind, large-scale battery storage and small modular reactor ("SMR") and advanced nuclear technologies. The Plan outlines near-term development and procurement needed in 2022-2024 to bring projects into service in the period of 2026-2029, along with development activities necessary for longer lead-time resources to remain on track to come online between 2030-2034 (consistent with the target dates reflected in the various portfolios). In summary, the Plan not only provides a modeled planning view of potential portfolios, but also overlays key execution recommendations and considerations that should guide the Commission's assessment of the Plan, including the timing of the Commission's decisions and the ways in which the iterative Carbon Plan process will evolve over the coming years under the oversight of the Commission and the PSCSC.

The Plan is organized in the following chapters, with further detailed information available in appendices.[4]

- **Chapter 1:** Introduction and Background
- **Chapter 2:** Methodology and Key Assumptions
- **Chapter 3:** Portfolios
- **Chapter 4:** Execution Plan

A Plan for the Carolinas' Systems

Under the oversight of the Commission and the PSCSC, the Companies have already made substantial progress in the energy transition, as evidenced by the retirement of 34 coal units in both

[4] For the benefit of the Commission, the Companies identified where in the Carbon Plan the Companies have addressed specific Commission requirements or expectations set forth in various Commission orders in Appendix T (Cross-Reference).

states, totaling 4,200 megawatts ("MW") over the past 11 years, all through the existing regulatory and legal structures. This transition has been achieved and facilitated by alignment between the states in support of cleaner energy resources through portfolio diversification. Through a series of strategic and constructive regulatory actions spanning decades, the Commission and PSCSC jointly enabled the Companies to operate and grow the dual-state systems to meet the needs of customers in both states. The Companies' dual-state systems have delivered tremendous economies of scale, resiliency, and savings to customers and communities in both states, creating competitive advantages for both states' economies and fueling job creation through the reliable and safe supply of electricity at rates consistently below the nation's average.

It is through this lens that the Companies view the emissions reductions targeted in HB 951. The targets established under HB 951 represent a formalization of the Companies' continued orderly transition away from continued reliance on emission-intensive resources, but also, an opportunity for the Commission and the PSCSC to apply least-cost planning principles to drive the energy transition of the Carolinas – all for the benefit of Duke Energy's customers.

Duke Energy acknowledges that the PSCSC is not bound by North Carolina law and recognizes that further proceedings before the PSCSC will be required subsequent to the Commission decision in this proceeding. As this Commission aptly stated, "engagement with the PSCSC to consider and examine the benefits of continued system-wide planning and operation for Duke Energy's customers in both states, in a manner that is consistent with applicable South Carolina law and [North Carolina] law and respectful of the jurisdiction and sovereignty of each state could be worth exploring."[5] If differences in state energy policy do not allow for alignment and system-wide planning, then the Companies may need to plan and operate as two different systems, which could result in ultimate separation of the utilities. This approach could increase costs and will, in general, make the energy transition less efficient.

Continuation of the dual-state planning for each system is in the best interests of customers and ultimately the economic development interests of both states. As the Commission has confirmed: "the DEP and DEC systems, each of which operates as a single integrated system across the Carolinas, for many generations have provided reliable, efficient, and affordable electricity to the residents of both states."[6] The Companies believe that continuation of the current well-planned and integrated single-system approach for each utility remains in the best interests of customers and will seek to achieve alignment by continuing to actively encourage South Carolina stakeholder participation in the energy transition planning process and then ultimately through the established regulatory processes, including primarily the comprehensive 2023 South Carolina Integrated Resource Plan ("IRP") review process required by South Carolina law. Further details regarding state alignment are discussed in Chapter 1 (Introduction and Background) and further timing details are described in Chapter 4 (Execution Plan).

[5] *Order Accepting Withdrawal of Petition for Joint Proceeding*, Docket Nos. E-2, Sub 1259 & E-7, Sub 1283, at 2 (February 1, 2022).

[6] *Id.*

Stakeholder Engagement

The Carbon Plan is informed by diverse stakeholder engagement, occurring before and after HB 951 became law. Duke Energy has engaged with stakeholders in North Carolina and South Carolina across a broad array of the Companies' operation and planning processes for a number of years, including with respect to energy efficiency and demand-side management ("EE/DSM"), IRPs, Integrated System & Operations Planning ("ISOP"), affordability, rate design, solar net metering, generator interconnection and a variety of other topics. In particular, the Plan is informed by the collaborative work of the recent 2020 IRP process,[7] the 2019 State Clean Energy Plan ("CEP")[8] process in North Carolina, as well as the Carbon Plan-specific stakeholder process that has occurred in the months leading up to this filing as directed and overseen by the Commission.[9] Through the Carbon Plan-specific stakeholder process,[10] Duke Energy actively engaged stakeholders across the Carolinas through three primary virtual stakeholder meetings, coordinating with over 500 participants from stakeholder groups, such as customer and consumer advocacy groups, community leaders and advocates, renewable energy developers, environmental interests and academia. In addition to the primary stakeholder meetings, multiple subgroup sessions were conducted based on specific technical or interest areas. Details of these activities, which were facilitated by an independent entity, the Great Plains Institute, can be found on Duke Energy's website.[11]

Stakeholder feedback directly influenced both the stakeholder process itself and the development of the Plan in a variety of ways, as illustrated in Figure 1 below. Stakeholder feedback also influenced Plan assumptions and execution considerations, such as the importance of timely and adequate grid investments to achieve Plan targets, navigating future regulatory uncertainty and risk management. Stakeholder feedback regarding community impacts of the energy transition in terms of environmental justice, local economies and employment will be used to inform execution decisions.

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[7] Duke Energy, Integrated Resource Planning, https://www.duke-energy.com/irp (last visited May 3, 2022).

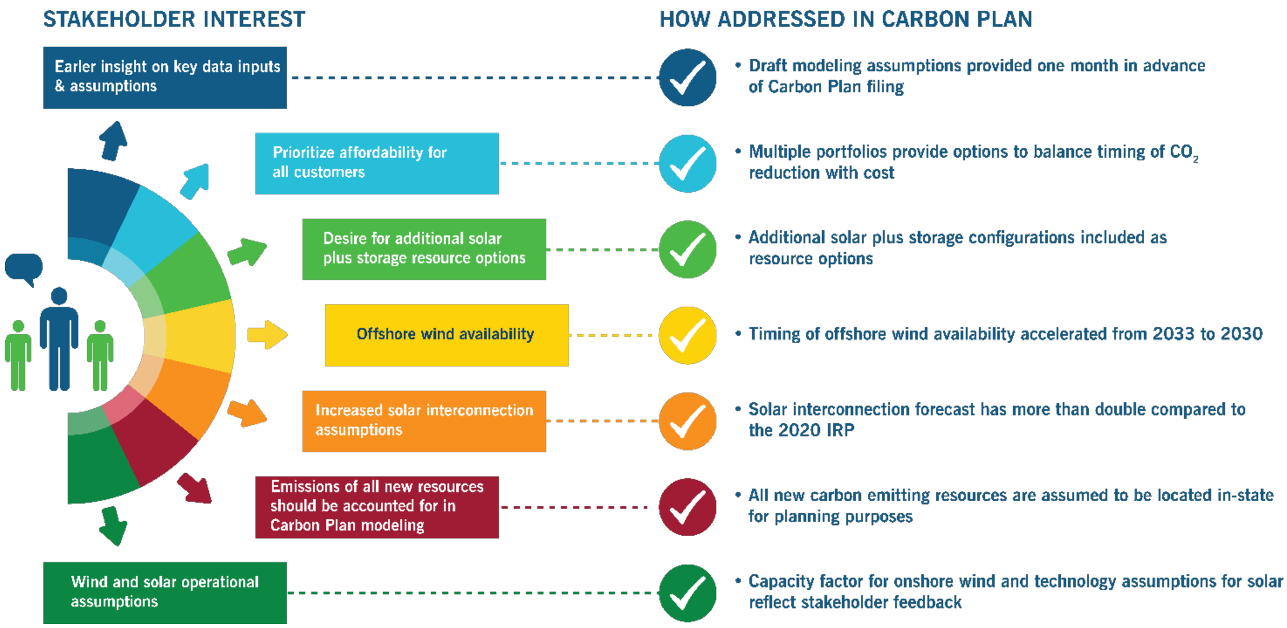
[8] In October 2019, Governor Roy Cooper issued the CEP, establishing goals for electric sector carbon reductions and regulatory modernization. This launched a 16-month stakeholder process aimed at developing recommendations supporting the CEP objectives. *See* N.C. Dept. Env. Quality, Clean Energy Plan, https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-plans-and-progress/clean-energy-plan (last visited May 3, 2022).

[9] *See* Appendix B (Stakeholder Engagement) for additional information regarding the stakeholder process, stakeholder forums, and the North Carolina CEP.

[10] *Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines*, Docket No. E-100, Sub 179 (November 19, 2022) ("Carbon Plan Procedural Order").

[11] *See* Duke Energy, Carolinas Carbon Plan, www.duke-energy.com/CarolinasCarbonPlan (last visited May 2, 2022).

Figure 1: Incorporation of Stakeholder Feedback



Specific stakeholder input to the Plan is included throughout the main body and subject matter appendices of the Plan. As of the date of this filing, Duke Energy has made available the final Carbon Plan modeling datasets, which will allow intervenors[12] to assess all aspects of the Companies' modeling analysis. Duke Energy also looks forward to participating in a series of upcoming public hearings across the State that are scheduled in the coming months.[13] Finally, the Companies anticipate substantial engagement with intervenors post-filing as directed by the Commission in its April 1, 2022 *Order Establishing Additional Procedures and Requiring Issues Report*. Additional detail on the Companies' stakeholder engagement efforts is provided in Appendix B (Stakeholder Engagement).

Planning Requirements Under HB 951

HB 951 establishes three primary requirements, all of which must be satisfied in the plan developed by the Commission to achieve the targeted CO_2 reductions. The first requirement is that the Commission must comply with current law and practice with respect to least-cost planning for generation.[14] The second requirement is that any generation and resource changes must maintain or

[12] As described in the Companies' April 5, 2022 letter in this docket and the cover letter for this filing, access to the modeling data will be made available upon request to intervenors whose participation in this docket has been approved by order of the Commission and who have submitted an executed confidentiality agreement to the Companies.

[13] *Order Scheduling Public Hearings and Requiring Public Notice Pursuant to House Bill 951*, Docket No. E-100, Sub 179 (March 9, 2022) ("Order on Public Hearings").

[14] HB 951, Section 1(2).

improve upon the adequacy and reliability of the existing grid.[15] The third requirement is that any new generation facilities or other resources selected by the Commission in order to achieve the CO_2 emissions reduction goals for electric public utilities must be owned and recovered on a cost of service basis by the applicable electric public utility, except in the case of energy efficiency measures and demand-side management, for which existing law applies, and in the case of solar generation, which is to be allocated according to the specified percentages.[16]

Defining the Baseline for CO_2 Emissions Reduction

Section 1 of HB 951 directs the Commission to take all reasonable steps to achieve two emissions reductions targets: (1) a 70% reduction in CO_2 emissions from electric generating facilities owned or operated by electric public utilities in North Carolina by 2030 from 2005 levels and (2) carbon neutrality by 2050, and further provides that the timing of achievement of the interim 70% reductions target may be adjusted based upon certain factors.[17] To achieve these CO_2 emissions reductions targets over the interim and long term, the Commission is tasked with developing a Carbon Plan, which "may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs[.]"[18]

As recognized by the Commission's initial Procedural Order, a prerequisite to development of pathways to meeting these targets is a clear understanding of the baseline for measuring progress toward meeting the goals.[19,20] The CO_2 emissions baseline and progression to achieve the interim 70% interim reduction target are shown below in Figure 2 and explained in more detail in Appendix A (Carbon Baseline and Accounting). Importantly, while HB 951 defines and allows for carbon neutrality by 2050 through the use of offsets,[21] the Plan does not currently assume utilizing offsets.

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[15] *Id.* Section 1(3).

[16] *Id.* Section 1(2).

[17] *Id.* Section 1(4).

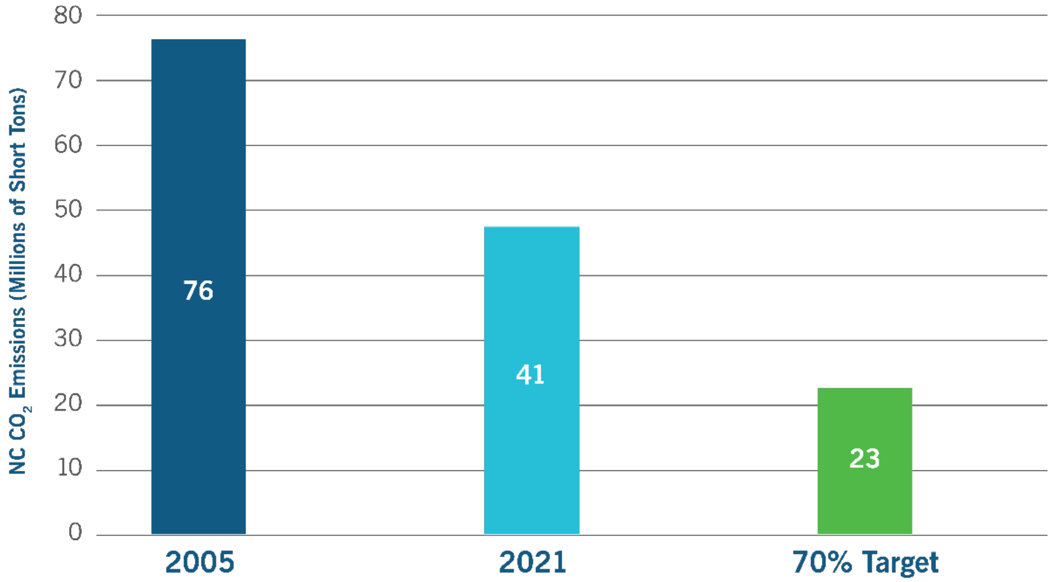
[18] *Id.* Section 1(1).

[19] Carbon Plan Procedural Order, at 3.

[20] *See* Appendix A (Carbon Baseline and Accounting) for specific methodologies for CO_2 emissions baseline calculation and CO_2 emissions accounting, along with key definitions for carbon neutrality and offsets.

[21] HB 951, Section 1.

Figure 2: North Carolina CO_2 Emissions Baseline, Progress and 70% Reduction Target



HB 951 establishes CO_2 emissions reductions targets for Duke Energy's electric generating facilities located in North Carolina. In light of Duke Energy's dual-state systems, stakeholders expressed concerns regarding a strategy that involves use of CO_2-emitting resources located outside of North Carolina.

First and foremost, the Companies are committed to systemwide CO_2 emissions reductions, targeting carbon neutrality for their entire system by 2050. Second, the Companies affirmed during the stakeholder process that, for modeling purposes, they would assume that any new CO_2-emitting resources selected in the model would be sited in North Carolina.

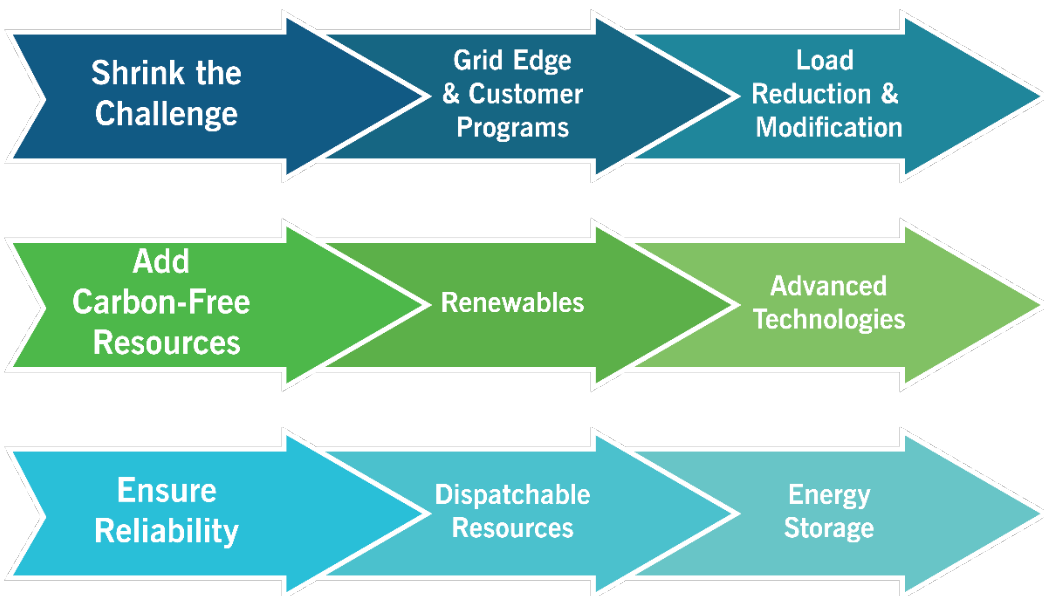
However, consistent with past practice, in most cases, the selection and siting of new resources will occur after completion of the modeling process (with such modeling results, including any modifications ultimately required by the Commission, informing the procurement process). This approach will ensure that the most cost-effective resources are selected for the benefit of customers, taking into account a range of site-specific and other factors that are not practical for inclusion in the modeling process.

Therefore, the Companies request Commission confirmation with respect to two issues concerning CO_2 emissions accounting under HB 951. First, the Companies request Commission approval of the methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking achievement of HB 951's CO_2 emissions reductions targets. Second, the Companies request that the Commission determine whether CO_2 emissions from out-of-state generating resources ultimately selected to be part of the Plan should be accounted as if such emissions occurred in the State. Once again, for modeling purposes, the Companies assumed all new selected resources would be sited in North Carolina.

Carbon Plan Illustrates Pathways to 70% CO_2 Emissions Reductions

The Companies intend to take a multipronged approach to maintaining affordable and reliable service while also meeting CO_2 emissions reduction targets. As depicted in Figure 3 below, the Companies first plan to "shrink the challenge" by reducing energy requirements and modifying load patterns through grid edge and customer programs[22] allowing more tools to respond to fluctuating energy supply and demand. The second and third prongs focus on development of diverse portfolios of carbon-free and flexible, dispatchable energy supply sources to facilitate CO_2 emissions reductions while maintaining reliable energy service.[23] Supply resource diversity provides flexibility and mitigates the risk over reliance on any one technology to meet reliability and resilience requirements as the energy transition evolves how the Companies operate the grid.

Figure 3: Three-Pronged Approach to Planning



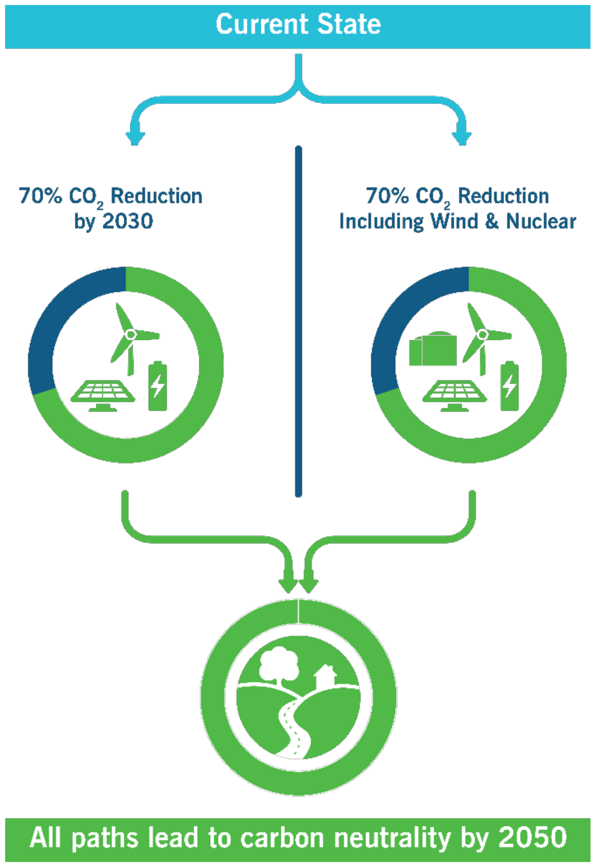
Two Pathways to 70% CO_2 Emissions Reductions

The Plan explores the risks and benefits of two pathways for achieving the interim 70% reduction target, with both pathways resulting in carbon neutrality of the systems by 2050. As shown in Figure 4 below, one pathway achieves the 70% target by 2030 and the second pathway achieves the 70% target by 2034 through reliance on offshore wind and/or nuclear SMR generation technologies as is contemplated by HB 951.

[22] *See* Appendix G (Grid Edge and Customer Programs) for additional information.

[23] *See* Appendix I (Solar), Appendix J (Wind), Appendix K (Energy Storage), Appendix L (Nuclear), Appendix M (Natural Gas), Appendix N (Fuel Supply) and Appendix O (Low-Carbon Fuels and Hydrogen) for additional information.

Figure 4: Two Pathways to Carbon Neutrality



Defining Portfolios Within Each of the Two Pathways

The Companies have developed four portfolio options within the two pathways: Portfolio 1 achieves 70% CO_2 emissions reductions by 2030, and Portfolios 2-4 achieve the 70% reduction target between 2032 and 2034 relying on offshore wind and/or nuclear SMR generation technologies. The latter three portfolios are predicated on the flexibility and discretion provided to the Commission in HB 951 to determine the optimal timing and generation and resource mix to achieve the least-cost path to HB 951's CO_2 emissions reductions targets. Specifically, HB 951 provides that the Commission has "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" and pursuant to this discretion may approve a Carbon Plan that targets completion two years after the specified dates.[24] In addition, the Commission may approve a Carbon Plan that achieves the target after the specified dates "in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical or other factors beyond the control of the electric public utility, or in the event

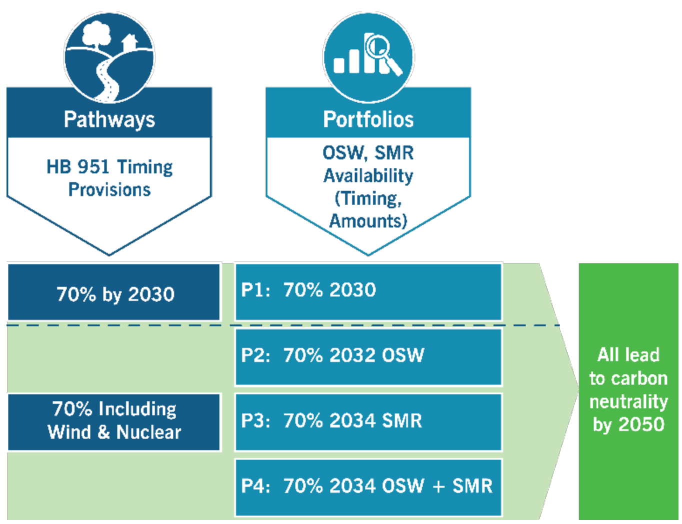
[24] HB 951, Section 1(4).

necessary to maintain the adequacy and reliability of the existing grid."[25] Therefore, the latter three portfolios rely on offshore wind and/or SMR to achieve 70% CO_2 emissions reductions to provide optionality for the Commission consistent with intent of the General Assembly, with all portfolios achieving the 70% interim target by 2034 and carbon neutrality by 2050.

Finally, each of the four portfolios was developed based on the key planning parameter of access to firm transportation for lower-cost natural gas from the Appalachia region. Recognizing the potential uncertainty in interstate pipeline availability, the Plan also includes an alternate fuel supply case sensitivity analyses for each of the portfolios to assess the impact on the portfolios should access to Appalachian gas not be achieved. The availability of firm transportation of natural gas to fuel existing natural gas generation resources and new flexible natural gas resources is critical to operate a reliable system, facilitate coal retirements (thereby reducing exposure to a deteriorating coal supply chain), and to integrate and reliably back-stand high levels of intermittent renewable resources on the system.[26] Importantly, the alternate fuel supply case evaluated for each portfolio should be understood as a future "pivot point." That is, the alternate fuel supply cases assess the future resource mix in the event that the Companies are not able to access new Appalachian natural gas, in which scenario the Companies would "pivot" to pursue the resources identified in the alternate case. The Companies' proposed near-term activities allow appropriate flexibility to accommodate such a pivot without material impact.

Figure 5 below illustrates the progression from the two pathways through to the four portfolios.

Figure 5: Pathways and Portfolios to 70% CO_2 Emissions Reductions



[25] *Id.*
[26] *See* Appendix N (Fuel Supply) for additional information.

Portfolio Results

Each portfolio presents a road map to transition away from continued reliance on emissions intensive resources via orderly retirement of coal facilities and prudent, planned additions of a diverse mix of low-carbon and emissions-free resources, all while keeping a keen eye on reliability and affordability. All portfolios assume acceleration of renewable technologies including solar, onshore and offshore wind, greater integration of battery and pumped storage hydro, expanded energy efficiency and demand response and deployment of new zero-emitting load-following resources such as nuclear SMRs, as well as hydrogen solutions in the longer term to achieve carbon neutrality by 2050. All resource types identified in each of the portfolios are likely to be needed either to achieve the interim 70% CO_2 emissions reduction targets or carbon neutrality over the longer term. The primary difference among the four portfolios largely relates to the pace of deployment.

Chapter 2 (Methodology and Key Assumptions) details the portfolio modeling inputs and assumptions, Chapter 3 (Portfolios) presents detailed information on the core Carbon Plan objectives and modeling outputs for each of the four portfolios (and corresponding alternate fuel case portfolios) included in the Plan, in addition to sensitivities of varying natural gas supply and prices, as well as technology capital costs for specific portfolios. Appendix E (Quantitative Analysis) provides additional modeling result details, including corresponding portfolios for the alternate fuel supply cases.

The following is a summary description of the four portfolios:

- **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.

- **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 by 2032.

- **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 the deployment of offshore wind. By extending the 70% interim target timeframe to 2034, this portfolio allows the first new nuclear unit (285 MW SMR), deployed in 2032, to contribute toward 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 by 2034 in this portfolio.

- **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 by 2034 in this Portfolio.

The following figures below present two distinct "snapshots" at two different points in time of the projected future resource mix under each of the four portfolios: Figure 6 provides a snapshot of the projected resource mix additions in the year in which 70% CO_2 emissions reductions are achieved (which varies across the four portfolios as discussed above) and Figure 7 provides a snapshot of the projected resource mix in 2035. By comparing and contrasting the portfolios, these figures, along with Table 1, illustrate how different mixes of resource types influence the pace and cost of the Companies' Carolinas' energy transition that supports ongoing reliable and affordable service while enabling future economic development in the Carolinas.

Figure 6: 70% Portfolio Snapshot at the Time of Achievement of Interim 70% Target (date of achievement varies across portfolios)

<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
IVVC growing to 96% (DEC) and 97% (DEP) circuits
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 rowspan="2"></td><td rowspan="2"></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></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.

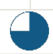
Figure 7: Portfolio Snapshot in 2035

<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
IVVC growing to 96% (DEC) and 97% (DEP) circuits
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.

As explained above, the Companies assessed each of the portfolios against four core Carbon Plan objectives - CO_2 reduction, affordability, reliability and executability. A summary of the results of the evaluation is provided in Table 1 below. As part of the evaluation, the Companies assessed the risk to achieving 70% CO_2 reduction by target year of each portfolio based on the complexity of execution associated with each portfolio in light of the technologies utilized and, importantly, the pace of deployment. The more a portfolio relies on technologies new to the Carolinas and the more substantial the pace and scale of deployment and dependence on constrained supply chains, the higher the risk of achieving 70% CO_2 reductions by the target year. The appendices for each resource type provide further background regarding such considerations. As shown in Table 1, portfolios with a more rapid progression toward 70% CO_2 reduction are projected to have greater impacts on customer costs. Further details regarding the core Carbon Plan objectives and the related quantitative analysis are provided in Chapter 3 (Portfolios).

Table 1: DEC/DEP Combined System Portfolio Results Table

CARBON PLAN PORTFOLIOS	P1		P2		P3		P4	
RESOURCES [MW] START OF YEAR (2030 | 2035)								
Total Contribution from Grid Edge & 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 & 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		$56		$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 & 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/yr | 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-hr and 6-hr 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

Planning for Coal Retirements

Under the oversight of the Commission and the PSCSC, the Companies have already made substantial progress in executing a planned, orderly emissions reduction trajectory over the past 11 years. Indeed, analyzing the need for and timing of coal-fired generating unit retirements are core components of the resource planning process, as evidenced by the retirement of 34 coal units totaling 4,200 MW since 2010. Orderly, planned retirement of such significant capacity resources across all portfolios mitigates fuel security and operational risks for customers and contributes significantly to CO_2 emissions reductions. The Companies' remaining coal units continue to provide year-round dispatchability that is especially critical during high load winter conditions and must be replaced by equally reliable resources.

The Companies utilized the enhanced modeling capability offered by EnCompass's capacity expansion model to perform coal unit retirement analysis within the Portfolio Development step.[27] As shown in Table 2 below, the projected coal unit retirement dates are substantially identical across all four portfolios, with the exception of Roxboro Units 3 and 4, with retirement of those units effective 2028 in P1, 2032 in P2 and 2034 in P3 and P4.

In all 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, the timing of actual retirements will ultimately be driven by the ability to place in service the necessary replacement resources and access to fuel supply. Decisive action is needed to achieve those outcomes as further described in the Execution Plan. By the end of 2035, and in order to maintain system reliability during peak periods, the only remaining unit would be Cliffside Unit 6, which would operate through the remainder of its economic life (through 2048) fueled by low-carbon natural gas. Table 2 summarizes the projected coal retirement dates across all four portfolios.

Table 2: Projected Coal Unit Retirements (effective by January 1 of year shown)

Unit[1]	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

[27] Appendix E (Quantitative Analysis) includes a detailed description of endogenous coal retirement analysis.

Unit[1]	Utility	Winter Capacity (MW)	Effective Year (Jan 1)
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 & 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.

Although the current coal units provide valuable capacity to maintain reliability through winter weather events, coal generation is a progressively small contributor to system energy needs and the average age of the Companies' remaining coal assets is now nearly 50 years. Operational risks of continued coal operation will only increase over time as these older units are called upon to run even more infrequently. In addition, coal supply chains continue to deteriorate, further increasing risk of continued coal operations for customers.[28] HB 951 recognized the importance of coal retirements to meet CO_2 emissions reductions targets by including provisions to facilitate securitization of subcritical coal assets that are retired early.[29] As the Companies continue the transition to cleaner energy sources, Duke Energy will engage and assist communities that experience adverse economic effects from fossil fuel plant closures, as well as consider locating replacement generation within those communities when feasible.

Grid Investments and Operational Flexibility Key to Energy Transition

Grid investments and operational flexibility are critically important to both the pace and the reliability of the energy transition. The Companies and stakeholders agree on the importance of timely and prudent transmission and distribution investments in both the near term and long term to enable the interconnection of an unprecedented amount of solar, storage and wind resources. Grid investments required for coal retirements and the additions of other new resources such as nuclear, flexible natural gas and energy storage are also critical to support grid stability. Additionally, efficient system operation optimizes costs for customers and creates operational flexibility to strengthen reliability consistent with the least cost and reliability provisions of HB 951.[30]

With respect to the transmission investments, the Companies are evaluating all potential options to leverage transmission planning to meet the Plan targets, including through the potential for proactive

[28] *See id.* for additional information on coal fuel supply.

[29] HB 951, Section 5.

[30] *Id.* Section 1.

transmission investments.[31] As identified in Chapter 4 (Execution Plan) and further discussed in Appendix P (Transmission Planning and Grid Transformation), the Companies are already engaging through the North Carolina Transmission Planning Collaborative ("NCTPC") to advance consideration of transmission projects in the near term that have been identified as needed to facilitate more solar interconnections and achieve targeted carbon reductions in a least cost manner while maintaining reliability. In addition, the Companies are exploring options for accelerating interconnection construction timelines.[32]

With respect to the distribution grid, the Companies are developing and implementing necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased adoption of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs and rate designs. Distribution grid control enhancement investments are foundational across all portfolios, improving flexibility to accommodate increasing levels of distribution-connected renewable resources while developing a more sustainable and efficient grid. The Companies continue to develop ISOP tools and processes to identify and prioritize future grid investment opportunities that can combine benefits of non-traditional solutions such as energy storage, innovative rate designs and customer programs to minimize total costs across distribution, transmission and generation.[33]

Finally, the grid operates as a holistic, interconnected system and various factors can cause rippling effects to grid operations as the resource mix changes and the system relies on higher levels of weather-dependent intermittent resources. Having flexibility through system operations and availability of fast-responding dispatchable resources is necessary to maintain all federally mandated NERC reliability standards and to maximize fuel and resource cost-effectiveness for customers. To that end, the Companies are pursuing consolidating DEC and DEP system operations to build upon the reliability and fuel efficiency benefits of the existing JDA.[34] Customers in North Carolina and South Carolina will benefit from flexibility, production cost savings, and simplification through a consolidated DEC and DEP system operations function. As discussed previously, the retirement of substantial coal units and integration of unprecedented amounts of intermittent renewables will require new flexible natural gas resources to balance the system during this energy transition,[35] a need underscored by NERC leadership.[36] The combination of consolidating system operations and implementing flexible dispatchable resources simultaneously manages costs and ensures reliability for customers.

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[31] *See* Appendix P (Transmission System Planning and Grid Transformation) for additional information.

[32] *See* Appendix I (Solar) for additional information.

[33] *See* Appendix S (Integrated System and Operations Planning) for additional information.

[34] *See* Appendix R (Consolidated System Operations) for additional information.

[35] *See* Appendix Q (Reliability and Operational Resilience Considerations) and Appendix M (Natural Gas) for additional information.

[36] James B. Robb & Mark Lauby, *3-D Grid Transformation: Mitigating the Risks,* Pub. Utils. Fortnightly, at 5 *available at* https://www.fortnightly.com/3-d-grid-transformation-mitigating-risks ("We must invest to maintain (and improve) the natural gas system's ability to meet the balancing and synchronization needed to assure reliability of the power sector").

Customer Financial Impacts

The Companies are committed to the continued provision of affordable electricity for residents, businesses, industries, and communities in the Carolinas. Seeking the appropriate pace of technology adoption to achieve CO_2 emissions reductions targets requires careful balancing of a variety of factors, including affordability. Throughout the Carbon Plan stakeholder process, stakeholders consistently reinforced the importance of mitigating cost impacts on customers and communities. While the Plan forecasts incremental system revenue requirements and system residential bill impact differences associated with each of the Plan portfolios, the projected cost impacts will change over time with evolving market conditions and policy mandates. Cost and bill impacts presented are associated with incremental resource retirements and additions identified in the Plan and as such do not include potential efficiencies, offsets, or costs in other parts of the business. Factors such as changing cost of capital, inflation, and changes in other costs will also influence future energy costs and will be incorporated in future Plan updates and forecasts as market conditions evolve. Finally, future cost of service allocators and rate design will impact how these costs are spread among the customer classes and, therefore, ultimate customer bill impacts.

The Companies have identified several additional strategies to manage costs during the energy transition. The Companies' Execution Plan outlined in Chapter 4 (Execution Plan) ensures the use of competitive procurements and other practices to ensure that the most cost-effective solutions are identified for the benefit of customers. This diligence includes market exploration to determine availability of cost-effective generating facilities and other resources for purchase and for third-party engineering, procurement, and construction efficiencies for both turnkey projects and component activities of projects. The Companies will pursue Infrastructure Investment and Jobs Act ("IIJA") opportunities to seek funding alternatives to benefit customers where feasible.[37] On a related note, the Low Income and Affordability Collaborative[38] has undertaken important work to address affordability of electric service for low-income customers. Finally, the EE/DSM Collaborative continues to seek cost-effective programs to reduce energy usage and modify load, resulting in customer and system savings.

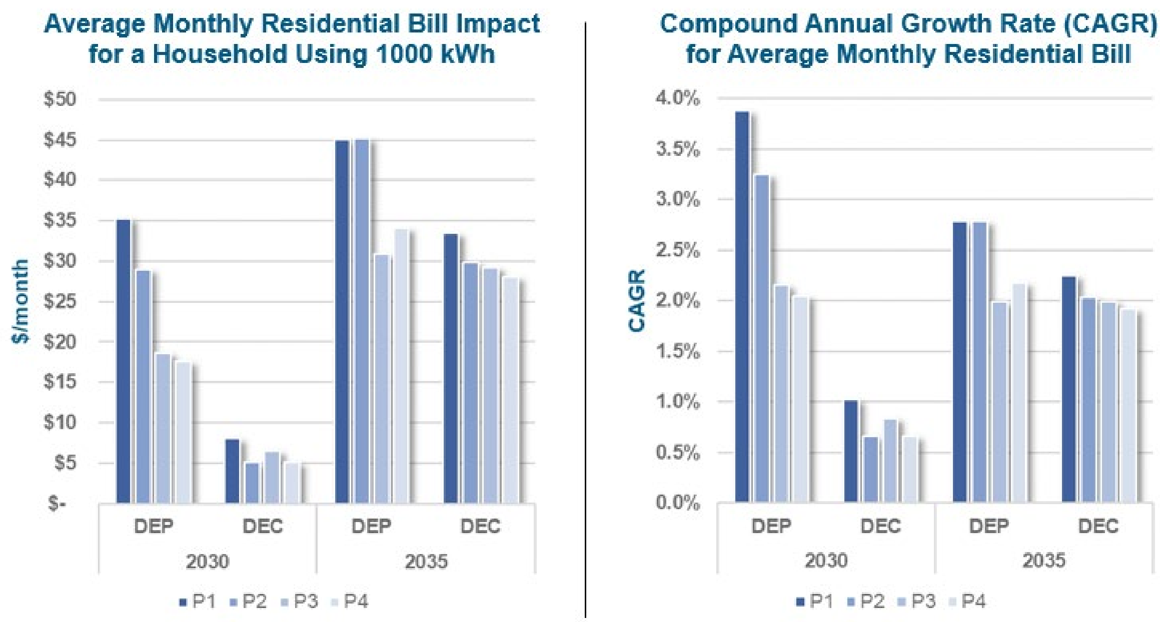
When developing the portfolios, the Companies applied least cost planning principles to achieve CO_2 reductions within specified constraints that reflect the availability and maturity of new resources. All portfolios utilize the most economic coal unit retirement date assumption, rather than relying on the depreciable lives of the coal units. The variation in timing of retirements and pace of new resource additions results in variations in incremental costs and customer bill impacts as shown in Figure 8 below. More specifically, due to the accelerated timeline for achievement of the interim target, Portfolio

[37] *See Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. M-100, Sub 164 (March 15, 2022) and *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. M-100, Sub 164 (April 14, 2022) (explaining Companies' plans to identify opportunities to use IIJA-related funds to offset customer costs).

[38] *Order Accepting Stipulations, Granting Partial Rate Increase and Requiring Customer Notice,* Docket Nos. E-2, Sub 1219 & Sub 1193 (April 16, 2021); *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice,* Docket Nos. E-7, Sub 1213, Sub 1214, and Sub 1187 (March 31, 2021).

1 has the most substantial bill impact by 2030. By 2035, the bill impact differences between P1 and P2 narrow but P3 and P4 continue to have a smaller bill impact relative to P1 and P2.

Figure 8: Intermediate-Term Residential Bill Impact by Portfolio



The Companies recognize the potential for further rate disparity across DEC and DEP, principally driven by optimal location of new generation and transmission investments required to meet CO_2 reduction targets. As discussed in Appendix R (Consolidated System Operations), the Companies will continue to evaluate potential solutions for the rate disparities, including whether a full merger of the DEC and DEP utilities is in the best long-term interests of our customers.

New Carbon Plan Execution Planning Framework

The Execution Plan in Chapter 4 (Execution Plan) provides a detailed summary of the steps the Companies will take, as well as key enablers needed to deliver Plan results. In addition, the Execution Plan identifies key "signposts" the Companies will monitor during execution to navigate Plan uncertainty.

The Execution Plan represents an evolution from the short-term action plan framework presented in past IRPs to a more detailed and comprehensive assessment of near-term actions, intermediate-term actions and long-term planning, with associated risk and signpost monitoring. Near-term actions are those activities in the 2022-2024 time frame needed to advance the Plan components across all portfolios and involves an all-of-the-above approach involving Grid Edge initiatives to shrink the challenge, optimizing existing assets (including through the continued, disciplined pursuit of Subsequent License Renewals ("SLR") for the Companies' existing nuclear fleet, which is a foundational need for the energy transition), pursuit of consolidated system operations and development and procurement activities for new supply-side resources.

With respect to supply-side resource, Table 3 below summarizes the near-term procurement and development activities proposed by the Companies for approval, which are prudent and orderly steps that support optionality beneficial to all portfolios.

Table 3: Supply-Side Resources Requiring Actions in Near-Term

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2029		
Carbon Plan Solar	3,100 MW	• Begin Public Policy Transmission projects in 2022[6] • Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage
Battery Storage	1,600 MW	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar
Onshore Wind	600 MW	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024
New CT[1]	800 MW	• Submit CPCN for 2 CTs totaling 800 MW in 2023
New CC[2]	1,200 MW	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability
Proposed Resource Development: Options for 70% Interim Target		
Offshore Wind[3]	800 MW	• Secure lease • Initiate development and permitting activities for 800 MW[7] • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission
New Nuclear[4]	570 MW	• Begin new nuclear early site permit ("ESP") for one site • Begin development activities for the first of two SMR units
Pumped Storage Hydro[5]	1,700 MW	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing

Note 1: CPCN for two CTs (800 MW) estimated for in-service 2027-2028
Note 2: CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
Note 3: Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
Note 4: New nuclear capacity represents first two SMR units, planned in-service date through 2034.
Note 5: Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
Note 6: Projects subject to North Carolina Transmission Planning Collaborative (“NCTPC”) approval.
Note 7: Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan (“SAP”); or ii) a combined SAP and Commercial Operation Plan.

As shown in Table 3 above and detailed further in Chapter 4 (Execution Plan), the Companies propose to implement substantial procurement and development activities for new supply-side resources in the near-term (2022-2024). These activities include the targeted procurement of 3,100 MW of solar to be in-service 2026-2028 (660 MW of which is assumed to include paired storage), along with the commencement of necessary transmission projects (pending NCTPC approval). The Companies will also seek to procure 600 MW of onshore wind and initiate development activities for 1,000 MW of batteries. With respect to natural gas, the Companies will need to begin developing 800 MW of CTs (two units at single site) and 1,200 MW of CCs (one unit) during the near term, which will also require subsequent CPCN proceedings projected to occur prior to the next biennial Carbon Plan update. In this respect, the Companies' near-term Execution Plan recognizes the importance of siting new natural gas at the Companies' retiring coal unit sites and also recognizes that prudent and least-cost development of new natural gas resources will be informed by future accessibility of Appalachian gas and provides a flexible path and pivot point by 2024 if firm transportation is not obtained. The Companies believe that it is appropriate for these resources to be deemed selected at this time for purposes of HB 951, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule.

In all cases, the Companies will leverage its procurement expertise to drive down costs for customers, in part, by identifying optimal resource locations in North Carolina or South Carolina. This procurement process will also ensure alignment between the costs assumed for modeling purposes and the actual prices delivered by the market and will provide substantial opportunities to "check and adjust" procurement activities as more refined and updated information is gathered and through further engagement with the Commission and the PSCSC in CPCN proceedings and other regulatory processes and updates.

Finally, the near-term activities include substantial development work on three longer lead time resources - offshore wind, SMR and new pumped storage hydro - all of which are likely to be needed either to achieve the interim 70% CO_2 emissions reductions target or carbon neutrality over the longer term. Such development work is needed both to gather information to provide a more refined cost estimate to the Commission in the 2024 Carbon Plan update, as well as to be positioned to implement such resources on a timeline consistent with the portfolios. As is explained in more detail in Chapter 4 (Execution Plan) and the applicable appendices, if the Companies do not undertake development activities in the near term for these long lead-time resources, such resources will not be available on the timelines contemplated by the portfolios. Finally, the Companies believe that it is reasonable for the Commission to approve these development activities as reasonable steps under the Carbon Plan, as well as the related accounting requests, for the reasons more fully described in Chapter 4 (Execution Plan). The Companies are not at this time requesting selection of these resources for purposes of HB 951, Section 1.(2), since such selection would be premature at this time before the Companies have detailed proposals with more defined cost estimates, projected construction timelines, *etc*. The Commission will be able to more fully consider the potential selection of these resources in future regulatory proceedings (such as the 2024 biennial Carbon Plan update) in which the Commission can consider in more detail the specific resource proposal and all related issues (*e.g.,* necessary cost recovery mechanisms).

Intermediate-term actions reflect activities in the planning period beyond 2022 to 2024 to achieve the interim 70% CO_2 emissions reductions target. For this planning period, the Companies present an intermediate-level of detail on business planning and regulatory execution strategy. Finally, long-term actions refer to those planning activities that support the 2050 carbon neutrality target. In this long-term planning period, the Plan presents a very high-level business planning and regulatory execution strategy, with long-term signpost monitoring.

Developing an Executable Plan to Advance the Energy Transition

The Companies' proposed Carbon Plan provides for the Commission a critical snapshot in time of four options for continuing the energy transition in the Carolinas, including further substantial progress in CO_2 emissions reductions that are consistent with prudent utility planning and the targets established under HB 951.

As described in more detail in Chapter 2 (Methodology and Key Assumptions) and Appendix G (Grid Edge and Customer Programs), the Companies' Carbon Plan modeling assumes nation-leading amounts of EE and DSM (targeting 4,230 MW of contribution by 2035 in all scenarios). These higher levels of EE and other demand-side options are not supported by current evaluation frameworks. Achieving the aggressive level of demand-side program growth assumed in the Carbon Plan will require changes to current cost/benefit processes to reflect their value on par with the cost of carbon-free supply-side alternatives such as wind, solar paired with storage or SMRs. To this end, after the conclusion of this proceeding, the Companies will proceed to propose appropriate changes to the derivation of utility system benefits as defined in the Companies' approved EE/DSM Cost Recovery Mechanism. These processes must necessarily follow this initial development of the Carbon Plan, but, once again for the sake of clarity, this Carbon Plan rests upon an assumption of substantial growth of EE/DSM.

As the Commission and intervenors consider this Carbon Plan, a number of key "lenses" should be applied:

- First, it is important to understand the difference in the purpose and intent of long-term planning versus plan execution. Long-term planning is, by nature, dependent on numerous modeling inputs and assumptions about future conditions that are based on a "snapshot in time" at the time the plan is developed. Based on the Companies' experience with prior IRPs, there will undoubtedly be some amount of disagreement from intervenors regarding certain key assumptions utilized in the Companies' modeling, though the Companies have sought to the greatest extent possible through the stakeholder process and past IRPs and Commission decisions to narrow the range of disputes. However, while that long-term view is crucial, Carbon Plan implementation will be equally (if not more so) guided by the real-world execution activities, which the Companies have described in Chapter 4 (Execution Plan). It may not be necessary for the Commission to resolve each and every dispute concerning modeling assumptions, when the outcome of such disputes do not fundamentally alter the activities needed in the near term.

- Second and relatedly, it is important to consider how the Carbon Plan will develop over time through the iterative process contemplated by HB 951 and through the coordinated input of the PSCSC. This initial Carbon Plan proceeding is certainly a crucial first step in the continued energy transition. But it is obviously not the final step. The next two-year period following the Commission's decision in this proceeding will offer substantially greater clarity and precision regarding a range of issues that will significantly impact the longer-term trajectory of the Carbon Plan. A crucial near-term post-2022 factor will be the PSCSC's review of the Carbon Plan in the 2023 IRP, which will provide important direction for further development of the Carbon Plan for the Companies' combined Carolinas systems. In addition, there is a wide range of other crucial information that will be gathered between now and the 2024 biennial Carbon Plan update as the Companies begin to execute the Carbon Plan. That information includes, but is not limited to, more refined cost estimates and timelines for technologies new to the Carolinas, the availability of pipeline capacity to source gas supply from Appalachia, more clarity on the longer-term state of supply chain challenges, more detailed market information gathered from procurement activities, and better estimates on timelines for long lead time grid transmission upgrades. In addition, numerous follow-on regulatory processes will be required prior to the next Carbon Plan biennial proceeding, including numerous CPCN proceedings for resources selected by the Commission in its initial plan and docketed proceedings regarding EE/DSM and customer programs. Such CPCN proceedings and other regulatory processes will provide ample opportunities for the Commission to assess more detailed market information, refined cost estimates and updated schedules to ensure alignment with the approved Carbon Plan trajectory. And future EE/DSM and customer program dockets will provide opportunities to build on the Carbon Plan through implementation of customer-facing programs and initiatives.

- Third, it is important to consider the execution plan over both the intermediate horizon and the long-term horizon contemplated by HB 951. While there are some important distinctions regarding pace in the various portfolios on the trajectory toward 70% CO_2 emissions reductions, those differences substantially diminish by 2035 and effectively disappear over the longer-term trajectory toward carbon neutrality in 2050. Stated differently, there will likely be some differences of perspective in this proceeding regarding the pace of implementation and technology focus in the short term; but, over the longer term, the energy transition undoubtedly will require a diversified all-of-the-above strategy including new and emerging technologies. Therefore, the near-term Execution Plan reflects a disciplined pursuit of a range of solutions, including near-term procurements and development of longer-lead time resources, some of which are new to the Carolinas resources (Onshore and Offshore Wind and SMR) and others of which are not (pumped hydro expansion). All such long-lead time resources (and more) will potentially ultimately be needed on the pathway to 2050 and therefore initial development work in the near term is beneficial in all future scenarios.

In summary, the near-term supply-side activities and enabling transmission represent the "reasonable steps" that are proposed by the Companies to continue the energy transition through 2024, at which point the Commission will have a further opportunity to "check and adjust" the strategy with the benefit of substantial additional and more refined information. As explained above and further throughout this

Plan, execution will be critical both with respect to the ability to achieve timelines assumed in the modeling but also with respect to providing the Commission a more refined Plan in the future. Over the next few years, timelines and costs assumed in the modeling will either be validated or challenged by the real-world execution path and such information will be used to refine strategies and improve benefits for customers.

To be clear, the near-term supply-side activities proposed by the Companies are meaningful and varied and will leverage all available demand- and supply-side resources to accelerate the energy transition. The Companies are proposing definitive next steps with respect to the procurement of solar, batteries, onshore wind, and transmission upgrades. The Companies are also proposing for Commission approval definitive but preliminary steps with respect to the development of CTs, CCs, offshore wind, nuclear and pumped hydro - in all of those cases, the Commission will have further opportunity to review and assess such resources either through subsequent regulatory processes (*i.e.,* a CPCN proceeding) or the next biennial Carbon Plan process.

The Companies request that the Commission approve the Companies' proposed Carbon Plan in its entirety, which includes both a defined set of near-term procurement and development activities and four primary portfolios that allow for flexibility over time, instead of approving a single portfolio which would be premature at this time before more information is gathered regarding the longer-lead time supply side resources. Stated differently, the Companies believe that the Commission should approve the proposed near-term activities and further affirm that the Companies' Carbon Plan modeling across all portfolios is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning. At the time the 2024 Carbon Plan update is filed, 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 both the interim and long-term targets.

Achievement of the energy transition, particularly over the long term, will likely require breakthrough technologies, as is contemplated by HB 951. The Companies are engaged throughout the industry in monitoring and assessing potential breakthrough technologies that have the greatest potential for benefit to customers. Ultimately, it may be prudent for the Commission to approve and the Companies to pursue one or more such breakthrough technologies in order to facilitate and even hasten industry and technology evolution. Such initiatives could be particularly beneficial where the Companies are able to leverage partnerships and external funding for the benefit of customers and gain experience in real-world operation on a small scale before large-scale deployment. The Companies are currently evaluating a number of such opportunities involving long-duration storage and hydrogen production, storage, transportation and generation.

Going forward, the Companies will remain laser focused on both reliability and affordability. Specifically, as the Companies gather more information and increasing amounts of new resources are added to the system, the Companies will continually reassess whether the existing reliability of the system is being maintained or improved as is required under HB 951. The projected retirement timelines for existing coal units will remain inextricably linked to the timeline for completion of replacement resources needed to ensure reliability - delays in the completion of replacements will necessarily cause the Companies to readjust schedules as needed to ensure reliability. Similarly, the strategy over time will be adjusted to the extent that cost impacts over time materially diverge from projected impacts.

Closing and Summary of Requests to Commission

The Plan proposed herein provides a comprehensive and detailed analysis supporting the continued energy transition that is balanced, reasonable and executable and importantly, will ensure reliable electric service for the Companies' customers at affordable rates over the short and long term. Duke Energy looks forward to continued engagement and collaboration regarding the Plan in this proceeding with Public Staff and intervenors and to further engagement with regulators and stakeholders in the future as the Plan evolves.

The Companies request that the Commission adopt the Companies' proposed Plan and make the following specific findings:

- Affirm that the Companies' Carbon Plan modeling is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning;

- Approve the near-term supply-side development and procurement activities identified above in Table 3, including by

    - Deeming the following resources as being selected in this initial Carbon Plan for purposes of HB 951, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule:

        - 3,100 MW of solar generation (including 750 MW requested to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired storage;

        - 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar);

        - 600 MW of onshore wind;

        - 800 MW of CTs; and

        - 1,200 MW of CC

    - Approving the Companies' plans to pursue initial development activities to support the future availability of offshore wind, SMRs and new pumped storage hydro at Bad Creek to ensure that these resources are available options for the Companies' customers on the timelines identified the portfolios if selected in future Carbon Plan updates;

- Making the following additional determinations with respect to the project development activities summarized in Table 3:

  - Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;

  - To the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and

  - That in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time.

- Approve the Companies' proposed actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of SLRs for the Companies' existing nuclear fleet;

- Approve the Companies' plans to advance Grid Edge and Customer Programs and to update the underlying the determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism;

- Acknowledge that HB 951 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the Open Access Transmission Tariff and direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the North Carolina Transmission Planning Collaborative and other appropriate forums;

- Approve the Companies methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking achievement of HB 951's CO_2 emissions reductions targets and confirm the Commission's accounting requirements for emissions from new out-of-state resources selected by the Commission (if any) as described above;

- Affirm that the first biennial Carbon Plan update proceeding should be held in 2024 and that the Companies' next biennial IRPs will be held in abeyance to 2024 to align with the Carbon Plan update, as further discussed in Chapter 4 (Execution Plan); and
- Direct the Companies and Public Staff to develop and propose for comment by January 31, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan	))))	ORDER ADOPTING INITIAL CARBON PLAN AND PROVIDING DIRECTION FOR FUTURE PLANNING

HEARD: Monday, July 11, 2022, at 7:00 p.m., in Courtroom D7, Durham County Courthouse, 510 S. Dillard St., Durham, North Carolina 27701

Tuesday, July 12, 2022, at 7:00 p.m., in Courtroom 317, New Hanover County Courthouse, 316 Princess Street Wilmington, North Carolina 28401

Wednesday, July 27, 2022, at 7:00 p.m., in Courtroom 1-A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina 28801

Thursday, July 28, 2022, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 E. 4th Street Charlotte, North Carolina 28202

Tuesday, August 23, 2022, at 1:30 p.m. and 4:30 p.m. via Webex

Tuesday, September 13, 2022, at 9:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, Floyd B. McKissick, Jr., and Karen M. Kemerait

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INDEX TO SUBSTANTIVE ISSUES

I. PRELIMINARY MATTERS AND CONTEXT

BY THE COMMISSION: On October 13, 2021, Governor Cooper signed into law House Bill 951 (S.L. 2021-165). Section 1 of S.L. 2021-165, codified as N.C. Gen. Stat. § 62-110.9, directs the Commission to take all reasonable steps to reduce carbon dioxide emissions originating from electric generating facilities owned or operated by Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC; together with DEP, Duke), in the state. More specifically, the statute directs the Commission to develop by December 31, 2022, a plan (the Carbon Plan) to achieve a 70% reduction in carbon dioxide emissions from 2005 levels (Interim Target) by the year 2030, subject to certain discretionary conditions, and carbon dioxide neutrality by the year 2050 (2050 Target). Section 62-110.9(4) affords the Commission flexibility in implementing the statute, including the ability to delay the achievement of the carbon dioxide emissions reduction mandates by up to two years, or longer if construction of a nuclear or wind energy facility requires additional time or if delay is necessary to maintain reliability of the grid. The statute further directs the Commission to review the plan every two years after the adoption of the initial Carbon Plan. In planning resources to achieve the carbon dioxide emissions reduction mandates, the statute requires that the Commission adhere to the principle of least cost planning and ensure the maintenance of reliability. Finally, N.C.G.S. § 62-110.9 requires that the development of the Carbon Plan include stakeholder input.

Relatedly, N.C.G.S. § 62-110.1(c) requires the Commission to analyze the long-range needs for expansion of facilities for the generation of electricity in North Carolina. To meet the requirements of this statute, Commission Rule R8-60 requires that all electric public utilities develop an Integrated Resource Plan (IRP) and provide details of that IRP to the Commission with a biennial report in even-numbered years. Given the overlap between the planning and execution components of N.C.G.S. § 62-110.9 and the planning requirements of N.C.G.S. § 62-110.1(c), the Commission finds good cause to synchronize proceedings advancing these two purposes, going forward, as the Commission further directs herein.

The findings of fact, supporting evidence, and resulting conclusions and directives presented in this Order represent the Commission's initial Carbon Plan, per N.C.G.S. § 62-110.9. The Commission has developed this initial Carbon Plan based upon competent, material, and substantial evidence Duke and the intervening parties presented, and upon the sworn testimony of public witnesses and public comment.

N.C.G.S. § 62-110.9 requires the Commission to direct and oversee the continued transformation of the electric system in North Carolina toward carbon dioxide neutrality. The guidance the General Assembly provided to the Commission for this task is clear: the Commission must find the least cost path to compliance with the carbon dioxide emissions reduction requirements while maintaining or improving the reliability of the electric system. Developing the path to least cost compliance with the carbon dioxide emissions reductions that the law requires is complex and will, necessarily, be an iterative process given the rapid pace of change of the electric industry. In fulfilling its obligation, the Commission has endeavored to balance the need for action in the immediate term against the deferral of actions when doing so is in the best interest of customers and the reliable operation of the electric system. In undertaking this task, the Commission has considered the need for urgency that certain circumstances related to the transition dictate but has been, and must continue to be, mindful of the rapid pace of change and associated potential benefits that could inure to customers in the future.

The least cost path to compliance has been and will continue to be squarely within the Commission's focus. To this end, the Commission expects and will direct Duke to investigate and to doggedly pursue every opportunity to apply downward pressure on rates and to optimize the use of the electric system to reduce system average cost. A reduced system average cost will benefit all customers. The work of the Low-Income Affordability Collaborative, presented most recently in its final report filed with the Commission, reveals, starkly, the magnitude of the challenges that a significant percentage of residential customers in North Carolina face and underscores the need for Duke, and this Commission, to pursue every chance to apply downward pressure on rates. Joint North Carolina Low-Income Affordability Collaborative Quarterly Progress Report, Docket Nos. E-7, Subs 1187, 1213, and 1214 and E-2, Subs 1219 and 1193 (Aug. 12, 2022). To this end, the Commission has expected and will continue to expect Duke to pursue every opportunity that may arise through tax incentives or federal funding to benefit its customers. In fact, even since the outset of this proceeding merely 14 months ago, we have experienced a bellwether for the significant escalation of the transformation and very likely a reduction in cost with the passage of the Inflation Reduction Act of 2022 (the IRA) on August 16, 2022. But the implications of the IRA on costs that Duke will incur and, therefore, the implications for Duke's customers remain mostly unknown. For this reason and others, the Commission must maintain the ability and flexibility to adapt, as necessary, to this dynamism.

The statute unambiguously directs the Commission to guard the reliability of the electric system. For many decades, the electric system has served North Carolina well. This record will continue. However, the transformation of the electric system — both in terms of the changing mix of generating resources and the changing ways in which customers are relying on the system — brings with it new challenges for system operators. As the system transitions to include more weather-dependent and time-limited resources, system operators must have an increasingly diverse and flexible set of tools to anticipate and address the challenges that arise. The increasing electrification of home heating influences (and, increasingly, so might the electrification of transportation) the timing and extent of peak demand in the winter, placing stress on the electric system. Additionally, extreme events — be they related to weather, cybersecurity, fuel supply, and the like — pose an additional risk to the electric system which the utilities and the Commission must navigate and account for amidst the transformation. Indeed, the North American Electric Reliability Corporation (NERC), the federal regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid, has acknowledged that traditional resource planning methods may not consider the real-world grid impacts and interactions of an evolving resource mix with less baseload generation and more variable generation, inverter-based resources, storage, and distributed energy resources (DERs), leading to potential generation or transmission insufficiencies. Tr. vol. 19, 133. Additionally, NERC's 2022-2023 Winter Reliability Assessment, which evaluates the generation resource and transmission system adequacy needed to meet projected winter peak demands and operating reserves as well as identifies potential reliability issues for the 2022–2023 winter period, notes that in the SERC-E region, which includes North Carolina, shrinking capacity and demand growth cause a risk of shortfall in extreme cold weather events. 2022–2023 Winter Reliability Assessment of the North American Electric Reliability Corporation at 21 (Nov. 17, 2022).[1] The emergency outage events experienced by some Duke customers in late December of this year during extreme cold temperatures provides a sobering example of the consequences to customers during times of stress on the electric system and underscores the vigilance with which the Commission must act in overseeing the utilities' planning efforts and implementation of the carbon dioxide emissions reductions to ensure that appropriate replacement generating units and associated transmission infrastructure are in service before existing generating units are retired.

PROCEDURAL HISTORY

Over the course of this proceeding, the Commission has issued numerous procedural orders, and the parties hereto have filed many pleadings, all of which are a matter of record herein. The following is a summary of only the most pertinent occurrences.

Stakeholder Process, Intervening Parties, Comments, and Expert Witness Hearing

On November 19, 2021, the Commission issued an Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines (November 19, 2021 Order) which states that, in developing the Carbon Plan, the Commission will look to, but will not strictly adhere to, Commission Rule R8-60. The November 19, 2021 Order acknowledges the overlap between the IRP process pursuant to N.C.G.S. § 62-110.1(c) and the analyses required to meet the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9, and further states an intent to eventually synchronize the IRP and Carbon Plan processes. Also, the November 19, 2021 Order delays DEC's and DEP's next comprehensive IRP filings that Commission Rule R8-60(h)(1) requires to September 2023 and forecasts that the Commission will undertake a rulemaking process separate from the Carbon Plan proceeding to revise Commission Rule R8-60 to synchronize the Carbon Plan and IRP proceedings. Finally, the November 19, 2021 Order directs Duke to conduct at least three stakeholder meetings consistent with the stakeholder input directive of N.C.G.S. § 62-110.9(1) before filing its Carbon Plan proposal.

The intervention and participation of the North Carolina Utilities Commission – Public Staff (Public Staff), an independent agency tasked with representing consumer interests before the Commission, has been recognized pursuant to N.C.G.S. § 62-15(d), and N.C.G.S. § 62-20 affords the North Carolina Attorney General's Office (AGO) intervention in Commission proceedings. In addition to the Public Staff and the AGO, the Commission granted numerous additional parties intervention in this proceeding: Appalachian Voices; Apple Inc., Google LLC, and Meta Platforms, Inc., (appearing jointly as Tech Customers); Avangrid Renewables, LLC (Avangrid); Brad Rouse; Broad River

[1] Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

Energy, LLC (Broad River); the Carolina Industrial Group for Fair Utility Rates II and the Carolina Industrial Group for Fair Utility Rates III (appearing jointly as CIGFUR); the Carolina Utility Customers Association, Inc. (CUCA); the Carolinas Clean Energy Business Association (CCEBA); the City of Asheville and Buncombe County (appearing jointly as Asheville et al.); the City of Charlotte (Charlotte); the Clean Energy Buyers Association (CEBA); the Clean Power Suppliers Association (CPSA); ElectriCities of North Carolina, Inc. (Electricities), the North Carolina Eastern Municipal Power Agency, and the North Carolina Municipal Power Agency Number 1 (appearing jointly as the Power Agencies); the Environmental Justice Community Action Network and the Down East Coal Ash Environmental and Social Justice Coalition (appearing jointly as EJCAN et al.); the Environmental Working Group (EWG); Fayetteville Public Works Commission (FPWC); Kingfisher Energy Holdings, LLC (Kingfisher); MAREC Action (MAREC); NAACP Charlotte-Mecklenburg County Branch #5376-B (Charlotte-Mecklenburg NAACP); NC WARN; the North Carolina Alliance to Protect our People and the Places We Live (NC-APPPL); the North Carolina Council of Churches (Council of Churches); the North Carolina Electric Membership Corporation (NCEMC); the North Carolina Pork Council (Pork Council); the North Carolina Sustainable Energy Association (NCSEA); Person County; Sean Lewis; the Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council (appearing jointly as SACE et al.); the RedTailed Hawk Collective and the Robeson County Cooperative for Sustainable Development (appearing jointly, along with EJCAN et al., as RTHC et al.); TotalEnergies Renewables USA, LLC (TotalEnergies); Walmart Inc. (Walmart); and 350 Triangle.

The Commission held three conferences, occurring on February 7, 2022, March 7, 2022, and April 4, 2022, for parties to update the Commission on the sufficiency of the Duke-led stakeholder meetings as they occurred.

Consistent with the Commission's directive, Duke filed its Carbon Plan proposal on May 16, 2022. On July 15, 2022, the Commission received comments and alternative proposed Carbon Plans from certain intervenors. On July 29, 2022, the Commission scheduled a hearing to receive expert witness testimony into the record for the purpose of informing the Commission's analysis and development of the initial Carbon Plan. The Commission also allowed parties to file responsive comments on specific, designated legal issues by September 9, 2022. This matter came before the Commission for an expert witness hearing beginning on September 13, 2022, and continuing through September 29, 2022, during which the Commission received expert witness testimony and exhibits from the following parties: Duke, the Public Staff, the AGO, Appalachian Voices, Tech Customers, Avangrid, Brad Rouse, CIGFUR, CUCA, CCEBA and MAREC, jointly, CPSA, EWG, the Charlotte-Mecklenburg NAACP and NC WARN, jointly, NCEMC, and NCSEA and SACE et al., jointly. At the conclusion of the expert witness hearing, the Commission directed parties to file post hearing proposed orders and briefs by October 24, 2022.

Public Witness Hearings and Consumer Statements

In addition to the expert witness hearing, the Commission conducted five public witness hearings to receive testimony from members of the public, four at locations across the state and one remotely via two separate Webex sessions on Tuesday, August 23, 2022. The four in-person hearings took place as follows:

> Monday, July 11, 2022, at 7:00 p.m., in Courtroom D7, Durham County Courthouse, 510 South Dillard Street, Durham, North Carolina 27701
>
> Tuesday, July 12, 2022, at 7:00 p.m., in Courthouse Courtroom 317, New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina 28401
>
> Wednesday, July 27, 2022, at 7:00 p.m., in Courtroom 1-A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina 28801
>
> Thursday, July 28, 2022, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 East 4th Street, Charlotte, North Carolina 28202

The following persons appeared and testified at the public witness hearings:

> Monday, July 11, 2022, in Durham: Gordon Phillip Allen, David Sokal, Tobin Freid, William Terry, Lieceng Zhu, Russ Outcalt, Jason Torian, Jessica Rowe, Montravias King, Bobby Jones, Hope Gattis, Aaron Hope, Robby Phillips, Peter Morcombe, Scott Cline, Rachel Woods, Katie Craig, William Scott, Dan Figgins, Dale Evarts, Lois Nelson, Daksh Arora, Denise Frizzell, Lib Hutchby, Claudia Berry Hill, Thomas Carlyle Dowd, Ziyad Habash, Betsy Bickel, Lauren Nadine Martin, Barry Strock, Michael Audie, Keval Khalsa, Maple Mary Ann Osterbrink, David Allen Kirkpatrick, Geraldine Nelson, and Gary Nelson
>
> Tuesday, July 12, 2022, in Wilmington: Alexander Brown, Esther Murphy, Ivan Bartley, Beth Hansen, Carl Parker, Deborah Dicks Maxwell, Rachel Mitchell, Robert Parr, M.D., Isabella Peadon, Lindsey Hallock, Paul Summers, Andy Wood, and Marcel McFadden
>
> Wednesday, July 27, 2022, in Asheville: Sherry Vaughan, Steven Norris, Lauren Steiner, Pam Brown, Rob Denton, Melanie Chopko, Gray Jernigan, Carlton Angell, Maggie Ullman Berthiaume, Shannon Bodeau, Steffi Rousch, Anne Craig, Clare Hanrahan, Phil Bisesi, Melody Shank, Elsa Enstrom, Shelby Cline, Maureen Linneman, Tim Birthisel, Sawyer Bryan, Cathy Scott, John Ager, Kendall Hale, Jodi Lasseter, Rachel Bliss, Mary Olson, Patrick Sawyer, Richard Fireman, Joe Beckham, Judy Mattox, Farah Ogletree, Michael Churchman, Ken Brame, Drew Ball, Ruffin Shackleford, Bruce Santorini, Don Nicholson, Holly Beveridge, Sophie Loeb, and Sara Tew
>
> Thursday, July 28, 2022, in Charlotte: Billie Anderson, June Blotnick, Majeed Ederer, Babak Mokari, Karen Hodges, Amy Brooks Paradise, Jennifer Roberts, Tina Katsanos, Hannah Stephens, Lisa Huntting, Tom Lannin, Meg Houlihan, Donna Durfee, Lawrence Toliver, Brenda Gasior, Faith Silva, Michelle Carr, Jill Palmer, Debbie Foster, Beth Henry, Susan Tompkins, Janet Palmer, John

Gaertner, Matthew Withrow, Jeff Robbins, Keith Banner, Mary Jo Klingel, David Walsh, Nancy Neely, Skip Hudspeth, John Rochester, Maria Portoue, Jerome Wagner, Martin Fiedler, and Bailey Scarlet

Tuesday, August 23, 2022, via Webex: William McNeil, Mary Abrams, David McGowan, Jane Barnett, Pam Hemminger, Kathleen Liebowitz, Jean Pudlo, Kay Reibold, Katherine Wyszkowski, Michael Totten, Barron Northrup, John Wait, Maren Mahoney, Peter Krull, and Nancy Carter

Public witness testimony covered a variety of topics relating to Duke's Carbon Plan proposal and the intervenors' alternative proposed Carbon Plans. Public witnesses represented the diversity of North Carolina's populace, ranging from retirees, doctors, physicists, college and high school students, and environmentalists. Additionally, public witnesses offered eclectic opinions varying from disapproval to approval of Duke's Carbon Plan proposal.

The Commission heard witnesses' criticisms of Duke's Carbon Plan proposal and the Commission's approach in developing the initial Carbon Plan. Witnesses expressed particular concern that the Commission tasked Duke with preparing the primary draft Carbon Plan proposal and urged the Commission to take a more active role in developing the Carbon Plan. Several witnesses noted that three of Duke's four proposed portfolios fail to achieve the Interim Target by 2030. Public witnesses expressed apprehension about the practicality of using unproven technologies such as small modular reactors (SMRs) and hydrogen-fueled turbines to produce energy. Witnesses questioned Duke's continued reliance on nuclear and natural gas-fired generation and the pace of the retirements of Duke's coal fleet.

Witnesses stated their preference for renewable generation, including wind, solar, and hydropower, and for more aggressive implementation of energy efficiency (EE) measures, battery storage, and improvements to the transmission grid. Further, public witnesses testified about the adverse impacts of climate change, such as the recent abnormal number of storms resulting in significant property damage throughout North Carolina, especially the coastal region. Witnesses testified about persons and communities often hardest hit by climate change, including those of low-to-moderate income levels and people of color, who because of excessive power bills and the cost of electric bills, often must make difficult decisions prioritizing basic necessities.

Some witnesses raised concerns about the potential for adverse impacts to their communities, such as those to Roxboro's local economy where Duke plans to retire coal plants. These witnesses requested that Duke site replacement generation in those communities or that the Commission defer coal plant retirements.

Witnesses also testified about the negative correlation between climate change and public health. Witnesses pointed to the increase in cases of asthma, post-traumatic stress disorder, and a person's lack of physical activity due to extreme temperatures.

Additionally, witnesses opined that climate change will have a profound effect on agriculture, resulting in a shortage of certain foods.

Witnesses expressed concern regarding Duke's lack of communication to the public about renewable energy education and information, specifically information about rebates and incentives encouraging customers to adopt renewable energy technologies.

Finally, a public witness at the Wilmington public hearing testified specifically that Duke's environmental justice outreach about its proposed Carbon Plan had been inadequate. Tr. vol. 2, 29-32.

In addition to receiving testimony from public witnesses, the Commission also accepted consumer statements from interested members of the general public. In total, members of the public filed more than 489 consumer statements in Docket No. E-100, Sub 179CS. Similar to the testimony received by the witnesses at the public hearings, the consumer statements covered a variety of topics relating to Duke's Carbon Plan proposal, including expressing support for renewable energy resources and stating opposition to new nuclear generation resources.

JURISDICTION

No party has contested the fact that DEC and DEP are public utilities subject to the Commission's jurisdiction pursuant to the Public Utilities Act. DEC and DEP are "electric public utility[ies] as defined in N.C.G.S. § 62-3(23) serving at least 150,000 North Carolina retail jurisdictional customers as of January 1, 2021[,]" and, therefore, are subject to N.C.G.S. § 62-110.9. Based upon the foregoing, the Commission concludes that it has personal jurisdiction over DEC and DEP and subject matter jurisdiction over the matters presented in this proceeding.

STANDARD OF REVIEW

The Public Utilities Act establishes state policy to promote adequate, reliable, and economical utility service. The Public Utilities Act further tasks the Commission with developing resource plans to ensure sufficient resources to meet future load growth and provide for adequate, reliable utility service achieved via the least cost mix of generation and demand-reduction measures. N.C. Gen. Stat. §§ 62-2 and 62-110.1(c).

As noted above, the Commission's November 19, 2021 Order states that the Commission will look to, but will not strictly adhere to, Commission Rule R8-60 in developing the Carbon Plan. Commission Rule R8-60 outlines the IRP planning process, in which the Commission investigates utility proposals to implement "the least cost mix of generation and demand-reduction measures" to meet electric power requirements in North Carolina. N.C.G.S. §§ 62-2(a)(3a) and 62-110.1(c). Pursuant to Commission Rule R8-60(g), the utility must consider all "potential resource options and combinations of resource options to serve its system needs." Furthermore, utility proposals "should take into account, as applicable, system operations, environmental impacts, and other qualitative factors." *Id.*

When fulfilling its resource planning duties, the Commission also acts in a legislative capacity. In *State ex rel. Utils. Comm'n v. N.C. Elec. Membership Corp.*, 105 N.C. App. 136, 412 S.E.2d 166 (1992), addressing the character of proceedings relating to utilities' IRPs, the Court of Appeals stated: "[T]he least cost planning proceeding should bear a much closer resemblance to a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions may be made at a later time." *Id*. at 144, 412 S.E.2d at 170. As a result, the Commission views information and data that it receives through comments, reply comments, consumer statements of position, and legal briefs as information the Commission should consider and use in its investigation and decision-making process when developing resource plans.

Further, "[f]or the purpose of conducting hearings, making decisions and issuing orders, and in formal investigations where a record is made of testimony under oath, the Commission shall be deemed to exercise functions judicial in nature . . . . " N.C.G.S. § 62-60. In developing the Carbon Plan, the Commission has acted in a judicial capacity by conducting hearings to receive evidence, including testimony under oath, consistent with its authority pursuant to N.C.G.S. § 62-60.

When acting as a court of record, the Commission must apply the rules of evidence "in so far as practicable" and must base its decision upon competent, material, and substantial evidence upon consideration of the whole record. N.C.G.S. § 62-65(a). The Commission may in its discretion exclude incompetent, irrelevant, immaterial, and unduly repetitious or cumulative evidence. *Id.* Further, "[a]ll evidence, including records and documents in the possession of the Commission of which it desires to avail itself, shall be made a part of the record in the case by definite reference thereto at the hearing." *Id.*

In addition to considering the record evidence, the Commission may take judicial notice of credible sources including its decisions, published reports of federal regulatory agencies, state and federal statutes, public information, data that official state and federal agencies publish, and generally recognized technical and scientific facts within the Commission's specialized knowledge. N.C.G.S. § 62-65(b).

Taking competency into consideration, the Commission determines the appropriate weight it will give to any particular piece of evidence or other information received during its analysis and development of the Carbon Plan. Ultimately, the Commission must base its decisions regarding the Carbon Plan upon competent, material, and substantial evidence it derives through consideration of the whole record. N.C.G.S. § 62-65(a).

SUMMARY OF PROPOSED CARBON PLAN PORTFOLIOS

Duke and the intervening parties have presented the Commission with a number of portfolios that aim to achieve the Interim Target as well as the 2050 Target. This section briefly summarizes the portfolios that Duke and the intervening parties have presented.

The following sections will provide additional detail and analysis of these portfolios, as necessary, in the context of specific resources and the related discussion and conclusions by the Commission.

Duke's Proposed Portfolios

Duke's Carbon Plan proposal includes four distinct portfolios designed to illustrate two potential pathways to achieving the Interim Target by replacing its coal fleet with new generation and other resources.

Presently, Duke relies upon approximately 9,294 megawatts (MW) of coal-fired generation, all sited within the state, representing roughly 25% of its total system[2] generating capacity. In order to meet the directives of N.C.G.S. § 62-110.9, Duke proposes to retire the vast majority of its coal fleet (8,445 MW).[3] Duke's proposed coal fleet retirements are mostly consistent across the four portfolios. Portfolios 1 through 4 (P1, P2, P3, and P4, respectively) commonly retire Allen Units 1 and 5 in 2024; Cliffside Unit 5 in 2026; Marshall Units 1 and 2, Mayo Unit 1, and Roxboro Units 1 and 2 in 2029; Marshall Units 3 and 4 in 2033; and Belews Creek Units 1 and 2 in 2036. Roxboro Units 3 and 4 retirements vary between portfolios, with retirement of those units effective in 2028 in P1, in 2032 in P2, and in 2034 in P3 and P4.

P1 achieves the Interim Target by 2030. Portfolios 2-4 take advantage of the Commission's limited discretion to extend the Interim Target compliance date. More particularly, P2 achieves the Interim Target by 2032; P3 achieves the Interim Target by 2034 by incorporating a 285 MW SMR; and P4 achieves the Interim Target by 2034 by incorporating a 285 MW SMR but with other resource selection variances from P3.

All of Duke's proposed portfolios incorporate demand response and EE measures, new solar generation, new natural gas-powered combined cycle (CC) and combustion turbine (CT) generation, battery storage capacity, and onshore wind to achieve the Interim Target. In addition to these baseline resources, P1 utilizes offshore wind generation to achieve compliance with the Interim Target by 2030. Compared to P1, P2 incorporates offshore wind generation, additional onshore wind generation, and slightly less battery storage capacity to achieve compliance with the Interim Target by 2032. P3 foregoes offshore wind but utilizes SMR capacity to achieve the Interim Target by 2034. Finally, P4 achieves the Interim Target by 2034 with offshore wind again in the mix but with slightly reduced CT capacity.

Duke's proposed portfolios range in projected costs through 2050 between $95 billion and $101 billion in present value revenue requirement (PVRR). Duke projects P1 to be the costliest of its proposed portfolios and projects P3 to be the least costly. P1

[2] As used herein, "total system" refers to the combined DEP and DEC North Carolina and South Carolina systems.

[3] Duke does not slate Cliffside 6, which is capable of operating 100% on natural gas, for retirement but assumes that it will cease coal operations by the beginning of 2036.

achieves the greatest carbon dioxide emissions reduction for the state, leading all portfolios in carbon dioxide emissions reductions by both 2030 and 2035, while P4 has the least impact on carbon dioxide emissions within the same timeframes. Finally, Duke assesses P1 as carrying the greatest level of risk to achieving the Interim Target, with P4 being the least risky.

Public Staff's Proposed Portfolios

During the proceeding, Duke developed two proposed supplemental portfolios (SP5 and SP6) based upon various recommendations by the Public Staff, the AGO, and CPSA. SP5 achieves the Interim Target by 2032, and SP6 achieves the Interim Target by 2034. The supplemental portfolios push back the retirement of Belews Creek Units 1 and 2 to 2037 with continued operation on both coal and gas. Both SP5 and SP6 primarily add new solar generation, onshore wind, and battery storage to achieve the Interim Target. SP6 uses pumped hydro storage, but SP5 does not do so until after Duke achieves the Interim Target. Neither SP5 nor SP6 rely on offshore wind to achieve the Interim Target. In modeling SP5 and SP6, Duke allowed the EnCompass model to optimize charging and discharging of battery storage paired with solar generation (Solar Plus Storage) facilities and removed cumulative limits on 4-hour and 6-hour batteries. SP5 and SP6 do not employ hydrogen (H_2) as a fuel blended with natural gas, and Duke's modeling allowed for the selection of both J-class and F-class CTs and CCs and used retirement dates for existing CTs that match the most recent depreciation studies. Also, SP5 and SP6 assume that Duke will not have access to natural gas from the Mountain Valley Pipeline (MVP) expansion. Finally, Duke modeled a higher limit on annual solar interconnections.

Intervenors' Proposed Portfolios

The AGO engaged Strategen, a consulting firm, to conduct a supplemental portfolio analysis. The AGO's proposed portfolio built upon the SP5 portfolio but included several modifications. Namely, the AGO's portfolio: (a) removed cumulative limits on Solar Plus Storage facilities; (b) set the useful life of new natural gas-fired facilities to 20 years; (3) economically selected coal retirement dates and converted Belews Creek Units 1 and 2 to 100% natural gas by 2028; (4) adjusted solar limits; (5) increased annual import limits using non-firm transmission; and (6) met the Interim Target by 2030. The AGO's proposed portfolio has a PVRR through 2050 of $100 billion.

CPSA engaged the Brattle Group to perform five alternative portfolio analyses: CPSA1-CPSA5. CPSA1 meets the Interim Target by 2030 and has no cap on solar capacity additions. CPSA2 and CPSA3 also meet the Interim Target by 2030 and are alternatives to Duke's P1: CPSA2 uses Duke's solar cap while CPSA3 uses a higher cap on solar interconnections. CPSA4 and CPSA5 meet the Interim Target by 2032 and are alternatives to Duke's P2: CPSA4 uses Duke's solar cap while CPSA5 uses a higher cap on solar interconnections.

NCSEA and SACE et al. (jointly referred to as NCSEA et al.) engaged Synapse to perform two portfolio scenarios: the "Optimized" scenario and the "Regional Resources" scenario. Synapse first created a "Duke Resources" scenario which it intended to provide a baseline and as such attempted to recreate the resources in Duke's P1 portfolio. Compared with Duke's P1, the "Optimized" scenario expanded EE and Net Energy Metering (NEM) forecasts, constrained SMR deployment, and allowed greatly increased solar, battery storage, and offshore wind deployments. The "Regional Resources" scenario additionally allowed the model to select power purchase agreements (PPAs) for Midwest wind imported through the PJM Regional Transmission Organization (PJM). Both of these scenarios met the Interim Target by 2030. These proposed portfolios have a PVRR through 2050 of $103.5 billion and $98.1 billion for the "Optimized" and "Regional Resources" portfolios, respectively.

Tech Customers engaged Gabel and Stratagen to create a "Preferred Portfolio." This portfolio built upon Duke's P1 but is characterized by: (1) significantly more Solar Plus Storage resources and behind-the-meter solar resources; (2) an EE forecast about twice that of Duke's; (3) greatly reduced future natural gas-fired capacity; and (4) no future SMR resources. Tech Customers' proposed portfolio meets the Interim Target by 2030 and has a PVRR through 2050 of $108.8 billion.

DISCUSSION AND CONCLUSIONS FOR THRESHOLD LEGAL ISSUES

Selection of No Single, Preferred Portfolio

One of the threshold matters on which the parties disagree is whether the Commission should or must select a single preferred portfolio as its initial "Carbon Plan" at this time.

Duke requests that the Commission affirm that its proposed suite of portfolios is reasonable for planning purposes and presents a reasonable plan for achieving the carbon dioxide emissions reduction directives in a manner consistent with both the law's requirements and prudent utility planning. Duke Post Hearing Br. at 72.

In support of this request, Duke argues that its proposed "approach is consistent with the Commission's historic approach to long-range planning," and that N.C.G.S. § 62-110.9 does not require the selection of a single portfolio. *Id*. Duke further asserts that approving a single portfolio at this time would be premature, particularly with regard to further information about market costs and long lead-time supply-side resources. Duke Pre Hearing Comments on Non-Expert Track Legal and Policy Issues at 18.

The Public Staff requests that the Commission determine SP5 to be reasonable for planning purposes and as a foundation for the 2022 Carbon Plan and associated near-term procurement and development activities. Public Staff Proposed Order at 3.

NCSEA et al. contend that Duke's "multi-pathway approach is not supported by H951." NCSEA et al. Joint Comments at 15. NCSEA et al. argue that "Section 1 of Part 1 of H951 directs the Commission to develop 'a plan,' in the singular, to achieve the law's carbon reduction requirements." *Id*. While NCSEA et al. acknowledge the need for flexibility and revision to a long-term plan, they nonetheless characterize Duke's multi-pathway approach as a "request not to be held accountable to a plan that gives clear guidance for how [Duke] should proceed with meeting their carbon pollution reduction targets." *Id.* However, NCSEA et al. Joint Brief and Partial Proposed Order states that Duke's approach of presenting at least four portfolios in its Carbon Plan, in addition to a near term plan, is generally reasonable and appropriate for purposes of providing the Commission and stakeholders with a range of options and paths from which the Commission may choose towards the achievement of the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 under a least cost framework. NCSEA et al. Joint Brief and Partial Proposed Order at 13.

At this time, the Commission concludes that it need not select a single portfolio as the basis for the initial Carbon Plan. The Commission has historically considered and accepted, as reasonable for planning purposes, multiple portfolios within its oversight of integrated resource planning. *See, e.g.*, Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning, *2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, No. E-100, Sub 165 (N.C.U.C. Nov. 19, 2021). Further, N.C.G.S. § 62-110.9 specifically directs the Commission to "take all reasonable steps" toward achieving the carbon dioxide emissions reduction mandates. Accordingly, the Commission views the development of the initial Carbon Plan pursuant to N.C.G.S. § 62-110.9 as a series of "reasonable steps" or actions in furtherance of the carbon dioxide emissions reduction mandates. As the compliance dates for the Interim and 2050 Targets get closer, the resource options available for the Commission to select will narrow and the Commission's selection or creation of a single portfolio may be reasonable at that time. Currently, however, it is reasonable for the Commission to decline to select a single portfolio, and instead, to focus on a series of near-term actions that support many of the portfolios the parties to this proceeding present. In the next Carbon Plan proceeding, the Commission expects parties to the proceeding to again present portfolios for the Commission's consideration that take into account the decisions the Commission makes in this initial Carbon Plan as well as up-to-date data and assumptions related to economic conditions, including developments such as the IRA, for example.

Further, as noted above, N.C.G.S. § 62-110.9 creates an Interim Target and provides the Commission flexibility to delay compliance with that Interim Target. The Commission finds that, at this time, it is not appropriate to determine whether it is reasonable or necessary to extend the Interim Target compliance date beyond 2030. The Commission expects Duke to continue to pursue compliance with the Interim Target, including proposing portfolios that comply with the Interim Target in future Carbon Plan proceedings. The Commission expects Duke to continue to consider the future recommendations of all stakeholders, which the Commission's decisions in this proceeding will presumably inform, in crafting a path to compliance with the Interim Target.

Approval of Supply-Side Activities to Be Undertaken in the 2023-2024 Timeframe

Duke requests that the Commission approve Duke's undertaking certain activities in the "near-term" 2023-2024 timeframe to advance the Carbon Plan components that are consistent across portfolios. Specifically, Duke requests Commission approval of its undertaking certain supply-side activities related to existing resources (the existing natural gas-fired fleet and nuclear fleet) and new resources (solar, battery storage, onshore wind, and new natural gas-fired generating resources). Tr. vol. 7, Duke Proposed Carbon Plan, Executive Summary, 23.

Duke also requests that the Commission approve certain initial development activities for Duke to undertake in the near term to support the future availability of certain supply-side resources — including offshore wind, new nuclear generation, and new pumped storage hydro at the Bad Creek facility — all of which Duke asserts are likely to be necessary in order to comply with the Interim Target and the 2050 Target. *Id.*

The table on the following page summarizes the near-term supply-side activities Duke proposes for the Commission's approval.

Table 3: Supply-Side Resources Requiring Actions in Near-Term

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2029		
Carbon Plan Solar	3,100 MW	• Begin Public Policy Transmission projects in 2022[6] • Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage
Battery Storage	1,600 MW	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar
Onshore Wind	600 MW	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024
New CT[1]	800 MW	• Submit CPCN for 2 CTs totaling 800 MW in 2023
New CC[2]	1,200 MW	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability
Proposed Resource Development: Options for 70% Interim Target		
Offshore Wind[3]	800 MW	• Secure lease • Initiate development and permitting activities for 800 MW[7] • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission
New Nuclear[4]	570 MW	• Begin new nuclear early site permit ("ESP") for one site • Begin development activities for the first of two SMR units
Pumped Storage Hydro[5]	1,700 MW	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing

Note 1: CPCN for two CTs (800 MW) estimated for in-service 2027-2028
Note 2: CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
Note 3: Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
Note 4: New nuclear capacity represents first two SMR units, planned in-service date through 2034.
Note 5: Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
Note 6: Projects subject to North Carolina Transmission Planning Collaborative ("NCTPC") approval.
Note 7: Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan ("SAP"); or ii) a combined SAP and Commercial Operation Plan.

Id.

Duke asserts that this proceeding "boils down to one simple question: what are the near-term 'reasonable steps' to be taken by Duke Energy to begin meaningful and substantial progress towards the 70% Interim Target on the path to Carbon Neutrality." Duke Post Hearing Br. at 11.

Other parties similarly have advocated for an initial Carbon Plan prioritizing actions that they characterize as "least regrets" or "no regrets." *See, e.g.,* Public Staff Witness Metz Testimony, tr. vol. 21, 142, 148; AGO Witness Burgess Testimony, tr. vol. 25, 236-38, 293, 295-96; NCSEA et al. Witness Caspary Testimony, tr. vol. 22, 232, 234-35, 247; CPSA Witness Norris Testimony, tr. vol. 26, 64; Tech Customers Post Hearing Br. at 8. For example, AGO witness Burgess testified in support of the solar, battery storage, and onshore wind procurements which Duke includes in its proposed near-term action plan and argues that Duke should pursue them as part of a "no regrets" approach. Tr. vol. 25, 295-96. As another example, Tech Customers advocate that the Commission should be looking for near-term, "no regrets" actions that keep open the potential to pursue multiple cost-competitive paths to a carbon-free grid, with due consideration given to the risks inherent in different generation technologies. Tech Customers Post Hearing Br. at 17.

Stopping short of recommending that the Commission adopt the AGO's proposed portfolio as its plan, the AGO proposes that the Commission's initial Carbon Plan should focus on the selection of resources and retirements that will achieve the Interim Target by 2030, the near-term actions to support those selections and retirements, and steps to prepare for longer lead-time resources that will continue reducing emissions over the next decades. The AGO notes that given the uncertainties of planning for later years, the AGO expects that the mix of resources and timing will evolve in subsequent Carbon Plan proceedings. AGO Post Hearing Br. at 24. While the AGO bases its recommendations primarily on its proposed portfolio, the AGO did point out that the range of portfolios parties presented to the Commission shared "a number of common features" as well as several distinctions. *Id*. at 25.

Duke's Modeling and Near-Term Actions Panel Rebuttal Table 1, which is shown on the following two pages, highlights Duke's proposed near-term supply-side resource activities and those that several intervenors propose, indicating at least some consistency in the resource types.

Rebuttal Table 1: Summary of the Companies' Proposed Near-term Actions with Intervenors' Suggested Modifications

	Solar (including SPS)	BESS Paired w/ Solar	BESS Standalone	Onshore Wind	CT	CC
Supporting deployment by:[1]	YE 2028	YE 2028	YE 2029	YE 2029	YE 2029	YE 2029
Duke Energy Proposal (MW)	**3,100**	**600**	**1,000**	**600**	**800**	**1,200**
Public Staff Proposal (MW)[2]	**2,630**	**820**	**1,130**	**600**	**800**	**1,200**
Alternative Proposals (MW)						
AGO[3]	3,100	600	1,000	600	0	0
Tech Customers[4]	3,450	1,600	2,900	1,200	400	0
CPSA[5]	4,800	1,650	*0*	*600*	*0 to 500*	*1,200*
NCSEA et al.[6]	4,000	0	4,000	600	0	0

Differences from Duke Energy Proposal						
Public Staff Proposal (MW)	**-470**	**+220**	**+130**	**0**	**0**	**0**
Alternative Proposals (MW)						
AGO	0	0	0	0	-800	-1,200
Tech Customers	+350	+1,000	+1,900	+600	-400	-1,200
CPSA	+1,700	+1,050	*-1,000*	*0*	*-800 to -300*	*0*
NCSEA et al.	+900	-600	+3,000	0	-800	-1,200

Note 1: Year End dates are selected based on the expected timeline from commencing development/procurement to project in service.
Note 2: Public Staff recommends including 440 MW of remaining CPRE capacity in the 2022 Carbon Plan solar procurement. CPRE amounts are excluded from the numbers in this table.
Note 3: Supports the Companies' proposed solar, storage, and onshore wind volumes as a "no regrets" floor for procurement. *See* AGO Burgess Direct Testimony at 69.
Note 4: Does not make a specific Near-Term Actions Proposal. Values used are based on Tech Customers' "Preferred" portfolio. *See* Tech Customers Roumpani Direct Testimony at 5.
Note 5: CPSA does not clearly advocate for specific volumes of resources for the near-term action plan other than solar and SPS. The volumes for other resources included in Rebuttal Table 1 reflect Portfolios CPSA3 and CPSA5, which "CPSA strongly recommends. . . inform Duke's near-term execution plan." *See* CPSA Norris Direct Testimony at 29. CPSA3 and CPSA5 both include two new CCs by 2030 totaling 2,400 MW, only one of which is reflected here, consistent with the Companies' approach to developing their own near-term action proposal.
Note 6: NCSEA et al. recommend beginning procurement of 4,000 MW each of solar and storage with target in-service dates of 2025-2028. Not shown above is additional recommendation for 2,500 MW of off-system onshore wind. NCSEA et. al Fitch Direct Testimony at 50-51.

Tr. vol. 27, 41, Duke's Modeling and Near-Term Actions Panel Rebuttal Tbl. 1.

Even though the parties have propounded specific portfolios for the Commission to consider or select in this initial Carbon Plan, no party has expressly opposed focusing on actions required in the near term to achieve the Interim Target, to avoid premature commitments, and to provide flexibility for longer-term decisions. The Commission concludes that an approach focused on near-term activities comprised of a number of reasonable steps needed to achieve the mandated carbon dioxide emissions reduction, which are generally supported as “no regrets,” is not only an appropriate course of action at this stage of implementation but is also well-supported by N.C.G.S. § 62-110.9, which contemplates review and adjustment of the Carbon Plan on an interim two-year basis. N.C.G.S. § 62-110.9(1). Accordingly, the Commission determines that it is properly within the Commission’s discretion to focus this initial Carbon Plan Order, in the context of supply-side resources, primarily, on a near-term plan, as discussed in greater detail in this Order.

Certificate of Public Convenience and Necessity Requirements

For clarification, Commission approval of, selection of, or support for a certain resource as part of the near-term plan does not constitute Commission approval for construction of a generating facility. The Commission agrees with Public Staff witness Thomas who notes that approval of a near-term action item should not be taken as approval of construction of generating plants or otherwise be controlling in a Commission certificate of public convenience and necessity (CPCN) proceeding. Tr. vol. 21, 98. More particularly, witness Thomas suggests that approval of a near-term action item provides clarification on what steps Duke is likely to need or should take in the planning horizon — here, the Commission’s immediate planning horizon is 2023-2024, which is the interim period between the issuance of this Order and the Commission’s next Carbon Plan which it is to issue on or before December 31, 2024. Parties should construe nothing in this Order as supplanting the Commission’s existing CPCN approval process. The Commission will consider and give appropriate weight to approval of a generation resource for planning purposes in a Carbon Plan proceeding in a future CPCN proceeding but will consider that factor in addition to all other evidence the law requires.

Cost Recovery Proceedings

Based on the commentary of Duke and other parties to this proceeding, the Commission deems it necessary to clarify the purpose of this Carbon Plan proceeding and subsequent combined Carbon Plan and IRP (CPIRP, as hereinafter defined) proceedings with regard to cost recovery for Carbon Plan execution costs. Duke seeks assurance that any decision to engage in initial project development activities for new nuclear facilities, offshore wind, and/or pumped hydro storage is a reasonable and prudent step toward Carbon Plan execution and that it will be assured future recovery of such initial project development costs. The Commission addresses this request for assurance and clarifies how this Carbon Plan proceeding, and subsequent CPIRP proceedings, relate to cost recovery.

Duke requests that the Commission make three determinations regarding Duke’s proposed project development activities for long lead-time activities: (1) that engaging in initial project development activities for new nuclear, offshore wind, and pumped hydro storage resources, in advance of receiving any required CPCN, is “a reasonable and prudent step” to enable future selection of those resources for the Carbon Plan; (2) that to the extent the Commission later finds the individual costs incurred to be reasonable and prudent, they will be recoverable in rates; and (3) that such reasonable opportunity for recovery will be available to Duke should any of these resources ultimately not be selected by the Commission in the future and the development activities, therefore, abandoned. Duke Post Hearing Br. at 82. On rebuttal, Duke witness Bateman confirmed that while in its initial Petition to the Commission, Duke requested the right to defer certain costs associated with the development of these resources, Duke has since modified its request to no longer seek any accounting deferral at this time. Tr. vol. 28, 88.

In support of these requests, Duke cites N.C.G.S. § 62-110.7, which authorizes the Commission to approve the decision to incur nuclear project development costs and provides that all reasonable and prudent nuclear project development costs thereby incurred shall be fully recoverable in a general rate case proceeding. Duke notes that in the event of cancellation of a project, all reasonable and prudently incurred nuclear development project costs are recoverable pursuant to N.C.G.S. § 62-110.7(d). With respect to the application of this special ratemaking treatment to other resources, Duke acknowledges that the statute only applies to nuclear facilities. Duke Post Hearing Br. at 83. Duke argues, however, that the Commission has previously granted the exact relief it now requests prior to the enactment of N.C.G.S. § 62-110.7, thereby demonstrating that the Commission has the authority and precedent to grant the requested relief outside of N.C.G.S. § 62-110.7 and for resources other than nuclear generation. *Id*. Duke explains that in 2006, it requested special ratemaking treatment for the proposed Lee Nuclear Station in Docket No. E-7, Sub 819. At the time, Duke expected to incur significant development costs prior to receiving its regulatory approval to construct, and the Commission, prior to enactment of N.C.G.S. § 62-110.7, found that it had the legal authority to grant the requested assurance of future cost recovery of initial development costs. Duke discusses the Commission’s decision in the Lee Nuclear Station proceeding and states, “[t]he exact same rationale underlying the Commission’s decision . . . applies in the context of the Carbon Plan.” *Id*.

Duke argues that the fact that N.C.G.S. § 62-110.7 is limited in scope to nuclear development costs does not change the fact that the Commission previously granted Duke’s requested relief without express statutory authority and does not indicate that the General Assembly believed the Commission should not have that authority for resources other than nuclear. Lastly, Duke points to the language in N.C.G.S. § 62-110.9 that directs the Commission to take “all reasonable steps” to achieve the emissions reduction targets in the legislation and argues that this should include pursuing new nuclear, offshore wind, and new pumped storage hydro at this early stage to ensure that these resources will be available when needed to meet the carbon dioxide emissions reduction mandates. Duke Post Hearing Br. at 84-85.

Relatedly, Duke contends that it has never been required to incur, prior to Commission approval, development costs of the magnitude that are required to ensure the availability of the long lead-time resources on the timelines contemplated by the Carbon Plan without some form of cost recovery assurance. Duke argues that this justifies its requested assurance in the present instance. Further, Duke states that it would be inconsistent with the regulatory compact to impose a legal obligation to perform substantial development work on Duke while denying any such assurance of future cost recovery. While it is possible that a long lead-time resource may not ultimately be selected as part of the Carbon Plan resource portfolio, Duke notes that this should not impact cost recovery for initial development activities deemed prudent for long-term planning purposes. Duke also argues that denial of its request will inequitably place all financial risk on Duke. Finally, Duke contends that in the absence of cost recovery assurance, customers could potentially lose the benefit of any resources Duke deems too risky to pursue. *Id*. at 85.

In response to the Public Staff's recommendation that requests for cost recovery assurances for nuclear development costs be addressed in a separate proceeding, Duke states that N.C.G.S. § 62-110.7 allows utilities to request special ratemaking treatment at any time prior to the filing of a CPCN application. Duke adds that it would be an inefficient use of regulatory resources to require it to initiate a separate proceeding to address the assurances being requested here. *Id*. at 86-87.

The normal regulatory mechanism for considering cost recovery is a general rate case proceeding; however, exceptions, both statutory and common law exist, including but not limited to statutorily authorized riders and Commission precedent authorizing accounting deferrals.[4] The immediate proceeding is neither a general rate case nor any other recognized cost recovery proceeding. Accordingly, absent an accepted regulatory exception, the Commission declines to make any determinations as to the reasonableness and prudence of specific Carbon Plan execution costs until such time that those specific costs are presented to the Commission in an authorized cost recovery proceeding. The Commission emphasizes that any approval of near-term development activities for the long lead-time resources or acknowledgment of Duke's proposed cost caps, discussion of which occurs in later sections of this Order, does not constitute a determination as to ultimate reasonableness and prudence of these specific costs.

The Commission finds that a detailed explanation of the timing of the Commission's decision to preauthorize the Lee Nuclear Station development costs and the enactment of N.C.G.S. § 62-110.7 is informative for the purpose of this discussion.

The pertinent facts, which are a matter of public record, are the following: On September 20, 2006, in Commission Docket No. E-7, Sub 819, DEC filed an Application for Authority to Recover Nuclear Generation Development Expenses, stating that "the evaluation and development of the Lee Nuclear Station also requires large sums of money. As noted above, the Development Costs through December 31, 2007, are anticipated to be as much as $125 million." DEC Appl. at 8-9. Following comments and

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[4] Duke having withdrawn its request for deferral authorization, the Commission will not discuss its accounting deferral precedents herein.

oral arguments, on March 30, 2007, the Commission issued a Declaratory Ruling stating that "it is in the public interest for the Commission to issue a declaratory ruling which gives Duke a general assurance that its activities in assessing the development of the proposed Lee Nuclear Station through December 31, 2007, are appropriate activities." Order Issuing Declaratory Ruling, *Application of Duke Power Company LLC d/b/a Duke Energy Carolinas LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment,* No. E-7, Sub 819, at 22 (N.C.U.C. Mar. 30, 2007). More particularly, the Commission found:

> It is appropriate in general for Duke to pursue preliminary siting, design and licensing of the proposed William States Lee II Nuclear Station (Development Work) through December 31, 2007, to ensure that nuclear generation remains an available resource option for Duke's customers, and such Development Work is generally consistent with the promotion of adequate, reliable, and economical utility service to the citizens of North Carolina and the policies expressed in G.S. 62-2.

Id. Moreover, future cost recovery was conditioned on "the specific activities involved in, and the costs of pursuing such Development Work" being found "to be prudent and reasonable (whether or not the Lee Nuclear Station is constructed)" "in a future general rate case proceeding[.]"[5] *Id.*

Shortly thereafter, on August 20, 2007, Session Law 2007-397 (also known as Senate Bill 3) became law, which in addition to enacting N.C.G.S. § 62-110.7 made other significant changes to the Public Utilities Act. In brief, N.C.G.S. § 62-110.7 provides that, prior to filing for a CPCN to construct a potential nuclear electric generating facility, a public utility may request that the Commission review the public utility's decision to incur project development costs,[6] and if the public utility demonstrates by a preponderance of the evidence that the decision to incur project development costs is reasonable and prudent, the Commission shall approve the public utility's decision to incur project development costs. In doing so, however, the Commission shall not rule on the reasonableness or prudence of specific project development activities or recoverability of specific items of cost. N.C.G.S. § 62-110.7(b). The statute continues that if the Commission deems the project development costs to be reasonable and prudent, the

[5] In a subsequent Order Clarifying Declaratory Ruling, the Commission stated "[c]learly this language has not pre-approved or denied any particular future ratemaking treatment for Development Costs regardless of whether the plant is never begun, abandoned, or completed. Instead, the Commission retains discretion to determine the appropriate ratemaking treatment in a future general rate case proceeding." Order Clarifying Declaratory Ruling, *Application of Duke Power Company LLC d/b/a Duke Energy Carolinas LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment*, No. E-7, Sub 819, 6 (Aug. 6, 2007).

[6] "'[P]roject development costs' mean all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs." N.C.G.S. § 62-110.7(a).

costs “shall be included in the public utility's rate base and shall be fully recoverable through rates in a general rate case proceeding . . . .” N.C.G.S. § 62-110.7(c). In the event that the project is cancelled, the statute also provides, “the Commission shall permit the public utility to recover all reasonable and prudently incurred project development costs in a general rate case proceeding pursuant to G.S. 62-133 amortized over a period equal to the period during which the costs were incurred or five years, whichever is greater.” N.C.G.S. § 62 110.7(d). Accordingly, nothing in N.C.G.S. § 62-110.7 can be construed to supersede the Commission’s oversight over a utility’s cost of service in a cost recovery proceeding based upon the standard of whether the expenditures are reasonable and prudent, nor does the statute create an ultimate presumption of reasonableness and prudency. Rather, not inconsistent with the Commission’s determination in the Lee Nuclear Station project development cost matter, N.C.G.S. § 62-110.7 codifies that in the limited case of highly capital-intensive nuclear development activities, where a utility can demonstrate by a preponderance of the evidence that the decision to incur project development costs is reasonable and prudent that it is in the public interest to give the utility limited and qualified assurance of cost recovery subject to standard review processes for cost recovery.

In light of the foregoing, the Commission concludes that N.C.G.S. § 62-110.7 is applicable only in the limited context of Duke’s decision to incur development activities associated with new nuclear facilities and not in the context of non-nuclear resources. The Commission considers Duke’s proposal to begin project development work on new nuclear facilities, including a fact-specific analysis, in its discussion related to Findings of Fact Nos. 40-43.

Further, consistent with the Commission’s Lee Nuclear Station precedent, the Commission concludes that where it approves a request from Duke to incur initial project development costs for purposes of execution of the Carbon Plan, the Commission’s approval constitutes reasonable assurance of recoverability in a future cost recovery proceeding, even if the resource is ultimately not selected by the Commission for the Carbon Plan. However, any such approval does not amount to the approval of the reasonableness or prudence of specific project development activities or the recoverability of specific items of cost. For the avoidance of doubt, any Commission approval of a request from Duke to incur initial project development costs does not constitute “preapproval” of cost recovery. Rather the approval is indicative that the Commission finds such actions to be a reasonable and prudent step in furtherance of the Carbon Plan, but that cost recovery will be conditioned on a full review for reasonableness and prudency during the appropriate cost recovery proceeding. With the exception of the Commission’s approval of the nuclear project development costs pursuant to N.C.G.S. § 62-110.7, the Commission retains discretion to determine the appropriate ratemaking treatment for any authorized actions in a future general rate case proceeding.

Third-Party Ownership

The next issue before the Commission concerns a matter of statutory interpretation — whether third parties may own the resources that the Commission selects to achieve the mandates of N.C.G.S. § 62-110.9.

Well-established principles of statutory interpretation in North Carolina dictate:

> The intent of the General Assembly may be found first from the plain language of the statute, then from the legislative history, the spirit of the act and what the act seeks to accomplish. If the language of a statute is clear, the court must implement the statute according to the plain meaning of its terms so long as it is reasonable to do so. Courts should give effect to the words actually used in a statute and should neither delete words used nor insert words not used in the relevant statutory language during the statutory construction process. Undefined words are accorded their plain meaning so long as it is reasonable to do so. In determining the plain meaning of undefined terms, this Court has used standard, nonlegal dictionaries as a guide. Finally, statutes should be construed so that the resulting construction harmonizes with the underlying reason and purpose of the statute.

Midrex Techs. v. N.C. Dep't of Revenue, 369 N.C. 250, 258, 794 S.E.2d 785, 792 (2016) (internal citations omitted).

The statutory provision at issue, N.C.G.S. § 62-110.9(2), states that "[a]ny new generation facilities or other resources selected by the Commission in order to achieve the authorized carbon dioxide emissions reduction mandates for electric public utilities shall be owned and recovered on a cost-of-service basis by the applicable electric public utility . . . ." The provision then lists an exception to the preceding requirement: "To the extent that new solar generation is selected by the Commission, in adherence with least cost requirements, the solar generation selected" is subject to the following ownership conditions: (1) PPAs with third parties must supply 45% of the solar generation the Commission selects; and (2) solar generation "owned and operated and recovered on a cost of service basis by the soliciting electric public utility" must supply 55% of the solar generation the Commission selects. N.C.G.S. § 62-110.9(2)(b).[7] While the statute includes the term "solar generation" at the beginning of the provision, the final sentence clarifies that "[t]hese ownership requirements shall be applicable to solar energy facilities (i) paired with energy storage and (ii) procured in connection with any voluntary customer program." *Id.*

While Duke, the Public Staff, and CPSA assert that the plain language of these provisions provides a limited exception for third-party owned solar resources, including standalone solar and Solar Plus Storage, other parties contend that the Commission should construe the statute to allow an exception when a PPA arrangement is the least cost option over utility ownership. *See, e.g.*, Duke Post Hearing Br. at 72-81 ("There is no ambiguity in HB 951 with respect to ownership of new generating facilities and other resources selected by the Commission in the Carbon Plan: third parties shall own 45% of new solar and solar paired with energy storage, and Duke shall own all other Facilities selected by the Commission to achieve the Carbon Plan."); Public Staff Witness Thomas Testimony, tr. vol. 21, 62 ("Section 110.9(2) requires Duke ownership of new generation facilities for purposes of Carbon Plan compliance"); CPSA Initial Comments at 6-7 (N.C.G.S. § 62-110.9(2) "prohibit[s] this Commission from approving a Carbon Plan that relies on new non-utility-owned generating resources, other than solar and solar-plus-storage, in order to meet the decarbonization mandates of H.B. 951"); CUCA Initial Comments at 2 ("If utility ownership is not the least cost option, then Duke should be required to pursue alternative options that result in savings for ratepayers."); Tech Customers Initial Comments at 18 ("Duke's proposed Carbon Plan reflects the preference to build new generation rather than purchase power from energy suppliers or otherwise participate in the market. This approach is likely to result in greater costs to consumers . . . and the omission of purchased power as an alternative to new-build generation is contrary to the expectations of Session Law 2021-165.").

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[7] In its entirety, N.C.G.S. § 62-110.9(2)(b) provides:

> To the extent that new solar generation is selected by the Commission, in adherence with least cost requirements, the solar generation selected shall be subject to the following: (i) forty-five percent (45%) of the total megawatts alternating current (MW AC) of any solar energy facilities established pursuant to this section shall be supplied through the execution of power purchase agreements with third parties pursuant to which the electric public utility purchases solar energy, capacity, and environmental and renewable attributes from solar energy facilities owned and operated by third parties that are 80 MW AC or less that commit to allow the procuring electric public utility rights to dispatch, operate, and control the solicited solar energy facilities in the same manner as the utility's own generating resources and (ii) fifty-five percent (55%) of the total MW AC of any solar energy facilities established pursuant to this section shall be supplied from solar energy facilities that are utility-built or purchased by the utility from third parties and owned and operated and recovered on a cost of service basis by the soliciting electric public utility. These ownership requirements shall be applicable to solar energy facilities (i) paired with energy storage and (ii) procured in connection with any voluntary customer program.

N.C.G.S. § 62-110.9(2)(b).

As detailed above, the law is unambiguous in dictating the Commission's analysis of this matter, and the Commission must apply the plain language of the statute. First, in "determining generation and resource mix for the future," the Commission is bound to "[c]omply with current law and practice with respect to the least cost planning for generation." N.C.G.S. § 62-110.9(2). However, the Commission cannot construe the concept of "least cost" planning as a strict mandate wherein the Commission abandons all other concerns, including compliance with the plain language of N.C.G.S. § 62-110.9(2) in order to achieve the lowest possible cost for consumers. Rather, the concept is highly nuanced, and the Commission must reasonably balance least cost planning with other critical factors such as providing fair regulatory practices; assuring resource adequacy; promoting the provision of adequate, reliable, and economical service that is consistent with the level of energy needed for the public health and safety; promoting resource conservation and efficiency; and ensuring the overall public interest. *See* N.C.G.S. § 62-2.

While the first sentences of the provision at issue are clear that the Commission must economically select resources to replace retired coal generation, further provisions include more specific legislative caveats to this general requirement.

The first legislative caveat, that "[a]ny new generation facilities or other resources selected by the Commission in order to achieve the authorized carbon dioxide emissions reduction mandates for electric public utilities shall be owned and recovered on a cost of service basis by the applicable electric public utility[,]" is subject only to the limited exception for third-party owned solar, inclusive of standalone solar and Solar Plus Storage, contained in N.C.G.S. § 62-110.9(2)(b).[8] The Commission specifically notes that the statute's use of the word "and" dictates that the Commission must honor both the conditions of utility ownership *and* cost recovery on a cost-of-service basis. The second legislative caveat provided in N.C.G.S. § 62-110.9(3) is that "any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."

The Commission interprets the preceding legislative caveats as specific provisions honing the more general directive for least cost planning for generation resources. Therefore, based on the foregoing, the Commission determines that while least cost, economic selection of resources is an important general factor that the Commission must consider, it must also balance such consideration with the General Assembly's more specific directives regarding utility ownership and reliability. More specifically, on this matter, the Commission determines that the plain language of N.C.G.S. § 62-110.9(2) dictates that new generation resources that the Commission selects to achieve the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 must be utility-owned with

[8] The Commission notes that N.C.G.S. § 62-110.9(2)(a) provides that "[e]xisting law shall apply with respect to energy efficiency measures and demand-side management."

costs recovered on a cost-of-service basis, with the express exceptions of standalone solar and Solar Plus Storage.[9]

Methane Emissions

While acknowledging that "HB 951 is tailored to the reduction of carbon dioxide emissions and arguably does not address the emissions of other greenhouse gases, such as methane," intervenors NC WARN and Charlotte Mecklenburg NAACP contend that the Commission should nonetheless consider the impacts of methane emissions from natural gas facilities. NC WARN and Charlotte Mecklenburg NAACP Joint Initial Comments at 20. In response, Duke states that carbon dioxide and methane are "distinct chemical compounds" and observes that had the General Assembly desired to target methane emissions as it did with carbon dioxide emissions, it could have done so. Duke Post Hearing Br. at 59-60.

Absent such an exercise of its legislative powers, the Commission must assume that the General Assembly did not intend to address methane in N.C.G.S. § 62-110.9. In this statute, the General Assembly has vested the Commission with discrete and limited authority to regulate carbon dioxide emissions from electric generating facilities located in the state that are owned, operated by, or operated on behalf of Duke. Section 62-110.9 does not extend authority to regulate methane emissions to the Commission.

For the reasons explained herein, methane emissions are not within the Commission's authority under N.C.G.S. § 62-110.9. The Commission notes that Duke has outlined its voluntary corporate methane emissions reduction goals in its Post Hearing Brief, including a company-wide goal to achieve net-zero methane emissions from natural gas distribution by 2030 and net-zero methane by 2050 for upstream emissions related to purchased natural gas. Duke Post Hearing Br. at 62.

Consolidation of the Integrated Resource Planning and Carbon Plan Processes for Duke

For regulatory efficiency, the Commission deems it reasonable and necessary to consolidate its IRP planning function pursuant to N.C.G.S. § 62-110.1(c) and its Carbon Plan development and execution oversight function pursuant to N.C.G.S. § 62-110.9.

As evident from the filings on this issue, the parties have attempted to reach consensus on how the Commission conducts future Carbon Plan proceedings. The Commission is not persuaded that a 2023 Carbon Plan update proceeding is appropriate and will, accordingly, decline to take up the rulemaking recommendations parties propose on this issue. Instead, the Commission will, as set forth below, initiate a process that will put it in a position to adopt the second Carbon Plan by the end of 2024.

[9] For the avoidance of doubt, the Commission does not intend that its decision on this matter exhaustively define utility ownership nor extend to resources the utility selects for purposes other than compliance with the carbon dioxide emissions reduction directives of N.C.G.S. § 62-110.9.

One of the Commission's key takeaways from this initial Carbon Plan proceeding is that 14 months is far too brief a period to adequately model, review, and develop a carbon plan — particularly as we approach the Interim Target compliance deadline. The Commission interprets the provisions of N.C.G.S. § 62-110.9 to require that it review and adjust as necessary the Carbon Plan every two years, making the Commission's next biennial Carbon Plan due on or before December 31, 2024. Compliance therewith does not afford time for the proposed "update" proceeding as well as a full Carbon Plan proceeding before December 31, 2024. While Commission Rule R8-60 requires the filing of IRP updates, N.C.G.S. § 62-110.1(c) does not compel these updates, nor does N.C.G.S. § 62-110.9 contemplate an "interim Carbon Plan update." Therefore, the Commission deems it prudent to forego a Carbon Plan update proceeding in 2023. Instead, the Commission finds good cause to require Duke to file a proposed consolidated, full Carbon Plan and IRP (CPIRP) by no later than September 1, 2023.

Further, the Commission directs Duke to engage with the Public Staff and any interested stakeholders to draft a new proposed Commission rule governing the CPIRP proceeding, subject to the following enumerated parameters and to file the proposed rule with the Commission by no later than April 28, 2023, in a new and separate proceeding:

1. By September 1, 2023, and every two years thereafter, Duke shall file with the Commission its proposed biennial CPIRP, including the testimony and exhibits of expert witnesses. At the time of the filing, Duke shall provide complete modeling input and output data files to intervenors. Each proposed biennial CPIRP shall include a proposed near-term plan discussing the specific actions Duke recommends taking over the near term following the Commission's final order on the proposed CPIRP;

2. No later than 180 days after the later of either September 1 or the filing of Duke's proposed biennial CPIRP, the Public Staff or any other intervenor may file testimony and exhibits of expert witnesses commenting on, critiquing, or giving alternatives to Duke's proposed CPIRP;

3. No later than 45 days after the filing of intervenor testimony and exhibits, Duke may file its rebuttal testimony and exhibits of expert witnesses;

4. The Commission shall schedule an expert witness hearing to review the CPIRP proposals beginning on the second Tuesday in May following Duke's proposed biennial CPIRP, and shall schedule one or more hearings to receive testimony from the public at a time and place of the Commission's designation; and

5. The proposed rule filing shall also propose a separate mechanism for the filing and review of annual compliance plans that DEP and DEC previously filed with their respective IRP filings.

WHEREUPON, the Commission makes the following

FINDINGS OF FACT

The Commission has received expert and public witness testimony from numerous witnesses in this proceeding as well as voluminous exhibits, reports, comments, consumer statements, and briefs. In making the following findings of fact, the Commission has carefully considered all of the evidence in the record, as well as the comments and briefs of the parties and the consumer statements of position. The Commission has duly considered the credibility of each of these submissions and, accordingly, has given each the weight that it is due. The following findings of fact are based upon competent, material, and substantial evidence derived through consideration of the complete record.

Carbon Dioxide Emissions Assumptions and Calculations

1. In 2005, North Carolina electric generation facilities owned, operated by, or operated on behalf of DEP and DEC produced 75,865,188 short tons of carbon dioxide emissions. A 70% reduction of the 2005 carbon dioxide emissions produces an Interim Target of 22,759,556 short tons of carbon dioxide. Stated another way, achieving the Interim Target will require that Duke limit carbon dioxide emissions from electric generation facilities located in the state and owned, operated by, or operated on its behalf to 22,759,556 short tons of carbon dioxide.

2. It is appropriate to assume, for modeling purposes, that all new carbon-emitting resources selected in the Carbon Plan will be located in North Carolina.

Inflation Reduction Act of 2022

3. President Biden signed the IRA into law on August 16, 2022. The IRA includes $369.75 billion in tax incentives and is expected to have a major impact on the development of generating facilities, potentially offsetting significant cost.

4. Duke filed its Carbon Plan proposal on May 16, 2022, before enactment of the IRA but performed preliminary modeling sensitivity analysis based on an initial review of the IRA. This sensitivity analysis generally supports Duke's proposed near-term actions in its Carbon Plan modeling.

5. It is appropriate for Duke to incorporate the impacts of the IRA, the Infrastructure Investment Jobs Act (IIJA), other future legislative changes, and the impacts of other changing conditions such as inflationary pressures, into its modeling and analysis for future proposed biennial CPIRPs.

Modeling – Optimization Period

6. Portfolio development utilizes a series of optimization steps, primarily utilizing algorithms within specialized software, to ultimately seek the least cost solution

to meet customer energy and demand needs and carbon dioxide emissions reduction mandates over the planning horizon. The goal of this modeling process is to develop a portfolio of resources that will minimize overall system costs, including capital costs for new resources and ongoing operation, maintenance, and fuel costs.

7. Modeling over the longest possible optimization period, considering other factors such as modeling times, aids in determining the least cost path that meets the mandated carbon dioxide emissions reductions of N.C.G.S. § 62-110.9.

Modeling – Battery Storage

8. Modeling of storage resources with endogenous dispatch provides the most potential for adequately valuing these resources in the Carbon Plan.

9. Duke's endogenous dispatch of Solar Plus Storage caused modeling times to be in the range of 12 to 48 hours as opposed to 2 to 3 hours for fixed dispatch modeling.

Modeling – Battery-CT Optimization

10. Duke performed a "battery-CT optimization" in its resource modeling that resulted in the replacement of some battery capacity with some natural gas-fired capacity.

Modeling – Reliability

11. Ensuring ongoing system reliability and compliance with mandatory NERC Reliability Standards during the ongoing energy transition is consistent with prudent utility planning and the requirements of N.C.G.S. § 62-110.9 and is nonnegotiable for Duke and its customers.

12. The modeling approach Duke employed in developing its Carbon Plan proposal considers system reliability at each progressive step. While the use of the Strategic Energy Risk Valuation Model (SERVM), a reliability and hourly production cost simulation tool managed by Astrapé Consulting, occurs outside of the primary modeling tool, EnCompass, it is an appropriate action for the purpose of ensuring system reliability and compliance with the statutory mandates.

Coal Plant Retirements

13. Retirement of Duke's coal generation fleet is a critical step in in the path to compliance with N.C.G.S. § 62-110.9.

14. The approach Duke utilizes in planning for the retirement of its coal generation fleet achieves the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 while maintaining adequacy and reliability of the existing grid.

15. Duke's modeling efforts consider least cost principles when determining the timeline for retirement of coal generation units.

16. In order to maintain adequacy and reliability of the existing grid while retiring its coal generation fleet, Duke must invest in replacement generation assets and upgrade its transmission network.

17. Undepreciated balances of certain of Duke's subcritical coal generation fleet are eligible for securitization at retirement pursuant to Section 5 of S.L. 2021-165 and Commission Rule R8-74.

Existing Resources – Subsequent License Renewals for Existing Nuclear Units

18. Duke currently operates 11 nuclear generating units that provide carbon-free baseload generation to Duke's customers in North Carolina and South Carolina.

19. Duke successfully obtained initial extensions of the operating licenses for all 11 of its existing nuclear generating units. To further extend the operating licenses for an additional 20 years beyond the initial extensions, Duke must pursue subsequent license renewal (SLR). Without SLR, the operating licenses for DEC's facilities will expire on the following dates: for the Catawba facility, located in York, South Carolina, Unit 1 and Unit 2 will both expire on December 5, 2043; for DEC's McGuire facility, located in Huntersville, North Carolina, Unit 1 will expire on June 12, 2041, and Unit 2 will expire on March 3, 2043; and for DEC's Oconee facility, located in Seneca, South Carolina, Unit 1 will expire on February 6, 2033, Unit 2 will expire on October 6, 2033, and Unit 3 will expire on July 19, 2034. Without SLR, the operating licenses for DEP's facilities will expire on the following dates: for the Robinson facility, located in Hartsville, South Carolina, Unit 2 will expire on July 31, 2030; for the Brunswick facility, located in Southport, North Carolina, Unit 2 will expire on December 27, 2034, and Unit 1 will expire on September 8, 2036; and for the Harris facility, located in New Hill, North Carolina, Unit 1 will expire on October 24, 2046.

20. Extending the retirement dates for the existing nuclear fleet an additional 20 years through SLR is foundational to Duke's Carbon Plan proposal, and all of Duke's proposed portfolios rely on SLR of the existing nuclear fleet.

Existing Resources – Natural Gas Fleet

21. Enhancing the flexibility of the existing natural gas fleet is one method to support renewable resource integration.

The Role of Natural Gas

22. The deliverability of natural gas for Duke's natural gas-fired generating resources faces sufficient current and future risks to warrant continued modeling of deliverability sensitivities in future resource modeling.

23. The natural gas price forecasting methodology utilized by Duke in its resource modeling relied on five years of natural gas market-based pricing and three years of transitioning from market-based pricing before fully utilizing fundamentals-based natural gas pricing forecasts beginning in year nine.

24. It is appropriate for Duke to plan for hydrogen fuel to replace natural gas and for the use of carbon dioxide offsets.

25. The 35-year operational life and capital cost assumptions for new CC and CT units are reasonable for planning purposes at this time.

26. Natural gas-fired generation is dispatchable; capable of providing baseload, intermediate, and peaking capacity; and supports system reliability during periods of high customer demand. Further, new natural gas-fired generation was selected by a number of the proposed portfolios submitted for the Commission's consideration.

27. Firm transportation capacity is essential to manage the natural gas supply security necessary for reliable, cost-effective generation and for the reliable operation of the electric system at this time.

Near-Term Development and Procurement Activities for New Standalone Solar Generation, Solar Plus Storage, Standalone Battery Storage, and Onshore Wind

28. Significant new solar generation must be added to Duke's resource mix in the short term to achieve the Interim Target.

29. On November 1, 2022, the Commission authorized Duke to procure 1,200 MW of new standalone solar resources via the 2022 Solar Procurement.

30. The 2022 Solar Procurement is subject to a Volume Adjustment Mechanism (VAM) which allows for an increase of up to 20% in the solar procurement target if the weighted average cost of the procured resources is less than or equal to 90% of the Carbon Plan Solar Reference Cost, meaning that if the weighted average cost of the procured resources is less than or equal to 90% of the Carbon Plan Solar Reference Cost, Duke may procure up to 1,440 MW of new standalone solar resources via the 2022 Solar Procurement.

31. Nearly all of the parties that performed modeling recommend the inclusion of Solar Plus Storage. Overall, proposed portfolios submitted to the Commission contemplate the addition of between 600 MW and 1,650 MW of new Solar Plus Storage by the end of 2028.

32. Nearly all of the parties that performed modeling recommend the inclusion of new standalone battery storage. Overall, proposed portfolios submitted to the Commission contemplate the addition of between 1,000 MW and 4,000 MW of new standalone battery storage by the end of 2029.

33. All proposed portfolios Duke submitted to the Commission include onshore wind capacity to achieve the Interim Target.

Development of Long Lead-Time Resources

34. Each of Duke's proposed portfolios and the Public Staff's proposed portfolios SP5 and SP6 select new nuclear resources and new pumped storage hydro (Bad Creek II) with the assumption that both resources in each portfolio will be in service no later than 2035.

35. Duke's proposed portfolios P1, P2, and P4 support the need to develop offshore wind either for compliance with the Interim Target or with the 2050 Target. Neither Duke's proposed portfolio P3 nor proposed portfolios SP5 and SP6 select offshore wind to achieve the Interim Target.

36. Bad Creek II is a second powerhouse that Duke proposes to construct at Duke's existing Bad Creek I pumped hydro storage facility located in Salem, South Carolina. Bad Creek I is currently undergoing work to expand its capacity from 1,360 MW to 1,700 MW with the project expected to be complete by 2023. Bad Creek II would include four new generating units that provide an additional 1,700 MW of capacity. The combined total capacity of Bad Creek I and Bad Creek II would be more than 3,300 MW. Bad Creek II would share the existing upper reservoir with Bad Creek I.

37. Bad Creek I operates as a daily-cycling facility, storing energy during low periods of demand and returning the energy to the grid at peak periods, which complements intermittent resources. Bad Creek I came online in 1991 and has been included in Duke's IRPs since that time, serving as a reliable asset for over 30 years. Bad Creek I is currently in the relicensing phase at the Federal Energy Regulatory Commission (FERC) with the opportunity to include Bad Creek II in the process if certain project development activities progress.

38. Pursuing a license with FERC for Bad Creek II separately from the Bad Creek I relicensing process would be unnecessarily duplicative and increase the in-service timeline by approximately five years.

39. Duke proposes the following near-term development actions for Bad Creek II for the period 2022 through 2024 for a total cost of $35,855,000: (a) conduct a feasibility study; (b) develop an engineering, procurement, and construction strategy; and (c) continue to develop the application to provide to FERC to relicense the Bad Creek I facility to incorporate operation of Bad Creek II.

40. New nuclear resources, including SMRs, advanced reactors (ARs), and microreactors, involve modular design and allow for offsite construction and potentially decreased production timelines.

41. ARs provide flexible operations that can support hydrogen production, thermal storage, and integration with variable renewable energy resources.

42. New nuclear generation is expected to provide firm, dispatchable, carbon-free electricity to the grid with greater operational flexibility than traditional nuclear generation.

43. Duke estimates that its proposed near-term development activities for new nuclear in 2022 through 2024 will cost $72,000,000 and include: (a) beginning new nuclear Early Site Permit (ESP) development; and (b) beginning development activities for the first two SMR units. The Commission finds that this authorization of initial development costs constitutes approval under N.C.G.S. § 62-110.7(b).

44. Offshore wind provides resource diversity to complement solar variability, especially in the winter months. Offshore wind's highest seasonal generation is in the winter mornings when solar generation output is not available.

45. Once an offshore wind lease for a Wind Energy Area (WEA) has been executed, it takes approximately 8 to 10 years to achieve commercial operation.

46. The Bureau of Ocean Energy Management (BOEM) to date has leased three WEAs near the coast of North Carolina for the potential development of offshore wind, including the Kitty Hawk, North Carolina WEA and two WEAs in the Carolina Long Bay (CLB) area near Cape Fear, North Carolina. Each WEA has a unique set of meteorological and geographical characteristics which will affect the WEA's cost of development and production profile, and therefore its economics.

47. All three WEAs would require cabling from the wind facility to onshore, with Kitty Hawk's having a significantly longer subsea cabling requirement due to its location near the North Carolina/Virginia border.

48. All three WEAs will require significant new transmission infrastructure in order to connect to the existing transmission system.

49. Duke Energy Renewables Wind, LLC, an affiliate of Duke, has acquired one of the two WEAs in the CLB Area. Duke remains open to pursuing other opportunities for ownership of cost-effective offshore wind WEAs.

50. Duke proposes the following offshore wind development activities for 2022 to 2024 at a total cost of $317,400,000: (a) enter into a lease ($155,400,000); (b) perform development activities ($62,000,000); and (c) construct transmission from landing site to point of injection ($100,000,000).

51. Avangrid Renewables holds the lease to the Kitty Hawk WEA and states that it is willing to negotiate for a sale of its interest to Duke.

Grid Edge and Customer Programs – Load Reduction

52. Reducing load through demand-side management and energy efficiency measures (DSM/EE), customer self-generation, and voltage management is a critical component of achieving the reductions in carbon dioxide emissions in a least cost manner as N.C.G.S. § 62-110.9 requires.

Grid Edge and Customer Programs – Electric Vehicles

53. Duke expects continued acceleration in electric vehicle (EV) adoption which requires planning and management by Duke in order to "do no harm" and to maximize potential system benefits.

Grid Edge and Customer Programs – New Regulatory Mechanisms

54. There is a need for new regulatory mechanisms for both DSM/EE and non-DSM/EE programs for Duke to reduce load through its Grid Edge programs.

Grid Edge and Customer Programs – Wholesale Customers and Dynamic Rate Design

55. Customer programs, including coordination with wholesale customers and dynamic rate design, may reduce load.

Transmission – Red Zone Expansion Projects

56. The 14 transmission projects listed on Transmission and Solar Procurement Panel Rebuttal Exhibit 3 under the heading "Acknowledge need for inclusion in the 2022 Local Plan" are necessary to enable the interconnection of solar generating capacity to meet the requirements of N.C.G.S. § 62-110.9 in a least cost manner.

Transmission – Planning

57. The addition of proactive transmission planning through the local transmission process, the North Carolina Transmission Planning Collaborative (NCTPC), integrated with resource planning, is reasonable and appropriate to meet the carbon dioxide emissions reduction mandates reliably and in a least cost manner.

58. To implement the Carbon Plan successfully, the NCTPC should evolve by expanding transparency and coordination to address the increasing complexity and potential cost of the addition of proactive transmission planning into the NCTPC process.

Transmission – Cost and Reliability Considerations

59. When proposing transmission projects as necessary for purposes of compliance with N.C.G.S. § 62-110.9, Duke should consider the full scope of the timing

and costs of the identified upgrades, any associated upgrades, Affected Systems costs, and coordination efforts with other load serving entities (LSEs).

60. Any transmission Network Upgrades Duke identifies as necessary for Carbon Plan compliance should not take priority over other transmission upgrade projects necessary to maintain reliability and service quality for Duke's retail and wholesale ratepayers.

Rate Disparity Between Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC

61. Based on rates effective August 1, 2022, a DEC residential customer consuming 1,000 kWh of electricity pays a monthly bill of $106.23, while a DEP residential customer with the same electricity consumption pays a monthly bill of $125.94, which is a rate difference of $19.71 or 19%.

62. The rate difference between DEC and DEP has existed since before the corporate merger of Duke Energy Corporation and Progress Energy, Inc., in 2012; however, the rate difference has increased consistently since the merger.

63. Numerous issues contribute to the rate difference between DEC and DEP; however, the significantly greater amount of solar generation in DEP's service territory compared to DEC's service territory, along with associated transmission and distribution upgrades, is one contributor to the rate disparity between DEC and DEP.

Present Value Revenue Requirements

64. Duke provided PVRR and bill impact calculations for the four proposed portfolios it presented as well as for the supplemental portfolios it prepared in response to the Public Staff's comments and others.

65. Various parties suggest that Duke should prepare analyses that include an "all-in cost" PVRR and bill impacts.

Environmental Justice and Impacted Communities

66. Successful execution of the Carbon Plan requires engagement by Duke on issues related to environmental justice and with frontline communities.

EVIDENCE AND CONCLUSIONS

As noted above, the Commission bases its findings of fact upon competent, material, and substantial evidence derived through consideration of the complete record. In providing the following evidence and conclusions in support of its findings of fact, the Commission does not exhaustively summarize the complete record.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

Carbon Dioxide Emissions Assumptions and Calculations

The evidence supporting these findings of fact is in Appendix A of Duke's Carbon Plan proposal, the direct testimony of Duke's Modeling Panel, the testimony of Public Staff witness Metz, and the entire record in this proceeding.

Duke states that in accordance with the provisions of N.C.G.S. § 62-110.9, it established the following parameters to calculate its 2005 carbon dioxide emissions baseline:

- The recommended 2005 baseline only considers carbon dioxide emissions;
- The recommended 2005 baseline only considers carbon dioxide emissions from electric generating facilities owned, operated by, or operated on behalf of Duke;
- The recommended 2005 baseline only considers carbon dioxide emissions from electric generation facilities located within the State of North Carolina; and
- The recommended 2005 baseline focuses on direct emissions from electric generation facilities.

Tr. vol. 7, Duke Proposed Carbon Plan, App. A, 1-2.

To set the 2005 carbon dioxide emissions baseline, Duke utilized the Environmental Protection Agency's (EPA) Emission and Generation Resource Integrated Database (eGRID), which is a publicly available, credible data source that the EPA manages. *Id.* at 3. Duke states that the EPA consistently publishes the data with results that are repeatable and consistent over time. *Id.* at 3-4. Duke states that eGRID's database compiles the EPA's Clean Air Markets Division (CAMD) Power Sector Emissions Data, which electric generating facilities report to the EPA to comply with regulations in 40 CFR Part 75 and 40 CFR Part 63. *Id.* at 4. Duke explains that most emissions data reported in eGRID is through Emissions Tracking Systems/Continuous Emissions Monitoring Systems (CEMS). *Id.* Further, Duke notes that emissions are quantified through actual measurements at the stack with systems regularly tested and calibrated to maintain accuracy. *Id.* Where CEMS data is not available, eGRID uses Energy Information Administration (EIA) reported fuel data (EIA-923) to estimate emissions based on fuel consumed and standard emissions rates for the applicable fuel type. *Id*. Duke notes that electricity generating facilities that the EPA's CAMD regulates must monitor and report carbon dioxide emissions annually. *Id.* Finally, Duke states that DEP and DEC (or predecessors) have used CEMS technology at their electric generation facilities for over 20 years to report actual stack emissions to the EPA. *Id.*

Using metrics from eGRID, Duke concludes that electric generation facilities located in the state, and owned, operated by, or operated on behalf of DEP and DEC (or their predecessors) emitted a total of 75,865,188 short tons of carbon dioxide in 2005. *Id.*; *see also id.* at Tbl. A-2.

Duke states that based on the 2005 baseline, to meet the Interim Target — defined by N.C.G.S. § 62-110.9 as a 70% reduction in carbon dioxide emissions from the 2005 baseline — it must reduce carbon dioxide emissions by 53,105,632 short tons.[10] *Id.* at 5. Accordingly, to achieve the Interim Target, Duke must limit carbon dioxide emissions from electric generation facilities it owns, operates, or that are operated on its behalf within the state to 22,759,556 short tons of carbon dioxide.

Duke further notes that N.C.G.S. § 62-110.9 applies solely to carbon dioxide emissions from electric generation facilities located within the State of North Carolina. Tr. vol. 7, Duke Proposed Carbon Plan, App. A, 1. As such, in calculating the 2005 carbon dioxide emissions baseline, Duke's carbon dioxide emissions calculations do not account for carbon dioxide emissions resulting from energy generated out of state and imported into the state. *Id.* Conversely, Duke included carbon dioxide emissions generated by in-state electric generation facilities but exported out of state. *Id.*

Duke acknowledges that stakeholders are concerned about the siting of new carbon dioxide-emitting resources outside the state as being counterproductive to achieving regional carbon dioxide emissions reductions. *Id.* at 6. "Recognizing the seemingly clear language of [N.C.G.S. § 62-110.9] and the questions raised by stakeholders," Duke requests that the Commission determine whether carbon dioxide emissions from out-of-state generating resources selected to be part of the Carbon Plan should be accounted for as if such emissions occurred in the state. *Id.*

On this point, Duke states that in modeling its Carbon Plan proposal it assumed that any new carbon dioxide-emitting resources would be sited in North Carolina. *Id.* However, Duke notes that to operate its dual-state systems reliably and cost-effectively for its North Carolina and South Carolina customers, it intends to site all new resources optimally based on several key parameters such as appropriateness of the site for the type of generation, access to fuel, ability to leverage existing infrastructure to reduce costs, and evaluation of community impacts, which could ultimately result in some new carbon dioxide-emitting resources being sited out of the state. *Id.* Duke further states that it committed to system-wide carbon dioxide emissions reductions and to carbon neutrality for the entire system by 2050. *Id.*

Public Staff witness Metz stated that Duke correctly accounted for the level of carbon dioxide output from its facilities in 2005 for purposes of complying with N.C.G.S. § 62-110.9. Tr. vol. 21, 108. In support of this conclusion, witness Metz testified that the Public Staff

[10] Interim Target = (1 – 0.7) x 2005 CO_2 Baseline [Short Tons CO_2]; N.C.G.S. § 62-110.9 Interim Target = 0.3 x 75,865,188 Short Tons CO_2; Interim Target = 22,759,556 Short Tons CO_2. Tr. vol. 7, Duke Proposed Carbon Plan, App. A, 5.

met with the North Carolina Department of Environmental Quality (NCDEQ) and Duke's staff multiple times to review historical emissions data and related information. *Id*.

No party disputes the 2005 baseline emissions calculation or the methodology Duke used to perform the calculation.

Public Staff witness Metz stated that the General Assembly intended for the emissions reduction targets to include only carbon dioxide "emitted in the State." *Id.* at 109. Witness Metz agreed with Duke's modeling assumption that all new carbon dioxide emitting resources will be located in North Carolina. *Id.* at 108. Moreover, witness Metz testified that he agrees with Duke's interpretation of N.C.G.S. § 62-110.9 that it should include only emissions from in-state (North Carolina) generation sources when calculating interim compliance and carbon neutrality. *Id*. at 109. However, witness Metz also testified that he recognizes the concerns stakeholders express that N.C.G.S. § 62-110.9's emissions boundary could lead to locating carbon dioxide-emitting resources outside of North Carolina as an "end-around" to the carbon dioxide emissions reduction mandates and stated that calculating carbon dioxide emissions on a system-wide basis reduces speculation regarding future asset locations and reduces modeling complexities. *Id*. Finally, Public Staff witness Metz encouraged the Commission to exercise oversight in further iterations of the Carbon Plan, IRP, CPCN dockets, and other proceedings to guard against this possibility. *Id*.

The Commission concludes that Duke's methodology for determining the 2005 baseline carbon dioxide emissions reasonably and appropriately relies on credible, widely-used data on emissions from the electric power sector. The Commission further concludes that Duke has correctly calculated the 2005 baseline and has correctly calculated the Interim Target. Additionally, the Commission concludes that it is appropriate for modeling purposes for Duke to assume that all new carbon dioxide-emitting resources will be located in North Carolina.

In response to Duke's request for guidance on the treatment of carbon dioxide emissions from facilities located outside of North Carolina, the Commission agrees with Duke and the Public Staff that the General Assembly intended for emissions reduction requirements to include only carbon dioxide emitted in North Carolina. The Commission is mindful of the concerns that the siting of new carbon dioxide-emitting resources outside the state could be counterproductive to achieving regional carbon dioxide emissions reductions. However, modeling all new carbon dioxide-emitting resources as if located in North Carolina mitigates this concern. The Commission confirms, though, that Duke must base ultimate siting of new resources optimally inside or outside of North Carolina on several factors — including, for example, the appropriateness of the site for the type of generation, access to fuel, ability to leverage existing infrastructure to reduce costs, and evaluation of community impacts — and not whether the resources will generate any associated carbon dioxide emissions inside or outside of North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-5

Inflation Reduction Act of 2022

The evidence supporting these findings of fact is in the direct testimony of Duke witness Bowman, the direct and rebuttal testimony of the Duke Modeling Panel, the testimony of Public Staff witnesses Thomas and Williamson, the testimony and Responsive Comments of RTHC et al., Brad Rouse, NCSEA et al., Tech Customers, AGO, CPSA, and CCEBA, and the entire record in this proceeding.

In her direct testimony, Duke witness Bowman stated that the IRA was enacted on August 16, 2022. She explained that Duke is actively continuing its analysis of the IRA, which contains many incentives associated with clean energy resources and electrification technologies. Tr. vol. 7, 57-58. She further stated that the clean energy tax credits in the legislation will enhance Duke's ability to develop and procure more clean energy in a least cost manner, including by mitigating recent inflationary and supply-chain pressures facing the industry; also, the tax benefits for new generation resources will directly benefit Duke's customers. She stated that the new law will enable investment in new infrastructure, supporting the communities Duke serves.

The Duke Modeling Panel also addressed the IRA and testified that implementation of the IRA will be one of the key developments that will be influential in updating the Carbon Plan for the 2024 proceeding. *Id*. at 215. They explained that Duke did not account for the IRA in its original load forecast because Congress did not pass the IRA until after Duke had completed its initial modeling. Tr. vol. 8, 215. The Panel noted that the IRA is very complex with a multitude of incentive options for supply-side resources, generally solar, wind, storage, and nuclear, including potential stackable incentives based on other factors such as siting. The Panel stated that Duke is continuing to evaluate tax implications and applicability of the IRA and how the incentives offset the inflationary impacts to the cost of resources such as solar, wind, and storage. Tr. vol. 27, 70-71.

Public Staff witness Thomas, discussing more generally the appropriateness of updating commodity and generation resource price forecasts after the parties performed initial Carbon Plan modeling, stated that modeling inputs must be final at some point, lest the biennial IRP proceeding devolve into an endless cycle of updating assumptions and re-running the models. He further stated that procedural schedules that allow for frequent IRP updates and a reliance on robust portfolios that cover a range of scenarios temper the consequences of this reality. Tr. vol. 21, 72. With respect to the IRA specifically, witness Thomas stated that while the IRA has extended the Investment Tax Credit (ITC) for renewables and included energy storage as a qualifying resource for the ITC, the tax credits are dependent on new factors (such as industry prevailing wages, siting, and source of raw materials), can be replaced with a Production Tax Credit (PTC) once energy production begins, and may eventually become technologically neutral. He also stated that financing for new nuclear development, including PTCs for nuclear resources, also appears to be included in the legislation, but the capital costs for new nuclear facilities are speculative at best. *Id.* at 82.

In sum, witness Thomas testified that incorporating the impacts of the IRA into Duke's models would be complex, as it is dependent upon Internal Revenue Service guidance and renewable developers and utilities being able to capture bonus tax incentives to the benefit of ratepayers. Witness Thomas also acknowledged that the IRA could impact the supply chain for solar. However, he did not assert that the Commission should direct Duke to update its Carbon Plan proposal with the impacts of the IRA because the Public Staff's modeling suggests that the resource selection within the timeframe of the near-term action plan is less sensitive to capital costs and is largely dependent upon model constraints, such as the first available selection year, the amount that can be interconnected annually, and annual carbon dioxide limits. Witness Thomas further described how the IRA would not only impact the cost of certain renewable and energy storage resources but could also impact electrification and EE, and that the net impact on load is complicated and load forecasting experts would need to study it. *Id.* at 82, 242. Public Staff witness Williamson stated that when Duke begins to prepare for its subsequent Carbon Plan filing, it will incorporate these effects on load. Tr. vol. 22, 381.

Several intervenors emphasize that the IRA will have a significant impact on resource costs, least cost determinations, technologies, and other factors that impact Carbon Plan considerations. RTHC et al. Responsive Comments at 2-5; tr. vol. 22, 88-89, 114; tr. vol. 23, 236, 240-50; tr. vol. 24, 179-81; tr. vol. 25, 67-68, 241-47, 274-75, 293-94; tr. vol. 26, 37, 248-49. For example, in their responsive comments, NCSEA et al. note that the IRA has dramatically altered the policy landscape in ways that will significantly reduce the costs of resources that can help Duke achieve the state's carbon dioxide emissions reduction requirements. They therefore recommend that to the extent the 2022 Carbon Plan's near-term action plan does not take policies under the IRA into account, there be an opportunity to provide supplemental modeling to update the Carbon Plan in early 2023 for the limited purpose of determining whether any modifications to the near-term action plan would be in the public interest. NCSEA et al. Responsive Comments at 1-2. Likewise, the AGO argues that the Commission should update the 2022 Carbon Plan to incorporate the impact of the IRA before syncing the timing of the Carbon Plan update proceedings and Duke's IRP proceedings. AGO Responsive Comments at 4-5.

In their rebuttal testimony, the Duke Modeling and Near-Term Actions Panel stated that Duke agrees that the tax credits and other incentives in the IRA will be beneficial for customers and may offset recent upward pressures on technology costs that have occurred since the development of Duke's Carbon Plan proposal. They added that the IRA incentives will lower costs for solar, storage, wind, and nuclear, and that in order to provide some preliminary high-level insight into the impact of the IRA and test the robustness of Duke's proposed near-term actions, they have conducted additional sensitivity analyses. The Duke Modeling Panel also stated that Duke must "snap a chalk line" at a specific point in time for purposes of fixing the modeling inputs and assumptions so that they can move forward with developing a plan. They argued that the modeling and analysis provided thus far in this proceeding are sufficient to support Duke's near-term actions. The Duke Modeling Panel also testified that the IRA is very complex, and that Duke is continuing to evaluate tax implications and the applicability of the new law and are confirming initial interpretations of the incentives for each resource. Tr. vol. 27, 48-

50, 70-71. Lastly, the Modeling Panel provided a description of the preliminary modeling sensitivity analysis they conducted based on their initial review of the IRA, as well as a description of the results of that preliminary modeling. Duke filed this IRA modeling sensitivity analysis as Duke Modeling and Near-Term Actions Panel Late-Filed Exhibit 1. *Id.* at 27, 72-75.

While the Commission agrees with the parties that the IRA will likely significantly impact the cost of compliance with N.C.G.S. § 62-110.9, it is also cognizant that Congress passed the IRA on August 16, 2022, three months after Duke completed its initial modeling in this proceeding, less than one month before the beginning of the evidentiary hearing, and a little over four months before the Commission's deadline for adopting the 2022 Carbon Plan. Such a timeline does not allow for the incorporation of the IRA into Duke's modeling or for a full review of the potential impacts of the legislation. The Commission further agrees with the Public Staff and Duke that modeling inputs must be final at some point, lest a proceeding "devolve into an endless cycle of updating assumptions and re-running the models." Tr. vol. 21, 72.

Therefore, based on the foregoing and the entire record in this proceeding, the Commission determines that it is appropriate for Duke to incorporate the impacts of the IRA, the IIJA, and other future legislative changes, as well as the impacts of other changing conditions such as inflationary pressures, into its first biennial CPIRP proposal that it will file with the Commission on or before September 1, 2023, and into any CPCN applications it files in the interim, so that Duke, the Public Staff, interested parties, and the Commission will have more comprehensive information on the IRA's impacts on Duke's execution and implementation of the Carbon Plan.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

Modeling – Optimization Period

The evidence supporting these findings of fact is in the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony of NCSEA et al. witness Fitch, the testimony of Tech Customers' witness Panel Borgatti, Kimbrough, and Roumpani, and the entire record in this proceeding.

Duke evaluated the period from 2023 through 2050, when it is required to achieve net zero carbon dioxide emissions. In selecting resources within capacity expansion, a full period optimization considers the costs of all resources and constraints through the entire study period. The Carolinas have a large number of resources and incorporating the additional constraint of achieving a declining carbon dioxide ton target made the problem size too large to solve within one full period in capacity expansion. Duke therefore did not study the entire 28-year period in one modeling run for each portfolio. Tr. vol. 7, 280-81.

Public Staff witness Thomas discussed the three eight-year optimization periods, and one five-year period, Duke used in its modeling. He explained that the optimization period is the length of time over which the model optimizes resource selection and dispatch, and that an eight-year optimization period indicates the model can only "see" costs and system conditions over an eight-year period (with a one-year extension) and is blind to any model inputs beyond the optimization period. He stated that an eight-year optimization period is problematic, particularly due to the hydrogen conversion costs in later model years. Tr. vol. 21, 25.

The Public Staff is satisfied with an eight-year optimization period for purposes of the 2022 Carbon Plan, although witness Thomas recommended that in future Carbon Plan proceedings, the Commission should direct Duke to utilize an initial optimization period of no less than 15 years and relax the Mixed Integer Programming (MIP) Stop Basis as necessary and within reason to reduce model run times. *Id.* at 53-54.

The Gabel Report, sponsored by the Tech Customers, used a single 28-year optimization period, and the Synapse Report, sponsored by NCSEA et al., used 15-year optimization periods. Both intervenors were able to complete their model runs by adjusting other settings to reduce run times, such as by increasing the MIP Stop Basis.

NCSEA et al.'s Synapse Report states:

> In the context of the current energy transition, where technology costs are changing rapidly and emissions are expected to decline over a multi-decadal time scale, longer planning horizons are important for integrating long-run industry transitions. Planning horizons that are too short may prevent resource planning tools like EnCompass from adequately taking long-term trends into account;" and "[c]apacity expansion modeling runs performed by Duke to develop its Carbon Plan proposed portfolios used a series of 8-year segments and a final 5-year segment . . . While 8-year planning segments are within the reasonable range of planning horizons used in detailed capacity expansion modeling, they also introduce risks that resources selected in the earliest segments may not be economical resource choices when viewed over the long term.

Tr. vol. 25, 205-06.

The Commission recognizes that certain modeling approaches, such as those that extend the optimization period, are likely to be more computationally intensive. Duke's Modeling and Near-Term Actions Panel stated that in response to Public Staff and intervenor recommendations to use longer optimization periods, Duke has committed to testing longer segmentation periods as it implements new versions of the model and will continue to engage with the Public Staff and other parties before the 2024 CPIRP filing.

Based on the foregoing, the Commission concludes that Duke's decision to use an eight-year optimization period for the capacity expansion modeling was appropriate, as it balanced model run times against the challenges associated with model foresight. However, the Commission directs Duke to test longer segmentation periods as it implements new versions of the model and to continue to engage with the Public Staff and other parties on this issue in preparation for its upcoming biennial CPIRP filing. The Commission concludes that it is reasonable for Duke to make all practicable efforts to maximize its modeling optimization period and to seek to model a 15-year, or greater, optimization period in its upcoming biennial CPIRP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

Modeling – Battery Storage

The evidence supporting these findings of fact is in the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony of NCSEA et al. witness Fitch, and the entire record in this proceeding.

Duke initially modeled Solar Plus Storage as "fixed-dispatch," meaning that charge and discharge times were preset to align with on-peak and off-peak times in applicable rate schedules included in certain PPAs.

After receiving comments from intervenors, Duke updated its modeling to allow for more dynamic dispatch of storage; the supplemental analysis (SP5 and SP6) allowed the EnCompass model to endogenously dispatch Solar Plus Storage. Duke subsequently found that modeling dispatched storage in conjunction with solar added an extensive amount of time to the modeling process. Tr. vol. 8, 46.

The Commission notes that as of August 2022, the EnCompass software was not capable of allowing a storage resource at a Solar Plus Storage facility to charge from the grid; however, the ability to charge storage with both DC energy and grid energy is expected to be available in an update to the EnCompass model to be released later in 2022. Tr. vol. 7, 346. Thus, as of August 2022, constraints within EnCompass limited Duke's ability to model the full functionality (or dynamism) of Solar Plus Storage.

Intervenors such as the Public Staff and NCSEA et al. agree that modelers should not model storage as fixed-dispatch and that dynamic dispatch is preferable, and Duke concedes the same, assuming that factors such as modeling times can be made to be reasonable. Tr. vol. 8, 47; tr. vol. 23, 54-56, tr. vol. 24, 165.

Duke's fixed dispatch approach to modeling Solar Plus Storage is not unreasonable for purposes of this initial Carbon Plan. However, the Commission finds that, going forward, the mechanics of modeling storage resources will be a key element to enable least cost compliance. Accordingly, the Commission concludes that Duke's first biennial CPIRP should model dynamic dispatch of Solar Plus Storage and, to the extent feasible, should incorporate bi-directional inverter capability. The Commission directs Duke and the Public Staff to work together closely on this issue during the next proceeding and, if they do not reach consensus on these modeling techniques, to each provide a robust explanation to the Commission as to the points of disagreement and agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

Modeling – Battery-CT Optimization

The evidence supporting this finding of fact is in Appendix E of Duke's Carbon Plan proposal, the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony of AGO witness Burgess, and the entire record in this proceeding.

Appendix E of Duke's Carbon Plan proposal describes the portfolio verification steps Duke undertook in modeling its proposed Carbon Plan to ensure least cost compliance and to ensure that the selected resources maintain or improve upon the adequacy and reliability of the grid. The Modeling and Near-Term Actions Panel further testified that, as part of the overall modeling framework, Duke took a portfolio verification step, which included production cost modeling within the EnCompass model to confirm economic selection of resources by the capacity expansion model. The Modeling and Near-Term Actions Panel testified that due to the simplified simulations used in capacity expansion modeling, the capacity expansion model alone could not evaluate in-depth economic operation of resources to ensure economic resource selection, especially in the case of energy-limited resources such as storage. Therefore, Duke used the production cost model to produce a more detailed and realistic simulation of the system to more accurately account for the cost to operate the system with these resources. Tr. vol. 7, 227-28.

Duke describes this process as necessary to ensure the inclusion of a least cost set of resources. In further explanation, Duke explains that in order to quickly assess a wide range of resource options, the capacity expansion resource screening model makes necessary simplifications in hourly loads and system operations to find potential least cost resource portfolios that will minimize the cost of the system. Further, Duke explains that because of these simplifications, the model evaluates resources against load shapes that account for monthly peak and low load conditions for each "typical day," while maintaining total average daily energy to ensure that the model selects resources that can meet these crucial planning requirements. Duke explains that this simplification (while necessary in the capacity expansion resource screening model) has the side effect of distorting the load shape in a way that does not reflect actual hourly needs on the system, which results in the capacity expansion model over-valuing short duration energy storage. Because the capacity expansion model over-ascribes value to energy storage resources, Duke explains that it is important to use additional analyses to verify if at least a portion of the energy storage, especially in the near term, included in the initial capacity expansion results is economic relative to other peaking resources, in this case CTs. Tr. vol. 7, 229.

To this end, Duke states that it replaced approximately 35% of the batteries that the capacity expansion model selected with CTs and re-ran the detailed production cost model with the adjusted resource mix (the Battery-CT Optimization Process). Duke explains that removing batteries and adding CTs typically increased modeled production costs, but because CTs are lower capital cost to build than batteries, the adjustment reduced the total capital costs of the portfolio. Duke explains that so long as the capital cost savings are more than enough to offset the production cost increase and Duke can still meet carbon dioxide emissions reduction mandates, the CTs are the more cost-effective resource. *Id.* at 230. Duke cautions that omitting this step could result in the inclusion in the portfolio of greater amounts of energy storage than is cost-effective.

Public Staff witness Thomas stated that the Battery-CT Optimization Process may not be reasonable for planning purposes and stated that Duke should have allowed the model to economically select battery storage. He explained that if the reliability validation step identified reliability issues, Duke could add CTs at that point to meet reliability thresholds. Tr. vol. 21, 43-47. Regarding whether the Battery-CT Optimization Process step results in cost savings for ratepayers, as Duke argues, witness Thomas stated that he found the overall cost savings to be relatively minor and sensitive to assumptions regarding natural gas prices and battery storage capital costs. He further stated that the Public Staff tested the robustness of Duke's savings estimates under two sensitivities: a 30% reduction to battery storage capital costs, representing the ITC that is now available to standalone energy storage systems, and the use of Henry Hub natural gas prices forecasted in the 2022 Annual Energy Outlook, Low Oil and Gas Supply case. He stated that the PVRR savings decreased dramatically for each portfolio, and that in P2 and P3 the replacement of 35% of battery storage with CTs resulted in a cost increase under these assumptions. *Id.* at 47-49.

Public Staff witness Thomas' concerns are that the Battery-CT Optimization Process: (1) produces minimal ratepayer savings; (2) is not robust to changes in capital costs, fuel prices, or natural gas consumption relative to Duke's assumptions; (3) forces in CTs to serve as essentially capacity-only resources, resulting in elevated reserve margins; and (4) is potentially redundant to the more detailed reliability validation analysis Duke undertook. *Id*. at 51-52.

AGO witness Burgess stated that while not all out-of-model adjustments are necessarily unwarranted, these kinds of additional steps can introduce a new potential "black box" that is non-transparent and can be difficult for stakeholders to independently assess. Thus, witness Burgess believes it is generally preferable to minimize these additional steps. Tr. vol. 25, 257.

Based on the foregoing, the Commission concludes that the Battery-CT Optimization Process step performed by Duke is justified at this time, given that the overall battery energy storage contemplated in the initial Carbon Plan is untested at scale in North Carolina currently. However, as planning tools are updated and Duke gains system operations experience with energy storage, this out-of-model step may no longer be appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

Modeling – Reliability

The evidence supporting these findings of fact is in the testimony and exhibits of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony NCSEA et al. witness Fitch, the testimony of Tech Customers' witness Panel Borgatti, Kimbrough, and Roumpani, and the entire record in this proceeding.

Duke's Carbon Plan proposal specifies that reliability is one of its core objectives, along with carbon dioxide emissions reduction, affordability, and executability. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 2. Chapter 2 to Duke's Carbon Plan proposal explains that N.C.G.S. § 62-110.9 requires that any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid and that the Commission may plan to achieve the Interim Target after 2030 if it is necessary to maintain the adequacy and reliability of the existing grid. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 2; App. Q, 1; App. E, 5. Appendix Q explains that this core statutory objective recognizes Duke's public service obligation to plan and operate their generating fleets and transmission and distribution systems to continually provide reliable power system operations to their customers in accordance with federally mandated NERC Reliability Standards. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 1.

Duke's Carbon Plan proposal includes multiple reliability inputs, including planning reserve margin, effective load-carrying capacity (ELCC) values for renewable and energy storage resources, and operational reserve requirements. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6-7. Duke's Carbon Plan proposal defines resource adequacy as "having sufficient resources available to reliably serve electric demand especially during extreme conditions," and explains that the planning reserve margin target is used in the planning process to ensure resource adequacy. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 9. The Carbon Plan proposal uses a 17% winter planning reserve margin to achieve a "one-day-in-10-year" industry standard Loss of Load Expectation (0.1 LOLE), or one firm load shed event every 10 years due to a shortage of generating capacity, as an acceptable level of physical reliability as determined by the 2020 Resource Adequacy Study conducted by Astrapé Consulting. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6; App. E, 9-10. Duke's Carbon Plan proposal uses a 2022 ELCC study developed in collaboration with Astrapé Consulting using the SERVM reliability and hourly production cost simulation tool to estimate the reliability capacity value attributable to variable solar and wind (seasonal contribution) and energy-limited storage resources. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6; App. E, 10-16. Finally, the Carbon Plan proposal uses a planning and reliability tool developed by the Electric Power Research Institute (EPRI) to calculate hourly operational reserves requirements to ensure that Duke will have sufficient flexible resources available to mitigate the risk of load and renewable output uncertainty. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6-7.

Duke's development of its Carbon Plan proposal includes simplified capacity expansion screening modeling in EnCompass with average representation of hourly system demand to determine optimal resource portfolios that meet reliability standards, carbon dioxide emissions reduction mandates, and least cost planning requirements. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 25-26; App. E, 4. The output of the capacity expansion model is used to develop operational reserve requirements in the EPRI tool to ensure adequate flexible resources to mitigate load and variable resource uncertainty; the capacity expansion is then reoptimized with the operational reserve requirements. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6-7, 26.

Duke's Carbon Plan proposal explains that this capacity expansion, due to its computational and data simplifications, was further modeled in more detail in the production cost stage to validate and adjust resources across cost, reliability, and carbon dioxide emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 25; App. E, 4. The portfolio outputs from the preliminary identification of resources in the capacity expansion model were run through the detailed EnCompass production cost model that reflected more detailed hourly dispatch versus an "average" representation in capacity expansion, thus developing refined resource outcomes based on more realistic hourly loads. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 26; App. E, 59.

The Battery-CT optimization step then considered hourly loads for each hour of the year to arrive at a portfolio that balanced carbon dioxide emissions reduction mandates while minimizing costs, and had the added benefit of enhanced system reliability by replacing shorter-duration batteries with CTs with longer duration capabilities to meet system needs 24 hours a day, every day of the year without limitation. *Id*.

Duke then performed resource adequacy and reliability verification using both the EnCompass production cost model and SERVM. Duke utilized the SERVM tool to assure that a portfolio with a high reliance on variable energy and energy-limited resources, which present risks that planning reserve margins do not adequately address, especially in severe weather events, would maintain system reliability. Tr. vol. 7, 228. DEC witness Roberts testified as to the importance of this additional reliability validation step, which reflects Modeling Team collaboration with the System Planning and Operations Team to ensure that the validation actually reflects realistic weather, demand, and outage operational patterns. Tr. vol. 19, 172.

The use of SERVM allows Duke to utilize 41 years of weather data, and other inputs, in order to perform a statistical determination of LOLE. Tr. vol. 9, 96. Duke has been using SERVM as its reliability tool for at least seven years. Tr. vol. 11, 150. The Public Staff reviewed the SERVM tool prior to these proceedings and expressed confidence in its ability to calculate LOLE. Tr. vol. 21, 374. NCSEA et al. witness Fitch argued that Duke's use of the SERVM tool is not commonly understood to be a necessary step in resource planning. Tr. vol. 24, 143. Witness Borgatti of Tech Customers expressed concern that intervenors cannot independently validate a proprietary tool such as SERVM. *Id.* at 354. While the Commission acknowledges the concerns of some intervenors as to the use of a reliability validation step outside of EnCompass, the Commission also gives significant weight to

Duke's arguments that a complete modeling exercise may consist of the use of more than one software tool. Based on the foregoing, the Commission concludes that Duke's use of a tool such as SERVM — to validate reliability — is appropriate.

Duke's Carbon Plan proposal explains that the power system transformation that the Carbon Plan portfolios contemplate raises many new challenges for managing the grid, as increasing levels of renewable generation will fundamentally change patterns of net load demand and increased uncertainty. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 17. While traditional planning metrics of adequate day-to-day operating reserves and long-term planning reserves necessary to meet customer demands during cold winter morning and hot summer afternoons are necessary, the change in resource mix due to the energy transition creates new challenges. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 3, 17; App. Q, 1. The proposed Carbon Plan introduces six reliability risks and mitigating solutions of the energy transition that will create new challenges for managing the grid. *Id.* at App. Q, 1-2. Those risks include: (1) resource and energy adequacy from renewables and storage; (2) access to firm interstate transportation of natural gas and new natural gas-fired generating resources; (3) coal-fired generator reliability during the transition; (4) the need for new carbon-free load-following resources that are flexible and dispatchable; (5) the need for adequate and reliable flexible resources to manage the reliable integration of renewables; and (6) system resilience to withstand extreme events such as weather or cyber disruptions.

Duke witnesses provided extensive testimony on practical and operational experience that inform the positions Duke takes in the proposed Carbon Plan. For example, DEC witness Holeman explained that from a System Operator's point of view, there are real-world implications that must be factored in when maintaining grid adequacy and reliability during the energy transition. Tr. vol. 19, 114-15.

Duke's Reliability Panel discussed the criticality of resource planning resulting in an orderly, planned transition of the system, and stated that Duke "must strive to reduce risks, not heighten risks, for their customers and communities as their resource mix transitions through the Carbon Plan to achieve vital carbon dioxide emissions reduction targets" as intended by N.C.G.S. § 110.9 to maintain or improve upon the reliability of the grid. Tr. vol. 19, 129-30,140. The Reliability Panel further noted that NERC has identified the risks of energy transition as "merit[ing] the highest attention and mitigation efforts from regulators and grid operators," specifically citing resource adequacy during extreme weather events, appropriate sequencing of resource transitions (retirements and replacements), and having adequate flexible and dispatchable resources. *Id.* at 131, 133-34.

Based on Duke's system operational experience and trends across the industry, Duke's Reliability Panel underscored the need for a carefully planned transition to retire more than 8,400 MW of coal by 2035, with assurance that there is timely replacement with a robust mix of resources with operational capabilities that coal provides — particularly in constrained periods and prolonged weather events. *Id.* at 134, 154-55, 161, 182; tr. vol. 30, 105-06. In response to CIGFUR questions on coal retirements, witness Holeman punctuated this concept: "Replace before you retire. So I believe I'm confident after 38 years in this industry in the operations area that if we keep that order right, we'll be able to deliver what's mandated in House Bill 951." Tr. vol. 19, 208.

The Commission notes that N.C.G.S. § 62-110.9(3) provides expressly that the Commission, in developing the Carbon Plan, *must* "[e]nsure any generation and resources changes maintain or improve upon the adequacy and reliability of the existing grid." The Commission is persuaded by the testimony of the Duke and Public Staff witnesses supporting and underscoring the need for the various steps taken to assess and ensure the reliable operation of the system, and is persuaded that Duke, in developing its Carbon Plan proposal, appropriately focused on maintaining adequacy and reliability of the existing grid. The Commission takes special note of the six specific risks to reliability Duke identifies and directs Duke to address robustly each of those risks, with updated information and modeling where appropriate, in its upcoming CPIRP filing. The Commission agrees with Public Staff witness Metz and with Duke, that "[n]ot all system operational factors can be captured within a model," and directs Duke to work with the Public Staff in leveraging actual operational experience to continue to plan for the future, mitigate foreseeable risk, and prepare for the challenges ahead.

The Commission concludes that ensuring system reliability and compliance with mandatory reliability standards in the face of the ongoing energy transition is a requirement of state law, is an obligation uniquely held by Duke and overseen by this Commission, and is nonnegotiable for the continued health and well-being of all North Carolinians.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-17

Coal Plant Retirements

The evidence supporting these findings of fact is in Duke's Carbon Plan proposal, the direct and rebuttal testimony of the Duke Modeling and Near-Term Actions Panel and the Transmission and Solar Procurement Panel, the testimony of the Public Staff, NCSEA et al., and the AGO, the Initial Comments of the Public Staff, CIGFUR, Tech Customers, and Person County, and the entire record in this proceeding.

Duke's approach to modeling began with a constraint which decreased carbon dioxide emissions linearly to achieve the Interim Target and the 2050 Target. The model could then economically select a mix of assets subject to this constraint. In each of Duke's proposed portfolios P1-P4, Duke would retire all coal generation capacity by 2035 at the latest. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, Tbl. E-47. In sensitivities SP5 and SP6 modeled at the request of the Public Staff, Belews Creek station is allowed to run as a coal-fired facility until the end of 2037. Tr. vol. 13, Official Exhibits, 30-31. The following table displays the amount of coal generation resources retired as of the date of achieving the Interim Target for each portfolio:

Portfolio	Interim Target Date	Coal Generation Retired
P-1	2030	4,900 MW
P-2	2032	4,900 MW
P-3	2034	6,300 MW
P-4	2034	6,300 MW

Tr. vol. 13, Official Exhibits, 38-39; tr. vol. 7, Duke Proposed Carbon Plan, App. E at 77. The Modeling Panel highlighted the scale of Duke's coal capacity reduction plans in the Carolinas, explaining that, including the coal-to-gas conversion of Cliffside Unit 6, Duke is planning to retire and/or replace 9,274 MW of coal capacity by the end of 2035. Duke asserts that compared to its southeastern peer utilities, Duke is reducing more coal capacity than any other utility surveyed. Tr. vol. 7, 335-36.

As explained in Duke's Carbon Plan proposal filing and through testimony, the timing of future coal retirements was first identified endogenously within Duke's EnCompass capacity expansion model. This is a significant enhancement over prior modeling and responds to criticisms made in connection with the 2020 IRP proceedings concerning Duke's methodology for determining coal unit retirement dates and to the directive the Commission gave in its Order accepting the 2020 IRPs. Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning, *2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, No. E-100, Sub 165, 12-13 (N.C.U.C. Nov 19, 2021). The capacity expansion model weighed the continued operational benefits to the system and costs to operate and maintain the coal units over time against the retirement and potential replacement of the coal units by available supply-side resources, while also meeting the operational and planning constraints of the system, including emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 44. As the Duke Modeling Panel described, capacity expansion modeling does not provide an exact date for the optimal timing to retire a unit, and its ability to do so is inadequate due to necessary simplifications used in the model. Numerous factors which could influence optimal timing of retirements do not lend themselves to perfect integration into the model, but Duke must consider them in determining the optimal timing of coal retirements. Tr. vol. 7, 326-28.

Duke's modeling fixed retirement dates for each coal unit through its depreciable life with two exceptions. Duke modeled Belews Creek to cease operations at the end of 2035, consistent with Duke's target to be out of coal by 2035 and in an effort to mitigate fuel security risks related to coal supply. Additionally, Duke modeled Allen Units 1 and 5 to be retired by the beginning of 2024, coincident with the timing of a transmission project under construction in DEC to enable the retirement of these units. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 45.

In the 2020 IRP, and as directed by prior Commission orders, Duke evaluated coal retirements without regard to the remaining net book value (NBV) of the units. However, for the Carbon Plan, because N.C.G.S. § 62.110.9 and Commission Rule R8-74 provide for securitizing remaining NBV of accelerated retirements of subcritical coal units, Duke factored into the coal retirement analysis the benefits associated with securitization of the remaining net book value of subcritical coal units at the time of modeled retirement. *Id*. at 44-47.

The determination of optimal coal retirement dates was a multi-step process. Duke explains that while it used the capacity expansion model to endogenously identify retirement dates economically, on a level comparison with new resources and in keeping with carbon dioxide emissions reduction requirements, relying exclusively on results from the capacity expansion model would not be the best practice for resource planning. *Id*. at 44. Duke explains that while the capacity expansion and production cost models are sophisticated tools, capacity expansion modeling, in general, is not an exact indication of the optimal selection of resources or the optimal timing to retire a unit. Tr. vol. 7, 326-27. Additionally, Duke states that there are several factors which could influence the optimal timing of retirements — including the timing of new resource additions, transmission constraints, and the ability to leverage sites for future development — and that these factors do not lend themselves to perfect integration into the EnCompass model. *Id.* at 327. For these reasons, Duke notes that the coal retirement dates the model selected were subject to additional analysis and adjustment in certain, limited instances. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 48-49.

In response to NCSEA et al. witness Fitch, the Modeling and Near-Term Actions Panel testified that Duke reviewed the analysis that witness Fitch used as a basis for his assertions and concluded that Synapse's analysis is flawed and that the Commission should disregard it. Synapse's report indicates that Duke made manual changes to coal retirement dates, functionally overriding the conclusions of the endogenous retirement analysis performed with EnCompass. Synapse's conclusion is that Duke's manual adjustments would cost ratepayers an additional $1.4 billion. Tr. vol. 25 (Public), NCSEA et al. and SACE et al. Initial Comments, Synapse Report, 28-29. The Panel explained that the cost Synapse calculates does not account for net capacity changes on the system — that is, the replacement resources — essentially only factoring in one side of the ledger. Furthermore, Duke asserts that the cost estimates are based on a generalized industry study that does not specifically apply to Duke's coal units in question, whereas Duke's decades of experience operating these units inform a more appropriate estimate when evaluating the cost for continued reliable operation of these units. Tr. vol. 7, 333-34.

The Modeling and Near-Term Actions Panel also explained the adjustments Duke made to the endogenously identified retirement dates for Marshall Units 1 and 2 and Roxboro Units 3 and 4, as examples, pointing to transmission projects necessary to enable the retirements or to the optimal timing of new resource availability. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 48. The Panel provided additional context related to Duke's need to delay retirements of these assets in the modeling. The Panel stated that optimally timing the coal retirements to recognize the necessary transmission construction timelines is an appropriate consideration. Doing so further allows for the selection from a wider array of resources to meet the near-term and long-term system needs. The timelines additionally allow Duke to take advantage of continued cost declines for certain resources, such as batteries, if they are selected as a part of the collective optimal replacement resources. Tr. vol. 7, 327-28; tr. vol. 7, Duke Proposed Carbon Plan, App. E, 48.

Specifically, the Modeling and Near-Term Actions Panel continued, to retire Marshall Units 1 and 2 without replacement resources on site would require the completion of the McGuire – Marshall 230 kV transmission project. The Panel explained that the earlier deployment of batteries (prior to the completion of the transmission upgrade) as a replacement resource at the site is not a feasible alternative solution, as the replacement resources contemplated by the adjustment to the Marshall retirement dates must be fully dispatchable and capable of longer run times than are currently possible for batteries in order to satisfy grid reliability requirements. Energy-limited batteries do not allow for avoidance of the transmission project to enable these coal retirements. Tr. vol. 7, 328-29.

Similarly, the Panel explained that the accelerated retirement of Mayo that the capacity expansion model identifies, without replacement by dispatchable resources capable of longer run times, requires several potential transmission projects that push the feasible retirement date of Mayo to later in the current decade, at the earliest. *Id.* at 329-30.

Duke witness Roberts testified as part of the Transmission Panel that Duke must ensure that any transmission projects required to accommodate coal retirements are in place prior to the planned retirement dates. He echoed Appendix P to Duke's Carbon Plan proposal that considering the planned retirement dates for Duke's coal units, Duke has performed varying levels of transmission planning analysis and considerations based on different scenarios for generation replacement. He explained that several of these scenarios reveal the necessity of replacing the retiring generation onsite connected to the same electrical point of interconnection. He noted that a major consideration with respect to the timing for retirement is whether Duke can avoid long-term transmission upgrades and that this issue was a major driver in Duke's request for FERC approval to incorporate a Generation Replacement process into the Large Generation Interconnection Procedures (LGIP). He testified that FERC's approval of this process, which Duke obtained on September 6, 2022, will be critical to efficient, timely, and cost-effective replacement of retired coal-fired generation with new generation interconnected at the same switchyard. Tr. vol. 16, 94-96; tr. vol. 7, Duke Proposed Carbon Plan, App. P, 15-16.

The Duke Transmission Panel testified that in planning for coal retirement, Duke must consider the adequacy of replacement resources and also plan for grid impacts such as voltage support, changing power flows, and the need for associated transmission investment. In defense of Duke's extension of the retirement dates for certain units, the panel testified that Synapse's critique ignores real-world execution and operations risks, and that scrutiny of model outputs is necessary to ensure that they reflect a reliable portfolio and consider these risks. The Synapse and Gabel reports both criticized Duke's manual changes to coal retirement dates, arguing that endogenous modeling only should drive coal retirements. Tr. vol. 25 (Public), NCSEA et al. and SACE et al. Initial Comments, Synapse

Energy Economics, 28-29; tr. vol. 25 (Public), Tech Customers Initial Comments, Gabel Report, 27-29. The panel's prefiled testimony outlines several of the upgrades that would be necessary to achieve the economic retirement dates, issues with which, the panel testified, Gabel and Synapse do not meaningfully engage, instead assuming that Duke can replace all retiring coal generation onsite. These necessary upgrades cause the panel to have significant executability concerns with the Synapse and Gabel proposed portfolios. Tr. vol. 16, 97-100.

As an example of the operational issues that Duke must address in settling upon retirement dates for coal units, witness Roberts testified concerning the critical role that coal and other dispatchable resources played during the extended winter peak event of 2018. Tr. vol. 19, 178-79. Witness Roberts provided a table which indicates that twelve of eighteen coal units in DEC and DEP operated at a 93% or higher capacity factor during the period January 2-8, 2018. He provided the Roxboro Plant as an example, which produced 392,786 MWh at 96% capacity factor during the 7-day period. Witness Roberts further testified that system operations must consider solar and wind facility performance to maintain reliability in extended cold weather periods, as well as how the planned retirement of the coal fleet impacts system operations reliability risks. *Id.* at 179-83. He further testified that Duke will need to carefully plan coal unit retirements to maintain resource adequacy and system reliability during the transition away from coal. Noting the actual customer demand and irradiance experience during January 2018, witness Roberts concludes that it would be impossible for him to agree with Synapse or Gabel that their portfolios could provide energy adequacy for reliably serving similar long duration winter events, as they over-rely on the weather-dependent resources of solar and wind. He added that the Synapse and Gabel proposed portfolios retire coal early without effectively providing replacement generation or resources that can achieve high-capacity factors for extended periods when needed as Duke's coal fleet did in January 2018. *Id.* at 182, 197-99.

With regard to the question of timing of coal retirements, Public Staff witness Metz testified that while maintaining the operation of any generating resource beyond its economic life is not preferable, there are operational and reliability implications that Duke must consider and manage as part of any coal exit strategy. He testified that the retirement schedule may need to reflect impacts of a range of factors including transmission, fuel supply, and system reserves to account for system abnormalities that occur outside of a model. Tr. vol. 21, 116-18.

Citing the need to maintain operational flexibility and reliability at a reasonable cost, witness Metz cautioned the Commission against ordering an overly prescriptive, inflexible retirement schedule for the entire coal generation fleet. *Id*. Witness Metz explained that Duke can use the coal generation assets that it does not retire before 2030 as capacity resources to meet reserve margin requirements while not dispatching them for daily system needs.[11] Duke would also use these units to account for system

[11] The Commission notes that a coal generation unit that Duke does not retire before 2030, may be idle but available when needed for purposes of responding to system anomalies or extreme contingencies. The coal

anomalies. *Id.* at 112-14. Witness Metz advised against a definitive coal retirement schedule and suggested the Commission's primary focus should be on maintaining operational flexibility and reliability at a reasonable cost. He recommended that Duke continue to update the Commission and stakeholders of any changes to the current retirement schedule on an ongoing basis. *Id*. at 116-17.

Public Staff Witness Boswell testified that Duke must comply with Commission Rule R8-74 and N.C.G.S. § 62-110.9 by securitizing 50% of the remaining NBV of all subcritical coal plants Duke retires early to achieve the carbon dioxide emissions reduction mandates in N.C.G.S. § 62-110.9. This securitization must be timely and maximize benefits to customers. Witness Boswell recommended that Duke maximize cost savings by assessing whether it would be in ratepayers' interest to securitize additional coal generation assets, including non-sub-critical coal units. Tr. vol. 23, 117-18.

In the Gabel Report, sponsored by Tech Customers witnesses, Tech Customers point out the undisputed fact that coal-fired generation is the largest source of carbon dioxide emissions in Duke's fleet. Tech Customers acknowledge that actual retirement decisions must consider factors outside those available in the model, though they insist that Duke make conclusions transparently and on the best available supporting data. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 27-28. While the Gabel Report's alternate Carbon Plan modeling accelerates the retirement of Duke's coal fleet to before 2030, it also describes its analysis as a "modeling exercise to illustrate hypothetical results that may be possible." *Id.* at 28.

Person County desires that Duke locate replacement resources at the retiring coal unit sites currently operating in that county in order to minimize cost to customers. Person County Initial Comments at 9. Person County also advocates for maintaining the Mayo and Roxboro units for as long as possible to support N.C.G.S. §110.9's requirement to maintain or improve upon adequacy and reliability of the existing grid and offers that it is prudent planning for Duke to extend the operational lives of Roxboro and Mayo past the retirement dates Duke's Carbon Plan proposal identifies, but to use them only for emergency purposes. *Id*. at 12-13.

In his testimony, AGO witness Burgess disputed Duke's out-of-model adjustments to its coal retirement dates, which he stated lead to significant changes in those dates. Specific to Duke's proposed portfolio P1, witness Burgess testified that the economic retirement dates for Belews Creek Units 1 and 2, Marshall Units 1 and 2, and Mayo Unit 1 occur much sooner than what Duke has proposed, and that earlier retirement may be economic and feasible. Tr. vol. 25, 285-86. In summary, AGO witness Burgess criticized Duke's support for these adjustments as insufficient given the degree of delay. He also advocated alternatives to delayed retirement, including battery storage at the site of existing coal plants, to mitigate the need for transmission upgrades, and stated that by overriding the model's retirement date selection, Duke also crowds out other more economic resources that it would otherwise

generation unit would no longer be regularly generating electricity, thus, it would produce decidedly less carbon dioxide emissions due to its limited operation.

consider earlier. In addition, witness Burgess critiqued the delayed retirement of Belews Creek from 2030 to 2036 due to necessary transmission upgrades and suggested there is ample time to complete any necessary upgrades by 2030. He also recommended that the Commission explore the feasibility of converting Belews Creek to 100% natural gas and direct Duke to include this as an option in all future scenarios.

AGO Witness Burgess also suggested increasing the natural gas co-firing at the Belews Station in lieu of accelerated retirement. AGO witness Burgess explained that in his alternate modeling, he modeled the conversion of Belews Creek to operate exclusively on natural gas starting in 2028. He stated that due to the complexities of modeling the Belews Creek gas conversion, this resource was assumed as an input for the 2028 timeframe rather than being a result of the model's resource selection process. While acknowledging that, ideally, modeling should support this scenario, he suggested that this is a reasonable approximation of the optimal outcome due to the considerably favorable economics of this conversion over a new natural gas plant addition. Tr. vol. 24, 281-83, 288.

Regarding the high gas price sensitivity scenarios, AGO witness Burgess cautioned that economic dispatch of the generation fleet could lead Duke to exceed its carbon dioxide emissions mandates by running relatively less expensive coal generation, specifically Belews Creek, more than it modeled. Giving weight to this sensitivity case increases the urgency of retiring Belews Creek and replacing it with cleaner resources. Tr. vol. 25, 290.

NCSEA et al. witness Fitch suggested that the adjustments to the endogenously identified coal retirements dates lack analytical justification and would result in additional costs to ratepayers. Witness Fitch asserted that the adjustments were not necessary to maintain reliability of the system and that Duke should have accepted the EnCompass optimization results as the most cost-effective retirement dates. He contended that the dates the model selected are the most optimal co-optimization of mix of resources. He argued that the reasoning Duke provided in its proposed Carbon Plan and in Duke witness Roberts' direct testimony rely too heavily on high level assumptions rather than detailed requirements and timelines. He presented Synapse's scenarios for coal unit retirement and recommends the Commission make all efforts to implement the most economic coal retirement dates. Tr. vol. 24, 171-77.

As an alternative to accelerating coal retirement and perhaps necessitating the deployment of replacement resources, in its Initial Comments the Public Staff recommends modeling Belews Creek as operating exclusively on natural gas post-2035 until the end of 2037, the end of the station's projected depreciable life. Public Staff Initial Comments at 21, 117-19.

In its initial written comments, CIGFUR contends that Duke failed to adequately consider, as a potentially more cost-effective alternative solution to reducing carbon dioxide emissions, retrofitting existing coal plants to burn natural gas as a means of extending the life of the assets. CIGFUR Initial Comments at 19-20.

With respect to the further conversion of coal units to operate primarily on natural gas and for longer periods of time, Duke responded that it evaluated the high-level business case of expanding natural gas co-firing beyond the current 50% at Belews Creek Units 1 and 2 and Marshall Units 3 and 4, and, while the expansions were potentially feasible (subject to detailed engineering studies to confirm), a recently completed evaluation did not indicate favorable economics for customers. Tr. vol. 7, 332; tr. vol. 27, 85.

Based on the foregoing evidence, the Commission finds Duke's coal retirement modeling and analysis, as well as the dates Duke targets for retirement and sets forth in Duke Table E-47 on the following page, to be reasonable for planning purposes.

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

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

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

Tr. vol. 7, Duke Proposed Carbon Plan, App. E, Tbl. E-47.

The coal retirement schedule Duke presents in its proposed Carbon Plan enables substantial reductions of carbon dioxide emissions that contribute to meeting the carbon dioxide emissions reduction mandates following least cost principles while maintaining system reliability. Duke employed a detailed multi-step modeling and analytical process to appropriately estimate the cost of continued operation and leveraged the results of the endogenous coal retirement analysis to inform and guide a coal retirement schedule that recognizes real-world operating constraints. The Commission recognizes the magnitude of the challenge Duke is undertaking over the next decade, including the significant fleet transition required to retire 8,400 MW of coal-fired units that are operating today by the end of 2035 and to replace more than 9,200 MW of coal capacity when also considering the Cliffside Unit 6 coal-to-gas conversion. While the Commission, too, is interested in Duke's considering all feasible options, such as converting the Belews Creek Station to operate 100% on natural gas, the Commission concludes that Duke is taking reasonable steps in this regard.

The Commission agrees with the Public Staff that planning for retirement of Duke's remaining coal fleet should continue to focus on maintaining operational flexibility and reliability at a reasonable cost. Retirements generally require replacement resources to maintain the resource adequacy of the system. Providing an overly prescriptive approach to coal unit retirement based solely on expansion planning model outputs is not prudent, and the Commission agrees with Public Staff witness Metz and Duke witness Roberts that accelerating coal unit retirements without enabling transmission or necessary replacement resources may risk the reliability of the grid. Duke's approach of an orderly transition provides time to evaluate transmission system needs, identify replacement resources, and pursue a holistic approach to an orderly transition of the fleet.

The Commission agrees with the Public Staff that it is appropriate for Duke to keep the Commission apprised of the timing of scheduled coal unit retirements. The Commission cautions that any slippage in the projected retirement dates set forth in Appendix E, Table 4-2 of Duke's Carbon Plan proposal has the potential to materially increase the risk of failure to meet the Interim Target by 2030. As stated above, the Commission understands and agrees on the need for Duke to retain a degree of flexibility with respect to the proposed retirement dates for purposes of reliability and cost management. However, Duke should not interpret that flexibility as open-ended. The Commission directs Duke to present a comprehensive analysis of the planned coal unit retirement schedule in its next CPIRP filing to specifically address the contingencies witnesses identified and discussed in this proceeding that may affect Duke's currently planned retirement dates of its coal-fired units, especially for the units Duke contemplates for retirement before 2030 (Cliffside Unit 5, Marshall Units 1 and 2, Mayo Unit 1, and Roxboro Units 1 and 2), and for Roxboro Units 3 and 4, which Duke retires in 2028 in its proposed portfolio P1. Duke shall further address steps it has taken and plans to take to ensure that those contingencies do not require delays to Duke's proposed retirement dates set forth in Appendix E, Table 4-2 of Duke's Carbon Plan proposal. The Commission will require Duke to show substantial justification for any delays and to present alternatives for reducing the additional carbon dioxide emissions that may result from delaying retirements beyond the dates currently proposed in its 2022 Carbon Plan filing.

Finally, the Commission notes that Duke conducted and completed its evaluation of the conversion of Belews Creek Units 1 and 2 from 50% natural gas capability to 100% capability before the passage of N.C.G.S. § 62-110.9 and not as part of the comprehensive analysis of Duke's overall resource portfolio that has been part of these proceedings or of the 2020 IRP proceedings. This evaluation did not, for example, consider whether Duke might justify the additional fuel source conversion at Belews Creek as an interim or bridge to a time when Duke could bring fully hydrogen-capable CT or CC generating units online, as an alternative to investing in new natural gas generating units now and then later incurring costs to convert those units to a zero-carbon fuel source. As another example, the earlier study did not evaluate whether the fuel source conversion might enable the Belews Creek units to provide additional, non-coal fired reserve capacity for the system and thereby help support the proposed retirement dates for others of Duke's coal-fired generating units. The Commission would benefit from additional review of such topics and others associated with the potential for fuel source conversion and directs Duke to re-study the potential costs and benefits of a further conversion of Belews Creek as part of its upcoming proposed biennial CPIRP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-20

Existing Resources – SLR

The evidence supporting these findings of fact is in Duke's Carbon Plan proposal, the direct and rebuttal testimony of Duke's Long Lead-Time Resource Panel, the direct testimony of Duke's Modeling and Near-Term Actions Panel (Snider), the direct testimony of Public Staff witness Metz, the direct testimony of CIGFUR witness Gorman, and the entire record in this proceeding.

Duke's Long Lead-Time Resource Panel testified that Duke currently operates 11 nuclear generation units that provide a total capacity of approximately 11,100 MW, over 50 percent of Duke's total electric generating capacity. The Panel stated that the existing nuclear fleet provides baseload generation to Duke's customers in North Carolina and South Carolina and that the existing nuclear fleet provides approximately 83% of all Duke's carbon-free electric generation.

In Appendix D, Table D-14 of Duke's Carbon Plan proposal, Duke includes a list of its existing nuclear generating facilities that denotes each facility's jurisdiction (DEC or DEP), location, date of the original operating license expiration, date of the Nuclear Regulatory Commission's (NRC's) approval of the initial extended operating license, and date of the initial extended operating license expiration, which is the current operating license expiration for each facility. Duke's Long Lead-Time Resource Panel explained that each of Duke's existing nuclear facilities has obtained an initial renewal of the operating license, extending the operational life of each facility to their current expiration dates. Due to these initial license renewals, the earliest unit's license is set to expire in 2030 and the last unit's license will expire in 2046. The Panel contended that SLR will extend the operating life of each nuclear generating facility by 20 years beyond the current operating license expiration. With SLR approval, the retirements for the nuclear fleet will shift to 2050 through 2066.

Duke's Modeling and Near-Term Actions Panel (Snider) testified that continued operation of the existing nuclear fleet is essential to achieve the 2050 Target, and all of Duke's proposed portfolios rely on SLR of the existing nuclear fleet. The Panel asserted that SLR of the existing nuclear fleet is foundational to Duke's Carbon Plan proposal and that achieving the carbon dioxide emissions reduction mandates N.C.G.S. § 62-110.9 sets will not be possible from reliability, cost, and executability perspectives without the relicensing of the existing nuclear fleet. Tr. vol. 12, 16.

No party opposes Duke's pursuit of SLR for the existing nuclear fleet. Public Staff witness Metz testified that no intervenors engaged in a substantive discussion of the specifics of Duke's SLR proposal. Witness Metz asserted that the existing nuclear fleet can serve as a foundational component for compliance with the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9. However, he testified that the Public Staff is not advocating that Duke pursue SLR blindly. He stated that Duke must demonstrate that costs associated with SLR of the existing nuclear fleet are reasonable and prudent before Duke may recover those costs from ratepayers. Finally, witness Metz recommended that in future Carbon Plan filings Duke clearly lay out a schedule for pursuit of SLR for each existing nuclear unit and develop a contingency plan should any nuclear unit not achieve SLR in time to continue operations.

Both Duke's Long Lead-Time Resource Panel and Public Staff witness Metz detailed the regulatory process for SLR of nuclear facilities. They each explained that SLR requires regulatory approval by the NRC and is necessary to extend the operational life of each nuclear facility by 20 years. Witness Metz testified that in early 2022, the NRC reset the SLR applications of two nuclear facilities, neither of which Duke owns or operates. He stated that typically, SLR requests have taken approximately two years to complete but may take longer if the NRC triggers a re-evaluation of a SLR. He asserted that, because Duke's earliest nuclear license will not expire until 2030, Duke has adequate time to address this topic in future Carbon Plan updates. He also recommended that Duke review the SLR applications that the NRC reset in early 2022 and incorporate any lessons learned when preparing its SLR applications.

Regarding the operational timeline for the existing nuclear fleet, Duke's Long Lead-Time Resource Panel explained that if Duke successfully obtains SLR, the retirement dates for the existing nuclear fleet will shift to the earliest retirement occurring in 2050 and the last retirement occurring in 2066. Appendix D of Duke's Carbon Plan proposal notes that Duke's earliest nuclear operating license is set to expire on July 31, 2030, for Robinson Unit 2. Duke's last nuclear operating license is set to expire on October 24, 2046, for Harris Unit 1. CIGFUR witness Gorman pointed out that without SLR of the existing nuclear generation fleet, Duke will lose approximately 793 MW of capacity in 2030 and a total of approximately 4,400 MW of capacity by 2035.

Finally, Public Staff witness Metz discussed NC WARN's recommendation that Duke convert its existing nuclear fleet to synchronous condensers after 2035. Witness Metz asserted that NC WARN's idea is novel but is likely not the best utilization of Duke's nuclear fleet. He stated that NC WARN does not provide substantive discussion to support its recommendation and does not identify alternative resources that would be necessary to replace the approximate 11 GW of nuclear base load capacity. For these reasons, the Commission agrees with the Public Staff that it is not appropriate for Duke to consider conversion of the existing nuclear fleet to synchronous condensers at this time.

Given that Duke's existing nuclear generation fleet provides baseload electric generation for customers in North Carolina and South Carolina, that the existing nuclear fleet provides a significant portion of carbon-free electric generating capacity, and that no party contests Duke's pursuit of SLR for the existing nuclear fleet, the Commission concludes that it is reasonable and appropriate for Duke to pursue SLR of the existing nuclear fleet. Further, based on the recommendations of the Public Staff, the Commission directs Duke to develop a schedule detailing its plans for SLR of the existing nuclear fleet and provide this information in its upcoming CPIRP filing. The Commission also directs Duke to review the SLR applications that the NRC reset in early 2022 and to incorporate any lessons learned in the preparation of Duke's SLR applications for its existing nuclear fleet.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

Existing Resources – Natural Gas Fleet

The evidence supporting this finding of fact is in Duke's Carbon Plan proposal, the direct and rebuttal testimony of Duke's Modeling and Near-Term Actions Panel, the testimony of Duke's Reliability Panel, the direct testimony of Public Staff witness Metz, and the direct testimony of AGO witness Burgess.

Duke requests that the Commission approve Duke expanding the flexibility of its existing natural gas fleet, naming projects that support more flexible operational capabilities of the natural gas fleet, including increasing up and down ramp rates, improving minimum load capabilities, and reducing minimum up and minimum down time to increase a gas-fired plant's ability to cycle more often. Tr. vol. 7, Duke Petition for Approval, 10-11, 16.

Duke's Modeling and Near-Term Actions Panel testified that achieving increased flexibility of the existing gas fleet is critical to successfully achieving the carbon dioxide emissions reduction mandates that N.C.G.S. § 62-110.9 establishes. Tr. vol. 7, 325-26. Appendix Q to Duke's Carbon Plan proposal explains that in coordination with energy storage, operating the CC fleet more flexibly to meet the ramping and cycling demands of portfolios with significantly increased amounts of intermittent resources will be necessary to maintain system reliability in all portfolios to achieve N.C.G.S. § 62-110.9's carbon dioxide emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 10. Appendix Q further explains that Duke has historically designed and operated its CC fleet specifically for baseload operations and has faced a limited need to cycle given the flexibility of the remaining generators. *Id*. Duke's Modeling and Near-Term Actions Panel testified, however, that for some of the proposed Carbon Plan portfolios to meet the carbon dioxide emissions reduction requirements of N.C.G.S. § 62-110.9, the majority of the CC fleet will require daily cycling for certain periods of the year in order for the system to receive injections of zero-carbon energy. Tr. vol. 7, 367-68. This operational approach will be new to Duke's fleet and will likely require changes to operations and maintenance practices as well as investments and upgrades to increase unit flexibility. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 10.

Duke's Reliability Panel testified that "[t]o maintain the grid, System Operators require adequate flexible and dispatchable operational reserves that can *persist* through prolonged extreme weather events." Tr. vol. 30, 106 (emphasis in original). This change in mission is particularly important as Duke retires remaining coal units and the system increasingly depends on intermittent renewable resources and limited duration storage technologies. Tr. vol. 7, Duke Proposed Carbon Plan, Chs. 3, 5; *see also* tr. vol. 7, 302 ("As the Companies reduce dependence on dispatchable fossil fuels and increase dependence on intermittent resources, prudent utility planning and HB 951 requires that this transition be planned and executed in a manner that does not impact reliability to customers."). The Reliability Panel testified that natural gas is "a bridge to integrate more renewables and batteries until hydrogen and long-duration storage and [zero emissions load following resources] are available and can replace at scale what gas contributes to the system." Tr. vol. 30, 106. The Modeling and Near-Term Actions Panel testified that expanding the flexibility of Duke's existing natural gas fleet "will allow the Companies to maintain system reliability and quality of service while integrating intermittent resources, such as wind and solar, that may not match customer demand." Tr. vol. 7, 325.

Public Staff witness Metz testified that the Public Staff supports expansion of the flexibility of the existing natural gas fleet provided that Duke identifies a targeted need for flexibility expansion on a project-by-project basis and that such projects prove to be least cost in order to meet required carbon dioxide emissions reductions. He testified that, as Duke's electric generation portfolio and load shapes change, Duke will be better able to identify specific flexibility expansion requirements for the existing natural gas fleet in future Carbon Plans. The Public Staff maintains that any expansion projects of the existing natural gas fleet to achieve flexibility in operations should demonstrate through cost-benefit analyses that the added benefits to flexibility justify the costs and that system flexibility cannot be achieved by alternative means. Public Staff Initial Comments at 159-60.

AGO witness Burgess testified that enhancing the flexibility of the existing natural gas fleet is one method to support renewable resource integration without the need to invest in construction of new generation. Tr. vol. 25, 303.

The Commission acknowledges that the ability to operate the fleet of natural gas resources to meet the ramping and cycling demands of portfolios with significantly increased amounts of variable and time-limited resources will be necessary to maintain system reliability while achieving the carbon dioxide emissions reduction requirements of the statute. Further, the transition of the generating fleet as well as the anticipated changes in load shapes will require system operators to have resources at the ready that are flexible in their ability to meet these new challenges. The Commission agrees with the Public Staff that the expansion of the existing natural gas fleet to allow for operational flexibility is necessary but expects Duke to identify targeted needs for expansion projects that will enhance flexibility and that meet the least cost path to compliance mandates. The Commission directs Duke to identify specific natural gas plants or regions of its service areas that would benefit from flexibility expansion projects and update the Commission on its analysis, including any change in carbon dioxide emissions from these changes, in future Carbon Plans.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-27

The Role of Natural Gas

The evidence supporting these findings of fact is in Duke's Carbon Plan proposal, the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Duke's Reliability Panel, the Initial Comments of the Public Staff, the testimony of Public Staff witness Thomas, the testimony of Public Staff witness Metz, the testimony of AGO witness Burgess, the Initial Comments of Appalachian Voices, the Initial Comments of CUCA, the Initial Comments of CIGFUR, the testimony NCSEA et al. witness Fitch, the

Initial Comments of NCSEA, the testimony of Tech Customers witnesses Borgatti and Kimbrough, and the entire record in this proceeding.

Duke asserts that natural gas plays a vital role in its compliance with N.C.G.S. § 62-110.9. Duke witnesses Holeman and Roberts explained that to meet the statutory mandates to maintain or improve upon the reliability of the existing grid during the transition, firm, dispatchable natural gas-fired generating resources serve as a reliability "bridge" to achieving carbon neutrality while filling the resource adequacy needs created by the retirement of coal units. Tr. vol. 19, 164, 183. Duke further explains that it will design any new natural gas-fired generating units to transition to using hydrogen blended with natural gas and to ultimately be able to utilize 100% hydrogen. Tr. vol. 7, Duke Proposed Carbon Plan, App. M.

Duke used several fuel side assumptions and constraints in modeling new natural gas units as selectable resources, including access to natural gas supply, the price of natural gas, the potential for hydrogen fuel to replace natural gas, and the asset life of new natural gas facilities. Those assumptions and constraints are discussed in the following sections.

Access to Natural Gas Supply Assumptions

Duke's four proposed portfolios assume a limited amount of firm transportation capacity to provide natural gas from the Appalachian region. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 24. Duke's Modeling and Near-Term Actions panel testified that using limited Appalachian natural gas accessibility follows the least cost planning principles and is in the best interest of ratepayers. The panel further testified that without this assumption Duke would face "increased fuel assurance risk, increased customer fuel cost exposure and increased risk of delayed coal retirements." Tr. vol. 7, 370.

DEC's and DEP's CC fleet is "currently deficient of interstate pipeline firm transportation capacity due to the cancellation of Atlantic Coast Pipeline (ACP)." Tr. vol. 7, Duke Proposed Carbon Plan, App. N, 7. Duke's Carbon Plan proposal indicates that "the major interstate pipeline supplying the Carolinas is fully subscribed, and during the coldest winter days, the gas demand for electricity generation coincides with peak Local Distribution Company demand. Currently, obtaining delivered gas supply into the Carolinas from the marketplace during these periods of high demand is constrained. The constrained market also leads to gas supply that can be cost prohibitive, if even available at volumes required." Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 5.

In the rebuttal testimony of its Modeling and Near-Term Actions panel, Duke clarifies that

> the Companies currently hold 434,560 Dth/day of Transco Firm Transportation capacity under long-term contracts that provides non-Zone 5 firm fuel supply. While this volume does not meet the natural gas needs of the entire CC fleet, this volume is greater than the peak day needs of the three gas-only combined

cycles in the fleet. Additionally, the Companies contract with third parties to deliver firm fuel supply to the Companies in Zone 5.

Tr. vol 27, 87.

In response to concerns the Public Staff and other intervenors expressed, Duke performed supplemental modeling that assumed no access to Appalachian gas supply as the base planning scenario and utilized the Public Staff's recommendation to allow Transco Zone 4 to supply all existing CC units as well as incremental Transco firm transportation to supply for two large, or three small, CC units. Tr. vol. 7, 251. This supplemental modeling, identified as portfolios SP5 and SP6, also excluded the selection of hydrogen fuel and instead relied on up to 5% carbon offsets in 2050. *Id.* The supplemental portfolios also allowed the selection of between 1,200 MW advanced J-Class and smaller 800 MW F-Class CCs. Tr. vol. 7, Duke Modeling and Near-Term Actions Panel Ex. 1, 7-8.

Public Staff witness Thomas testified that Duke's assumptions regarding access to natural gas supply are not reasonable and emphasized concerns regarding the availability of Appalachian natural gas to electric generating facilities in North Carolina. He noted that SP5 and SP6 included natural gas assumptions that the Public Staff recommended and that the changes modeled in SP5 have resulted in a shift of the location of CC plants. In the original four portfolios of Duke's Carbon Plan proposal, one CC was selected to be located in DEC and one in DEP, both in 2029. However, in SP5, both CCs are located in DEC's territory, and the need for one of the CCs is delayed until 2030. Public Staff witness Thomas testified that even if Appalachian gas is made available to North Carolina via the MVP and/or the MVP Southgate Pipeline, it is unclear whether this gas will have a firm intrastate pathway to locations in DEC's territory. Witness Thomas concludes that the Public Staff supports the "No App Gas" supply assumptions Duke used in SP5 and SP6 and notes that developments related to the MVP and MVP Southgate projects will be a matter of debate in future CPCN and Carbon Plan proceedings. Tr. vol. 21, 73-74.

The AGO, NCSEA et al., Tech Customers, CUCA, and CIGFUR also raise concerns regarding Duke's assumptions associated with access to natural gas supply. AGO witness Burgess argues that Duke lacks sufficient access to firm transportation capacity for its existing fleet and that new natural gas-fired generating facilities will introduce a new reliability risk in cold weather. Tr. vol. 25, 267. NCSEA et al. witness Fitch and Tech Customers witness Borgatti make similar assertions. Tr. vol. 24, 158; Tr. vol. 25, 59.

CIGFUR supports the addition of new natural gas-fired generating facilities but also expresses concern regarding reliability impacts if Duke is unable to secure an adequate supply of natural gas or to access sufficient firm pipeline capacity, or if the MVP is not placed into service. CIGFUR Initial Comments at 19. CUCA also supports natural gas but likewise raises concern that Duke's Carbon Plan proposal does not adequately address how to obtain additional firm transportation capacity for natural gas. CUCA Initial Comments at 9-10.

Natural Gas Price Assumptions

Duke's natural gas price forecast method relies on five years of natural gas market-based pricing, followed by three years of transition from market-based pricing before fully utilizing a fundamentals-based natural gas pricing forecast starting in 2031 for the remaining period. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 39. Given the variation in natural gas price forecasts among fundamentals providers, Duke developed its fundamentals-based forecast by averaging four recent natural gas price forecasts: (1) EIA's Annual Energy Outlook Reference case (2021 AEO); (2) Wood Mackenzie North American Power Markets (Base Case) (2021); (3) EVA FuelCast (2021); and IHS Markit Long-Term Natural Gas Outlook (August 2021). *Id*. at 39-40. In addition to the alternate gas supply sensitivity analysis, Duke performed a natural gas price portfolio sensitivity analysis on certain portfolios to assess whether the selection of natural gas resources would be affected by the adoption of high price forecasts. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 3, 13. However, even under the high gas price case, the model selected new natural gas capacity as least cost under these portfolios. *Id*.

Public Staff witness Thomas stated that the natural gas price forecasts that Duke used in its Carbon Plan proposal are reasonable and an improvement over prior methods Duke used in IRPs. Tr. vol. 22, 67-68. He further noted that the Public Staff is concerned with the risk to ratepayers in overreliance on natural gas considering recent increases in natural gas commodity prices. However, witness Thomas noted that, as Duke's Carbon Plan proposal reflects, ratepayers' exposure to volatile natural gas prices is less due to the decline in natural gas fuel consumption, which peaks around 2026 in all four portfolios and steadily declines through the remainder of the planning period. *Id.* at 70-71.

Witness Thomas acknowledged that, similar to the IRP process, modeling for the Carbon Plan is a complex task and typically begins six to nine months in advance of a filing. *Id.* at 71. Witness Thomas noted that fuel price forecasts are typically "locked in" by that time and that procedural schedules that allow for frequent updates and a reliance on robust portfolios that cover a range of issues temper the consequences of unanticipated changes in the market. *Id.* at 72. For example, he testified, the 2024 Carbon Plan update proceedings will utilize updated natural gas price forecasts. If future gas prices appear elevated at that time, the revised near-term action plan will reflect that forecast. *Id.*

Witness Thomas noted that more recent natural gas price forecasts continue to predict gas prices declining between 2023 and 2029, well before natural gas plants are economically selected in Duke's Carbon Plan proposal. *Id.* Last, witness Thomas noted that Duke must also obtain a CPCN for any new gas resources and that the Commission and the Public Staff will evaluate in detail the reasonableness of proposed natural gas plants after Duke files the CPCN application, which will include an analysis of the most recent gas price forecasts and market conditions. *Id.* at 73. For all these reasons, witness Thomas explained, the Public Staff does not recommend any changes to Duke's natural gas forecasting methodology or that the Commission direct Duke to update natural gas price forecasts. *Id*. at 67, 70.

On behalf of the AGO, witness Burgess expressed concern that Duke developed its plan before the recent and significant increase in natural gas prices driven in part by Russia's invasion of Ukraine and that current spot prices are significantly higher than the "worst case scenario" that Duke modeled in its Carbon Plan proposal. Tr. vol. 25, 264. Witness Burgess argued that there is uncertainty regarding when or if current prices will eventually subside and "return to normalcy." *Id.* at 264-65.

Appalachian Voices, Tech Customers, CUCA, NC WARN, and NCSEA et al., similarly raise concerns that Duke's natural gas price forecasts do not reflect the recent surge in natural gas prices. Appalachian Voices Initial Comments, Attach. A - PSE Health Report at 4-5; Tech Customers Initial Comments, Gabel Report at 29-30; CUCA Initial Comments at 10-12; tr. vol 22, 196; NCSEA et al. Initial Comments at 5-6.

Hydrogen Fuel Assumptions, Asset Life of New Natural Gas Facilities, and Other Natural Gas Capital Cost Assumptions

Duke states that while it designed its existing fleet of natural gas-fired generators to operate by utilizing natural gas or fuel oil, hydrogen could potentially blend with or replace existing fuels with some modifications to the CTs. Tr. vol. 7, Duke Proposed Carbon Plan, App. N, 7-8. Duke's Carbon Plan proposal models hydrogen capable simple-cycle CT capacity additions with sufficient ultra-low sulfur diesel back-up to eliminate the need for interstate firm transportation natural gas capacity. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 24. Duke represents hydrogen blending in its modeling with a starting point of 3% in 2035 and ramping up in several steps to 15% by 2041 and holding steady thereafter. Duke applies this blend to all natural gas assets existing or added before 2040. Duke's modeling assumes any new peaking CT units built in the 2040s are capable of being 100% hydrogen fueled. By 2050, the modeling assumes all existing CT and CC units continuing to operate on the system as well as all CTs and CCs Duke adds to the portfolios operate on hydrogen to achieve zero carbon dioxide emissions by the end of the planning horizon. *Id*. at 25.

Appendix E to Duke's Carbon Plan proposal explains that for planning purposes Duke assumed a 35-year asset life for new natural gas units selected under the model. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 31-32. For selectable CTs, Duke used a J-Class Frame CT with a selective catalytic reduction (SCR), with dual-fuel operations on natural gas and ultra-low sulfur diesel as the generic unit assumptions. According to Appendix E, this technology is a more efficient and flexible combustion technology than the F-Class Frame CTs that comprise the majority of Duke's existing peaking CT technologies. The J-Class Frame CTs also are currently more hydrogen capable than the F-Class Frame CTs and compatible with conversion to 100% operation on hydrogen in the future. *Id*. at 30. With respect to CCs, Duke used two configurations for the Carbon Plan: (1) a 2x1 J-Class CC with Duct Firing (CC-J) as the generic unit assumption; and (2) a 2x1 F-Class CC with dual fuel capabilities (CC-F), operating on both natural gas and ultra-low sulfur diesel (ULSD) in the alternate fuel supply sensitivity. *Id*. at 30-31.

Duke's Modeling and Near-Term Actions Panel's rebuttal testimony highlights that the IRA and IIJA provide potential funding and significant incentives to promote near-term development and scale up of the hydrogen economy. Tr. vol. 27, 76-77. The Modeling and Near-Term Actions Panel explained that these new policy incentives for developing hydrogen fuel further increase the likelihood of Duke's original planning assumption and reduce alleged stranded cost risk associated with the limited CC and CT capacity that Duke is recommending in its near-term actions. *Id.* at 77. During the hearing, witness Snider stated that Duke has other options to ensure that new natural gas assets will not be stranded, including offsets and sequestration. In addition, if no other technology comes to fruition, N.C.G.S. § 62-110.9 allows Duke to continue running natural gas resources on a limited basis if needed to maintain reliability. Tr. vol. 10, 100; Tr. vol. 27, 271.

The Modeling and Near-Term Actions Panel also acknowledged that, as part of the CPCN process, Duke will continue to evaluate the impact of changing resource technology costs, tax incentives, and commodity pricing with respect to the overall economics and need for a project, including project-specific cost estimates rather than generic cost estimates Duke uses in planning. *Id.* Duke also plans to update its IRPs soon to assess changing market conditions, including updated commodity price forecasts, technology cost projections based on prevailing market conditions, and a more comprehensive analysis of the tax benefits attributable to the IRA. The CPCN application will provide detailed updates to project costs, commodity costs and many other project and site-specific considerations while the 2023 IRP update will assess changing market conditions from a system perspective. Tr. vol. 27, 59-60.

The Public Staff expresses concern regarding the inclusion of hydrogen in the Carbon Plan modeling. The Public Staff notes that Duke bases its assumptions regarding the availability of hydrogen fuel on achieving United States Department of Energy (DOE) target electrolysis efficiencies and having sufficient excess renewable energy to produce the necessary quantities of hydrogen. Public Staff Initial Comments at 16. Accordingly, in the Public Staff's view, incorporating hydrogen fuel conversion assumptions for new natural gas CC and CT capacity represents a portfolio risk because if the production and blending of hydrogen does not materialize, meeting the carbon dioxide emissions reduction mandates will require substantial new generation to replace natural gas plants that would become stranded assets for which ratepayers would be responsible. *Id.* Accordingly, the Public Staff recommends that Duke not include hydrogen in base case modeling at this time. Tr. vol. 21, 47; Public Staff Initial Comments at 76. Nevertheless, the Public Staff acknowledges that Duke should consider hydrogen in an alternative portfolio analysis until Duke and the hydrogen industry resolve uncertainty around development risk, deliverability, and cost. *Id*.

Witness Thomas explained that the Public Staff finds Duke's modeling based on a 35-year useful life for natural gas-fired electric generating resources to be reasonable, and the Public Staff does not recommend any changes to either the capital costs or operable life assumptions in this proceeding. Tr. vol. 21, 81-82. Witness Thomas stated that the Public Staff is not persuaded by Tech Customers' Gabel Report or witness Kimbrough that Duke's capital cost assumptions for new natural gas resources are out of line with market benchmarks. While witness Thomas acknowledged that the publicly available sources the Gabel Report and witness Kimbrough cite were higher than Duke's assumptions, witness Thomas stated that Duke's assumptions are more reasonable for a number of reasons. *Id.* at 380. Public Staff witness Metz also highlighted that the Commission and the Public Staff extensively considered the issue of CT capital costs in recent avoided cost proceedings. *Id*. at 379.

AGO witness Burgess suggested that many of the cost assumptions Duke used to model hydrogen resources are speculative and that the feasibility of Duke's plan to utilize hydrogen is questionable. Tr. vol. 25, 271. Regarding Duke's cost assumptions, witness Burgess argues that the potentially significant future cost of hydrogen conversion of gas resources is largely missing because Duke only performed PVRR calculations through 2050. *Id.* Regarding the feasibility of hydrogen, witness Burgess noted that the availability of a robust hydrogen market by 2050 remains uncertain. *Id.* at 272.

Accordingly, AGO witness Burgess argues that Duke should model new CC and CT units assuming 20-year lifetimes, rather than the 35-year lifetimes that Duke has assumed, at least until there is more clarity on the future of the hydrogen market. According to witness Burgess, it may also make sense to delay a decision on new CC and CT additions as long as possible in order to monitor the development of clean hydrogen technologies, gain further clarity on costs, and avoid stranded asset risks for consumers. *Id.* at 273.

Tech Customers similarly argue that hydrogen generation is not commercially viable and is, therefore, too speculative for Duke to include in future planning. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 4. As noted above, Tech Customers witness Kimbrough questions the reasonableness of Duke's capital cost assumptions for new natural gas-fired resources, suggesting they are out of line with a number of national industry publications that show higher costs for a single unit site. Tr. vol. 25, 79; *see also* tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 8. According to witness Kimbrough, Duke assumes that natural gas-fired CC and CT units will be approximately 27% less expensive than market benchmarks for comparable resources, while capital cost assumptions for solar and battery storage resources is approximately 12% to 59% more expensive than market benchmarks. According to witness Kimbrough, the combined impact of these purported cost disparities means that the model is more likely to select new gas resources over new solar or battery storage resources. Tr. vol. 25, 249.

NCSEA et al. witness Fitch argued that it may not be technically feasible or cost-effective in the future to convert and operate combustion turbines on hydrogen. Tr. vol. 24, 158. Witness Fitch noted that if technical issues prevent cost-effective turbine conversion or a sufficient supply of zero-carbon hydrogen is not available, existing and planned gas plants risk becoming obsolete, and the burden of paying off stranded gas assets will fall on either shareholders or Duke's ratepayers. *Id.* at 158-59.

NCSEA et al. recommend several revisions to Duke's Carbon Plan proposal inputs and modeling assumptions, including increasing capital costs for new natural gas resources to align with the EIA's Annual Energy Outlook 2022, and reducing the operational and book life of gas CCs and CTs from 35 years to 25 years for operational life and 20 years for the purposes of natural gas plant depreciation. Tr. vol. 25, NCSEA et al. Initial Comments, Synapse Report, 10. According to NCSEA et al. witness Fitch, this approach avoids stranded asset risk as carbon requirements decline toward zero by 2050. Tr. vol. 25, 160.

Timing of Natural Gas Generation Additions

Multiple parties recommend that the Commission delay selecting new natural gas-fired generating resources. AGO witness Burgess argued that the Commission should delay a decision on new CT or CC additions in order to monitor costs and hydrogen development and in order to avoid the possibility of stranded costs. *Id.* at 271. AGO witness Burgess also noted that Duke did not include an evaluation of the conversion of Belews Creek to natural gas and recommends that conversion of Belews Creek to natural gas should be an option in the resource model. *Id.* at 290. At the hearing AGO witness Burgess further noted that there is already existing gas infrastructure at these units. *Id.* at 339.

In its Initial Comments, CIGFUR contends that Duke failed to adequately consider, as a potentially more cost-effective alternative solution to reducing carbon dioxide emissions, retrofitting existing coal plants to burn natural gas as a means of extending the life of the assets. CIGFUR Initial Comments at 19-20.

Regarding the conversion of coal units to utilize exclusively natural gas, Duke responds that it evaluated the high-level business case of expanding natural gas co-firing beyond the current 50% at Belews Creek and Marshall, but that while the expansions were potentially feasible, subject to detailed engineering studies to confirm, the evaluation did not indicate favorable economics. Tr. vol. 7, 332; tr. vol. 27, 85.

Tech Customers recommend that the Commission defer a decision to invest in new natural gas generation resources in this proceeding and eliminate new CCs as a selectable resource in their modeling. Tr. vol. 25, 57; tr. vol. 25, Tech Customers Initial Comments, Gabel Report. According to the Gabel Report, natural gas plants built in the early 2030s will survive well past 2050, and their cost-effectiveness is heavily reliant on Duke's assumptions regarding green hydrogen. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 29. The Gabel Report also argues that new gas generation is not necessary until at least 2029 and may not be necessary at all given that investment in evolving technologies like battery storage could satisfy the capacity need. *Id*. at 30. To avoid the construction of new natural gas units and the risk of stranded assets, the Gabel Report suggests that Duke may be able to expand its contract capacity with existing North Carolina resources, including the Cleveland CT, Rowan CT, and Rowan CC, when those facilities' existing contracts with other purchasers expire. *Id.* at 30-31.

Duke argues that delay of the new natural gas-fired resources would limit its ability to retire its existing coal units. The Modeling and Near-Term Actions Panel's testified that Duke's planned coal unit retirements require replacement resources that can provide firm, dispatchable, and equally reliable capacity like peaking CTs and baseload CCs. Without such replacement resources, Duke cannot retire coal on an accelerated schedule. Tr. vol. 27, 80-81. The Panel noted that delaying a single natural gas CC and keeping an equivalent amount of coal online results in an increase of nearly two million tons of carbon dioxide on the system in the year 2030. *Id.* at 80.

Conclusions on Natural Gas

The assumptions related to natural gas and the role of natural gas-fired generating resources reflect one of the most significant resource planning decisions in this proceeding. Duke's near-term action plan includes 1,200 MW of new CCs and 800 MW of new CTs. Based upon the foregoing and the entire record in this proceeding, the Commission makes the following conclusions.

The Commission gives substantial weight to the fact that Duke's modeling across all portfolios, supplemental portfolios, and Duke's preliminary additional IRA sensitivity analysis demonstrate a need for new CCs as part of a least cost plan to continue the energy transition, to retire coal resources, and to meet the mandates of N.C.G.S. § 62-110.9. Selection of new CC capacity in Duke's Carbon Plan proposal's initial high gas sensitivity, supplemental modeling analysis, as well as preliminary IRA modeling provide further evidence of the need for limited new natural gas CC resources as part of least cost portfolio. Numerous modeling portfolios, including intervenor-sponsored modeling, also identified the need for new natural gas CTs by 2030. Additionally, the Commission recognizes Duke witness Roberts' testimony that generator replacement (natural gas replacing coal) on existing sites may obviate the need for investment in significant transmission upgrades at certain sites.

With respect to access to gas supply, the Commission agrees with Duke, the Public Staff, and other parties that there continues to be significant uncertainty around the sufficiency of interstate natural gas transportation capacity to deliver gas into North Carolina. However, Duke's Modeling and Near-Term Actions Panel has explained, in detail, a plan to obtain firm transportation of new natural gas to its system in a variety of contingencies. The Commission is persuaded that Duke will be able to pivot to an alternate plan if the MVP is never completed or not timely completed. However, the Commission concludes that the execution risk associated with fuel deliverability for Duke's natural gas-fired electric generating resources warrants, at least for the initial CPIRP filing, the modeling of portfolios with appropriate sensitivities to capture feasible fuel deliverability options for applicable future years. Thus, the Commission directs Duke to use natural gas pricing and supply assumptions that reflect the most recent developments that would impact natural gas access in North Carolina, including the development of natural gas pipeline capacity.

With respect to the method for developing the natural gas price forecast, the Commission concludes that the natural gas price forecast method Duke used in the Carbon Plan proposal is reasonable. Further, the Commission reiterates the following provision from its recent Order in the 2021 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities proceeding:

> The Commission further notes that once the Commission approves the Carbon Plan, the natural gas forecasting method proposed by Duke in its Carbon Plan will be more appropriate for use in the subsequent avoided cost biennial proceeding. The Commission agrees with the Public Staff that consistency is appropriate and warranted.

Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, *2021 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities,* No. E-100, Sub 175, 23 (Nov. 22, 2022). Accordingly, the Commission directs Duke to use the method approved herein in its proposed biennial CPIRP and in subsequent avoided cost proceedings.

With respect to the assumptions related to capital cost and operational life, the Commission gives substantial weight to the Public Staff's testimony that Duke's CC and CT capital cost assumptions and 35-year operational life assumptions are reasonable for planning purposes, even though the Public Staff believes it is premature to include hydrogen. The Commission notes that although the ability to select hydrogen was completely removed from SP5 and SP6 at the Public Staff's recommendation, those models allowed for the use of carbon offsets and selected a natural gas CT generating unit. Tr. vol 21, 75. While the Commission understands the Public Staff's and certain intervenors' position that there remains uncertainty in the development of a hydrogen market, the Commission does not believe it would be reasonable to reduce the operable life of new natural gas resources for modeling purposes or to exclude hydrogen as a selectable resource at this time. Duke witnesses stated that Duke intends to "check and adjust" these assumptions as part of the 2024 Carbon Plan proceeding, and the Commission will reassess the reasonableness of those assumptions at that time.

To reassess the reasonableness of the 35-year operational life assumption, the Commission directs Duke to provide additional information on the appropriateness of this assumption in its future filings. In response to a question on the options available for new natural gas generation resources after 2050, Duke witness Snider responded that the options are conversion to hydrogen, the offset market, sequestration, or long-duration storage. Tr. vol 27, 271. If Duke uses an operational life for any new natural gas generation facility longer than 20 years, the Commission directs Duke to provide additional information outlining why this assumption continues to be reasonable, including an analysis of its modeling inputs for the cost of the options witness Snider outlines for the natural gas generation facilities after 2050.

The Commission gives substantial weight to Duke's testimony that Duke's planned coal unit retirements require replacement resources that can provide firm, dispatchable, and equally reliable capacity like peaking CTs and baseload CCs and that without such replacement resources, Duke cannot retire coal on an accelerated schedule. The Commission also takes note that Duke argues that delay of the new natural gas resources would limit its ability to retire its existing coal units. The Commission likewise gives substantial weight to Duke's testimony that the limited new natural gas CC and CT resources Duke identifies in the near-term action plan are essential to achieving the Interim Target, while maintaining or improving reliability, and doing so along a least cost path. In particular, the Commission is persuaded by the testimony of Duke witnesses Holeman and Roberts that Duke needs flexible and dispatchable new gas resources on the system as Duke moves forward with retiring 8,400 MW of coal unit capacity by the end of 2035. Similarly persuasive was the Modeling and Near-Term Actions Panel's testimony that failing to develop new natural gas resources jeopardizes Duke's ability to achieve the mandated carbon dioxide emissions reduction, including witness Snider's testimony that new CC capacity resources are approximately 60% less carbon dioxide emitting per MWh compared to the coal they are replacing.

The Commission also gives substantial weight to Public Staff witness Thomas' testimony that almost all the proposed portfolios include natural gas CC in the near-term, and that if new natural gas facilities are not an option, then Duke may need to consider delaying its planned coal retirements. Tr. vol. 23, 47-48.

Finally, the Commission finds persuasive Duke's testimony that a failure to consider new natural gas resources may increase the cost of operating the system and curtail future longer-term development of the hydrogen economy or appropriately structure a North Carolina carbon offset market that may provide a pathway for continued operation of new CC and CT resources beyond 2050 in a manner consistent with N.C.G.S. § 62-110.9.

The Commission determines that planning for approximately 800 MW of CTs and a CC of up to 1,200 MW is a reasonable step for Duke to take at this time. This should include assessing replacement generation options at the sites of retiring coal units on the DEC and DEP systems. However, as multiple parties note, the availability of interstate pipeline firm transportation capacity is an ongoing concern. If and when Duke applies for a CPCN for any new natural gas-fired generating facility, the Commission will evaluate the need for the facility, using this 2022 Carbon Plan as one factor in determining the need. The Commission will also evaluate the projected costs of the facility, including all the costs associated with construction of the facility itself. The Commission will also consider the availability of firm transportation capacity to North Carolina, the status of any necessary pipeline expansion projects, and the availability of firm intrastate pipeline capacity. Due to uncertainty of interstate transportation as well as the very recent enactment of the IRA, it would not be appropriate to give the Commission's approval for planning purposes of 800 MW of CTs and 1,200 MW of CC dispositive weight in the future related CPCN proceedings. The Commission directs Duke to include in its initial CPIRP filing a detailed discussion of interstate transportation capacity and modeling analysis to demonstrate that any natural gas resource selected in future plans continues to be part of the least cost path to compliance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-33

Near-Term Development and Procurement Actions for New Standalone Solar Generation, Solar Plus Storage, Standalone Battery Storage, and Onshore Wind

The evidence supporting these findings of fact is found in Duke's Carbon Plan proposal, the direct and rebuttal testimonies of the Duke Modeling and Near-Term Actions Panel, the direct testimony of the Duke Utilities Operations Panel, the direct testimony of the Duke Transmission Panel the direct testimony of Public Staff witnesses Thomas, Metz, and McLawhorn, AGO witness Burgess, CCEBA witness DiFelice, CPSA witnesses Norris and Hagerty, Tech Customers witness Borgatti, NCSEA et al. witness Fitch, and CIGFUR witness Muller; and the entire record in this proceeding.

Duke's proposed near-term plan for new supply-side resources includes: (1) 3,100 MW of solar generation (including the capacity targeted to be procured in the 2022 Solar Procurement Program[12]), of which a substantial portion is assumed to include Solar Plus Storage; (2) 1,600 MW of battery storage (comprised of 1,000 MW of standalone storage and 600 MW of Solar Plus Storage); (3) 600 MW of onshore wind; (4) 800 MW of CTs; and (5) 1,200 MW of CCs. Duke Proposed Order at 108 (citing to Duke Proposed Carbon Plan, Ch. 4, 3-5).

Having already addressed new natural gas-fired generation, the Commission now considers Duke's proposed actions related to standalone solar generation, Solar Plus Storage, standalone battery storage, and onshore wind.

Duke states that "the accelerated timeframe to deliver new resources, along with the interdependencies between generation and transmission needed to achieve the target in-service dates presented in the Carbon Plan, underscores the importance of Commission approval and support for near-term Execution Plan activities in this initial Carbon Plan." *Id*. Nonetheless, Duke also notes:

> [T]he dates and quantities in [Duke's Carbon Plan proposal portfolios] should be considered directional and not exact. The specific resources (technology, design, capacity) to be developed and optimal in-service dates will be refined through the development and siting processes as Plan components are executed. As more information is gathered through execution, [Duke] will keep the Commission apprised of material developments through future

[12] Duke requests in its proposed order that the Commission select 3,100 MW of solar generation, including 750 MW requested to be procured through the 2022 Solar Procurement Program. Duke notes the 750 MW amount to be procured through the 2022 Solar Procurement Program because Duke filed its proposed order on October 24, 2022, which is before the Commission authorized Duke to procure 1,200 MW in the 2022 Solar Procurement Program in its Order Permitting Additional CPRE Program Procurement and Establishing Target Procurement, Docket Nos. E-2, Sub 1297 and E-7, Sub 1268 (Nov. 1, 2022).

biennial Carbon Plan updates, as well as through resource-specific regulatory processes or approvals (e.g., a CPCN proceeding).

Id.

While Duke has proposed a set of recommended near-term supply-side actions, the Commission is not obligated to accept the entirety of Duke's recommended actions. Rather, the Commission has considered each individual near-term action requested by Duke, along with the recommendations of the intervenors, to assess whether Duke's near-term supply-side plan will result in the least cost path to compliance with the carbon dioxide emissions reduction mandates in N.C.G.S. § 62-110.9 and is supported by competent, material, and substantial evidence.

New Solar Generation, Solar Plus Storage, and Standalone Battery Storage

As mentioned above, as part of Duke's proposed near-term plan, Duke recommends that the Commission select 3,100 MW of solar generation (including the MW targeted to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired storage, and 1,600 MW of battery storage (1,000 MW of standalone storage and 600 MW of Solar Plus Storage). Tr. vol. 7, Duke Proposed Carbon Plan, Tbls. 4-6, 4-11; Duke Proposed Order at 108.

Duke states that from 2022 to 2030, approximately 5,980 to 7,930 MW of new solar resources will need to be added to its system in order to achieve the carbon dioxide emissions reduction mandates in N.C.G.S. § 62-110.9. Tr. vol. 7, Duke Proposed Carbon Plan, App. I, 1. Further, Duke notes that adding this significant amount of new solar resources to its system will require the accelerated interconnection of solar resources at a rate of approximately 2.5 times that of the historic maximum amount of utility-scale solar that Duke has ever connected in a single year in the Carolinas. *Id*. Duke also states that one of the key barriers to adding generation resources, particularly solar resources, to its system is the substantial transmission upgrades required to interconnect these new resources, as is discussed further in the "Transmission" section of this Order. *Id.*

Appendix K of Duke's Carbon Plan proposal states that battery storage will play an important role in meeting the carbon dioxide emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, App. K, 1. Each of Duke's proposed portfolios, including the supplemental portfolios, requires the addition of significant battery storage assets to achieve the Interim Target. *Id.* Duke states that new battery storage capacity is necessary to support the continued and increasing pace of interconnection of carbon-free intermittent resources, such as solar and wind, to the grid. *Id*. More particularly, Duke states that, as coal plants are retired and replaced with those intermittent resources, its need for firm capacity will grow. *Id*. Duke maintains that with the increased interconnection of solar and wind resources to the grid, battery storage, particularly long-duration battery storage, will become increasingly important to maintain the reliability of the grid. *Id.* Specifically, Duke proposes that long-duration battery storage will be an essential source of firm capacity in order to provide real time balance for the system and to maintain adequate frequency, voltage, and reliability of the grid. *Id*. Duke further asserts that battery storage is cost-competitive with other peaking generation resources over the planning horizon. *Id*.

As noted above, on November 1, 2022, the Commission authorized Duke to target a total 2022 Solar Procurement amount of 1,200 MW, which is inclusive of the 441 MW CPRE shortfall. *See* Order Permitting Additional CPRE Program Procurement and Establishing Target Procurement Volume for the 2022 Solar Procurement, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Joint Petition for Approval of Competitive Procurement of Renewable Energy Program and Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2(c),* Nos. E-2, Sub 1159, E-2, Sub 1297, E-7, Sub 1156, and E-7, Sub 1268 (N.C.U.C. Nov. 1, 2022). The 2022 Solar Procurement Program includes a VAM to mitigate pricing risk to customers. Before selecting the portfolio of winning solar proposals, Duke must calculate the weighted average cost of the total portfolio of both utility-owned and third-party-owned solar resources along with their assigned transmission upgrade costs. 2022 Solar Procurement Program Final RFP and pro forma PPA Compliance Filing, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2(c),* Nos. E-2, Sub 1297, E-7, Sub 1268 at Attach. A, 2. If the weighted average cost of the solar resources to be procured is greater than or equal to 110% of the Carbon Plan Solar Reference Cost (the assumed cost of solar capacity, energy, and related upgrades used to develop the Carbon Plan), the target procurement amount may be decreased by as much as 20% (subject to the 700 MW minimum target), effectively eliminating the highest cost proposals from selection in the 2022 Solar Procurement Program and deferring some of the modeled procurement volume to future solar procurements. *Id.* Conversely, if the bid pricing is competitive because the weighted average cost of the solar resources to be procured is less than or equal to 90% of the Carbon Plan Solar Reference Cost, the target procurement amount may be increased by up to 20% above the volume targeted by the procurement request for proposals (RFP) (which is 1,200 MW in the 2022 Solar Procurement), thereby procuring more competitively priced, low-cost solar resources for customers through the 2022 Solar Procurement because they are less expensive than assumed in the Duke's Carbon Plan proposal and will provide savings to customers. *Id.* Thus, if the weighted average cost of the total portfolio of the 2022 Solar Procurement portfolio is less than or equal to 90% of the Carbon Plan Solar Reference Cost, the target procurement amount will be adjusted upwards by 20% — to procure a total of 1,440 MW of solar resources.[13]

Considering the Commission's November 1, 2022 decision on the targeted amount for the 2022 Solar Procurement, Duke recommends that the Commission authorize Duke to target a minimum of 2,350 MW[14] of new solar resources from 2023 to 2024 and allow Duke to "determine the optimal timing and mix of new standalone solar and solar paired with storage." Duke Proposed Order at 15. Duke further recommends that the Commission direct Duke to "consider volume adjustments or other mechanisms similar

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[13] 1,200 MW x .20 = 240 MW. 240 MW + 1,200 MW = 1,440 MW.

[14] 3,100 MW – 750 MW = 2,350 MW.

to the 2022 Solar Procurement during this period to competitively procure additional solar at least cost." *Id.*

Also, when taking into account the targeted amount of capacity to be procured in the 2022 Solar Procurement, the Public Staff recommends that the Commission direct Duke to target the procurement of 950 MW of new solar generation in 2023 and 1,150 MW of new solar generation in 2024 (for a total targeted procurement of 2,100 MW between 2023 to 2024, which is 250 MW less than Duke's recommendation). The Public Staff also recommends that the Commission authorize the procurement of a minimum of 400 MW of at least 2-hour co-located storage in 2023 and also in 2024. Public Staff Proposed Order at 11. Public Staff witness Thomas states that its recommendation of solar resources and Solar Plus Storage in the near-term procurements is appropriate because procurement of these resources must appropriately balance the risks of waiting to procure solar resources with the risks of procuring them too early and placing the risk of additional cost on customers. Tr. vol. 21, 320. Also, witness Thomas recommends that 1,125 MW of standalone battery storage be procured as part of the near-term plan, which he states is consistent with SP5. *Id.* at 91.

AGO witness Burgess testified that Duke's proposed near-term solar and battery storage procurements should be pursued as part of a "no regrets" strategy and that greater quantities of these resources may be warranted due to the incentives provided in the IRA, which witness Burgess opined will significantly reduce the cost of the solar resources and battery storage. Tr. vol. 25, 296, 324. AGO witness Burgess further suggested that "it may be better to aim high and miss the mark by a year or two, rather than aim low out of an overabundance of caution and fail to meet the statutory requirements [for carbon dioxide emissions reductions.]" *Id*. at 323-24.

Tech Customers witness Borgatti testified that the Tech Customers' strategy in terms of near-term actions prioritizes near-term investment in infrastructure necessary for any Carbon Plan, including each of Duke's proposed portfolios, while avoiding or delaying investments that may not be needed or are reliant on speculative or unproven technology. *Id.* at 47. With regard to new solar resources, witness Borgatti testified that the Tech Customers' preferred portfolio includes no standalone solar before 2030. *Id.* Nonetheless, in information submitted after the hearing, Tech Customers support Duke's recommended near-term target of 3,100 MW of new solar resources through 2024 (inclusive of the amount of solar resources procured in the 2022 Solar Procurement). *See* Tech Customers Partial Proposed Order at 11. Further, Tech Customers' preferred portfolio recommends 1,000 MW of Solar Plus Storage with a 25% 4-hr battery ratio in 2027 to 2028, 3,750 MW of Solar Plus Storage with a 50% 4-hr battery ratio in 2027 to 2029, 2,850 MW of standalone 4-hr battery storage and 50 MW of standalone 6-hr battery storage in 2027 to 2029. Tr. vol. 25, 47.

CPSA witness Norris addressed the near-term procurement of new solar resources based on modeling performed by CPSA witness Hagerty. Witness Norris recommended that the Commission direct near-term procurement of 4,800 MW of new solar resources from 2022 to 2024 as follows: 1,500 MW in 2022, 1,500 MW in 2023, and

1,800 MW in 2024. Tr. vol. 26, 52. CPSA recommended that its alternate portfolios CPSA3 and CPSA5, which are based on more aggressive solar interconnection assumptions, be included in the 2024 CPIRP proceeding for further consideration and to inform Duke's proposed near-term plan. Witness Norris criticized Duke's excessive conservatism about the rate of solar interconnections and testified that Duke's proposed near-term procurement targets are insufficient to achieve compliance with the 2030 Interim Target, even under the most solar-reliant of Duke's proposed portfolios (portfolio P1). *Id*. at 28-29, 39. Witness Norris argued that Duke's proposed low amounts of early solar procurement are inconsistent with achieving the 2030 Interim Target. *Id*. at 49.

NCSEA et al. witness Fitch recommended that the Commission direct Duke to achieve the Interim Target by 2030, advising that such an approach would allow for flexibility in later CPIRP proceedings in the event that unforeseen delays occur and if the Commission determines that a delay is warranted. Tr. vol. 24, 157, 160. More specifically, witness Fitch argued that 7,200 MW of solar resources should be interconnected by 2030, 4,000 MW of which should be procured from 2022 to 2024 and in-service between 2025 and 2028. *Id.* at 177-78. Also, NCSEA et al. witness Fitch recommended that the Commission direct Duke to begin procurement for 4,000 MW of standalone storage with target in-service dates of 2025 to 2028. *Id.* at 178.

Public Staff witness Thomas contended that intervenors such as CPSA and NCSEA et al. are requesting solar procurement targets that rely on unrealistic near-term annual interconnection limits and high interconnection costs. Witness Thomas agreed that all portfolios eventually require the interconnection of 10 gigawatts (GW) of solar resources, but with different completion dates. However, he cautioned the Commission against procuring large amounts of solar resources too quickly. Tr. vol. 21, 320-21. Public Staff witnesses Thomas and Metz contended that there must be an orderly transition from fossil fuel resources to renewable resources and faults the CPSA and Brattle modeling for not considering transmission upgrades that might result in greater cost as they trigger affected system studies and create wide-ranging impacts beyond the local network. *Id*. at 319. Public Staff witness Thomas cautioned against only looking at solar resource interconnections when considering the challenges associated with interconnections

> So looking at it just in terms of how much solar can we interconnect is a bit myopic. And we need to look at the whole resource portfolio that we're trying to interconnect and realize that this is a challenge for Duke's transmission interconnection studies and Duke's transmission planners that I don't believe they've ever faced before, in term of interconnecting this volume of intermittent resources and dispatchable resource and energy storage simultaneously. So I think we need to temper this with some dose of reality.

Tr. vol 21, 249-50.

From a customer perspective, CIGFUR witness Muller testified that a more measured pace of transition enables North Carolina to be flexible and in a position to take advantage of new information, technology advancements, and other changed circumstances that could warrant altering the path forward in the future. Witness Muller similarly highlighted, from an affordability perspective, that a less accelerated pace of transition could make the year-to-year rate impacts for ratepayers more manageable and could also ensure that the least cost plan is selected. Tr. vol. 25, 364.

On rebuttal, the Duke Modeling and Near-Term Actions Panel explained that Duke seeks permission to procure significant Solar Plus Storage resources in future near-term procurements (procurements from 2023 to 2024). Tr. vol. 27, 57. While most of the recommended 2,350 MW of solar resources will include battery storage, the required amount of Solar Plus Storage should be based on the optimal configuration of the Solar Plus Storage that can be procured at least cost while recognizing system needs. *Id*. The Duke Modeling and Near-Term Actions Panel addressed the remaining 2,350 MW of solar resources (inclusive of 600 MW of Solar Plus Storage) to be procured, and explains that if all future Solar Plus Storage includes storage that is 25% of the solar nameplate capacity, then Duke would need to procure 2,400 MW of Solar Plus Storage to reach the 600 MW of Solar Plus Storage target, and thus no additional standalone solar would be required. *Id*. If all future Solar Plus Storage includes storage that is 50% of the solar nameplate capacity, then Duke would need to procure 1,200 MW of Solar Plus Storage to reach the 600 MW of Solar Plus Storage target. *Id*.

The Duke Modeling and Near-Term Actions Panel also noted that Duke's proposed near-term actions do not include solar and battery storage procurement targets for 2025 that would be assumed to come online in 2029, as procurement that far in the future should be further informed by the outcomes of the earlier solar procurements and the subsequent Carbon Plans. *Id*. at 67. According to the Modeling and Near-Term Actions Panel, this approach affords the Commission the time and flexibility to wait an additional two years to determine procurement targets for resources expected to come online in 2029 and in advance of the 2030 Interim Target. *Id*.

The Duke Modeling and Near-Term Actions Panel disputed CPSA witness Norris' claim that approval of Duke's proposed near-term actions would make the 2030 Interim Target unachievable. *Id.* at 56-60. The Modeling and Near-Term Actions Panel explained that Duke expects to procure 3,550 MW (inclusive of the 441 MW CPRE shortfall) in years 2022, 2023, and 2024, which leaves an additional 2,300 MW to be procured to reach P1 solar additions by 2029. *Id.* Assuming that a VAM similar to the 2022 Solar Procurement is included in future solar procurements, Duke could procure additional solar volumes in the near term to remain on track to meet the P1 solar volume. *Id.* at 58-59. The Panel also noted that there are numerous other considerations and aspects of an "all of the above" Carbon Plan that need to be considered to meet the carbon dioxide emissions reductions mandates; as such, the pace of solar procurements must be viewed in the broader context of other resources to be added to the system and the infrastructure needed to allow the interconnection of the new solar resources to achieve the required carbon dioxide emissions reductions in an orderly fashion. *Id*. at 60. The Modeling and Near-Term Actions Panel concluded that its near-term actions for 2022 to 2024 are appropriate and that pre-emptively selecting the significantly higher volumes of solar resources and battery storage recommended by CPSA and NCSEA et al. would significantly increase execution risk and is not a reasonable step. *Id.* at 67.

Duke's targeted near-term solar capacity addition is informed by what Duke deems as limits, based on engineering judgment, on its ability to interconnect solar capacity. Tr. vol. 7, Duke Proposed Carbon Plan, Apps. I, P; tr. vol. 7, 349-53. The Duke Utilities Operations Panel testified that its solar interconnection assumptions, including constraints on interconnections, within the model were supported by quantitative analysis and that it relied on its expert engineering judgment from transmission planning and transmission construction teams in formulating its positions. Tr. vol. 11, 75-76. The Panel additionally testified that the time period to interconnect solar resources — from executing an interconnection agreement to placing the solar resource in service has increased. At the time of the hearing, the time to place solar resources in service was averaging about 26 to 32 months for projects that do not require the construction of transmission upgrades. Tr. vol. 8, 39-41. Additionally, the Panel testified about the work on the electric system that is necessary to interconnect new generating facilities, including solar resources, and details the transmission line outages that must be coordinated to interconnect solar resources without jeopardizing Duke's ability to manage contingencies on its system and ensure that reliable service is provided to customers. Tr. vol. 16, 164-65.

With respect to battery storage, Public Staff witness Metz recommended that commercial terms be created so that dispatch of battery storage can occur and that those terms fairly compensate owners and protect ratepayers. Tr. vol. 21, 234-35. Also, CCEBA witness DiFelice testified that contract structures that allow the utility full control over third-party battery storage assets, within certain technical parameters, currently exist in jurisdictions such as the Tennessee Valley Authority, where a Solar Plus Storage procurement is underway. Tr. vol. 26, 278. Regarding witness Metz' recommendation for the development of commercial terms for contracts for Solar Plus Storage, the Duke Utilities Operations Panel testified that it is striving to replicate the same flexibility it has with utility-owned Solar Plus Storage assets for third-party-owned PPAs so that Duke's system operators will have the same operational flexibility for both utility-owned Solar Plus Storage assets and third-party-owned PPAs. Tr. vol. 12, 22. Duke witness Farver further testified that it is important to develop contracts for Solar Plus Storage resources that allow Duke to have control over the timing and use of the storage component of the Solar Plus Storage facilities in order to provide flexible uses beyond capacity. She also opined that third party developers should be appropriately compensated for the value they provide. Tr. vol. 16, 130-31, 133.

Public Staff witness Thomas indicated that he expects that Solar Plus Storage resources will be competitively procured through annual procurements that are similar to the 2022 Solar Procurement, albeit expanded to procure Solar Plus Storage resources in addition to standalone solar. Tr. vol. 21, 63. During these future procurements, witness Thomas opined that a wide variety of Solar Plus Storage configurations will be submitted for evaluation. *Id.* at 64. Witness Thomas stated that, assuming the first Solar Plus Storage procurement will take place during the 2023 Definitive Interconnection System Impact Study (DISIS), there should be sufficient time to incorporate common configurations and costs into a subsequent Carbon Plan. *Id.* As such, witness Thomas recommended that Duke file the preliminary 2023 Solar Procurement results in the 2024 Carbon Plan proceeding and explain how its Solar Plus Storage modeling is influenced by the results of the 2023 Solar Procurement. *Id.* Witness Thomas stated that the Public Staff supports CCEBA and CPSA's recommendation that Duke work with stakeholders in advance of the 2023 DISIS to develop appropriate Solar Plus Storage PPA structures that appropriately value third-party Solar Plus Storage resources. Tr. vol. 7, 264. Witness Thomas noted that Duke has agreed to this recommendation. *Id.*

Overall, the Commission notes that one of the few areas of consensus among Duke and the intervenors, as confirmed by the various modeled portfolios, is that a significant amount of solar resources and Solar Plus Storage must be included in Duke's resource mix in the near term to reach the Interim Target. More specifically, Duke states that up to 5.4 GW of solar resources needs to be added to the system to meet the 2030 Interim Target. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 3, Fig. 3-5; Duke Proposed Order at 27, 175, 179. The Brattle Group's modeling achieves the 2030 Interim Target by adding between 5.2 GW to 9.5 GW of solar resources by 2030. Tr. vol. 25, 438-39. Synapse's modeling achieves the 2030 Interim Target by adding 7.2 GW of solar resources by 2030. Tr. vol. 24, 178. The Gabel Report's Preferred Portfolio achieves the 2030 Interim Target by adding similar amounts of solar resources (but with more emphasis on Solar Plus Storage and behind-the-meter solar generation). Tr. vol. 25, 5.

The Commission gives weight to the substantial evidence of the need for the near-term procurement of new solar generation and complementary storage resources, the characterization by multiple parties of Duke's proposed 2022 to 2024 procurement targets as "no regrets" actions, and caution from the Public Staff and Duke that the near-term procurement of solar resources must appropriately balance the risks of waiting to procure solar resources with the risks of procuring them too early and placing the risk of additional cost on customers. The Commission recognizes the critical role that solar resources have and will continue to have in meeting the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110. However, the need to develop solar generating capacity must be balanced against the cost to customers as well as the risks to the electric system. Ultimately, it is critical that new solar resources, including Solar Plus Storage, must be interconnected and integrated in a manner that poses no risk to the reliability of the system and affords customers and the electric system as cost-effective a resource as possible.

Based on the foregoing and the entire record in this proceeding, the Commission directs Duke to target 2,350 MW of new solar resources in the 2023 to 2024 timeframe. The Commission directs Duke to design the future solar procurements to incorporate a VAM, similar to the VAM in the 2022 Solar Procurement, that would allow for the procurement of increased amounts of solar resources should the winning portfolios produce cost-effective bids.

The Commission also directs Duke to target procuring 1,000 MW of standalone battery storage and 600 MW of Solar Plus Storage in the 2023 to 2024 timeframe. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4 – Execution Plan, 22-23; Duke Proposed Order at

236. In making this determination the Commission is mindful of the need to balance several considerations associated with rapidly developing battery technologies. The most widely commercialized and cost-competitive technology today uses lithium-ion cells in various configurations that yield storage capacity of relatively short duration. Both Duke and various intervenor parties have focused their attention in this proceeding on that readily available and cost-effective current storage technology. While such storage is undoubtedly a great benefit in addressing problems associated with intermittent energy resources such as solar PV and wind generation, cost-effective long duration storage solutions will be required in order to deal with larger issues of grid operations and stability and to provide reliable, dispatchable reserve capacity to meet extreme weather events or other anomalies creating abnormal demands on the grid.

The Commission notes that battery technologies and costs are evolving, if anything, even more rapidly than was the case with solar PV technologies in the past two decades. Many participants in this proceeding have expressed concern about investments in new natural gas generating facilities, which they fear will become outmoded before the end of their economically useful lives, leaving ratepayers to bear the costs of unrecovered investments made by the utilities. In the Commission's view, this same risk of potentially stranded costs is equally, if not more, present in the case of storage technology due to the pace of change in the development of alternatives to the prevailing lithium-ion model and in the costs of achieving longer duration storage capacities. The near-term investment in storage approved by the Commission in this proceeding will allow the utilities and ratepayers to reap the benefits current short-term storage technologies provide relative to the addition of more intermittent generating resources, but it will not, the Commission believes, incur an unreasonable risk of excessive near-term investment in technologies and systems that may very likely be superseded or surpassed in the intermediate and longer term.

Onshore Wind

Every portfolio in Duke's Carbon Plan proposal, as well as SP5 and SP6, selected 600 MW of onshore wind by 2030. Tr. vol. 12, 66. Likewise, modeling conducted by Tech Customers, CPSA, and NCSEA et al. selected onshore wind in modeling resource portfolios to achieve the Interim Target. More particularly, modeling conducted on behalf of Tech Customers selected 1,200 MW of onshore wind by 2028; CPSA's modelling scenarios each selected 600 MW of onshore wind by 2030; and modeling conducted on behalf of NCSEA et al. selected 900 MW of onshore wind by 2030. Tr. vol. 24, 177-178; tr. vol. 25, 88; tr. vol. 26, 46-47.

Consistent with the Commission's determination herein that pursuant to N.C.G.S. § 62-110.9(2), "Commission-selected" new generation resources must be utility owned (subject to specific exceptions for solar generation and Solar Plus Storage) and recovered on a cost-of-service basis, the Duke Utilities Operations Panel stated that Duke modeled onshore wind assuming it would be owned by DEP and paid for by DEP customers. Tr. vol. 15, 33. Public Staff witness Thomas also testified that Duke modeled onshore wind as a utility-owned resource consistent with the ownership requirements of N.C.G.S.

§ 62-110.9(2). Tr. vol. 22, 316.[15] The Duke Utilities Operations Panel further stated that if onshore wind is ultimately selected by the 2022 Carbon Plan, then Duke will consider whether DEP and DEC could jointly own wind generation. Tr. vol. 15, 14. For the avoidance of doubt, the Commission finds good cause to direct that all subsequent modeling of onshore wind resources should be compliant with the ownership requirements for Commission "selected" resources pursuant to N.C.G.S. § 62-110.9(2).

Public Staff witness Thomas found Duke's assumptions with respect to onshore wind interconnections to be reasonable for the development of the Carbon Plan, absent convincing evidence that large quantities of onshore wind will be available to Duke earlier than 2029 or that more than 300 MW could be interconnected annually. Tr. vol. 21, 59. As the Duke Near-Term Actions Plan Panel calls for the procurement of 600 MW of onshore wind in DEP's territory, Public Staff witness Thomas testified that should the 2022 Carbon Plan include onshore wind, Duke should work to procure these resources in accordance with the Commission's interpretation of the statute and provide updated assumptions in the 2024 CPIRP. *Id*. at 61. Public Staff witness Thomas further recommended that the 2022 Carbon Plan and the near-term plan include 600 MW of onshore wind, consistent with SP5. *Id*. at 63.

Duke witness Snider advised that it is important for Duke to strive to procure onshore wind in the near-term plan, as it has synergies with solar resources because the wind blows at different times than solar power is available, such as winter mornings and at night. Tr. vol. 11, 100. He also stated that developing onshore wind assets would provide additional diversification benefits from a technological, load profile, and supply chain perspective. *Id*. Witness Snider recommended that in the next CPIRP, Duke should report to the Commission about its efforts to procure onshore wind, and potentially adjust the amount of onshore wind that could be added at that time. *Id*. at 101-02. Further, witness Snider stated that there are a limited number of sites in North Carolina with

[15] There is some disagreement among the parties as to whether Duke's onshore wind modelling assumptions include power purchased from third parties. *See, e.g.*, Tech Customers Partial Proposed Order at 23 ("Finally, [Duke] appear[s] to have modeled the purchase of onshore and offshore wind on a purchased basis. The offshore wind selected in Duke's proposed P1 is modeled based on a generic offshore wind block and not on a site-specific selection because Duke assumes it will have to "partner[]" with "on an offshore project that has already evolved beyond the leasing stage." *See* tr. vol. 7, Duke Proposed Carbon Plan, App. J, 6. Similarly, due to the various logistical and siting challenges identified by Duke in its plan, Duke's proposed plan for DEC is reliant on up to 600 MW of onshore wind "assumed to be sourced from PJM but could also be sourced from Midcontinental Independent System Operator, Electric Reliability Council of Texas, or other jurisdictions with strong wind profiles." *See* id. at 13). The Duke Transmission Panel testified that Duke considered importing Midwest onshore wind unfeasible at this time due to the needed transmission upgrades, the costs of those upgrades, and the time needed to complete the upgrades. Tr. vol. 16, 104. Duke also indicated that it has submitted a 1,000 MW first transmission service request to PJM to validate these results, which will be considered in future Carbon Plan iterations. *Id*. The Transmission Panel further states that the proposed Carbon Plan considered importing Midwest onshore wind onto Duke's system and used the PJM border rate for the transmission cost adder. *Id*. Duke had PJM conduct a feasibility study in 2019 for importing 300 MW into DEC, and the upgrades needed on the PJM side of the system were $411 million and expected to take up to 84 months to complete. *Id.* at 104-05. Witness Roberts further testified that if Duke were to import onshore wind from the Midwest, it would have to pay wheeling charges to PJM and potentially MISO, depending on where the resources were sited. Tr. vol. 17, 28.

significant onshore wind resource potential. *Id*. at 97. He testified that Duke must work with the communities and wind developers to determine if those sites are actually viable. *Id*. If those sites are determined to be viable, witness Snider added that Duke must determine the transmission plan to bring those resources to load centers. *Id*. Finally, witness Snider stated that while Duke has a proxy interconnection cost in the model for onshore wind, that price does not have the transmission study history that the solar interconnection cost does. *Id*. at 97-98.

Duke witness Pompee with the Long Lead-Time Resources Panel testified that onshore wind is considered a mature technology and that the only emerging technologies he is aware of that would increase the potential for onshore wind in North Carolina are "high hub height wind," which allows developers to place the wind turbines higher to achieve a bigger wind profile. Tr. vol. 18, 92. He admitted that the siting limitations in North Carolina would not necessarily change if the geographical area where a commercially viable wind turbine could be built were expanded. *Id*.

Duke witness Farver with the Duke Transmission Panel testified that Duke is excited about the opportunity to include onshore wind in its generation mix, but recognizes that there are challenges, particularly with siting. Tr. vol. 18, 125. She stated that Duke is ramping up internal preparations and capabilities for self-development and is also starting informal conversations with the onshore wind development community. *Id*. Witness Farver explained that onshore wind is a nascent technology in North Carolina. She stated that Duke is attempting to gather more information to determine if there is a pipeline of projects that would be interested in a 2023 RFP opportunity for acquisition, but there have not yet been any formal stakeholder meetings to gather that information. *Id*. As such, she concluded that Duke does not have sufficient market information to believe that the expense of an RFP would be worthwhile. *Id*.

Witness Roberts of the Duke Transmission Panel testified that since Carteret County is the area with the greatest onshore wind potential, there would most likely be transmission constraints that would need to be resolved due to the aggregation of solar, offshore wind, and onshore wind resources that could influence power flows in the area. While the main transmission line in Carteret County is not currently constrained, witness Roberts testified that she did not know how much headroom is available on that line. *Id*. at 127-28.

Public Staff witness Thomas testified that there are currently two onshore wind farms in North Carolina: the operational 208 MW Amazon Wind facility in Perquimans and Pasquotank Counties, and the planned 189 MW Timbermill Wind facility in Chowan County, both of which are in PJM's territory. He provided the history of the projects and describes the timelines under which they became permitted and, in the case of Amazon Wind, operational. He stated that given this history and the absence of any wind projects in Duke's interconnection queues, it is unlikely that any onshore wind projects in Duke's territory will be able to achieve operation prior to 2029. He added that onshore wind imported from PJM or other neighboring areas would require firm point-to-point transmission service and would be subject to the appropriate border or wheeling charge.

Public Staff witness McLawhorn also testified that the Public Staff is concerned about the transmission development required to interconnect onshore wind in DEP's service territory without a plan to allocate some of the costs to DEC. Tr. vol. 23, 96-97.

Several intervenors criticize Duke's assumptions of onshore wind availability in Duke's Carbon Plan proposal. CPSA argues that the Carbon Plan likely overstates the potential for onshore wind development, exclusive of imports, noting the 2016 to 2018 legislative moratorium and the fact that no onshore wind projects were in the recently completed DISIS queue. CPSA Initial Comments at 45-46. CPSA also stated that the development pipeline for new onshore wind farms and the timeline for such facilities in the Carolinas is "highly uncertain." Tr. vol. 25, 427.

AGO witness Burgess testified that Duke's proposed near-term wind procurements should be pursued as part of a "no regrets" strategy and that greater quantities of these resources may be warranted due to the IRA. Id. at 296.

AGO witness Burgess further testified that it is premature to assume both that no more than 300 MW of onshore wind can be procured and that a 2029 in-service date is required prior to testing the market through a competitive procurement solicitation. *Id.* at 254. He also argued that Duke should explore the potential for non-firm or "energy only" type of transmission service for wind imports. *Id*. at 255. Furthermore, NCSEA witness Fitch testified that the Synapse Report includes 2,500 MW of onshore wind from the Midwest and 900 MW "in-state" onshore wind by 2030. Tr. vol. 24, 178.

Modeling conducted by intervenors relied on lower cost, publicly available onshore wind technology costs. Tr. vol. 7, 384-86. Both Synapse and Brattle relied on 2022 NREL ATB costs while Strategen relied on 2022 EIA AEO costs. Tr. vol. 24, 145 (Synapse), 422 (Brattle); AGO Initial Comments, Attach. 1 at 23.

The Public Staff recommends that the Commission find that "it is appropriate to include 600 MW of onshore wind in the 2022 Carbon Plan for planning purposes at this time," and that the Commission direct Duke to continue gathering information as stated by witness Farver on the possible market for an onshore wind RFP and its ability to procure and place into service 600 MW of onshore wind capacity by 2030. Public Staff Proposed Order at 90. Finally, the Public Staff recommends that the Commission direct Duke to, within 60 days of the date of this Order, file a report proposing a plan to assess potential interest in an onshore wind RFP, including the potential inclusion of out-of-state wind resources; "determine the potential locations and timelines for procuring and placing into service onshore wind facilities[;] and estimate the potential transmission upgrade projects necessary to interconnect the facilities. *Id.* at 90-91. Further, the Public Staff recommends that, in the event that Duke determines than an onshore wind RFP would attract sufficient bids for a competitive procurement, the Commission should require Duke to submit a proposed timeline for submitting an RFP to the Commission for approval. *Id.* at 91. Finally, the Public Staff requests that the Commission require Duke to provide a cost allocation methodology for sharing the costs of the facilities and the requisite transmission upgrades between DEP and DEC.

Based on the foregoing and the entire record in this proceeding, the Commission finds that the characteristics of onshore wind make it a compelling complement to solar generation that could help foster system reliability, but whether Duke can reasonably put into service 600 MW of utility-owned onshore wind in order to achieve the Interim Target is uncertain based upon a number of variables. The Commission finds it reasonable to direct Duke to engage with onshore wind stakeholders and any others Duke finds are necessary to support its request that the Commission select onshore wind as part of its future preferred Carbon Plan portfolio as soon as practicable on the issues identified by the Public Staff. In formulating its first biennial CPIRP, Duke shall consider onshore wind and particularly any pertinent information gleaned from its stakeholder engagement, and, to the extent that future Encompass modeling economically selects utility-owned onshore wind resources, Duke should support that proposal in detail in its first biennial CPIRP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-51

Development of Long Lead-Time Resources

The evidence supporting these findings of fact is in the testimonies of Duke witnesses Repko, Immel, Nolan, and Pompee (Long Lead-Time Resources Panel); the testimonies of Public Staff witnesses Metz and Thomas; the direct testimony of AGO witness Burgess; the testimonies of Avangrid witnesses Starrett and Gallagher; the testimony of NCSEA et al. witness Fitch; the testimony of Tech Customers witness Roumpani; the testimonies of Duke Modeling and Near-Term Actions Panel witnesses Snider, McMurry, Quinto, and Kalemba; the testimony of Duke Transmission and Solar Procurement witness Roberts; the testimony of EWG witness Makhijani; the testimony of NC WARN witness Powers; and the testimony of CPSA witness Hagerty.

As part of complying with the requirements of N.C.G.S. § 62-110.9, Duke contemplated utilizing a variety of low or zero carbon-emitting electric generating resources. Some of the contemplated resources will either take several years to develop or will require further evaluation for feasibility and cost. In particular, Duke focused on three categories of resources: (1) nuclear, including SLRs for its existing nuclear fleet and development of new nuclear facilities; (2) additional pumped storage hydro; and (3) offshore wind. Tr. vol. 7, Duke Petition for Approval, 9. Duke refers to these resources as “long lead-time resources.”

Duke explains that these resources have substantially long lead times and greater external dependencies than other resources discussed in the Carbon Plan proposal. As a result, Duke asserts that it will need to perform critical development work in the near-term to maintain optionality and the potential for in-service dates consistent with those Duke’s modeling contemplates. Duke is not requesting that the Commission “select” such resources at this time. Rather, Duke explains that it needs to do initial development work both to gather information to provide a more refined cost estimate to the Commission in future proceedings, and to allow Duke to position itself to implement such resources on a timeline consistent with the modeled portfolios. Duke asserts that if it does not undertake these development activities in the near-term for offshore wind, new nuclear, and additional pumped storage hydro, then these resources will not be available on the timelines the various portfolios contemplate. Tr. vol. 17, 77-78.

Duke witnesses testified that, in this proceeding Duke is asking for permission to incur the costs associated with the development of the three long lead-time items. Duke witness Repko explained that Duke would ask in another, separate proceeding for cost recovery, with the expectation that in that proceeding it would have to demonstrate the reasonableness and prudence of the costs associated with development of these resources. *Id.* at 155-56.

New Nuclear

Duke's existing nuclear fleet is composed of traditional, large-scale nuclear power plants typically with a nameplate capacity of approximately 1,000 MW or more. In the United States, new construction of these types of large nuclear facilities has been logistically problematic and has resulted in significant cost overruns and even cancelations of projects. Tr. vol. 21, 130-31. However, there are two additional types of nuclear generation Duke addresses in its Proposed Carbon Plan: ARs and SMRs.

ARs are nuclear generation facilities that do not use water as the primary coolant. Such ARs use liquid metal, molten salts, or high-temperature gas for cooling. *Id.* at 131. There are currently no commercially operating AR generating facilities in the United States. Tr. vol. 17, 183-84. While Duke believes that SMRs have a less challenging licensing path than ARs because the design for SMRs is based on existing large light-water designs, Duke states that the ESP they intend to pursue will be neutral to either technology. *Id.* at 97, 100.

SMRs are described by their name. They are physically smaller and generate less electricity than traditional nuclear plants, are modular in the sense that much of the construction can be completed offsite, and rely on nuclear reactors to generate electricity. Tr. vol. 21, 128. SMRs are smaller scale in terms of size, cost, and construction time due to their modular characteristics. In addition, the size and modularity provide for more flexibility in terms of siting and land requirements. *Id.* at 131. SMRs use water for cooling, just like the traditional nuclear fleet Duke presently operates. SMRs therefore use well-known and proven technology and as such should both have a more readily available supply chain and a less challenging licensing path than ARs. Tr. vol. 29, 97.

Duke is experienced with storing used nuclear fuel through its operation of its large, traditional nuclear fleet. Duke testified it is reasonable to expect that it would handle used nuclear fuel resulting from future operations of SMRs similar to Duke's current practices. *Id.* at 108.

Duke's modeling has demonstrated the need for nuclear generation for meeting the carbon dioxide emissions reduction mandates set forth in N.C.G.S. § 62-110.9. Tr. vol. 17, 176. Tech Customers' "Preferred Portfolio" also demonstrates the need for SMRs for reaching net zero carbon dioxide emissions. Tr. vol. 25, 47. SMRs are present in all six portfolios Duke modeled. Some portfolios selected SMR generation as early as 2032, but by 2035 all six portfolios include approximately 600 MW of SMRs. By 2050, models predict that new nuclear resources will provide generation comparable to that which Duke's traditional nuclear fleet currently provides. Tr. vol. 7, Duke Proposed Carbon Plan, App. E at 54-55, 86; tr. vol. 7, 262.

Although there is much interest in the utility sector in SMRs, Duke acknowledges that they are not a mature technology. Tr. vol. 18, 33-34. Presently, there are no SMRs in commercial operation. Tr. vol. 17, 183. Duke concedes that having SMRs in commercial operation by 2032 represents an "aggressive" schedule. *Id.* at 36.

Some intervenors oppose Duke's future use of SMRs, arguing that the technology is unproven, expensive, unlikely to be available, and will generate radioactive waste. *See, e.g.*, tr. vol. 22, 154-214; tr. vol. 24, 68-121. According to AGO witness Burgess, "[t]he Commission should use extreme caution in approving any development activities for new nuclear." Tr. vol. 25, 301.

Although SMRs are not a mature technology, they represent one of the "breakthrough technologies" that N.C.G.S. § 62-110.9(1) contemplates. In support of this point, Duke witness Nolan testified

> SMRs and ARs are distinctly different than the large light-water-cooled nuclear plants (i.e., Generation III/III+) that were planned to be built during the early 2000s. The next generation SMRs and ARs have significant advantages over their historical counterparts. The modular design of these new reactors allows for more off-site construction and decreases production and construction timelines. *Designs have become smaller, meaning units require less capital investment and are more flexible, allowing for greater ability to match power output to system loads. In addition, the new generation of nuclear plants have* [sic] *significant safety enhancements.* Inherent safety features, such as passive shut down and self-cooling through natural circulation, mean that the system can turn off and cool itself with no operator intervention. *This enhanced safety makes the plants less complicated (i.e., fewer systems needed), enabling easier construction and operation.* The ability to build these next generation advanced nuclear plants much quicker and with less financial risk, while providing always-on baseload power generation, will help enable Duke's transition to net-zero carbon dioxide emissions.

Tr. vol. 29, 106-07 (emphasis added). Duke witness Nolan testified that while none of the new nuclear reactor designs have been approved, this should not delay Duke's pursuit of near-term development activities. *Id*. at 107. He testified that the focus at this time is to pursue siting for an SMR by developing an ESP, allowing time for reactor technologies to develop.

Duke proposes to undertake certain near-term development activities between now and 2024 related to new nuclear facilities, as follows: (1) organize nuclear development staff for new nuclear builds; (2) perform new nuclear alternative siting study; (3) perform new nuclear technology selection; (4) begin new nuclear ESP development; (5) choose the advanced nuclear technology/company to build the first plant(s); and (6) develop a new nuclear construction and operating license application. The projected cost of the near-term development activities for new nuclear generation is $72 million. Tr. vol. 17, 102. Duke witness Repko testified that Duke proposes to limit the costs associated with the new nuclear near-term development actions to $75 million. Tr. vol. 29, 105.

The focus of the near-term development activities is to pursue siting for new nuclear facilities by developing an ESP. The multi-year process of obtaining such permits allows time for the reactor technologies to develop. Moreover, the NRC approves an ESP for up to 20 years, and Duke can renew the ESP. *Id.* at 107. Duke testified that it intends to be a "second mover" in the SMR field in an attempt to avoid first-of-a-kind costs. Tr. vol. 17, 105, 211.

Several SMR projects are expected to be operating in North America over the next decade. *Id.* at 98-99. Public Staff witness Thomas testified that 19 utilities across the country are planning to incorporate SMRs into their future generation plans. Tr. vol. 21, 77. The Public Staff testified that it is reasonable to include SMRs as a potential future generation resource since it is highly likely the technology will be approved and deployed. *Id.* at 258-59.

The Commission concludes that Duke's request to undertake limited development activities for new nuclear facilities is appropriate, and notes that Duke relies upon new nuclear technology in all of its modeled portfolios. Although new, commercial SMR technology relies on existing technology and represents an important developing field that has the potential to be executable and provide carbon-free, reliable power at least cost relative to other resources. This is the type of "breakthrough" technology N.C.G.S. § 62-110.9 contemplates. The Commission recognizes the risks of pursuing breakthrough technologies, but Duke's experience with existing nuclear technology, especially operating water-cooled nuclear reactors and managing spent nuclear fuel, mitigates the risk associated with new nuclear. The fact that Duke will review potential nuclear generation resources to determine the most viable and cost-effective technologies and provide the Commission with additional information and more refined cost estimates regarding new nuclear facilities in future proceedings further mitigates risk. The Commission concludes further that it should not view the risks of new nuclear in isolation from alternative portfolios that rely more heavily on other technologies, which place greater reliance on weather conditions, for example. Diversifying the risk of its generation portfolio is a prudent step which Duke has successfully managed over its history as it has reliably served North Carolina customers at reasonable rates. The Commission places great weight on Duke's pledge to be a "second mover" and allow time for reactor technology to develop and complete the NRC licensing phase. Finally, the Commission is mindful of the importance of monitoring the development activities related to this breakthrough technology.

Accordingly, the Commission orders Duke to provide updates on its progress, and any significant developments in the industry impacting Duke's plans, in its first CPIRP filing.

Consistent with its authority under N.C.G.S. § 62-110.7(b), the Commission determines that Duke, in this proceeding, has demonstrated by a preponderance of the evidence that the decision to incur the project development costs outlined in its proposed Carbon Plan, with respect to SMRs and ARs, is reasonable and prudent. The Commission is not ruling on the reasonableness or prudence of specific project development activities or on the recoverability of specific items of cost at this time. To the extent the Commission finds, in a future general rate case proceeding, the specific activities involved, and the costs of pursuing these limited development activities, to be prudent and reasonable (whether these nuclear resources are ultimately selected or not selected or canceled), Duke shall recover in rates the North Carolina allocable portion of Duke's share of such costs pursuant to N.C. Gen. Stat. § 62-133 and N.C.G.S. §§ 62-110.7(c) and/or (d). Further, the cost cap for the time period spanning 2022 through 2024 for expenditures related to SMRs and ARs, which Duke shall not exceed without Commission approval, shall be $75 million. In its first CPIRP filing, Duke is directed to report on its activities and costs incurred to date in pursuing such the authorized development work; this report shall be for informational purposes only, and Duke shall not use this report as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and costs reported therein.

Bad Creek II

Since 1991, Duke has successfully operated the Bad Creek I energy generation facility. Bad Creek I stores and generates energy by moving water between two reservoirs at different elevations. During times of low electricity demand, surplus energy is used to pump water to an upper reservoir while during periods of high demand, the stored water is released down through turbines. As with traditional hydroelectric stations, the flow of water through turbines generates electricity. Bad Creek I provides 1,360 MW of capacity. Presently, Duke is making upgrades to Bad Creek I that will increase its capacity to approximately 1,700 MW in 2023. Tr. vol. 17, 85-86; tr. vol. 21, 124.

The DEC system has benefited greatly from the operating reserves and flexibility provided by pumped storage hydro. Tr. vol. 19, 176. Duke has determined that an additional 1,700 MW of capacity can be added to the Bad Creek station through the addition of four new generating units and other improvements. Hereinafter, this pumped storage hydro resource expansion project is referred to as "Bad Creek II." Tr. vol. 17, 87.

Duke has already undertaken some development activities related to Bad Creek II, including retaining an engineering firm to perform a feasibility study scheduled for completion this year. Tr. vol. 17, 89; tr. vol. 21, 125-26. Duke has projected $35,855,000 in expenses related to Bad Creek II near-term development activities. Given the anticipated time involved in obtaining licensure and then completing construction, Duke projects Bad Creek II will be in service in 2033. Tr. vol. 17, 90. The Public Staff notes that this timeline may not be realistic and requests periodic reporting on the project's status. Public Staff Initial Comments at 98-99.

All six portfolios Duke modeled (P1 through P4, SP5, and SP6) include 1,700 MW of capacity from Bad Creek II coming online in the mid-2030s and remaining in service through at least 2050. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 86; tr. vol. 7, 262.

Duke opines that there appears to be substantial support for Bad Creek II. Tr. vol. 29, 91. Duke is correct that intervenors largely did not take issue with the near-term Bad Creek II development activities Duke proposed. Many included the capacity of Bad Creek II in their own proposals. *See, e.g.*, tr. vol. 25, 47; tr. vol. 27, 94-95. AGO witness Burgess finds pumped storage hydro to have "the most certainty" of the long lead-time resources. Tr. vol. 25, 300.

The Commission concludes that Duke's request to undertake limited development activities related to Bad Creek II is appropriate, as Bad Creek I presently serves as a unique and valuable system resource, and that Bad Creek II would add to that value. In making this decision, the Commission gives significant weight to the testimony of DEC witness Holeman, the Vice President of Transmission System Planning and Operations for Duke Energy Corporation who joined Duke in 1985 and has since that time held various engineering and management positions of increasing responsibility in system operations, regarding the value of Duke's operational experience with the long duration storage that the Bad Creek facility provides, as well as the operational potential of the long duration storage provided by the facility. Tr. vol. 19, 237-38. The Commission notes that all modeled portfolios rely on Bad Creek II's pumped storage hydro and that there was no substantial opposition to Bad Creek II among intervenors.

Based upon the foregoing, the Commission approves Duke's request to incur costs associated with the limited development activities it outlines in its Carbon Plan proposal for new pumped storage hydro capacity at Bad Creek II to ensure that these resources remain an available resource option for Duke's customers for purposes of Carbon Plan execution. To the extent the Commission finds, in a future general rate case proceeding, that the specific activities involved and the costs of pursuing these limited development activities are prudent and reasonable (whether or not this resource is ultimately selected for the Carbon Plan), Duke may recover in rates the North Carolina allocable portion of Duke's share of such costs at the time(s) and in the manner determined to be appropriate by the Commission and as otherwise allowed by North Carolina law. To further clarify, the Commission is not preapproving any particular future ratemaking treatment regardless of whether the plant is ultimately never begun, abandoned, or completed. Instead, the Commission retains full discretion to determine the appropriate ratemaking treatment in a future general rate case proceeding. Further, the Commission notes and places weight on Duke's estimate that its proposed activities shall cost $40 million. In its first CPIRP filing, Duke is directed to report on its activities and costs incurred to date in pursuing the authorized development work; this report shall be for informational purposes only, and Duke shall use the report as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and costs reported therein.

Offshore Wind

Duke witness Repko testified that Duke has requested that the Commission approve certain near-term development actions related to offshore wind. Tr. vol. 17, 81-82. Duke witness Pompee testified that while Duke has yet to develop an offshore wind facility, the deployment of the technology has a 25-year global track record. *Id*. at 110. Duke states that the domestic offshore wind market is growing, as there are over 30 GW of projects with leases in place to achieve the State's carbon dioxide emissions reduction mandates and economic policy goals. *Id*. at 110. Duke proposes to develop the CLB WEA, which is one of three currently available siting opportunities in the Carolinas (which includes CLB and the Kitty Hawk WEAs). *Id*. at 111-12. In May 2022, Duke Energy Renewables Wind LLC (DERW), an unregulated affiliate of Duke, entered into a lease for the CLB WEA, approximately 20 miles from Cape Fear. This wind lease area consists of approximately 55,000 acres and cost $155,000,000. *Id.* at 111; tr. vol. 29, 103.

Duke witness Pompee testified that the three WEAs off North Carolina could produce approximately 4,800 MW of offshore wind energy. Tr. vol. 17, 111. Witness Pompee stated that offshore wind offers numerous benefits, such as "carbon [dioxide] emissions reduction, fuel cost savings, and increased renewable resource diversity in regions with high penetration of solar energy." *Id*. at 112. In addition, the relatively high capacity factors and lower intermittency compares favorably with other low carbon resources, and the distance from shore provides an opportunity to create larger and taller wind towers, thus resulting in site outputs that are measured in gigawatts. *Id*. at 112-13.

Duke testified that a variety of obligations and timing requirements accompany holders of leases for offshore wind energy areas. Duke agrees that under the applicable law and lease, DERW would have to submit a site assessment plan before June 1, 2023, and a construction operations plan before either December 2026 or June 2027, unless DERW seeks and is granted additional time from BOEM, the federal agency that regulates offshore wind development in federal waters. Tr. vol. 17, 113-14; tr. vol. 29, 127, 133. If DERW fails to comply with these obligations (in the absence of the grant of additional time), Duke agrees that DERW runs the risk of having BOEM cancel its CLB lease. Tr. vol. 29, 129-30.

Duke testified that after obtaining a lease for an offshore WEA, it can take eight to ten years to get to the point where electric power is commercially available. Tr. vol. 18, 80. In order to achieve offshore wind generation in this eight-to-ten-year timeframe, Duke outlines a series of steps that would be necessary, including: (1) obtaining BOEM's approval of a site assessment plan by 2024 for the CLB WEA; and (2) submitting a construction and operations plan to BOEM by 2027. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4, 20-21.

Duke does not necessarily have to be the entity obtaining approval of a site assessment plan and submitting a construction and operations plan in order to keep offshore wind on the eight-to-ten-year timeframe. If DERW complies with the applicable law (without seeking extensions), it would meet the timeframe Duke proposes. Duke agrees that if DERW moved expeditiously, DERW's actions would keep Duke on the same timeframe as outlined in its near-term action plan. Tr. vol. 29, 134.

In fact, Duke believes its affiliate DERW is currently working on a site assessment plan that it targets for completion by mid-2023. Tr. vol. 17, 120; tr. vol. 18, 121. When asked if DERW would sell to Duke in five years, witness Repko testified: “I don’t know. I presume so.” Tr. vol. 18, 83.

Under the rules governing affiliates, Duke’s purchase from DERW would be made at the lower of cost or market. Duke asserts that because the auction was an independent, third-party process, the May 2022 auction necessarily set the market price. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4, 19; tr. vol. 29, 103. Duke testified that its assertion regarding market price has not accounted for the IRA’s impact on the offshore wind moratorium. Tr. vol. 18, 83.

Duke projects the near-term costs associated with offshore wind development to be $317,400,000. It would use approximately half of the funds to purchase DERW’s CLB lease. Tr. vol. 17, 119. Duke was unaware of whether DERW would purchase its lease back if Duke acquired it from DERW and then did not move forward with offshore wind generation. Tr. vol. 18, 83-84.

Two intervenors in this case, TotalEnergies and Avangrid, have also leased offshore wind lease areas. TotalEnergies has leased approximately 55,000 acres in the CLB offshore WEA that is adjacent to that of DERW. Tr. vol. 17, 111. Avangrid has leased 122,405 acres approximately 27 miles from the Outer Banks (the Kitty Hawk lease area). Avangrid Initial Comments at 5.

Duke and Avangrid both support the need to develop offshore wind, as Duke witness Pompee testified that Duke’s modeling economically selected 800 MW of offshore wind energy in 2029 for both Portfolios 1 and 2. *Id*. at 123-24. Avangrid witness Starrett testified “that at least 1.3 GW of offshore wind can . . . serve as a cornerstone to meeting the 70% reduction target required by N.C.G.S. § 110.9. by 2030, with more offshore wind capacity available to follow thereafter.” Tr. vol. 23, 165. But testimony from Duke and Avangrid reveals differing views of the benefits of the various WEAs. Avangrid purchased the lease for the Kitty Hawk WEA. *Id*. at 177. Duke’s unregulated affiliate, DERW, purchased the lease for one of the CLB WEAs. Tr. vol. 29, 95. Avangrid states that the Kitty Hawk lease area is on a much more advanced permitting timeline than that of DERW. Avangrid Initial Comments at 15-17. Avangrid witness Starrett testified that — using publicly available data — the Kitty Hawk WEA provides a superior net capacity factor (NCF) of 43% versus the 36% for the CLB WEA. Tr. vol. 23, 181-82. Duke witness Pompee testified that Duke disagrees with Avangrid’s calculated NCF for the CLB WEA. As witness Pompee testified, “[d]etermining the NCF of any lease area requires detailed site assessment planning and, at this time, [Duke] does not believe that any party has performed the requisite analysis to definitively establish an NCF of 36% for the Carolina Long Bay WEA.” Witness Pompee concludes that the NCF for the CLB WEA that DERW owns is not known without further study, the kind that will occur if Duke pursues the development activities. Tr. vol. 29, 114.

Witness Pompee also testified that the Kitty Hawk WEA would require longer undersea cable than Avangrid claims. The shortest route for undersea cable for the Kitty Hawk WEA would have to traverse the Pamlico Sound, an environmentally sensitive area. According to Pompee, crossing the Pamlico Sound "introduces significant uncertainty due to challenges that could be encountered from a permitting, timing, and cost perspective, and it is likely that BOEM will require an assessment of multiple alternatives to a cable route through Pamlico Sound to reduce potential impacts." *Id.* at 111-13. Avangrid witness Starrett responded that the National Park Service and North Carolina Division of Marine Fisheries suggested crossing the Pamlico Sound as a potential preferred route but admitted permitting could complicate matters. Tr. vol. 23, 207. Witness Pompee testified that the less challenging undersea cable route for the Kitty Hawk WEA would require roughly 100 miles of additional cabling.[16] This longer route would add approximately $350 million to the cost of developing the Kitty Hawk WEA which could offset the lower NCF from the CLB WEA that DERW owns. Tr. vol. 18, 105 (transcript error; Pompee answering). Whether or not a route crossing the Pamlico Sound is ultimately feasible is unknowable at this time.

Avangrid testified that it "is open to any manner of transaction that is on reasonable terms and fairly values the Kitty Hawk lease area, including PPA transactions, or a sale of the lease area, in whole or in part." *Id.* at 173. However, testimony from Avangrid witness Starrett revealed that the ability to advance development of the Kitty Hawk WEA for the benefit of Duke's ratepayers is uncertain. *Id.* at 211-12; 217, 219. First, Avangrid witness Starrett admitted that the current iteration of the Construction and Operations Plan (COP) for the Kitty Hawk North WEA places its interconnection point at Virginia Beach, Virginia, and amending the COP to change that interconnection point to a point in North Carolina could add approximately 18 months to the site's development timeline. *Id*. Second, Avangrid witness Starrett also admitted that while the COP for Kitty Hawk South WEA lists North Carolina counties as possible interconnection points, they could easily amend the COP to list Virginia counties as interconnection points through PJM. Tr. vol. 23, 216-17. Third, Public Staff witness Thomas testified that development of the Kitty Hawk parcels is not as straightforward because "there is no guarantee that the more advanced Kitty Hawk offshore wind resource can be secured by Duke, as electric public utilities in Virginia also have stringent carbon reduction requirements under the Virginia Clean Economy Act." Tr. vol. 21, 62.

Duke's proposed portfolio P1 includes the addition of 800 MW of offshore wind to the generation mix in 2030 with no increase through 2050. Portfolio P2 includes the addition of 800 MW of offshore wind to the generation mix in 2030, the addition of 800 MW in 2032, and the total offshore wind capacity climbing to 3,200 MW by 2050. Portfolio P3 includes no offshore wind as part of the generation mix through 2050. Portfolio P4 includes the addition of 800 MW of offshore wind to the generation mix in 2032 with no increase through 2050. Portfolios SP5 and SP6 did not select offshore wind as part of the generation mix

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[16] *See also* tr. vol. 29, 111 ("[Duke] disagrees with Avangrid's analysis that the export route differential is only 25 km. Our analysis of transmission routing indicates an estimate of a longer cable by about 170 km.").

until the 2040s but include at least 1,600 MW of capacity by 2050. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 73-77; tr. vol. 7, 262; tr. vol. 10, 133.

Offshore wind is selected in only half of the portfolios before the year 2040. Tr. vol. 18, 81. Public Staff witness Metz, therefore, recommended that Duke re-evaluate the need for offshore wind in the 2024 Carbon Plan. Tr. vol. 21, 221-22. Public Staff witness Metz recommended that, at this time, the Commission deny the request to begin the near-term development activities Duke seeks, especially the affiliate transfer from DERW to DEP. *Id.* at 127. Public Staff witness Thomas stated that DERW can undertake the development work for the offshore lease before transferring the lease to Duke. Witness Thomas asserted that this would help ratepayers by reducing risks, supports Duke's "check and adjust" plan, and provides the Commission with an opportunity to evaluate the other lease areas. Tr. vol. 22, 334-35.

For his part, Duke witness Repko testified that if the Commission were to adopt the Public Staff's position, it "would effectively eliminate the ability to keep offshore wind as an option to meet the 70% Interim Target of the Carbon Plan," and goes on to reemphasize Duke's "all of the above" strategy. Tr. vol. 29, 96.

While it is well established globally, with more than 30 GW installed capacity, primarily located in Europe and Asia, offshore wind development in the United States on the scale Duke proposes is nascent. Tr. vol. 7, Duke Proposed Carbon Plan App. J, 1; tr. vol. 21, 127. Presently, hurdles exist with offshore wind, including the lack of Jones Act-compliant seagoing ships needed for construction activities and the risk of strong hurricanes in the area. Public Staff Initial Comments at 91-92.

Offshore wind generation requires undersea cabling, landfall facilities, and overland routing to the point of interconnection to Duke's grid. The NCTPC performed a 2020 Offshore Wind Study which provided a comprehensive screening analysis for several potential points of interconnection. However, that study was not an official generator interconnection study responding to an interconnection request a facility submitted to the DEP Transmission Provider in accordance with the FERC-approved process in the Open Access Transmission Tariff (OATT). In order for offshore wind to appropriately connect to the grid, DEP would have to conduct such studies. Tr. vol. 16, 100.

The Commission concludes that at this time the facts do not support Duke's request for approval of an affiliate transfer of the CLB WEA lease. Given the uncertainty around the price and nature of any potential deal for the Kitty Hawk WEA, and the very early state of understanding of the CLB WEAs, the Commission cannot determine whether or not a transfer from DERW to DEP is consistent with least cost principles at this time. While Avangrid argues that Kitty Hawk will provide the most value to ratepayers, Duke counters that the price certainty of its proposed CLB-first approach outweighs Kitty Hawk's supposed advantages. Duke admits that it cannot determine yet the relative merits of the various WEAs. The Commission requires a better understanding of the variables in order to determine prudence. To the extent Duke chooses to pursue offshore wind development in the near-term, and views purchase of a WEA lease as necessary to furtherance of that objective, it should be prepared to support that decision in a future proceeding, including information showing that its course of action was in keeping with least cost principles.

The Commission supports offshore wind and agrees that Duke's "no regrets" and "all of the above" approaches are appropriate. However, the near-term development steps Duke outlines with respect to offshore wind first require identification of the appropriate WEA. Therefore, the Commission determines that Duke should commence evaluating the three alternative WEAs. The Commission directs Duke to study and consider each of the three WEAs off the coast of North Carolina before pursuing acquisition of a leasehold. This evaluation should include best estimates of all relevant costs to acquire and develop a WEA and deliver energy to the point of injection into Duke's grid. To the greatest extent practicable, this evaluation should compare the WEAs on a similar basis to one another, including a comparison of the levelized cost of energy to the point of injection into Duke's grid.

The Commission notes that offshore wind is not selected until the 2040s in SP5 and SP6 and is not selected at all in P3. However, offshore wind is selected in portfolios P1, P2, and P4, representing both pathways as Duke lays out in its proposed Carbon Plan. The Commission is not persuaded by the Public Staff's contention that because offshore wind is not selected until the 2040s, or ever, in half the portfolios modeled, the Commission should deny near-term actions at this time. Denying all the near-term actions would prevent Duke from using offshore wind within 8-10 years of any eventual decision to go forward, effectively nullifying the portfolios that rely upon offshore wind within that timeframe. On the other hand, even if Duke does not need offshore wind for interim compliance, the near-term actions would be foundational if it does eventually need offshore wind energy.

DERW is not a party to this proceeding, and it is not clear what actions DERW can or will take with respect to development of the CLB lease. The Commission notes for clarity that this Order in no way applies to DERW or any other wind lease holder that this Commission does not regulate, nor does this Order prevent their undertaking any work on or development of an offshore wind lease.

The Commission rejects Duke's assertion that Duke's failure to acquire DERW's lease in the near term will "effectively eliminate" offshore wind as an option for interim compliance. The Commission finds that holders of offshore wind leases may develop the offshore WEAs without Duke's ownership. In fact, both the applicable law and provisions of the BOEM lease require such activities. Should holders of offshore wind leases fail to move forward with the development of their areas for generation, they run the risk of cancelation. Bolstering the Commission's finding, Duke testified that it believes DERW is currently working on the required site assessment plan. Moreover, now that the Commission has clarified the issue of ownership, Duke may have additional options to purchase the other WEAs off the coast of North Carolina. Avangrid testified that it is willing to engage in discussions with Duke for the sale of its offshore wind lease.

The Commission directs Duke to report the findings of its evaluation of the WEAs to the Commission either in the first CPIRP filing or sooner for consideration. This study will permit more accurate modeling in the CPIRP proceeding and enable the Commission to better understand the costs and benefits of potential offshore wind resources. Both Avangrid and the Public Staff argue for an independent third party to conduct this study. While the Commission recognizes that third-party studies can provide benefits, the Commission determines that Duke is the proper party to make this evaluation and that a third-party study is not necessary. The Commission notes the potential that the sunk cost of the CLB WEA lease, from the parent company's perspective, may bias the outcome of the decision, and as such, directs Duke to adopt steps in its evaluation process to protect against this potential bias. Further, to the extent there are any near-term development activities common to all the WEAs under evaluation, including the related onshore transmission infrastructure needed from the point of injection into the Duke grid and thence inland to load centers, Duke may proceed with these activities. Also, the Commission directs Duke to investigate and pursue any federal funding that is available, through the IIJA or the IRA or any subsequent legislation, for offshore wind facilities and associated infrastructure. To the extent that Duke chooses not to pursue any such funding, the Commission expects Duke to provide sufficient justification for why doing so was prudent.

As is the case for pumped storage hydro, the Commission deems Duke's decision to incur costs associated with the limited development activities outlined in the preceding paragraph to be reasonable and prudent in furtherance of the Carbon Plan. To the extent the Commission finds, in a future cost recovery proceeding, the specific activities involved in, and the costs of pursuing these limited development activities to be prudent and reasonable (whether or not the Commission ultimately selects offshore wind for the Carbon Plan), Duke may recover in rates the North Carolina allocable portion of Duke's share of such costs at the time(s) and in the manner determined to be appropriate by the Commission and as otherwise allowed by North Carolina law. To further clarify, the Commission is not preapproving any particular future ratemaking treatment regardless of whether the plant is ultimately never begun, abandoned, or completed. Instead, the Commission retains full discretion to determine the appropriate ratemaking treatment in a future general rate case proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

Grid Edge and Customer Programs – Load Reduction

The evidence supporting these findings and conclusions is in Duke's Carbon Plan proposal, testimony and exhibits of Duke's Modeling and Near-Term Actions Panel and Grid Edge Panel, Appalachian Voices witnesses McIlmoil and Kinkhabwala, NCSEA et al. witness Fitch, Public Staff witness Williamson, and the entire record in this proceeding.

In its Carbon Plan proposal, Duke includes certain modeling assumptions that reduce its peak demand and load forecasts based on demand-side activities. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 7. Duke characterizes this as the first prong of its three-step approach to maintaining reliability while reducing carbon dioxide emissions. Duke seeks to "shrink the challenge" through load reduction from these demand-side activities. *Id.* at 1. Duke groups Grid Edge and other customer programs into three categories: (1) programs that allow customers to reduce carbon dioxide emissions;

(2) programs that reduce carbon dioxide emissions by reducing demand; and (3) programs that allow the use of more resources that reduce carbon dioxide emissions. Tr. vol. 7, Duke Proposed Carbon Plan, App. G, 1.

Duke Grid Edge Panel described Duke's proposed Grid Edge programs as "certain rate designs, voltage control efforts, and other customer programs, such as EE and DSM programs, as well as renewable energy programs and electric transportation programs" where these programs allow customers to manage their use of electricity. Tr. vol. 13, 34. Duke Grid Edge Panel further explained that these programs allow Duke to reduce the amount of load they must serve in order to further the carbon dioxide emissions reduction requirements. Tr. vol. 13, 34-35.

The Modeling and Near-Term Actions Panel explained that Duke applied several load modifiers for its Carbon Plan proposal modeling to account for load projections that decrease load. These include Utility Energy Efficiency (UEE), dynamic rate designs, and behind-the-meter renewables including NEM. Tr. vol. 7, 308; Duke Proposed Carbon Plan, Ch. 2, Tbls. 2-1 to 2-4. Duke also included load modifiers to account for activities that could increase load including EV charging. *Id*.

The Duke Grid Edge Panel noted that Duke includes several categories of EE in its load forecast, including EE improvements customers install outside of UEE programs. Tr. vol. 13, 45. The Grid Edge panel also noted that the IRA could have an impact on EE programs going forward, and that at the time of the hearing Duke was still evaluating those impacts with a focus on UEE. *Id.* at 175. However, the Duke Grid Edge Panel noted that Duke plans to ensure that its customers are aware of the EE incentives, including non-utility EE, available in the IRA. Tr. vol. 14, 55. The Grid Edge Panel also noted that its current evaluation of its UEE programs seeks to isolate and remove the non-utility EE impacts from UEE. *Id.* at 59.

The Commission is persuaded that Duke's assumption that it can achieve a 1% reduction in eligible retail load through UEE programs is an "obtainable modeling assumption" as Duke characterizes the goal. Tr. vol 13, 37. Duke defines "eligible load" to mean the load attributable to retail customers except that portion of nonresidential customers who have elected to opt out of either EE or demand response (DR) programs or both. Tr. vol. 14, 93.

In past IRP proceedings, Duke used Market Potential Studies to identify the amount of EE load reduction that Duke could reasonably achieve. Tr. vol. 13, 38. Public Staff witness Williamson contends that Duke's assumption of 1% of load reduction through EE is too high and not reasonable and that the Commission should direct Duke to return to its use of Market Potential Studies as the basis for its EE forecast. Tr. vol. 21, 189.

Other parties argue that Duke's UEE forecast is too low. NCSEA et al. and their consultant Synapse's modeling utilized EE assumptions of approximately 1.5% of *total* load as opposed to eligible load as Duke modeled. Tr. vol. 25, NCSEA et al. Synapse Report, 24-25, 44. Tech Customers and their consultant, Gabel Associates, claim that a

7.7% reduction in the load forecast is achievable with EE alone. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 12. The AGO similarly states that Duke's EE assumptions are "arbitrary" and that Duke should model EE as a selectable resource, while the City of Asheville/Buncombe County and City of Charlotte argue that EE targets based on 1% of retail sales are below other states' EE targets. AGO Initial Comments at 22, 32; City of Asheville and County of Buncombe Initial Comments at 5-6; City of Charlotte Initial Comments at 3, 12.

Both NCSEA et al. and Tech Customers rely in large part on a finding from the 2020 American Council for an Energy Efficient Economy (ACEEE) Report, "How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy Cost and Greenhouse Gas Impacts" (ACEEE Report). In addition to the ACEEE Report, the ACEEE also released a Scorecard in 2020, which Tech Customers and NCSEA et al. also cite to as evidence that Duke can achieve more aggressive EE targets. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 41. Duke asserts that the ACEEE Report ignores several factors relevant to North Carolina and assumes that certain legislative changes will occur in the future. Tr. vol. 13, 48-50.

NC WARN asserts that Duke's projection of growth for NEM has significantly declined between its filing in this proceeding and its forecast in the 2020 IRP Proceeding. Tr. vol 22, 209. The Modeling and Near-Term Actions Panel, referring to Appendix F of Duke's Carbon Plan proposal, describes how Duke determined the NEM forecast. The Panel explains that Duke derived the rooftop solar forecast from a series of capacity forecasts and hourly production profiles tailored to residential, commercial, and industrial customer classes, with each capacity forecast being the product of a customer adoption forecast and an average capacity value. Duke develops the adoption forecasts using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes, and bill savings. Tr. vol. 7, 316-17. The Public Staff notes that Duke bases the NEM forecast on the currently approved NEM tariffs, and that the current forecast does not reflect changes to Duke's NEM policies that are currently pending with the Commission. Tr. vol. 21, 175. The Duke Modeling and Near-Term Actions Panel acknowledges that future state and federal policy changes may change the NEM forecast but asserts that the forecast Duke used in its Carbon Plan proposal was appropriate at the time of filing. Tr. vol. 7, 319.

The Commission finds Duke's modeling assumption related to UEE to be reasonable. The Commission is not persuaded by the Public Staff's argument that Duke should limit its forecasts to the savings identified in Market Potential Studies. In response to a request made by Commissioner McKissick during the hearing, Duke identifies potential enablers that would allow it to be more of a leader in EE and obtain annual energy savings over the next five years that are closer to 1.5% of eligible retail sales. Duke provides a high-level list of potential enablers that could allow for the achievement of these aspirational levels over the next five years in Grid Edge Panel Rebuttal Exhibit 1 as informative as to what measures Duke believes would be necessary to meet a 1.5% of eligible retail sales target versus 1.0% of retail sales. Tr. vol. 14, 73-82; tr. vol. 29, Grid Edge Panel Rebuttal Exhibit 1.

The Commission finds that Duke's current forecast of 1% of eligible load is an appropriate bridge between the existing practice of using Market Potential Savings Studies to estimate UEE savings and the intervenors' UEE forecast goals. The Commission is persuaded that Duke can achieve greater load savings than what the Market Potential Savings Studies identify and encourages Duke to continue to improve its efforts and aim higher than the current 1% of eligible load forecast. In weighing the need for the load forecast to be as accurate as possible, the Commission is not persuaded by the intervenors' reliance on the ACEEE Report and will not direct Duke to increase the UEE forecast at this time. Therefore, the Commission directs Duke to seek an aspirational goal of 1.5% and further directs Duke to provide an alternative modeling scenario in its initial CPIRP filing that uses a UEE forecast of 1.5% of eligible retail sales in addition to its proposed UEE forecast of 1% of eligible retail sales.

The Commission is also not persuaded by the AGO's assertion that Duke should allow the model to select EE as a resource. Tr. vol 25, 311. The Commission finds persuasive Duke's assertions that EE is a unique resource, in that customer adoption levels restrain it, and that allowing the model to select EE may overstate the amount of EE that Duke may cost effectively implement. Tr. vol. 13, 43.

The Commission determines that Duke's proposal to reduce load through Grid Edge programs, including demand-side management, EE, customer self-generation, and voltage management, is a reasonable step towards achieving reductions in carbon dioxide emissions as required by N.C.G.S. § 62-110.9. The Commission further determines that the load modifiers Duke used for these programs in this proceeding are reasonable. The Commission directs Duke to utilize the Grid Edge programs to the greatest extent possible. However, the Commission gives substantial weight to Public Staff witness Williamson's testimony that the load forecast must be as accurate as possible in order to avoid creating shortfalls in the load forecast that will then need to be addressed in future proceedings. Tr. vol. 21, 365. Public Staff witness Williamson noted that if the forecasted reduction in load is overstated, Duke will have to take other actions to maintain reliability and serve actual load. Using accurate forecasts provides a greater likelihood that Duke will address future load and reliability in the least cost manner. *Id.* at 187. It is vital that Duke strive to achieve these ambitious goals while maintaining accurate load forecasts. To that end, Duke should seek to quantify the adoption of non-utility EE to accurately reflect the adoption of EE programs in its load forecasts. While Duke has noted that its load forecasts capture these "naturally occurring" EE impacts, due to the tremendous potential for increases in customer driven EE due to the IRA, it is imperative that Duke accurately reflect the adoption of EE — both UEE and non-utility EE — in its forecasts.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

Grid Edge and Customer Programs – EVs

The evidence supporting this finding of fact and conclusions is in Duke's Carbon Plan proposal; testimony and exhibits of Duke's Modeling and Near-Term Actions Panel and Grid Edge Panel, Appalachian Voices witnesses McIlmoil and Kinkhabwala, NCSEA et al. witness Fitch, Public Staff witness Williamson, and the entire record in this proceeding.

Duke testified that it continues to work with industry groups to understand the expected pace of EV adoption in its service territories. As of May 31, 2022, approximately 5,800 new EVs were registered year-to date in Duke's North Carolina and South Carolina service territories. This total outpaces the approximately 4,000 registrations for the same period in 2021, representing an increase of 45% year over year. In North Carolina specifically, the EV market has continued to grow. As of March 31, 2022, there were more than 36,000 EVs operating in Duke's North Carolina service territories compared to approximately 25,000 EVs in May 2021. Given the expected continued acceleration in EV adoption, Duke is developing programs to both encourage EV adoption and manage the impact of the new load associated with EVs. Tr. vol. 14, 31.

Appendix E to Duke's Carbon Plan proposal explains the base EV load forecast using trends and assumptions current as of Fall 2021. The base forecast did not include specific projections of future growth resulting from policies or trends from federal government incentive programs. Duke's EV forecast as it describes in Appendix F states that Duke incorporated recent goals from the Biden Administration providing that 50% of new United States passenger car and light truck sales will be electric by 2030. Additionally, major automakers have announced a goal of 40% to 50% of new vehicle sales being electric by 2030. Additionally, North Carolina Executive Order 246 directs the North Carolina Department of Transportation to develop a plan to achieve 1.25 million registered zero-emission vehicles on the road by 2030. Applying these assumptions, Duke used the Vehicle Analytics and Simulation Tool to produce hourly load shapes to determine the demand and energy requirements necessary to forecast the EV potential for the system over the planning horizon. Tr. vol. 7, Duke Proposed Carbon Plan, Apps. E, 18; F, 11.

The Modeling and Near-Term Actions Panel noted that a few potential variables could impact Duke's EV forecast. Examples of variables that may lead to higher adoption levels include increased consumer acceptance, automaker commitments, and strong public government support (policy and funding); examples of variables that may lead to reduced adoption levels include the current global chip shortage, supply chain issues, cost of EVs for the public, and manufacturing limitations. The Panel explained that the EV forecast in Duke's Carbon Plan proposal considered these variables when Duke developed the forecast. The Panel stated that Duke will continue to evaluate the EV marketplace and will continue to update the forecast and that if actual EV adoption differs from Duke's forecasts, Duke will reflect such changes in future Carbon Plan iterations. Tr. vol. 7, 320-21.

The Public Staff in its Initial Comments states that it does not dispute Duke's underlying forecast regarding EVs. The Public Staff acknowledges the nascent nature of the EV market, Duke's current efforts to research the EV market through EV-specific programs, and the EV market's potential to introduce significant amounts of additional load in the coming years. The Public Staff notes that rates and programs that Duke is implementing now can shape customers' charging behaviors and habits, rather than Duke waiting to implement new rates after EV adoption is more mature and customers have established charging behaviors. Although the Public Staff does not find it unreasonable that Duke did not include the impacts of EV-specific programs and rate schedules in its EV load forecast due to the uncertainty of customer response to these programs, it cautions that failure to properly manage new EV load could result in increased system peaks and acceleration of the need for new system resources in the future. Public Staff Initial Comments at 64-65.

Several intervenors, including the City of Charlotte, Durham County, and EWG, recommend that the Commission fully analyze the impact of EVs on load forecast. City of Charlotte Initial Comments at 10-11; Durham County Initial Comments at 6; EWG Initial Comments at 3.

With respect to taking action to optimize the potential electric system benefits of transportation electrification, Duke witness Huber testified that there are

> two parts that it is trying to solve for: 1) one is a do-no-harm piece to the rate design that says, hey, this as a time you don't want to charge, if you do, we'll have to have system upgrades, it's going to be expensive; and 2) another part of that rate design that says, hey, charge here, that will help the system with, you know, possible integration costs of higher renewables, for instance, so it's doing both.

Tr. vol. 14, 95-96. At the expert witness hearing, Duke also recognized that it must design rates to encourage EV charging at times that minimize harm and maximize benefit to the electric system and facilitate charging at locations on the grid that avoid the need for upgrade to the grid and, perhaps, facilitate operation of the grid. *Id*.

The Commission is persuaded that it is appropriate and critical for Duke to consider the impact of EVs on its load forecasts based on the regulatory environment at the time of its modeling. In addition, the Commission directs Duke to continue the two-pronged approach described above. Ultimately, load growth associated with EVs has the potential to reduce system average cost and possibly lead to more optimal system operation at times. Duke must pursue this opportunity to the fullest extent.

The Commission directs Duke, in its upcoming proposed biennial CPIRP, to include a separate and robust analysis of the electrification of transportation, including both load projections and actions Duke undertakes to encourage charging at off-peak times or during times of excess energy. The Commission further directs Duke to facilitate the location of charging infrastructure on the system that avoids or obviates the need for system upgrades or provides additional system benefit.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54

Grid Edge and Customer Programs – New Regulatory Mechanisms

The evidence supporting this finding of fact and conclusions is in Duke's Carbon Plan proposal, testimony and exhibits of Duke's Grid Edge Panel, Appalachian Voices witnesses McIlmoil and Kinkhabwala, Public Staff witness Williamson, and the entire record in this proceeding.

In identifying the load reduction that Duke can achieve through the Grid Edge programs, Duke also identifies several enablers that would be necessary to continue to meet the load reduction through EE on a long-term, annual basis. The Grid Edge Panel requested that the Commission approve several enablers that Duke identifies in its Carbon Plan proposal. Tr. vol. 7, Duke Proposed Carbon Plan, App. G. Duke asserts that there is value in the Commission acknowledging and affirming at this time the enablers Duke identifies in order that the work on the Grid Edge programs can begin. The enablers the Grid Edge Panel identifies include: (1) updating the inputs underlying the determination of the utility system benefits; (2) moving to an "as-found" baseline; (3) expanding the pool of low-income customers; (4) obtaining approval of Duke's proposed tariff on-bill programs; and (5) adopting new flexibility and rapid prototyping guidelines to ensure timely regulatory approval of new DSM/EE pilots and rate designs. Tr. vol. 13, 32-33.

Generally, the Public Staff asserts that it is not appropriate or necessary for the Commission to acknowledge in this proceeding that the enablers Duke identifies are necessary to achieve targeted UEE savings. The Public Staff asserts that acceptance of these enablers would require either public policy decisions by the Commission, legislative action, or proceedings in separate dockets to investigate the impacts of any proposed enablers. Tr. vol. 21, 208-09.

Other intervenors also criticize specific enablers that Duke requests. AGO witness Burgess argues that Duke's proposal to shift to an as-found baseline would include "fictitious" energy savings and would not be reasonable. Tr. vol. 25, 316. AGO Strategen Report, 44-45. Appalachian Voices witnesses McIlmoil and Kinkhabwala disagree with Duke's proposal to expand the pool of low-income customers and argue that DSM/EE programs for low-income ratepayers are insufficiently funded. Tr. vol. 24, 43-44.

The Commission acknowledges that Duke identifies certain enablers that would allow it to achieve greater load reduction through its Grid Edge programs. While the Commission encourages Duke to utilize its Grid Edge programs, the Commission is persuaded by the Public Staff that all enablers related to the DSM/EE mechanism should be discussed within the context of a full DSM/EE mechanism review. The Commission approved the most recent DSM/EE mechanism for each company in October 2020 in Dockets No. E-2, Sub 931, and E-7, Sub 1032. Tr. vol. 13, 39. The Commission is persuaded by the Public Staff's assertion that "any modifications to individual components of the Mechanisms must take place in the context of a full, formal review of the entire Mechanisms, so that any impacts of other components of the Mechanisms can be analyzed at the same time." Tr. vol. 21, 193. With one exception, the Commission determines that it is not reasonable to make any determination on the specific enablers in this proceeding but directs Duke to initiate a review of DEC's and DEP's DSM/EE Mechanisms within 120 days of the issuance of this Order.

The Commission is also persuaded that the adoption of new flexibility and rapid prototyping guidelines to ensure regulatory approval of new customer programs, pilots and rate designs in a timely manner would be appropriate at this time. Tr. vol. 13, 32-33. The Grid Edge Panel explained that other states have expedited implementation processes for customer programs and that Duke believes that similar guidelines in North Carolina can help enable timely implementation of the energy transition and the Carbon Plan. The Grid Edge Panel noted that the current "Flexibility Guidelines" the Commission has approved as part of Duke's Mechanisms for DSM/EE programs is an example of such a guideline, and that a similar expedited approval process for new customer programs and pilots for non-DSM/EE programs would better allow Duke to innovate, shrink the challenge, and timely implement the Carbon Plan. The Commission is receptive to this approach and directs Duke to file a formal proposal with the Commission.

In addition, the Commission finds that Duke can also reduce load by decreasing the number of nonresidential customers that elect to opt out of its DSM/EE programs. As Duke witness Duff noted a "significant portion" of Duke's nonresidential customers, representing approximately 30% of its load, have opted out of participation. Tr. vol. 14, 93-94. Duke witnesses testified that "to achieve the aggressive long-term energy efficiency projection necessary for energy transition and included in the Carbon Plan, the Companies recognize that they must increase the efficiency savings from customers that are participating in the Companies' portfolio *and* obtain savings from customers not participating in its portfolio of EE/DSM programs or, as the Companies call it, expanding the pool for savings." Tr. vol. 13, 65 (emphasis added). Duke witness Huber outlined some of the actions Duke has taken to reduce the number of customers that opt out of participating in the portfolio of DSM/EE programs including working with CIGFUR to develop new DR programs and streamlining the way for customers to opt in. Tr. vol. 13, 128; tr. vol. 30, 64. Duke's Grid Edge Panel further noted that Duke has "a long history of working with stakeholders in the DSM/EE Collaborative to ensure that their portfolios of nonresidential programs are both attractive and comprehensive." The Commission directs Duke to focus on expanding the pool for savings by developing programs aimed at reducing the number of DSM/EE opt outs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 55

Grid Edge and Customer Programs – Wholesale Customers and Dynamic Rate Design

The evidence supporting this finding of fact is found in the testimony of NCEMC, Power Agencies Initial Comments, Duke's Initial Comments, and the entire record in this proceeding.

Coordination with Wholesale Customers

The Power Agencies contend that the Carbon Plan cannot comply with N.C.G.S. § 62-110.9's least cost mandate without taking full advantage of as much load-side management as its wholesale customers can possibly provide. The Power Agencies claim that Duke's current plan "effectively ignores the potential for demand reduction associated with as much as 30% of DEP's load" and recommend that the Commission direct Duke to take full advantage of as much load side management as wholesale customers can provide. Power Agencies Initial Comments at 4-5.

NCEMC witness Ragsdale testified that NCEMC and its 26 member-distribution cooperatives[17] have developed and implemented the NCEMC Distribution Operator (DO), a single entity that monitors and coordinates DER and DR resources for the electric membership co-ops across the State. Tr. vol. 26, 207-08. Witness Ragsdale noted that the Commission has previously recognized the value of the DO in contributing reliability benefits to Duke's system, and that coordination of such efforts between Duke and NCEMC was consistent with least cost planning. *Id*.

Duke Transmission Panel witness Roberts described Duke's coordination with NCEMC and its DO platform. He indicated that Duke included in its General Load Reduction Plans the fact that it is able to coordinate operating instructions to utilize NCEMC's DO capabilities for emergency purposes, and that Duke continues to have collaborative meetings with NCEMC to coordinate the utilization of the DO function from a reliability perspective. Tr. vol. 26, 120-21.

Duke argues that the Power Agencies' request would be outside the bounds of the Carbon Plan proceeding. Duke explains that, as the North Carolina Court of Appeals has recognized, "exclusive jurisdiction over interstate wholesale electric power transactions is conferred upon FERC."[18] Duke further notes that Duke's wholesale requirements contracts with multiple entities in the Carolinas are on file with FERC and subject to its jurisdiction, including as they relate to how the wholesale customers' DSM/EE programs interact with wholesale charges. Duke Pre Hearing Comments at 63.

As NCEMC witness Ragsdale noted, the Commission has previously recognized the growing relationship between resource and distribution planning between the electric public utilities and their load serving entity customers. In its April 6, 2020 Order Accepting Filing of 2019 IRP Update Reports and Accepting 2019 REPS Compliance Plans in Docket No. E-100, Sub 157, the Commission recognized the benefits of including the electric membership cooperatives in the Integrated Systems and Operations Planning (ISOP) process.

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[17] For clarity, NCEMC notes that its 25 participating and independent members, as well as French Broad EMC, a member of the North Carolina Association of Electric Cooperatives, Inc., participate in the DO platform.

[18] *State ex. rel. Utils. Comm'n v. N.C. Electric Membership Corp*., 105 N.C. App. 136, 142 (1992) (affirming that issues affecting wholesale rates were appropriately not addressed in IRP proceeding as "such an issue is more appropriately addressed to FERC"); *see also Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 964 F.3d 1177, 1181 (2020).

The Commission recognizes that contractual arrangements between Duke and its wholesale customers associated with the operation of DER, demand reduction measures, and any compensation mechanisms associated with such resources are FERC-jurisdictional. However, the Commission acknowledges the very real potential that coordinated use of these resources has to influence a lower-cost path to compliance with N.C.G.S. § 62-110.9. Therefore, the Commission directs Duke to continue to coordinate with NCEMC and other LSEs in both its ISOP process and the Carbon Plan stakeholder process regarding the utilization of the capabilities of their DER programs and the ability of such programs to contribute to Duke's ability to comply with the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 in a least cost manner that at a minimum maintains or improves the reliability of the entire grid network in North Carolina. Duke in its upcoming proposed biennial CPIRP shall include a report on the discussions between it and the other LSEs in the state, provide an estimate of the future potential of those coordinated DER resources to contribute to future Carbon Plan compliance, and make reasonable efforts to incorporate those measures in its 2024 CPIRP filings. Duke shall also include a discussion of progress with the wholesale customers, as well as any impediments it identifies regarding the capability of these coordinated DER resources to contribute to low cost, reliable Carbon Plan compliance in such filings.

Dynamic Rate Design

Chapter 4 of Duke's Carbon Plan proposal briefly discusses some of the possible near-term rate design actions to encourage customers to change their load profiles to better support lower- and zero-carbon resources. These include updating pricing structures for distributed solar resources, developing new real-time pricing tariffs for large business customers, and piloting subscription rates to encourage customers to actively manage their charging behaviors. Duke intends rate programs such as critical peak pricing and peak-time programs to send signals to customers to incentivize reduction of their energy consumption during peak hours. Duke captures the effects of these and other rate programs in the load forecast and models them as a reduction in load. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4, 32; App. E, 24.

The Grid Edge Panel explained that Duke engaged a third-party facilitator to support a broad stakeholder process covering both DEC and DEP rate designs over the course of 12 months, concluding in March 2022. The Grid Edge Panel described the collaborative process as including participation from more than 50 organizations including commercial and industrial customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy companies, and legal/consulting companies covering a comprehensive number of topics. The Grid Edge Panel explained that this stakeholder engagement resulted in Duke's crafting an informed vision and direction for future pricing and rate design options in the form of a Roadmap, which Duke filed with the Commission in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219 on March 31, 2022. Tr. vol. 13, 67.

The Grid Edge Panel also provided examples of specific program concepts that Duke has discussed with stakeholders including a revised Green Source Advantage

(GSA) program, a "Clean Energy Impact" program for residential and business customers who want to support the advancement of renewables by purchasing locally generated renewable energy certificates (RECs) from Duke-owned renewable resources, and the Clean Energy Connection Program, which is a subscription solar program for all customer types to support renewable energy in North Carolina. *Id.* at 69-71.

The Public Staff recommends that the Commission explore the proposals stemming from the Comprehensive Rate Design Study and that Duke at a minimum offer them on a pilot basis if they improve system efficiency and avoid significant cost shifts between customer classes. The Public Staff notes that it does not oppose specific rate design proposals at this time but also does not recommend any of the specific rate design proposals in the proposed Carbon Plan given its view that the Commission should review any such proposals as part of a program application. Public Staff Initial Comments at 67-68.

CIGFUR also asserts that Duke should explore rate design options that could potentially reduce load. Tr. vol 22, 43.

The Commission finds the proposal for Duke to pursue dynamic rate design reasonable but is persuaded by the Public Staff that the Commission must fully review and evaluate all programs within the proper proceeding. The Commission directs Duke to engage with stakeholders to develop dynamic rate designs and to propose such rate designs in future rate cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 56

Transmission – RZEP

The evidence supporting this finding of fact is in Appendix P to Duke's Carbon Plan proposal, the direct and rebuttal testimony and exhibits of the Duke Transmission and Solar Procurement Panel, the testimony of Public Staff witness Metz, CPSA witness Norris, and NCSEA witness Caspary.

The "Red Zone" consists of several non-contiguous geographic areas in DEC and DEP territories where transmission constraints exist, as depicted in Figure P-1 of Appendix P. As Public Staff witness Metz testified, the Red Zone is highly suitable for solar development due to its flat terrain, relatively low land costs, and relatively high solar insolation; however, historical load requirements and, more recently, increased solar development highly constrain the transmission in this area. Tr. vol. 21, 140. The historic success of solar development interconnected to Duke's distribution and transmission systems in these areas has contributed to the transmission system reaching a saturation point, i.e., the system has too much generation and not enough load in discrete line segments of the distribution and transmission system. *Id.*

Duke witness Roberts explained how Duke identified four transmission upgrade projects in the DEC territory and 14 transmission upgrade projects in the DEP territory, which Duke calls Red-Zone Transmission Expansion Plan (RZEP) projects. In March of

2022, prior to its Carbon Plan filing, Duke presented the RZEP projects to the Oversight Steering Committee (OSC) of the NCTPC. The NCTPC is the local transmission planning body in which Duke participates in order to satisfy its obligations under FERC orders. Tr. vol. 16, 67; Transmission Panel Exhibits 1 and 2. Class 5 estimates for all of the 18 RZEP projects exceed $560 million. Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 14-15. In June 2022, the NCTPC distributed a draft of the 2021 Mid-year Update Report to the Transmission Advisory Group (TAG) of the NCTPC for review prior to the June TAG meeting; the draft 2021 Mid-Year Update Report proposed adding the RZEP projects to the Local Transmission Plan. Tr. vol. 16, 68. Duke planned to seek approval of the 2021 Plan Mid-Year Update Report, including the 18 RZEP projects, from the OSC by mid-August, pending feedback from TAG stakeholders. *Id*.

However, on June 10, 2022, the Commission directed Duke not to include RZEP projects in the 2022 DISIS baseline, concluding that doing so would be premature because "no party has presented competent evidence that the RZEP projects are necessary to achieve the Carbon Plan." Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2.(c)*, Nos. E-2, Sub 1297, E-7, Sub 1268 (N.C.U.C. Jun. 10, 2022). Duke witness Roberts testified that, based on the Commission's directive as well as feedback the NCTPC received from TAG stakeholders, the NCTPC communicated that it would no longer consider the RZEP projects for inclusion in the 2021 Plan Mid-Year Update Report. Tr. vol. 16, 69.

In its Issues Report filed in this proceeding on July 22, 2022, Duke agreed to perform supplemental analysis for the Public Staff to address the need for RZEP projects. Tr. vol. 21, 140. Accordingly, Duke performed a revised transmission study to address some of the concerns the Public Staff raised in the NCTPC process, such as isolating solar facilities that were extraneous and required substantial line upgrades that primarily benefited one interconnection request. Tr. vol. 21, 142-43. Duke's recent supplemental transmission studies show the need for 11 of the original 14 RZEP projects in DEP, in order to enable 2,778 MW of solar projects to interconnect in the DEP Red Zones, and 981 MW of solar project to interconnect in the DEC Red Zones, all 4 of the original RZEP projects in DEC.

More specifically, Duke concludes that the supplemental studies demonstrate that it can delay DEP Projects #9 (Rockingham-West End 230 kV West), #11 (Erwin-Milburnie 230 kV line), and #12 (Sutton-Wallace 230 kV line) until future studies again show a reliability need or generation addition need. This would reduce the RZEP project group from 18 to 15 projects. Tr. vol. 16, 74-75.

Looking to the original 18 proposed projects, Public Staff witness Metz recommended against construction of DEC Project #4, the Clinton 100 kV line, because there were relatively few generator facilities impacting that line and the relationship between future solar generation and that upgrade is unclear. Tr. vol. 21, 145-46. Witness Metz similarly recommends against construction of DEP Projects #7, #9, #11, #12, and #14 because relatively fewer interconnections impact them as compared with the other

RZEP projects. At the same time, Witness Metz opined that interconnection requests are likely to increase in the Red Zone after completion of the upgrades, potentially leading to more congestion. Tr. vol. 21, 149. If the Commission were to adopt the Public Staff's recommendations, it would reduce the RZEP project group from 18 to 12 projects.

In rebuttal, Duke Transmission Panel witnesses agreed that Duke could postpone Project #14 — the Camden-Camden Dupont 115 kV line upgrade — at this time. However, Duke testified that that prior generator interconnection studies and the supplemental studies demonstrate that DEC Project #4 (Clinton 100 kV line) and DEP Project #7 (Erwin – Fayetteville 115 kV line) will be necessary to integrate hundreds of MW of generation in the Red Zone area. Tr. vol. 28, 130-32. Furthermore, Duke estimated that DEC Project #4 will take 48 months to build, and that DEP Project #7 will take 54 months. *Id.* at 132-33. If the Commission adopts the recommendations in Duke's rebuttal testimony, it would restore two projects that the Public Staff recommends postponing and increase the RZEP project group from 12 to 14 projects.

Duke witness Roberts described the Red Zone as "fertile ground" for development of utility-scale solar projects and testified that these are areas in which Duke would develop solar on its own, even if it were not purchasing from third parties. Tr. vol. 19, 60-62.

Duke notes that all of the portfolios the parties to this proceeding propose require interconnection of at least 5 GW of solar over the next decade, including solar combined with storage. *See* tr. vol. 21, 142. Without completion of the RZEP projects, Duke concludes it would be "extremely challenging" if not impossible to meet the Interim Target. Tr. vol. 16, 187; tr. vol. 19, 61. Duke has completed no significant development work for the RZEP projects, and certain RZEP projects have lead times of up to 4.5 years. Tr. vol. 16, 68-69.

Duke sees benefits flowing from the RZEP projects, aside from the requirements of N.C.G.S. § 62-110.9. Duke assessed the reliability benefits of the RZEP projects, using two different methodologies, and determined that the projects had cost-benefit ratios ranging between 5.1 to 22.5 as many of the projects will be replacing aging facilities with newer and more efficient and resilient components. Id. at 78-79. Duke also identifies additional benefits from the RZEP projects, such as increased ability of solar in the Red Zones to charge standalone battery storage located close to load centers and discharge during net demand peak periods. *Id.* at 71.

CPSA witness Norris testified that "Duke has amply demonstrated that the RZEP upgrades are needed to achieve compliance with HB 951." Tr. vol. 26, 25. Based on the additional analysis the supplemental studies provide, he describes them as a "no-regrets" set of upgrades. He noted that the supplemental study is consistent with CPSA members' experience in developing solar projects in the Carolinas. *Id*. at 63-64. Likewise, NCSEA witness Caspary testified that the RZEP projects are necessary to achieve the Interim Target by 2030. He endorsed the efficiency of planning resources and transmission at the same time and agrees with Duke that the risk of underutilization of the RZEP projects is low. Tr. vol. 22, 13-15.

Based on the foregoing, including the fact that the Public Staff is overall supportive of the majority of the RZEP projects, the Commission concludes that the fourteen 2022 RZEP projects are necessary to achieve the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 in a least cost manner. The Commission's conclusion is in keeping with the directive from the North Carolina General Assembly that the Commission consider transmission as an element of the Carbon Plan. N.C.G.S. § 62-110.9(1).

The Commission gives substantial weight to Duke's testimony regarding the necessity of the fourteen 2022 RZEP projects, including DEC Project #4 and DEP Project #7, given their long lead times and the fact that they should allow hundreds of megawatts of solar energy to interconnect to Duke's system. The Commission finds that the risk of those upgrades being underutilized is low. Even the Public Staff expects interconnection requests in the Red Zone to increase after construction of the upgrades.

Completion of the 2022 RZEP projects is a necessary first step to interconnect the solar volumes necessary to execute the Carbon Plan, both in terms of carbon dioxide emissions reductions and in terms of the timelines N.C.G.S. § 62-110.9 mandates. The 2022 RZEP projects will allow the interconnection of approximately 3,759 MW of solar generating facilities in Duke's territory — 2,778 in DEP and 981 in DEC — as the aforementioned supplemental transmission studies evidence.

The 2022 RZEP projects are appropriate for Duke to construct as a reasonable early step to meet with the requirement of N.C.G.S. § 62-110.9 that the Carbon Plan must constitute the least cost path that meets the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 and provides additional operation and resiliency benefits.

In regard to bids for solar facilities that are dependent on the RZEP projects in the 2022 Solar Procurement, the Commission notes that NCSEA et al. seek to alter the assignment of RZEP project costs to those bids if the NCTPC approves the RZEP projects and, therefore, includes them in the Local Transmission Plan. Once in the Local Transmission Plan, the RZEP projects would be part of Duke's "baseline" for interconnection studies going forward. Tr. vol. 29, 33. Specifically, NCSEA et al. request that if the NCTPC approves the RZEP projects in 2023, the Commission order Duke to use the DISIS Phase 1 Upgrade cost allocations for the bids for solar projects that depend on the RZEP, as opposed to the DISIS Phase 2 results, for purposes of the 2022 Solar Procurement final bid evaluation, VAM calculations, and assessment of compliance with the CPRE avoided cost cap. *See* NCSEA, SACE et al., CCEBA, CPSA, and MAREC Joint Br. and Partial Proposed Order at 231. They point out that Duke witness Farver stated that Duke is in the process of seeking approval from the NCTPC to include the RZEP projects in the 2022 Local Transmission Plan that will be finalized in early 2023, and that the 2022 Local Transmission Plan will likely include the RZEP projects by the time the Step 2 evaluation of the 2022 Solar Procurement is conducted. Tr. vol. 29, 72-73; NCSEA, SACE et al., CCEBA, CPSA, and MAREC Joint Br. and Partial Proposed Order at 228. They argue that bids for solar projects that depend on the RZEP projects present a "particular problem" with regard to assignment of Network Upgrade costs in the 2022 Solar Procurement. NCSEA, SACE et al., CCEBA, CPSA, and MAREC Joint Br. and Partial Proposed Order at 228. They state that because Duke did not include the RZEP projects in the baseline for the DISIS Phase 1 study, the full costs of the RZEP projects will be assigned to any projects that trigger those upgrades in the DISIS study and those assigned upgrade costs will influence the evaluation of projects in the 2022 Solar Procurement RFP. *Id.* NCSEA et al. contend that assignment of the full cost of the RZEP projects to bids for solar projects that depend on the RZEP projects in the 2022 Solar Procurement RFP is likely to have "undesirable and problematic consequences." *Id.* They argue that because the number of solar projects being procured in the 2022 Solar Procurement is smaller than the total number of solar projects that will benefit from the RZEP projects, it would be inappropriate to assign the full cost of the RZEP projects to a smaller number of solar projects and thus drive up the apparent cost of the 2022 Solar Procurement. *Id.* at 227, 229. They are concerned that assignment of the RZEP projects to bids for solar projects that depend on the RZEP projects could result in rejection of those bids in the 2022 Solar Procurement. *Id.* at 229. They state that even if the bids that depend on the RZEP projects are selected in the 2022 Solar Procurement, Duke should not assign the full cost of the RZEP projects in calculating the cost for purposes of the VAM and for purposes of determining whether projects selected to fulfill the CPRE capacity allocation in the 2022 Solar Procurement meet the avoided cost cap. *Id.* at 229-30.

The Commission finds that NCSEA et al. are effectively asking the Commission to modify the Commission's orders regarding the 2022 Solar Procurement, along with the 2022 Solar Procurement RFP, while the bid evaluation process is underway.[19] In response to this request, the Commission notes Duke witness Farver's explanation of the effect of any NCTPC approval of the RZEP projects — that Duke will classify the RZEP projects as "Contingent Facilities" and include them in Duke's "baseline" and will not assign costs of the RZEP projects in Interconnection Agreements coming out of the 2022 DISIS process and in subsequent DISIS processes. Tr. vol. 29, 29, 33, 34. Duke witness Farver, who cautioned against making any changes to the 2022 Solar Procurement process at this point, testified about her concerns regarding the NCSEA et al.'s request. Tr. vol. 29, 29-30, 77. She stated that if the costs of the RZEP projects were not assigned to the bids for solar projects that trigger the need for the RZEP projects, then the ranking of projects in the 2022 Solar Procurement could change. *Id.* She also testified, in support of not making a change to the 2022 Solar Procurement process at this point in spite of the NCSEA et al. concern, that "we don't know if all of those upgrades identified in [DISIS] Phase 1 will still be necessary in Phase 2, so as there are fewer projects, perhaps there are fewer upgrades needed." Tr. vol. 28, 183.

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[19] *See* Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2.(c)*, Nos. E-2, Sub 1297, E-7, Sub 1268 (N.C.U.C. Jun. 10, 2022) and Order Permitting Additional CPRE Program Procurement and Establishing Target Procurement Volume for the 2022 Solar Procurement, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Joint Petition for Approval of Competitive Procurement of Renewable Energy Program and Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2(c),* Nos. E-2, Sub 1159, E-2, Sub 1297, E-7, Sub 1156, and E-7, Sub 1268 (N.C.U.C. Nov. 1, 2022).

The Commission agrees with Duke witness Farver that it is not appropriate to "change the evaluation process mid-flight in the current 2022 RFP." Tr. vol. 29, 77. Not only would it be inappropriate to change the rules of the 2022 Solar Procurement "mid-flight" and potentially unfair to bids for solar projects that are not dependent on the RZEP projects, the Commission has made it abundantly clear in its 2022 Solar Procurement Orders that "the [2022 solar] procurement process must evaluate bids that takes into account all costs for the proposed facilities, including Network Upgrades . . . Duke is directed not to include the RZEP projects in the 2022 DISIS baseline." The Commission reiterated its direction to Duke and the parties to allocate Network Upgrade costs in the bid evaluation process in its November 1, 2022 Solar Procurement Order. However, to again be clear, the Commission denies the request of NCSEA et al. to modify the Commission's 2022 Solar Procurement orders and the Solar Procurement Program RFP and directs Duke to comply with the procedure the 2022 Solar Procurement Program RFP requires (i.e., to include the Network Upgrade cost estimate in the Part B Price for bids for solar projects that depend on the RZEP).

Duke witness Farver also stated that it is unclear how Network Upgrades that solar projects trigger and that Duke also includes in the baseline (assuming, again, NCTPC approval) would be assigned to the bids for solar projects that depend on the RZEP projects in the 2023 Solar Procurement and subsequent solar procurements. Tr. vol. 29, 28. While she opined that designing an appropriate RFP for the 2023 Solar Procurement will be "new territory" for Duke, she testified that the 2023 Solar Procurement RFP might be designed "such that it's not just zero assigned to those Red Zone projects, but that there's some cost reflected in the evaluation process to recognize that there was a transmission cost associated with it." Tr. vol. 29, 28. Duke witness Farver further testified:

> I think for future solar procurements we should have further discussion about how best to account for transmission costs assigned to projects — I should say transmission costs assigned to projects for evaluation purposes if those transmission costs are not being borne by the generator in the DISIS interconnection process. So for a Red Zone upgrade, how are we making sure that we're not assigning a zero transmission cost to a project that's benefiting from Red Zone upgrades that were approved through a different mechanism [the NCTPC], but also not assigning one project the full cost of all of the Red Zone upgrades because that also is not an accurate reflection of the — I suppose the project's cost.

The Commission agrees with Duke witness Farver that it is important that the 2023 Solar Procurement RFP ensure that bids for solar projects that depend on the RZEP projects are assigned an appropriate percentage of RZEP project costs since those solar projects have caused the need, in part, for the RZEP projects but will not have to pay for it. As Duke witness Farver noted, bids for solar projects that depend on the RZEP projects should be evaluated in solar procurements' RFPs based upon the projects' costs, including the Network Upgrades. The Commission points out that the necessity of evaluating bids for solar projects considering the projects' total costs is not confined to the RZEP projects; instead, any projects triggering Network Upgrades that the NCTPC has approved, and that Duke has included in the “baseline” should be evaluated based upon the projects’ total costs. Accordingly, the Commission directs Duke to prepare a mechanism for the 2023 Solar Procurement that evaluates bids for solar projects that depend on the RZEP that includes an appropriate cost for the RZEP projects.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 57-58

Transmission – Planning

The evidence supporting these findings of fact is in Appendix P and Appendix S to Duke’s Carbon Plan proposal, the direct and rebuttal testimony and exhibits of the Duke Transmission Panel, the testimony of Public Staff Witness Metz, CCEBA witness Gonatas, CPSA witness Norris, and NCSEA witness Caspary, and the entire record in this proceeding.

Duke explains in Appendix P that executing the Carbon Plan will require a transformation of the DEC and DEP transmission system in the near-term and long-term to interconnect the unprecedented amount of new supply-side resources that will be necessary to retire significant amounts of coal-fired generation and achieve the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9.

Duke requests the Commission to direct Duke to continue to study future transmission needs and to reliably implement the Carbon Plan primarily through the NCTPC, whose transmission planning procedures are set out in Attachment N-1 of Duke’s OATT and are designed to meet the requirements of FERC Order Nos. 890 and 1000. Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 7-8. The members of the NCTPC are DEC, DEP, ElectriCities, and NCEMC. Tr. vol. 16, 53, Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 7. The Duke Transmission Panel provided an overview of the NCTPC process and explained that the NCTPC solicits input and recommendations from stakeholders through the TAG. Tr. vol. 16, 54-57; Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 6-9. State public utility commissions may receive periodic status updates and progress reports on the NCTPC process. *Id.* at 8. Duke participates in regional transmission planning in compliance with FERC Order Nos. 890 and 1000 through the Southeastern Regional Transmission Planning (SERTP) process. *Id*. at 9.

Duke witness Roberts opined that to meet the N.C.G.S. § 62-110.9 carbon dioxide emissions reduction mandates, Duke must integrate transmission planning with resource planning, consistent with the Commission’s and FERC’s respective authorities. Tr. vol. 16, 59. He explained that failure to do so could lead to insufficient timely transmission development and that the lack of transmission infrastructure to reliably support coal retirements and integrate significant amounts of new generation would put Carbon Plan execution at risk. *Id.* at 61-62.

Duke witness Roberts also explained that Duke embraces least regrets planning and expects to identify future transmission upgrades in a variety of ways, including generator interconnection requests, DISIS studies, and scenario-based planning, in order to identify holistically the transmission upgrades necessary to provide the most benefits for the least cost. *Id.* at 168-69.

The Public Staff supports, as does Duke, the need to evolve and move away from a solely reactive transmission upgrade approach, where upgrades are constructed in response to generation interconnections, to a proactive approach that also considers upgrades in anticipation of future generation needs. *Id.* at 63-66.

Duke witness Roberts stated that "[a]n effective transmission planning process is necessary for system adequacy and reliability . . . and Duke views the transmission planning process as a key enabler of achieving the goals of the Carbon Plan." *Id.* at 59. He noted that the Commission's Final Order on the Duke's 2020 IRP highlighted the Commission's focus on transmission planning and the transmission Network Upgrades necessary to retire coal facilities and integrate new resources to achieve the least cost energy transition N.C.G.S. § 62-110.9 requires. *Id*. at 60.

Duke agrees with the Public Staff and other intervenors that the NCTPC planning process must evolve to meet the needs of executing the Carbon Plan. *Id.* at 86. Duke commits to working with NCTPC OSC members and stakeholders to consider changes to the local transmission planning processes reflected in Attachment N-1 of Duke's OATT that would improve coordination with Carbon Plan execution and ensure timely and robust review of transmission projects necessary to meet generation needs. *Id.* at 85-87.

Public Staff witness Metz testified that a transformation in the generation fleet cannot be considered in isolation from the impact on the transmission system. Tr. vol. 21, 139. The Public Staff states that proactive transmission upgrades require a balance of least cost and least-regrets planning, coupled with a robust, forward looking planning process. The Public Staff further states that a least-regrets approach for proactive transmission is reasonable because Duke will add solar and other low or no carbon resources in later years, likely exceeding the 5 GW amount by the late 2030s. *Id.* at 142.

NCSEA witness Caspary recommended that the scope of studies the NCTPC and SERTP perform needs to better inform regional and interregional plans to ensure least regrets plans which maximize net benefits and address the decarbonization requirements of N.C.G.S. § 62-110.9 through 2050. Tr. vol. 22, 247.

Witness Caspary stated that for its Carbon Plans, the Commission should direct Duke to incorporate the results of long-range joint studies with other utilities and stakeholders to determine optimal expansion plans in lieu of Affected System studies. Tr. vol. 22, Ex. 2, 10. He further testified that the Commission should encourage Duke to provide some leadership to expand the current SERTP and NCTPC processes, while at the same time leveraging the DOE-funded Atlantic Offshore Wind Transmission Study, to better identify long-term needs of Duke and its neighbors. Finally, he stated that it is imperative that neighboring systems work together to identify and address future system needs in an open and transparent manner, implementing the best solutions to improve grid performance. Tr. vol. 22, 240.

Based on the foregoing, the Commission concludes that it is reasonable for Duke to engage in the process of making changes to transmission planning to reliably implement the Carbon Plan through the NCTPC, SERTP, and other transmission planning forums that Appendix P identifies, and witness Roberts discussed. The Commission supports Duke's acknowledgement that changes to the NCTPC are necessary and strongly advises Duke to initiate a review of its processes and quickly implement any improvements that FERC may require in a final rule resulting from the Notice of Proposed Rulemaking in FERC Docket RM21-17-000. The Commission agrees with witness Roberts that Duke must integrate transmission planning with resource planning to maintain the reliability of the electric system and to ensure a least cost path to compliance with N.C.G.S. § 62-110.9.

Furthermore, based upon the potential magnitude of future transmission expenditures, the Commission urges Duke to explore all possible efficiencies and to be vigilant in its participation in SERTP and in its coordination with PJM to assure a least cost path to achieve the carbon dioxide emissions reduction requirements while maintaining and improving reliability.

In addition, the Commission notes that there are important linkages between the work of Duke's ISOP teams relative to distribution level Grid Edge programs and impacts on the design and operation of the bulk power system that may result. The Commission encourages Duke, in its future transmission planning efforts, to support ISOP's strengthening these linkages between the bulk power system and distribution level DER programs.

Although the Commission will not dictate any specific changes to the NCTPC, the Commission encourages Duke to engage with stakeholders and the other members of the NCTPC immediately to improve the NCTPC process and address requests to increase transparency and coordination and to provide more opportunities for stakeholder input.

Further, due to the increasing significance of transmission and potential increased investment in transmission pursuant to this Order, the Commission will avail itself of Section 2.5 of Attachment N-1 of Duke's OATT and require periodic status updates and progress reports on the NCTPC process. The Commission shall open a sub docket to the CPIRP process in order to receive these updates and reports pursuant to the FERC OATT.

States, and not the federal government, have responsibility for resource adequacy, determining the generation mix, and siting of transmission, distribution, and generation facilities. *See, e.g.,* Federal Power Act § 201(b)(1), 16 U.S.C. § 824(b)(1); Federal Power Act § 211(d)(1); *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205, 103 S. Ct. 1713, 75 L. Ed. 2d 752 (1983)("[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the [s]tates."). Meeting the requirements of N.C.G.S. § 62-110.9 in a least cost manner will mean holistically considering the costs and benefits of the generation mix in the context of the costs and benefits of the associated transmission needs. For instance, there will be times when the most cost-effective solution to a constraint on the transmission system is not more transmission, but rather generation assets located near load. Moreover, the Commission is ultimately responsible for ensuring fair and reasonable retail rates, including bundled transmission rates. Finally, given the Commission's role in ratemaking and issuing CPCNs and, where appropriate, certificates of environmental compatibility and public convenience and necessity (CECPCNs) for transmission facilities, and given the interface between the issues considered in the NCTPC process and proceedings pending before the Commission, the Commission finds it necessary to receive robust information in this newly created sub docket.

In other words, because the Commission retains certain jurisdiction over transmission facilities under N.C.G.S. § 62-101, over bundled retail rates, and over resource adequacy and generation mix, which is dependent on transmission facilities needed to interconnect generation resources, Duke must keep the Commission informed of its transmission planning by means of filings in the Commission's sub docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-60

Transmission – Cost and Reliability Considerations

The evidence supporting these findings of fact and conclusions is set forth in Duke's Carbon Plan proposal, the direct and rebuttal testimony of Duke's Transmission Panel, the testimony of NCEMC witness Ragsdale, and the entire record in this proceeding.

Duke witness Roberts stated that the initial RZEP projects would be "the first phase" with respect to executing the Carbon Plan, but that there would likely be the need for more upgrades in the future on top of the initial RZEP projects. Tr. vol. 17, 37-38.

NCEMC witness Ragsdale testified that Duke indicated in the supplemental studies that it did not conduct an analysis of Affected Systems. Witness Ragsdale therefore concluded that there may be additional costs and potential execution risks associated with the RZEP projects to consider and recommends that the Commission require Duke to not only coordinate with other transmission providers, but also with LSEs in North Carolina to ensure consideration of all Affected Systems. Tr. vol. 26, 204-05. These efforts should include both an evaluation of any costs associated with equipment upgrades on the LSE systems resulting from the RZEP upgrades, as well as increased coordination of the outages and other scheduled maintenance work on NCEMC delivery points. Witness Ragsdale noted that NCEMC's members have 45 delivery points within the DEP RZEP areas located in North Carolina that the proposed upgrades would potentially impact. *Id*. at 219. These could include impacts on substation equipment at those delivery points that should also be considered in evaluating the systems the RZEP projects affect. *Id*.

In addition, NCEMC witness Ragsdale testified that NCEMC currently has multiple delivery point repairs and upgrade requests to service its member-consumers it is coordinating with Duke that if delayed, could result in impacts to the reliability and service quality to electric cooperative member-consumers. Therefore, witness Ragsdale stressed that Duke's expedited timeline for RZEP projects should not result in the RZEP projects having priority over other transmission or distribution projects necessary for reliability and maintaining service quality for retail and wholesale ratepayers. *Id*. at 205. To the extent that Duke seeks to accelerate the RZEP project timelines, there should be no delays to Duke's traditional transmission provider obligations, including managing the network reliably, serving current load, and expanding the network to meet load growth and long-term service requests.

In response to Commission questions, witness Roberts and witness Farver indicated that it is their understanding that the RZEP projects by themselves should not cause an Affected System upgrade, and that any Affected System costs resulting from the RZEP projects would not occur until new generation interconnected to those upgrades. Tr. vol. 29, 82-83. Witness Roberts further stated his understanding that the upgrades that witness Ragsdale is referring to is short-circuit availability, and that as Duke adds more inverter-based resources and retires more synchronous generation, one would likely see less fault current and short-circuit availability. Therefore, it is likely there would be fewer issues or upgrades resulting to EMC points of delivery than the EMCs anticipate as a result of the RZEP upgrades themselves. *Id*. at 84.

As noted by NCEMC witness Ragsdale, N.C.G.S. § 62-110.9(3) requires that any resource changes "maintain or improve upon the adequacy and reliability of the existing grid." This provision does not apply solely to Duke's transmission grid or the grids of other transmission providers, and Duke must as a primary step ensure that any transmission or distribution upgrades it undertakes to interconnect the significant amounts of new resources called for in its recommended Carbon Plan pathways do not in any way negatively impact the adequacy or reliability of the existing grid across the Carolinas. Affected Systems studies for these projects will confirm the impact these projects have on LSE facilities and maintaining the adequacy of the grid. Prioritizing these upgrades over other necessary upgrades could shift cost and/or reliability risk to Duke's retail and wholesale ratepayers and is, therefore, unsustainable and incompatible with Duke's obligation to plan and operate its system in a safe and reliable manner for all ratepayers.

As noted by Duke's witnesses, the goal of the RZEP projects is to facilitate an aggressive timeline for the interconnection of a significant number of new resources for Carbon Plan compliance, and those additional resources will potentially impact the transmission and distribution systems of other LSEs in the state. To ensure that any resource changes maintain or improve upon the adequacy and reliability of the existing grid, the Commission directs Duke, in any future transmission upgrades proposed as necessary for Carbon Plan compliance, to ensure that it has evaluated the potential Affected System impacts on all LSEs in North Carolina, from both a cost and coordination perspective, and appropriately consider those impacts in its evaluation of the necessity for those upgrades, as well as the potential for execution risk associated with those projects. This also includes the coordination with Affected Systems both at the time of consideration of transmission upgrades, as well as at the time when new generation requests to interconnect to the upgraded facilities to ensure that the additional generation would not negatively impact delivery substations or other equipment LSEs operate in the state. Duke shall include a discussion of its efforts to coordinate the timing, cost, and scheduling of those resources in its future Carbon Plan biennial filings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 61-63

Rate Disparity Between DEP and DEC

The evidence supporting these findings of fact is set forth in Duke's Carbon Plan proposal, the testimony of Duke's Carolinas' Utilities Operations Panel, the testimony of the Modeling and Near-Term Actions Panel, the rebuttal testimony of Duke witness Bateman, the testimony of Public Staff witness McLawhorn, the testimony of AGO witness Burgess, the testimony of NCEMC witness Fall, the testimony of CUCA witness O'Donnell, the testimony of CIGFUR witnesses Gorman and Muller, the Initial Comments of the Public Staff, CIGFUR, and CUCA, and the entire record in this proceeding.

Appendix R to Duke's Carbon Plan proposal explains that DEC and DEP currently operate as separate NERC registered Balancing Authorities (BA), Transmission Operations (TOP), and Transmission Service Providers (TSP) and plan as separate NERC-registered Transmission Planners. Tr. vol. 7, Duke Proposed Carbon Plan, App. R, 1. As registered BAs, DEP and DEC separately integrate unit commitment plans ahead of time, maintain generation-load-interchange-balance within each BA Area and contribute to interconnection frequency in real time. DEC has one BA Area, and DEP has two BA Areas. As registered TOPs, DEP and DEC are responsible for the real-time operating reliability of the transmission assets in their separate TOP Areas. Dukes' TOPs have the authority to take certain actions to ensure that they operate reliably. As registered TSPs, Duke administers the FERC-approved OATT for the separate Duke transmission zones and provides transmission service to transmission customers under applicable transmission service agreements. *Id*. In response to a question from Chair Mitchell, Duke witness Peeler explains that Duke developed and modeled the Carbon Plan assuming consolidation of these system operations. Tr. vol. 16, 25; *see also* tr. vol. 7; Duke Proposed Carbon Plan, App. E, 8.

On behalf of the Carolina Utilities Operations Panel, witness Peeler explained that Duke proposes to consolidate system operations — including the BA, TOP, and TSP operating functions — through a merger of DEC and DEP. Tr. vol. 15, 24. Witness Peeler explained that consolidated operations provide a number of customer benefits, including lowering reserve requirements, improving dispatch efficiencies, reducing carbon dioxide emissions, and allowing more solar generation to serve Duke's customers. *Id.* According to witness Peeler, combining into a single BA to manage load and resources produces savings annually for customers, helps accommodate expanded levels of variable renewable energy resources, substantially reduces forced solar curtailment, and eliminates several hundred annual CT starts that increase fleet maintenance costs. Tr. vol. 7, Duke Proposed Carbon Plan, App. R, 2; tr. vol. 15, 24. Witness Peeler explained that each of these improvements provides annual direct benefits to customers in the form of lower fuel costs and reduced carbon dioxide emissions. *Id.* Accordingly, the Modeling and Near-Term Actions Panel confirmed that the Carbon Plan assumes consolidated system operations in its modeling. Tr. vol. 7, 292; Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 8.

Witness Peeler explained that Duke believes a merger of DEP and DEC is the best long-term path to achieve the benefits of consolidated operations for a number of reasons, including addressing rate differences between DEC and DEP over time, helping to moderate rate impacts by spreading new investments over a larger customer base, reducing complexity, and achieving regulatory efficiency. Tr. vol. 15, 25.

Importantly, witness Bateman explained that a merger is the most straightforward and direct way to address rate differences between DEC and DEP. *Id.* at 29. According to witness Bateman, if stakeholders and regulators can agree on an approach that is equitable to all jurisdictions, customer classes and Duke, and a merger receives the necessary approvals, there are various approaches to preventing further rate divergence and addressing historical differences between DEP and DEC. *Id.* at 30. Duke could adopt the approach taken by Florida Power & Light, conducting cost of service studies for both the standalone and merged entities, and proposing a rider that would move the rates from the standalone cost of service study for each utilities' customers to the combined one over a five-year period. *Id*. In the alternative, Duke could create a combined cost of service study with one rate base and combined accounting records but maintain the separate legacy rate schedules. In each rate case, the combined utility could apply the new rate increase for each customer class to the legacy rate schedules within the class and then also make further adjustments to move the rate schedules closer together over time. This approach leaves more flexibility to consider other factors in each rate case rather than committing to a fixed five-year schedule and is consistent with how Duke currently addresses rate schedules that vary from the cost of service within a rate class. This is similar to the approach that DEC took after the merger with Nantahala Power & Light Company. *Id.* at 31.

Witness Bateman noted that these two options address base rates, but Duke will also have to propose how to combine the riders, the most impactful of which will be the fuel riders. As witness Bateman explained, the jurisdictional shifts in cost would happen right away, but the Commission would have discretion on how quickly to merge the DEC and DEP rates within the retail jurisdiction. *Id.* at 22.

In addition to merging the rates, witness Bateman noted that there are numerous complexities that Duke will need to be worked through before fully merging the rate schedules. For example, DEC currently offers voltage differentiated rates for commercial and industrial customers while DEP does not. DEC's fuel rates are differentiated between commercial and industrial, not by rate schedule. DEP fuel rates follow the rate schedules and are not different between commercial and industrial. These are just a few examples. *Id.*

Duke is also evaluating alternatives to achieve equitable allocation of Carbon Plan costs if Duke cannot achieve the proposed merger. *Id.* at 32-33. For example, witness Bateman explained that Duke is evaluating whether DEC could own solar generation in DEP's service territory and whether DEP and DEC could jointly own offshore wind generation. *Id.* at 33-34.

Witness Bateman explained that Duke is also looking at the allocation of transmission investments. Even without a merger of DEC and DEP, CSO would require a combination of the BAs and a combined OATT rate for wholesale customers. Duke could take a similar approach in retail rates and combine the transmission costs for DEP and DEC and then allocate them back to the separate utilities based on a transmission allocation method. *Id.* at 34-35.

Public Staff witness McLawhorn testified that, on average, DEP's customers pay rates that are substantially higher than those of DEC's customers even though the Commission has found the rates of both utilities to be just and reasonable. Tr. vol. 23, 91-92. Witness McLawhorn acknowledged that some amount of rate difference is normal given that DEC and DEP are separate utilities, each possessing a unique service territory, customer base, and generation, transmission, and distribution assets. *Id.* at 92. However, witness McLawhorn expressed concern that such rate differences have grown significantly since the 2012 merger. *Id.* Witness McLawhorn noted that there are many issues that could have contributed to this growing disparity over time, but points to the impact of the significantly greater amount of solar generation developed in DEP's service territory, along with associated transmission and distribution system upgrades, as a likely significant driver of the current disparity. *Id.* at 93.

Witness McLawhorn noted that N.C.G.S. § 62-110.9 presents a state-wide mandate to achieve a 70% reduction in carbon dioxide emissions from 2005 levels by 2030 and carbon neutrality by 2050, including through the development of additional significant amounts of solar and other renewable generation. According to witness McLawhorn, DEP's service territory will continue to be the likely location for much, if not all, of the solar, Solar Plus Storage, and onshore wind resource development, and any offshore wind generation will require significant transmission development and upgrades on DEP's system. *Id.* at 96. Witness McLawhorn expressed concern that DEP's retail customers will absorb a disproportionate share of the costs to achieve statewide compliance with the Carbon Plan without action to address the growing rate differences. Witness McLawhorn further noted that it may become increasingly difficult to recruit new economic development into DEP's service territory, and the higher electricity costs will likely drive out existing business. *Id.* at 97.

To address these concerns, witness McLawhorn stated that "the most efficient way to achieve a least cost Carbon Plan is through a full merger of DEC and DEP." *Id.* at 91. Witness McLawhorn stated that the Public Staff recommends that the Commission order the utilities to begin implementing plans to merge DEC and DEP into a single utility as soon as reasonably practicable. *Id*. at 102. In addition, the Public Staff recommends that the Commission instruct Duke to take immediate steps to allocate all Carbon Plan costs proportionately between DEC and DEP to ensure that DEP customers to not disproportionately bear costs Duke incurs to achieve system-wide carbon dioxide emissions reduction. Finally, the Public Staff recommends that the Commission require Duke to work with the Public Staff and other interested intervenors to develop a plan for this allocation. *Id.* At the hearing, witness McLawhorn stated that the merger timeline presented by Duke appears reasonable. *Id*. at 145.

On behalf of the AGO, witness Burgess stated that he supports the proposal to consolidate Balancing Authorities (BAs) for a variety of reasons, including that it will aid in the integration of variable resources, improve operational efficiency, reduce related operating costs, and enhance reliability. Tr. vol. 25, 303. NCEMC witness Fall similarly stated that NCEMC supports the proposed consolidation of DEC and DEP system operations. Tr. vol. 23, 308. Witness Fall noted that consolidation of system operations presents a broad range of customer benefits, including operational efficiencies and cost savings benefiting transmission customers. Witness Fall further acknowledged that a merger of DEC and DEP presents even greater overall potential benefits to Duke's retail and wholesale customers. *Id.* Further, witness Fall stated that the merger timeline Duke witness Bateman presents appears reasonable. Ultimately, witness Fall stated that NCEMC recommends that the Commission issue a procedural order to establish a process for stakeholder engagement and reporting timelines consistent with the schedule Duke proposes. *Id.* at 308-09.

In her rebuttal testimony, witness Bateman reiterated that one of the primary reasons for the current and historic rate differences between DEC and DEP is fuel costs. Tr. vol. 28, 54. DEC has a higher percentage of low fuel cost nuclear generation than DEP has. In addition, due to its geographic location, DEP has higher fuel transportation costs than DEC does. These fuel differentials have led to DEP having higher avoided cost rates than DEC, which has contributed to DEP's higher volume and cost of Public Utility Regulatory Policies Act (PURPA) contracts, and to a higher DSM/EE rate. *Id.* Witness Bateman agreed with Public Staff witness McLawhorn that these types of differences can be expected based on unique characteristics of each utility. Witness Bateman additionally noted that while DEP's rates are higher than DEC's, they are still below the national average. *Id*. In response to a question from Commissioner Clodfelter, witness Bateman explained that the existing rate difference is not the result of something that Duke has done wrong or that Duke should have been working to remediate since the time of the merger. *Id.* at 100. Instead, as Public Staff witness McLawhorn acknowledged, the disparity is the result of a variety of regulatory requirements with which DEP had to comply, such as the purchase of solar PPAs under PURPA. *Id.* at 100-01. In response to questions from Chair Mitchell at the hearing, witness Bateman stated that Duke has sought to make DEC's and DEP's rates as low as possible, not more even. According to witness Bateman, one utility subsidizing the other would violate Duke's Regulatory Conditions Code of Conduct. In other words, Duke does not charge DEC customers more to make the rates more even. *Id*. at 111. Witness Bateman agreed with witness McLawhorn that because N.C.G.S. § 62-110.9 is a statewide policy, the cost of complying should be spread more evenly across DEC and DEP. *Id*. at 102. Witness Bateman explained that four of the six Carbon Plan portfolios reduce the rate difference in 2026, and the other two increase the rate difference by just 8 cents per MWh and 55 cents per MWh, respectively. *Id.*

Looking to the future, witness Bateman stated that Duke agrees with witness McLawhorn that merger is the most straightforward way to address rate differences. Nevertheless, witness Bateman explained that Duke does not believe an interim cost allocation is necessary given the timing of the Carbon Plan investments and the timing of the merger. *Id.* at 56. Witness Bateman explained that the projected impact of Carbon Plan investments on current rate differences prior to the targeted merger date of the end of 2026 is “minimal to non-existent.” *Id.* Given that, Duke believes that attention and resources should be devoted toward pursuing the potential merger rather than pursuing a stop-gap method for cost allocation that is not necessary at this time. *Id*.

Based upon the foregoing and the entire record in this proceeding, the Commission finds that it may be appropriate for Duke to pursue a merger of DEC and DEP according to the timeline set forth in the panel testimony of Duke witnesses Peeler and Bateman; however, the Commission will not prematurely judge the prudency of such a merger proposal and will only consider such when an application is properly before the Commission. Until such a time, the Commission directs Duke to take reasonable steps to mitigate further exacerbation of the rate disparity between DEC and DEP attributable to the Carbon Plan by presenting solutions where appropriate, including but not limited to in its pending general rate case applications.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 64-65

Present Value Revenue Requirements

The evidence supporting these findings of fact and conclusions is in Duke’s Carbon Plan proposal, the testimonies of Duke’s Modeling and Near-Term Actions Panel, Duke witness Bateman, Public Staff witnesses Metz and McLawhorn, CUCA witness O’Donnell, and CIGFUR witness Muller, and the entire record in this proceeding.

In its Carbon Plan proposal, Duke presented the PVRR and bill impact calculations it used to compare the relative costs of the various Carbon Plan portfolios. Tr. vol. 7, Duke Carbon Plan, App. E, 81-83. Duke witness Quinto with the Modeling and Near-Term Actions Panel stated that the PVRR is a comparison metric only and is not useful for nor intended to be useful for evaluating the total cost of serving customers. Tr. vol. 7, 289. Witness Quinto further stated that the bill impact estimate, like PVRR, is a metric for comparing the cost of alternate Carbon Plan portfolios and that Duke did not develop it for the purpose of estimating the future total cost of serving customers. *Id.* at 289-90. Finally, witness Quinto stated that including costs that are common across all portfolios would obscure differences that do exist across portfolios and make them appear less significant. *Id.* at 290.

Public Staff witness Metz disagreed with the exclusion of SLR costs from the bill impact calculations. Tr. vol. 21, 138. Public Staff witness McLawhorn testified that the Public Staff does not have concerns with Duke’s calculations of PVRR and retail bill impacts. Witness McLawhorn stated that because Duke did not include costs that are common across all portfolios in the bill impact analysis, he believes it is likely that Duke substantially understated the rates. He further stated that in the future, Duke should provide bill impacts in two ways — a comparative analysis between portfolios as Duke has provided, as well as “all-in cost” bill impacts. Tr. vol. 23, 106-08.

CUCA witness O’Donnell and CIGFUR witnesses Gorman and Muller agreed with the Public Staff’s request for an all-in cost bill impact analysis. Tr. vol. 22, 43-44; tr. vol. 25, 220, 352-56.

In rebuttal testimony, Duke witness Bateman testified that Duke's presentation of the rate impacts with only revenue requirements the individual portfolios cause was consistent with how it had traditionally presented PVRRs in its IRPs. She also noted that all-in cost forecasts of future bill impacts would inevitably be incorrect due to the many factors over which Duke has no or limited control, such as interest rates, inflation, fuel costs, government regulations, amortization periods for deferred costs, etc. Witness Bateman stated that she is not aware of any utility in the country that develops such long-term, all-in cost forecasts. She testified that in discovery, Duke asked the Public Staff, CIGFUR, and CUCA to provide any all-in cost forecasts that they are aware of from other utilities. Witness Bateman commented that Duke did not receive any such forecasts from these intervenors in response to the discovery request. Tr. vol. 28, 57-60.

The Commission finds that the PVRR and bill impact calculations provided by Duke in this proceeding are reasonable for planning purposes and provide a helpful tool to compare the relative benefits of the different portfolios. The Commission notes that the focus of this proceeding and future Carbon Plan proceedings is on evaluating various portfolios in order to determine the least cost path, subject to other statutory mandates, to achieve the carbon dioxide emissions reduction mandates. Although the Commission understands the Public Staff's, CIGFUR's, and CUCA's desire for Duke to provide all-in cost PVRR and bill impacts in its Carbon Plans that present the total cost of electricity ratepayers will pay as Duke implements the Carbon Plan, the Commission gives significant weight to the testimony of Duke witness Bateman that there are substantial uncertainties associated with projecting all-in costs for an extended future period. Further, neither Duke nor any other party was aware of any other utilities providing such all-in forecasts. Thus, the Commission determines that Duke does not have all the information that it would require to provide the Commission realistic and meaningful long-term, all-in cost bill impact projections. The Commission also gives significant weight to the testimony of Public Staff witness McLawhorn in which he states that the Public Staff does not have any concerns with Duke's calculations of PVRR and bill impacts in this proceeding and consequently concludes that the PVRR and bill impact analyses provided by Duke are sufficient for evaluating and comparing the relative benefits of the various portfolios Duke presents in the Carbon Plan proposal.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

Environmental Justice and Impacted Communities

The evidence supporting this finding of fact and conclusions is in the direct testimony of Duke witness Bowman and the entire record in this proceeding.

In recognition of the impact the provision of electric service and the transition to carbon dioxide neutrality will have on communities, Duke conducted targeted stakeholder engagement. Specifically, Duke convened a small group of environmental justice – focused stakeholders on May 3, 2022, and August 2, 2022, to discuss how to engage North Carolina communities and to understand what issues are important to low-income ratepayers and communities of color. Tr. vol. 7, 49. Each meeting included approximately ten stakeholders, representing a variety of interests, including health, environmental, and economic impacts of the Carbon Plan. *Id*. Duke explains that the stakeholder engagement effort will be ongoing and will involve a select number of individuals committed to working together with Duke to explore these complex issues and identify areas for potential partnership and progress. *Id*.

RTHC et al. express significant concern regarding the sufficiency of Duke's outreach towards — or accessibility to — low-income, minority, and rural communities, both in terms of quality of the outreach as well as timing of the outreach. They highlight for the Commission that "that only those living in impacted communities can capture the full range of the lived experience." RTHC et al. Partial Proposed Order at 6-7, 10.

Duke also held an Impacted/Frontline Communities stakeholder meeting on May 5, 2022, to initiate engagement with communities that Duke expects future coal retirements to impact. Tr. vol. 7, 49. Person County advocates that the Commission require Duke to provide community support, including workforce development and charitable contributions, to communities like Person County, which the transition will likely impact. Person County Partial Proposed Order at 11-12.

The Commission recognizes the extent of the stakeholder outreach Duke conducted in conjunction with this initial Carbon Plan proceeding and recognizes that the limitation of time was a very real constraint on Duke's ability to expand its engagement to all potentially impacted stakeholders. Duke understands that continued and expanded engagement will be necessary going forward, in order to hear from and respond to those communities uniquely impacted by the transition to a carbon neutral electric system. Tr. vol. 7, Duke Proposed Carbon Plan, App. B, 22-23. Accordingly, the Commission directs Duke to continue to develop targeted engagement plans for impacted communities, to enact these plans in the near term and to report to the Commission on these plans and the ensuing engagement with stakeholders in its upcoming CPIRP filing.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke shall file its first proposed biennial CPIRP by no later than September 1, 2023;

2. That Duke shall engage with the Public Staff and any interested stakeholders to draft a new proposed Commission rule governing CPIRP, subject to the following parameters, and file the proposed rule with the Commission by no later than April 28, 2023, in a new and separate proceeding:

a. By September 1, 2023, and every two years thereafter, Duke shall file with the Commission its proposed biennial CPIRP, including the testimony and exhibits of expert witnesses. At the time of the filing, Duke shall provide complete modeling input and output data files to intervenors. Each proposed biennial CPIRP shall include a proposed near-term action plan discussing the specific actions Duke recommends taking over the near term following the Commission's final order on the proposed CPIRP;

b. No later than 180 days after the later of either September 1 or the filing of Duke's proposed biennial CPIRP, the Public Staff or any other intervenor may file testimony and exhibits of expert witnesses commenting on, critiquing, or giving alternatives to Duke's proposed CPIRP;

c. No later than 45 days after the filing of intervenor testimony and exhibits, Duke may file its rebuttal testimony and exhibits of expert witnesses;

d. The Commission shall schedule an expert witness hearing to review the CPIRP proposals beginning on the second Tuesday in May following Duke's proposed biennial CPIRP filing, and shall set one or more hearings to receive testimony from the public at a time and place of the Commission's designation; and

e. The proposed rule filing shall also propose a separate mechanism for the filing and review of annual compliance plans that DEP and DEC previously filed with their respective IRP filings;

3. That to meet the Interim Target, Duke shall be required to reduce the carbon dioxide emitted by the electric generating facilities sited within North Carolina that it owns, operates, or that are operated on its behalf to 22,759,556 short tons of carbon dioxide;

4. That Duke shall incorporate the impacts of the IRA, the IIJA, and other future legislative changes, as well as the impacts of other changing conditions such as inflationary pressures, into its first biennial CPIRP that it will file with the Commission on or before September 1, 2023, and into any CPCN applications it files in the interim;

5. That in its first proposed biennial CPIRP Duke shall make all reasonable efforts to maximize its modeling optimization period, and seek to model a 15-year, or greater, optimization period;

6. That in its first proposed biennial CPIRP Duke shall model Solar Plus Storage resources using dynamic dispatch and bi-directional inverter capability, subject to modeling limitations. Furthermore, Duke and the Public Staff shall work together closely on modeling Solar Plus Storage resources during the next proceeding and, if they do not reach consensus on modeling techniques, each shall provide a robust explanation to the Commission as to the points of disagreement and agreement;

7. That in its first proposed biennial CPIRP Duke shall make all reasonable efforts to model storage resources in the capacity expansion and production cost modeling steps without manual adjustments, subject to modeling limitations, and if such limitations remain, that Duke shall develop robust cost sensitivity analyses that clearly demonstrate the cost impacts of potential resource replacement;

8. That Duke shall proactively address risks to system reliability in its upcoming first proposed biennial CPIRP, including but not limited to engaging with the Public Staff in leveraging actual operational experience to continue to plan for the future, mitigate foreseeable risk, and prepare for the challenges ahead;

9. That Duke shall take appropriate steps to optimally retire its coal fleet on a schedule commensurate with its Carbon Plan proposal filed on May 16, 2022;

10. That in determining the least cost path for ratepayers, Duke shall evaluate whether securitization of eligible costs related to subcritical coal-fired units will maximize ratepayer savings;

11. That Duke shall re-study the potential costs and benefits of a further conversion of Belews Creek and provide the results in its initial CPIRP filing;

12. That Duke shall continue to pursue SLR for its existing nuclear fleet and shall develop a schedule detailing its plans for SLR of the existing nuclear fleet and provide this information in its upcoming CPIRP filing;

13. That Duke shall continue to review the NRC SLR regulatory process, paying particular attention to the two nuclear licenses that the NRC reset in early 2022, and shall incorporate any lessons learned from its review into its first proposed biennial CPIRP;

14. That Duke shall pursue expansion of flexibility of its existing natural gas fleet and target specific natural gas plants or regions of its service areas that would benefit the most from flexibility expansion projects. In its planning for the expansion of the flexibility of the existing natural gas fleet, the Commission directs Duke to identify least cost flexibility expansion projects that will improve or maintain system operability and reliability;

15. That Duke shall analyze and incorporate, in future modeling efforts, realistic assumptions regarding the availability of firm natural gas transportation capacity and shall work with the Public Staff in achieving those assumptions;

16. That Duke shall use the natural gas price forecast method approved herein in its proposed CPIRP and in subsequent avoided cost proceedings;

17. That Duke, in its CPIRP filing, shall include in its modeling efforts the costs and assumptions for natural gas-fired generating facilities operating after 2050;

18. That in any future CPCN filing for natural gas-fired generating resources, Duke shall provide an analysis of the sufficiency of firm natural gas transportation capacity for the proposed facility;

19. That during the 2023-2024 period Duke shall target the procurement of 2,350 MW of new solar;

20. That Duke shall hold stakeholder discussions regarding a competitive, least cost 2023 Solar Procurement and shall file, by than no later than February 15, 2023, a proposal to procure new solar generation to be placed in service by 2028, subject to a VAM, including a targeted procurement of Solar Plus Storage in alignment with the 2023 DISIS. Duke's proposal shall include proposed terms and conditions, operational conditions, and a pro forma PPA to be used for Solar Plus Storage resources;

21. That Duke shall file, no later than February 15, 2024, a proposal to procure the remainder of 2,350 MW of new solar generation to be placed in service by 2028, subject to a VAM, including a targeted procurement of Solar Plus Storage in alignment with the 2024 DISIS;

22. That Duke is authorized to conduct the initial development and procurement activities for 1,000 MW standalone storage and 600 MW of Solar Plus Storage, consistent with those activities outlined for the 2022-2024 timeframe in Table 4-11 of Duke's Carbon Plan proposal;

23. That Duke shall engage with onshore wind stakeholders as soon as practicable and in formulating its first biennial CPIRP, Duke shall consider onshore wind and particularly any pertinent information gleaned from its stakeholder engagement, and, to the extent that future Encompass modeling economically selects utility-owned onshore wind resources, Duke should support that proposal in detail in its first biennial CPIRP;

24. That with respect to near-term development actions for small modular and advanced nuclear reactors, Duke is hereby authorized to take steps it outlines in its proposed Carbon Plan and this authorization constitutes approval under N.C.G.S. § 62-110.7(b). Duke shall report in its first CPIRP filing on the specific activities and costs incurred to date;

25. That the Commission approves Duke's decision to incur project development costs associated with the initial project development activities proposed for new pumped storage hydro at Bad Creek II and requires Duke to report in its first CPIRP filing on the specific activities and costs incurred to date;

26. That Duke shall study and consider each of the three currently available WEAs off the coast of North Carolina, adopting steps in its evaluation process to protect against any potential affiliate bias, and report the findings of its evaluation of the WEAs to the Commission in its first CPIRP filing;

27. That Duke shall investigate and pursue any federal funding that is available, through the IIJA or the IRA or any subsequent legislation, for offshore wind facilities and associated infrastructure;

28. That, in addition to Duke's proposed UEE forecast of 1% of eligible retail sales, Duke shall provide an alternative modeling scenario in its next CPIRP filing that uses a UEE forecast of 1.5% of eligible retail sales. Further, Duke shall continue to

explore avenues to increase load reduction by implementing new DSM/EE programs, implementing EE and load reduction programs for wholesale customers, and reducing the number of non-residential customers that that have opted out of the DSM/EE program;

29. That Duke should continue to explore rate design as a load shaping tool to encourage customers to change their load profiles to support the use of new generation facilities;

30. That Duke should include, in its CPIRP filing, a separate and robust analysis on the electrification of transportation, both in terms of load projections and actions undertaken to encourage charging at off-peak times or during times of excess energy and to facilitate the location of charging infrastructure on the system that avoids or obviates the need for system upgrades;

31. That Duke shall initiate a docket to review the DEC and DEP DSM/EE cost recovery mechanisms to consider the enablers Duke proposes, including: (i) updating the inputs underlying the cost benefit test in the mechanisms; (ii) using the as-found baseline for EE measures; (iii) changing the definition of low-income customer; and (iv) developing guidelines for expedited regulatory approval of DSM/EE pilot programs;

32. That Duke shall engage with stakeholders to develop guidelines for expedited regulatory approval of customer programs and pilots for non-DSM/EE customer programs that enable load reduction or load management consistent with the Carbon Plan including rate design programs and EV programs;

33. That Duke shall take all reasonably necessary steps to construct the fourteen 2022 RZEP projects further identified herein;

34. That Duke shall make all reasonable efforts in accordance with state and Federal law to update and improve its local transmission planning process including increasing transparency and coordination;

35. That Duke shall make semi-annual reports in the CPIRP sub-docket regarding the status of transmission upgrades including timing milestone completion, and cost estimates to the Commission pursuant to Section 2.5 of Attachment N-1 of the OATT;

36. That Duke shall make all reasonable efforts to comply with the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9, but shall not alter, delay, or modify any scheduled maintenance, asset management operations, or upgrades on its system or to the delivery points of other LSEs that would negatively impact the reliability or service quality of the customers of those LSEs;

37. That to the extent Duke proposes future transmission Network Upgrades to support its Carbon Plan compliance for consideration by the NCTPC, Duke shall include an assessment of the timing, costs, and benefits of the Network Upgrades on its system as well as the systems of other LSEs, in its future CPIRP filings, and shall also include

documentation of its efforts to coordinate with all LSEs in North Carolina on these upgrades;

38. That Duke shall address the rate disparity between DEC and DEP in its upcoming DEC general rate case application in Docket No. E-7, Sub 1276, in any update filing made in its DEP general case proceeding in Docket No. E-2, Sub 1300, and shall provide an update on rate disparity in its first biennial CPIRP filing along with an update of recent actions taken to pursue the recommended merger; and

39. That Duke shall continue to develop targeted engagement plans for impacted communities, as are further discussed in conjunction with Finding of Fact No. 66, shall enact these plans in the near term, and shall report to the Commission on these plans and the ensuing engagement with stakeholders in its initial CPIRP filing.

ISSUED BY ORDER OF THE COMMISSION.

This the 30th day of December, 2022.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Chief Clerk

Commissioner Daniel G. Clodfelter concurs.

DOCKET NO. E-100, SUB 179

Commissioner Daniel G. Clodfelter, concurring:

I am in full agreement with and join in the Commission's order issued today. I write separately only to underscore one point I believe deserves emphasis. Some may be concerned that the Commission does not select or settle upon one of the various 2030 resource portfolios offered by Duke, by the Public Staff, or by several intervenor parties and members of the public. They may even think that in not doing so the Commission has failed to prepare and adopt a Carbon Plan as directed by N.C.G.S. § 62-110.9. It would be a mistake to think this.

A proposed configuration of generating and transmission resources is not a plan. It is instead simply a snapshot of how the generating and transmission resources of the electricity system might look at some instant in time — now, next year, 2030, or perhaps 2050 — whatever point in time may be selected. Looking at a proposed resource portfolio tells one nothing about how it came to be configured in just such a way at just such a point in time, in the same way that looking at a photograph tells one absolutely nothing about what it took for the image in the photograph to appear in exactly the way it did at the instant the camera's shutter clicked. But that question — "how did this come to look this way?" — is exactly the question planning must answer. Said another way, a "plan" is not the same as an "outcome." Rather, it is the organized series of actions that are required to produce an outcome. That is why I believe the Commission has correctly centered its initial response to the directive in N.C.G.S. § 62-110.9 on the series of actions that must be undertaken today and in the succeeding two years before the next biennial review in order to achieve the targeted reductions in carbon dioxide emissions mandated by the General Assembly in N.C.G.S. § 62-110.9.

Anyone not persuaded that this is so might try thinking about planning in a more familiar context. Suppose you are intending a vacation to Europe, and I ask you to tell me about your travel plan. In response you excitedly pull out and show me a photograph of the Eiffel Tower, and then one of Big Ben, and perhaps also one of the Colosseum in Rome. That's my plan, you say. I would certainly reply that I understood *where* you are going, but I really want to know something about your plan for the trip. Will you fly or will you take a longer and more exotic ocean voyage? If you are flying, will you be able to get a direct flight or will you have to make connections? Will you be staying in hotels or perhaps in private bed and breakfasts? Are you travelling with a group and a guide or will you make up your own itinerary? Will you have time for any side excursions, or will you just visit the main tourist sites? And so on and so on. I know your destination, I would say, but I am interested in how it will all work out along the way so that you enjoy your trip once you get there.

This same dialogue translates to the case of a Carbon Plan. We know the destination — a 70% reduction in carbon dioxide emissions by 2030 and no net carbon dioxide emissions by 2050. That has already been set by the General Assembly. But merely picking a mix of resource and transmission assets for 2030 and then another set for 2050 is not planning and does not constitute a plan; it is no different from your showing me your picture of the Eiffel Tower and calling it the "plan" for your trip to Europe. The General Assembly understood this. It did not direct the Commission to select a portfolio of resources and call it a "carbon plan"; instead, it directed the Commission to "take all reasonable steps" to achieve specific reductions in carbon dioxide emissions by the target dates, and it is those "reasonable steps" that constitute the Carbon Plan. Certainly, if the Commission and the utilities succeed in fulfilling their charge, the mix of generation and transmission resources will have a particular configuration in 2030 and another in 2050. Those will be the "resource portfolios" as of those dates. But as the record amply demonstrates, there is no single, unique resource portfolio that satisfies the required emissions reduction goals, just as there is no single picture — not the Eiffel Tower alone or the Colosseum alone — that is "Europe."

The travel analogy is apt for a second reason. You intend your vacation in Europe to be an extended one, perhaps several weeks long. Over that time many things will unfold that you cannot presently foresee. Depending on the time of year or your choice of destinations, you may have to pack clothes for highly variable weather conditions. Depending on such things as weather, public health concerns, labor disputes, or similar causes, you may have to deal with cancellations, delays, reschedulings, or closures. Depending on the vagaries of business cycles or financial markets, you may have to be prepared for price increases since the time you made your initial bookings and reservations or for currency fluctuations that will affect the cost of things once you arrive at your travel destinations. Your first steps in planning your trip should be those that will best preserve the flexibility you will need to accommodate those uncertainties and deal with unanticipated events if and when they arise over the course of your travels. You must think, for example, about whether you want to book the cheaper ticket that is nonrefundable and cannot be changed, or whether instead you want to purchase a more costly but more flexible fare option. You must decide whether you want to risk driving in what could be difficult mountain terrain and in possibly bad weather, or whether perhaps a more relaxed rail pass is a better way to see Switzerland. The more distant your actual departure date is from the time you are making your plan, the more likely such uncertainties must be taken into account in your planning.

For the first, 2022, iteration of the Carbon Plan the Commission has likewise chosen to emphasize those initial steps that are foundational to every possible itinerary and every possible route to the ultimate carbon-free destination, the ones that offer the most flexibility as the journey progresses and present the least risk of later, and perhaps costly, disappointment. I believe this is the most responsible way, and indeed the only responsible way, to proceed on a journey that starts today and will span the next twenty-eight years until 2050. I fully concur in the Commission's order issued today.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

Exhibit 3 SUPPLEMENTAL

EQUIPMENT AND COST INFORMATION

3.1 Estimated Construction Costs

The estimated cost of the Asheville Solar Facility is approximately $24.3MM

3.2 Estimated Construction Costs Expressed as $/MW

Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3.3 Estimated Annual Operating Expenses by Category

Average annual operating expense is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3.4 Estimated Annual Operating Expenses Expressed as $/MWH

Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** averaged over 35 years.

3.5 Projected Cost of Major Components and Schedule for Incurring Costs

[BEGIN CONFIDENTIAL]

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[END CONFIDENTIAL]

3.6 Utility Revenue Requirement During Construction

The Construction Work in Progress for this project will not be included in rate base, but instead will accrue AFUDC of $854,000. Therefore, there should be no impact on revenue requirements during the construction period.

3.7 Anticipated In-Service Expenses During the First Year

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**.

3.8 Anticipated Impact on Customers Rates. Estimated Construction Costs

The annual North Carolina retail revenue requirement for Year 1 of operation is estimated to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which would result in an approximate average retail rate increase of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Exhibit 3 SUPPLEMENTAL

EQUIPMENT AND COST INFORMATION

3.1 Estimated Construction Costs

The estimated cost of the Asheville Solar Facility is approximately ~~[BEGIN CONFIDENTIAL]~~ $24.3MM ~~[END CONFIDENTIAL].~~

3.2 Estimated Construction Costs Expressed as $/MW

Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3.3 Estimated Annual Operating Expenses by Category

Average annual operating expense is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

3.4 Estimated Annual Operating Expenses Expressed as $/MWH

Approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** averaged over 35 years.

3.5 Projected Cost of Major Components and Schedule for Incurring Costs

[BEGIN CONFIDENTIAL]

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[END CONFIDENTIAL]

3.6 Utility Revenue Requirement During Construction

The Construction Work in Progress for this project will not be included in rate base, but instead will accrue AFUDC of $854,000. Therefore, there should be no impact on revenue requirements during the construction period.

3.7 Anticipated In-Service Expenses During the First Year

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**.

3.8 Anticipated Impact on Customers Rates. Estimated Construction Costs

The annual North Carolina retail revenue requirement for Year 1 of operation is estimated to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which would result in an approximate average retail rate increase of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Exhibit 4 SUPPLEMENTAL

<u>CONSTRUCTION SCHEDULE AND OTHER FACILITY INFORMATION</u>

4.1. Anticipated Construction Schedule

Should the Commission approve the CPCN request, the Ashville Plant Solar Facility, construction would be targeted to allow for commission of the project by September of 2025, assuming timely authorization to procure major equipment and obtain necessary permits and approvals. A more detailed preliminary schedule can be seen below.

Activity Name	**Milestone Date**
Notice to Proceed	Q4 2024
Engineering/Procure Equipment	Q3 2023 – Q4 2024
Site Mobilization	Q4 2024 / Q1 2025
Placed in Service	September 2025
Final Commission	Q1 2026

4.2. Additional Generating Facility Information

The specific equipment suppliers have not been selected at this time for every component. However, the following is a preliminary description of the major components of the Asheville Plant Solar Facility.

Solar Array

The solar array is expected to consist of 1,106 strings of 430W modules for a total capacity of 12.8 MWdc.

Racking System

A fixed tilt racking system will be used to mount the modules. The racking will be set at a fixed tilt of 20°.

Solar Power Conversion Devices

Duke Energy plans to use a total of 13 TMEIC PVU-L0840GR inverters. Each sting inverter has a capacity of 840 kW to meet the net export capacity of 9.5 MW.

4.3. Qualifications and Selection Process for Principal Contractors

The Company plans to issue a competitive request for proposals ("RFP") to competitively source the EPC and major equipment to execute the project as cost-effectively as possible for customers. These activities are planned for the second half of 2023.

4.4. Risk Factors Related to the Construction and Operation of the Generating Facility.

There would be no additional risk for the construction or operation of this solar facility compared to other facilities owned or operated by Duke Energy. In response to Public Staff's request that the Company address potential construction risks given that the site is in the mountains; is subject to cold weather, fog and snow, as well as the timing of the projected spend, Duke Energy Progress states:

> The Company's proposed schedule accounts for potential winter weather delays in that the work within Q4 2024 and Q1 2025 is primarily receiving and staging materials and installing racking components. These activities are less likely to be impacted by inclement weather.

In response to Public Staff's request that the Company provided a verified statement that the facility will be capable of operating at -16 degrees Fahrenheit – the lowest recorded temperature at the site – and the performance of the facility if the calculated wind chill at the site is lower than -16 degrees Fahrenheit, Duke Energy Progress states:

> PV modules are rated for extreme temperatures with manufacturer data indicating performance at -40°C (-40°F) without issue. PV modules actually perform better at lower temperatures. Inverters are rated to -25°C (-13°F) for normal operations and may enter a standby mode at temperatures lower than the operational range. Standby temperatures mode is rated to -40°C (-40°F). Equipment is unaffected by wind chill and cannot be colder than the ambient air temperature.

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