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Transmission System Planning and Grid Transformation

Highlights

- Planning and constructing necessary transmission infrastructure is critical for implementing the Carolinas Resource Plan. This infrastructure is needed to ensure power supply reliability, to enable interconnection of new generating facilities and energy storage resource additions necessary to replace retiring resources, as well as to meet expected load growth.

- The Companies are working with other participating load-serving entities, with input from interested stakeholders, to evolve the Local Transmission Planning process to meet the changing energy landscape through increasing transparency and coordination and through process improvements that identify the best value transmission expansion projects for customers.

- Several of the Red Zone Transmission Expansion Plan projects were identified as needed in the 2022 Definitive Interconnection System Impact Study Phase 2 study for interconnecting Carolinas Resource Plan resources, and the Red Zone Transmission Expansion Plan projects will continue to provide benefits for customers and resource plan execution.

- To meet the challenge of interconnecting significant supply-side resources required by the Carolinas Resource Plan while ensuring adequacy and reliability of the existing grid is maintained or improved, Duke Energy will utilize the new annual Definitive Interconnection System Impact Study Cluster Study process and work through the Federal Energy Regulatory Commission jurisdictional transmission planning process to build out the transmission grid over time to meet Carolinas Resource Plan and reliability needs.

Transmission Planning in a Changing Energy Landscape

This Appendix discusses transmission system requirements and associated cost estimates related to the Carolinas Resource Plan for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") and, together with DEC, "Duke Energy" or the "Companies"). Planning and constructing needed transmission infrastructure to ensure power supply reliability and provide for resource supply additions necessary to replace retiring resources, as well as to meet expected load growth, are critical path processes for implementing DEC and DEP's resource plans.

This Appendix discusses transmission system adequacy and future 100 kilovolts ("kV") and above transmission needs to accommodate resource supply additions necessary to replace retiring resources, improve resiliency and reliability, enable siting of new resources and support load growth and economic development. Current utility local and regional transmission planning processes and planned revisions to those processes will be discussed, as well as transmission system needs and projects identified in the most recent local transmission planning report.[1] These transmission planning processes are critical to plan for transmission needs, to determine lead times for construction, to ensure transmission projects meet in-service dates, to ensure reliability and to provide for resource supply additions necessary to replace retiring resources, as well as to meet load growth and economic development.

In 2021, DEC and DEP evaluated the need to proactively identify and construct transmission network upgrades that repeatedly impeded generation interconnection requests in the high solar viability "red zone" areas of DEC and DEP transmission systems. This evaluation led to the identification of 18 Red Zone Transmission Expansion Plan ("RZEP") projects needed for reliability and resiliency during the energy transition, as well as integration of solar generation. 14 of the 18 RZEP projects were acknowledged as needed by the North Carolina Utilities Commission ("NCUC") in the 2022 Carbon Plan Order[2] and were subsequently approved to be included as part of the 2022–2032 local transmission plan in accordance with the Federal Energy Regulatory Commission ("FERC")-approved DEC and DEP Joint Open Access Transmission Tariff ("OATT"). Furthermore, in 2022, DEC and DEP developed strategic plans to seek FERC approval of a generation replacement process that would retain the interconnection rights of large generators being retired for the benefit of customers that had previously funded the transmission system upgrades to interconnect the retiring facilities. FERC accepted the generation replacement process in September 2022, and DEC and DEP are implementing it today. This Appendix will discuss how both achievements are now being leveraged in the execution of the Carolinas Resource Plan (the "Plan" or "the Resource Plan") for the benefit of customers.

[1] North Carolina Transmission Planning Collaborative, Report on the NCTPC 2022–2032 Collaborative Transmission Plan, February 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf.

[2] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No E-100, Sub 179 (Dec. 30, 2022) ("Carbon Plan Order").

Transmission planning, expansion and planning process reform are also critical to the success of identifying transmission system needs and evaluating alternative solutions to arrive at transmission plans that have material benefit-to-cost ratios and that benefit load-serving entity and customer reliability, as well as economic development and support Resource Plan implementation. Foundational to this planning, expansion and process reform is the outcome that the Companies' transmission systems are designed and operated to ensure adequate and reliable service to DEC's and DEP's customers while meeting all regulatory requirements and standards.

Existing Transmission Systems of DEC and DEP

DEC and DEP are each Transmission Owners[3] and Transmission Service Providers that independently own and operate transmission systems and provide transmission service under their OATT, which is filed with FERC.[4] DEC has approximately 12,957 miles of transmission and sub-transmission lines[5] in North Carolina and South Carolina at voltages ranging from 44 kV to 500 kV. DEP has approximately 6,306 miles of transmission lines in North Carolina and South Carolina at voltages ranging from 69 kV to 500 kV. Table L-1 below provides DEC's and DEP's installed transmission by voltage.

Table L-1: DEC and DEP Installed Transmission Circuit Lines by Voltage (in miles)

Circuit Voltage	44 kV	66–69 kV	100–199 kV	230 kV	500 kV
DEC	2,752	121	6,848	2,660	576
DEP	-	12	2,569	3,433	292

Table L-2 below identifies DEC's and DEP's transmission lines and associated facilities 100 kV and above that are under construction or for which DEC or DEP have approved specific plans for construction. In addition, Table L-2 reflects new transmission voltage class transformers planned or under construction. As discussed further below, DEC and DEP participate in FERC-regulated local, regional and interregional transmission planning processes and annually assess the reliability and adequacy of the interconnected transmission system to ensure the system is adequate to meet customers' electrical demands both in the near-term and long-term planning horizons. These transmission planning processes also encompass planning to satisfy generation resource additions and retirements, as well as increased load requirements. The Companies also identify the need for construction of new or upgraded transmission facilities through generator interconnection studies and transmission service requests in adherence to the FERC-approved joint OATT for DEC and DEP.

[3] Capitalized terms not defined herein are defined in the Companies' OATT.

[4] FERC, Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC Duke Energy Florida, LLC and Duke Energy Progress LLC, available at https://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf.

[5] Transmission voltage levels – 69 kV–500 kV; sub-transmission voltage levels 44 kV and below.

Table L-2: DEC and DEP Transmission Under Construction or Approved for Construction[6]

DEC/DEP	Year	From	To	Voltage (kV)	Capacity (MVA)	New/Upgrade
DEC	2024	Aquadale PV (50 MW)		100		New
DEC	2024	Blackburn PV (60.1 MW)		100		New
DEC	2024	Brookcliff PV (50 MW)		100		New
DEC	2024	Hornet PV (75 MW)		100		New
DEC	2024	IBM Tap	GE Aircraft Tap	100	200[1]	Upgrade
DEC	2024	Mebane Tie	Piedmont EMC 10	100	143	New
DEC	2024	Newberry PV (74.5 MW)		100		New
DEC	2024	Oakboro PV (40 MW)		100		New
DEC	2024	West River PV (40 MW)		100		New
DEC	2024	Wilkes 230/100 kV Transformer		230/100	448	New
DEC	2024	Woodruff Tie	BMW	100		New
DEC	2025	Allen 230/100 kV Transformer (2)		230/100	448	Upgrade
DEC	2025	Cliffside	Peach Valley Tie	100		Upgrade
DEC	2025	Healing Springs PV (55 MW)		100		New
DEC	2025	Hodges Tie	Coronaca Tie	100	450	Upgrade
DEC	2025	Lee	Shady Grove (Lee Lines)	100	368[1]	Upgrade
DEC	2025	Newberry Main	DESC Saluda	115	278[1]	Upgrade
DEC	2025	North Greenville 230/100 kV Transformer		230/100	448	Upgrade
DEC	2026	Boyd Switching Station		230		New
DEC	2026	Bush River Tie	Laurens Tie	100	368[1]	Upgrade
DEC	2026	Creto Tie	Coronaca Tie	100	404	New
DEC	2026	Hass Creek Switching Station		230		New
DEC	2026	Hilltop Tie	Shelby Tie	100		Upgrade
DEC	2026	Lee	Shady Grove (Piedmont Lines)	100	368[1]	Upgrade
DEC	2026	Lyle Creek Switching Station		100		New
DEC	2026	North Greensboro Tie	Greensboro Main (Page)	100	368[1]	Upgrade
DEC	2026	North Greensboro Tie	Greensboro Main (Guilford)	100	368[1]	Upgrade
DEC	2026	Oakvale Tie	East Greenville	100		Upgrade
DEC	2026	Statesville Tie	Perth Road	100		New
DEC	2026	Wylie	Indianland Ret	100		New
DEC	2026	Wylie Hydro	Woodlawn Tie	100	240	Upgrade
DEC	2027	Lancaster Main	Monroe Main	100	242	Upgrade
DEC	2028	Dixon School Road	New Customer	230		New
DEC	2028	Harrisburg Tie	Amity	100		Upgrade
DEC	2028	Lakewood Tie	Woodlawn Tie	100		Upgrade
DEC	2028	Lee CC	Lee Steam	100	484	New
DEC	2028	Mebane Tie	Pleasant Garden Tie	100		Upgrade
DEC	2028	Oak Hollow Switching Station		100		New
DEC	2028	Shelby Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Concord Main	Winecoff Tie	100		Upgrade
DEC	2029	Concord Main	Harrisburg Tie	100		Upgrade
DEC	2029	Harrisburg Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Hodges 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Newport Tie	Morning Star Tie	230	421	New

[6] Table L-2 lists projects 100 kV and above pursuant to Rule R8-60(ii) that are under construction or approved by Duke Energy for construction.

DEC/DEP	Year	From	To	Voltage (kV)	Capacity (MVA)	New/Upgrade
DEC	2029	Tiger Tie 230/100 kV Transformer		230/100	448	Upgrade
DEC	2029	Wildcat Tie	Westfork	100		Upgrade
DEC	2030	Dan River	N Greensboro	100	242[1]	Upgrade
DEC	2030	Lawsons Fork	W Spartanburg	100		Upgrade
DEC	2030	North Greenville	Marietta	100	484	Upgrade
DEC	2030	Research Triangle	Ellis Rd	100		Upgrade
DEC	2030	Shelby Tie	Cliffside	100		Upgrade
DEC	2031	Marshall Ret	Lookout Tie	100		New
DEC	2031	McGuire	Marshall	230		Upgrade
DEC	2032	Morning Star 230/100 kV Transformer (3)		230/100	448	Upgrade
DEC	2033	Dan River	Sadler (Wolf Creek)	100	242[1]	Upgrade
DEC	2033	Dan River	Sadler (Reidsville)	100	242[1]	Upgrade
DEC	2034	Winecoff Tie	Conley	100	484	Upgrade
DEP	2023	Havelock 230/115 kV Transformers		230/115	336	Upgrade
DEP	2023	Pig Basket Creek PV (80 MW)		230		New
DEP	2023	Porters Neck Tap	Porters Neck	230	442	New
DEP	2023	Wateree 115/100 kV Transformers (2)		115/100	336	Upgrade
DEP	2024	Camden	Camden Dupont	115	313	Upgrade
DEP	2024	Loftins Crossroads PV (75 MW)		230		New
DEP	2025	Arden Tap	Arden	115	280	New
DEP	2025	Carthage 230/115 kV Transformer Substation		230/115	336	New
DEP	2025	Craggy	Enka	230	644	New
DEP	2025	Weatherspoon	Marion	115	313	Upgrade
DEP	2026	Camden Junction	DPC Wateree	115	313	Upgrade
DEP	2026	Cape Fear	West End	230	1195	Upgrade
DEP	2026	Castle Hayne	Folkstone	115	296	Upgrade
DEP	2026	Erwin	Fayetteville East	230	1195	Upgrade
DEP	2026	Fayetteville	Fayetteville Dupont (4.9 miles)	115	313	Upgrade
DEP	2026	Holly Ridge North 115 kV Switching Station	JOEMC Folkstone POD	115	296	New
DEP	2026	Kingstree West PV (74.9 MW)		115		New
DEP	2026	Maxton	Pembroke	115	313	Upgrade
DEP	2026	Robinson	Rockingham	230	1195	Upgrade
DEP	2026	Sumter	DESC Eastover	115	270	Upgrade
DEP	2026	Weatherspoon	LREMC West Lumberton	115	313	Upgrade
DEP	2027	Robinson	Rockingham	115	310	Upgrade
DEP	2028	Delco	Leland Industrial	115	221	Upgrade
DEP	2028	Durham	Brier Creek	230	1195	Upgrade
DEP	2029	Cape Fear	Moncure	115	201	Upgrade

Note 1 : The MVA Capacity represents the capability for one circuit of the double circuit line.

Transmission System Planning to Ensure System Adequacy and Reliability

DEC and DEP manage the adequacy and reliability of their transmission systems and interconnections with neighboring entities through internal analysis and participation in regional reliability groups. The Companies' internal transmission planning team looks 10 years ahead at projected generating resources and retirements, as well as projected load to identify needs and requirements for transmission system upgrades and transmission expansion. The Duke Energy team plans and implements corrective actions in advance to ensure continued cost-effective and reliable service. In addition to the internally developed 10-year transmission planning process, DEC and DEP coordinate transmission planning with local and regional groups, as well as with reliability working groups related to North American Electric Reliability Corporation ("NERC") reliability standards.

DEC and DEP manage transmission system reliability through evaluating changes in load, generation, real and reactive capacity, transmission service needs, demand response resources and topography. A detailed annual screening ensures compliance with the Duke Energy Transmission Planning Summary for DEC[7] and DEP[8] for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation ("SERC") policy and NERC Reliability Standards, and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure there are no equipment overloads and adequate voltage is maintained to provide reliable service. Historically, the most stressful scenarios studied have been at projected summer and winter gross peak load and solar peak output. In addition to the base cases and in accordance with NERC Reliability Standard TPL-001-5.1 Requirement R2.1.4, sensitivity cases are utilized to demonstrate the impact of changes to the basic assumptions used in the base case models. To accomplish this, the sensitivity analysis varies one or more of the model conditions by an amount sufficient to stress the system within a range of credible conditions to evaluate their impact. Generation additions, retirements, or other dispatch scenarios are also considered in these NERC TPL-001 Standard transmission planning assessments. 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 system evaluations will need to consider when additional load is placed on the system with the demand of energy from energy storage systems such as charging batteries or pumping water at pumped storage hydro facilities. The Companies developed a transmission planning business practice to provide guidance on storage considerations.[9]

Transmission planning and requests for transmission service and generator interconnection are interrelated with the resource planning process. DEC and DEP currently evaluate all transmission reservation requests for impact on transfer capability, as well as compliance with the Companies' Transmission Planning Summary and the OATT. The Companies perform studies to ensure transfer

[7] Transmission Planning Summary document, available at: http://www.oatioasis.com/duk/index.html (this document contains an overview of the fundamental guidelines followed by DEC's Power Delivery employees to plan Duke Energy's 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV transmission systems. FERC Order 890 requires that public utilities document and make available to stakeholders their basic methodology, criteria, and processes in order to ensure that transmission planning is performed on a consistent basis. The Transmission System Planning Summary contains general information on DEC transmission planning practices and provides links to other DEC documents that contain additional detail.)

[8] Duke Energy Progress, Transmission System Planning Summary, May 2014, available at https://www.oasis.oati.com/CPL/.

[9] Duke Energy, Duke Energy Business Practice: Studying Storage Interconnection Requests in DEC and DEP, October 2022, available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/Storage_Studies_-_Duke_Energy_Business_Practice_2022-10-26.pdf.

capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures in the OATT and related North Carolina and South Carolina state procedures. It is important to note that location, megawatt ("MW") capacity of the interconnection requested, resource/load characteristics, and other clustered queued requests, both individually and in aggregate, are inputs that are determinative of the transmission network upgrades required to reliably accommodate the interconnection requests. While requests for transmission service and generator interconnection provide definitive details for these inputs, as some requests move forward and others do not, the aggregate impact of these modeling inputs changes, thus yielding a range of results — both in terms of cost and time to interconnection — for required transmission network upgrades. For this reason, transmission planning must be a continual and iterative process to calibrate transmission plans to objective and verifiable transmission needs.

DEC and DEP participate in several transmission-related planning group activities to ensure coordination of and collaboration for planning a reliable transmission system, as discussed further below.

Transmission System Planning Regulatory Requirements

The Companies' transmission systems are designed and operated to ensure adequate and reliable service to DEC's and DEP's customers while meeting all regulatory requirements and standards. The Companies are required to meet mandatory FERC, NERC and SERC reliability standards and planning requirements.

Pursuant to the Energy Policy Act of 2005 ("EPACT 2005"),[10] FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the Bulk Electric System ("BES") in the United States under a variety of operating conditions. The federally mandated NERC Reliability Standards constitute minimum criteria with which all public utilities must comply as components of the interstate electric transmission system. EPACT 2005 and FERC's implementing regulations and orders also mandate that electric utilities follow the NERC Reliability Standards and impose fines for noncompliance of approximately $1.3 million per day per violation. The Reliability Standards are a federal requirement and are subject to oversight and enforcement by the SERC, NERC and FERC.

The NERC Reliability Standards include transmission planning ("TPL") Standards that specify the transmission system planning performance requirements to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions. The TPL Standards also require study of a wide range of probable contingencies in both short-term (1–2 years) and long-term (10-year) scenarios to ensure system reliability. Together with any SERC regional planning criteria[11] and internal

[10] 16 U.S.C. § 824o.

[11] SERC Reliability Corporation, Standards & Regional Criteria, available at https://www.serc1.org/program-areas/standards-regional-criteria.

DEC/DEP specific transmission planning criteria, the TPL Standards define the minimum transmission system planning requirements to safely and reliably serve customers.

In addition to the TPL Standards, as Transmission Service Providers,[12] the Companies must also comply with FERC Order No. 890, which was issued on February 16, 2007, and reformed the decade-old open access regulatory framework adopted in Order No. 888, and with the more recent Order No. 1000. Order No. 1000 establishes transmission planning reforms that: (1) require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) require local and regional transmission planning processes to provide an opportunity to identify and evaluate transmission needs driven by public policy requirements established by state or federal laws or regulations; (3) improve coordination between neighboring transmission planning regions for new interregional transmission facilities; and (4) remove from commission-approved tariffs and agreements, a federal right of first refusal.[13]

Transmission Planning Processes

Local Transmission Planning Process

Attachment N-1 of the OATT reflects the Companies' Local Transmission Planning Process approved by the FERC for compliance with Order Nos. 890 and 1000. This Local Transmission Planning process for the Companies' interconnected transmission systems in North Carolina and South Carolina is effectuated through the North Carolina Transmission Planning Collaborative ("NCTPC").[14] North Carolina's major electric load-serving entities ("LSEs"), including DEC, DEP, ElectriCities of North Carolina, Inc. ("ElectriCities," which is the umbrella organization of municipal electric power suppliers in the state) and the North Carolina Electric Membership Corporation ("NCEMC," which is the umbrella organization of cooperative electric power suppliers in the state), created the NCTPC in 2005 to enhance transmission planning by allowing all stakeholders to participate in shaping the future transmission network in the areas of North Carolina and South Carolina served by the LSEs. An independent administrator facilitates the NCTPC to ensure that the interests of all stakeholders are fairly and meaningfully represented. More details on the Transmission Advisory Group stakeholder membership are provided in this section. The NCTPC is intended to create an integrated long-term transmission expansion plan that will result in a reliable (i.e., meets all applicable reliability criteria) and cost-effective (i.e., provides meaningfully greater benefits than costs for consumers) transmission system. As discussed below, the NCTPC plans to file with FERC in the October/November 2023 timeframe to propose certain improvements, including changing its name to the Carolinas

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[12] NERC, Glossary of Terms Used in NERC Reliability Standards, March 2023, available at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[13] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, available at https://www.ferc.gov/sites/default/files/2020-06/OrderNo.1000-B.pdf.

[14] As part of the proposed revisions to Attachment N-1 of the Companies' OATT described below, which the Companies are currently vetting with stakeholders and intend to file for approval from FERC in October/November 2023, the Companies have proposed to change the name of the NCTPC to the Carolinas Transmission Planning Collaborative or CTPC to more accurately reflect the scope of local transmission planning in both South Carolina and North Carolina that the collaborative has historically done and will continue to do.

Transmission Planning Collaborative to reflect its dual-state applicability, as well as other changes to Attachment N-1 to the Companies' OATT.

Currently, Attachment N-1, the Local Planning Process, addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads, as well as transmission upgrades needed for public policies and economic transfers analyzed. The Local Planning Process includes a base reliability study ("base case") that evaluates each transmission system's ability to meet projected load with a defined set of resources, as well as the needs of firm point-to-point transmission service customers, whose needs are reflected in their transmission contracts and reservations. A resource supply additions analysis is also conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements.

The NCTPC annually develops a single, coordinated local transmission plan ("Local Transmission Plan") that appropriately balances costs, benefits and risks associated with the use of transmission, generation and demand-side resources to meet the needs of LSEs, as well as Transmission Customers under the OATT. This local transmission planning process enables solutions to public policy requirements to be considered for adoption into the Local Transmission Plan.[15]

The Local Transmission Plan may be adjusted over time to reflect changing system conditions, the iterative nature of transmission planning and coordination with regional and interregional processes. If regional transmission constraints or concerns are identified in local transmission planning studies, such constraints identified can be elevated to the Southeastern Regional Transmission Planning ("SERTP") group discussed further below.

The NCTPC comprises three main groups and an Administrator that carries out its roles and responsibilities under the FERC-approved Local Transmission Planning process.

Planning Working Group ("PWG"): Identifies potential solutions to the transmission problems identified (including public policy transmission needs) and tests the effectiveness of potential solutions through additional analysis as required to ensure that the solutions meet the study criteria previously developed. The PWG membership comprises representatives from the member LSEs and the independent administrator.

Transmission Advisory Group ("TAG"): Provides stakeholder input and recommendations to the LSEs for consideration for incorporation into the Local Transmission Plan, including with respect to public policy-driven transmission requirements. The TAG membership is open to the public and any individual may be a TAG participant. In addition, state regulators, including state-sanctioned entities representing the public, like other members of the public, may choose to be TAG participants. State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the NCTPC Process. State public utility regulatory commissions may be TAG Sector Entities in the General Public Sector.

[15] Section 5.7.1, page 801 of the Joint OATT.

Oversight/Steering Committee ("OSC"): Manages the NCTPC Participants' Transmission Planning Process and is currently chaired by a representative of ElectriCities. The OSC membership is composed of representatives from the member LSEs and the independent Administrator. The duties of the OSC, for the areas in the states of North Carolina and South Carolina served by the NCTPC Participants, include the following:

- Participate in the reliability planning process and oversee the development of the Local Economic Study Process.
- Review and approve transmission planning criteria and critical assumptions for the bulk transmission system and, where appropriate, develop and recommend such criteria and assumptions to be used by the PWG.
- Promote the application of such planning criteria and/or assumptions within the territories served by the NCTPC Participants.
- Direct the activities of and provide oversight for the PWG.
- Nominate and approve the PWG members.
- Keep the State Commissions, Regulatory Staff (Public Staff and Office of Regulatory Staff) and non-LSE stakeholders informed concerning the work undertaken by the Local Transmission Planning process.
- Forward the draft Local Transmission Plan Report to the TAG participants for their review and discussion.
- Evaluate results, PWG recommendations and TAG participants' input, and approve the final Local Transmission Plan. The final Plan is posted on the NCTPC website, posted on the Companies' Open Access Same-Time Information System ("OASIS"), and distributed to the TAG participants.[15]

NCTPC Administrator: The Administrator serves as a facilitator for the group by working to bring consensus within the group through transmission planning expertise and by providing an independent third-party view. The Administrator assists the Chair and Vice-Chair in the performance of their duties as requested and ensures that OSC meeting minutes are recorded and distributed. The Administrator maintains a record of all OSC proceedings, including responses, voting records and correspondence, and manages the timely posting of relevant materials to the NCTPC website. The Administrator also provides the leadership role in managing the Stakeholder Process, subject to the oversight of the OSC and normal regulatory oversight.

Results of 2022–2032 Local Transmission Plan and Development of 2023–2033 Plan

2022–2032 Local Transmission Plan

The NCTPC 2022-2032 Collaborative Transmission Plan dated February 21, 2023 ("2022–2032 Plan") provides details on the development and evaluation of local transmission plan projects, including evaluation of the DEC and DEP supplemental studies that provided clear evidence of the need for strategic RZEP projects that would eliminate barriers to interconnecting resources in both South Carolina and North Carolina, and had stand-alone value based on the merits of replacing aging equipment and the associated reduction in the probability of customer service interruptions. The 2022–2032 Plan is the most recent annual local transmission plan prepared in accordance with FERC Order Nos. 890 and 1000 and includes the Reliability Planning and Local Economic Study Planning Processes, which are intended to be concurrent and iterative in nature.

The 2022–2032 Plan included 24 reliability projects and 14 RZEP projects. In addition, the OSC decided to examine the impacts of 14 different hypothetical transfers into, out of, and through the DEC and DEP systems under the Local Economic Planning Process. The results of the 14 hypothetical transfers under the Local Economic Planning Process are documented in the 2022–2032 Plan.

The study years and seasons for the 2022–2032 Plan were 2027 summer for evaluating near-term base reliability, 2027/28 winter for evaluating near-term base reliability, and 2032/33 winter for evaluating long-term base reliability. The results of the base reliability study, the resource supply option study and the local economic study were evaluated using established planning criteria. The planning criteria used to evaluate the results include: 1) NERC Reliability Standards; 2) SERC requirements; and 3) individual company criteria. The base case for the base reliability study was developed using the most current 2021 series NERC Multiregional Modeling Working Group ('MMWG") model for the systems external to DEC and DEP.

The MMWG model of the external systems, in accordance with NERC MMWG criteria, included modeling known long-term firm transmission reservations. Detailed internal models of the DEC and DEP East/West systems were merged into the base case, including DEC and DEP transmission additions planned to be in service by the period under study. In the base cases, all confirmed long-term firm transmission reservations with roll-over rights were modeled. Contingency screenings on the base cases and scenarios were performed using Power System Simulator for Engineering power flow or equivalent. DEC and DEP each simulated its own transmission and generation down contingencies on its own transmission system.

The 2022 base reliability study verified that DEC and DEP have projects already planned to address reliability concerns for the near-term (5-year) and long-term (10-year) planning horizons. There were no unforeseen problems identified in the reliability studies performed on the base cases.

The 14 non-simultaneous economic transfer studies identified issues requiring solutions within the applicable planning window. Where issues were identified, alternative solutions were discussed and a primary set of solutions was determined. All issues identified were either previously identified by the base reliability studies or can be mitigated with ancillary equipment upgrades.

The public policy study utilized the supplemental studies discussed in the 2022 Plan report. The OSC reviewed the supplemental study analysis and agreed with the study results and supported inclusion of the 14 RZEP projects in the 2022 Plan. The PWG did not identify, and the TAG stakeholder group did not recommend any alternative solutions to consider for the study.

2023–2033 Plan Development

During the June 21, 2023 Plan Mid-year Update Report to the TAG Stakeholder group,[16] an update was provided on the status of the 2023–2033 Plan. This update included an overview of the base reliability study that will assess DEC and DEP transmission systems' reliability and develop a single Collaborative Transmission Plan and the study scope for evaluating the combined public policy requests received in the first quarter of 2023. The base reliability study will evaluate reliability of the DEC and DEP transmission system for 2028 and 2033 projected summer peak load and for 2028/29 and 2033/34 projected winter peak load scenarios. The study cases will be “All Firm Transmission” cases, which consider all confirmed long-term firm transmission reservations with rollover rights applicable to the study years and do not include generation without an executed Interconnection Agreement (“IA”). Generation is economically dispatched in the base cases and generation offline cases are created from common base cases.

Two public policy requests were submitted in 2023 and were combined under one study scope document that is currently being studied by the NCTPC with the final report expected by first quarter 2024. The first request focused on Resource Plan portfolio execution and resulting additional 230 kV and/or 500 kV transmission that may be needed long term. The second request focused on starting with resource plan Portfolio P1 from the Companies’ initial 2022 proposed Carbon Plan and studying two different solar and solar paired with storage (“SPS”) volumes: 9.3 gigawatt (“GW”) and 12.5 GW by summer of 2033. As mentioned, these requests were combined into one study scope document.[17] The results of the public policy study requests will provide further input into the RZEP 2.0 project needs, as well as address long-term transmission project needs such as greenfield 230 kV and 500 kV transmission lines.

As discussed in the next section, the local transmission planning process for addressing and identifying local transmission project needs will be further enhanced in the future to reflect multi-value benefits for local transmission expansion plan projects.

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[16] North Carolina Transmission Planning Collaborative, Transmission Advisory Group Meeting, June 2023, available at http://www.nctpc.org/nctpc/document/TAG/2023-06-21/M_Mat/TAG_Meeting_Presentation_for_06-21_2023_FINAL.pdf.

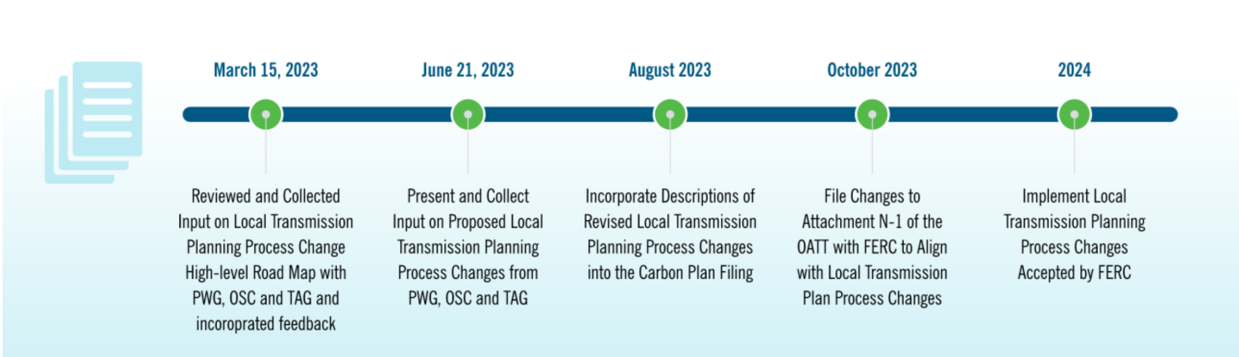
[17] North Carolina Transmission Planning Collaborative, Study Process Scope, June 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-06-12/2023_NCTPC_Study_Scope_06_12_2023%20_FINAL_DRAFT.pdf.

Revisions to the Local Transmission Planning Process

Through the development of the 2022 Local Transmission Plan and discussions with the TAG stakeholders, it was recognized that the Local Transmission Planning Process needed to be revised to increase transparency and coordination with stakeholders and improve processes to address the challenges of the ongoing generation transition. The NCUC also encouraged the Companies to engage with other NCTPC members to consider more strategic transmission planning opportunities to ensure reliability is maintained and to more robustly consider and develop strategic transmission planning requirements.[18]

Duke Energy, in coordination with the NCTPC OSC, established a plan for revising Attachment N-1 of the OATT, the Local Transmission Planning Process, to increase transparency and opportunities for engagement and coordination with stakeholders, as well as to create a new transmission planning process geared toward studying and developing strategic, multi-value transmission projects. In addition, a high-level presentation of the plans and timeline for revising the Local Transmission Planning Process was provided to the TAG stakeholder group in March 2023 with a more detailed presentation of the planned revisions and timeline provided to the TAG stakeholder group in June 2023.[19] Duke Energy recently shared the proposed Attachment N-1 revisions with TAG stakeholders for review and to provide feedback in early August 2023. Duke Energy plans to file proposed revisions to the Local Transmission Planning Process with the FERC in the October/November 2023 time frame and will implement these changes upon FERC acceptance of the proposed revisions. The timeline for the Local Transmission Planning process changes and the FERC filing is provided below in Figure L-1.

Figure L-1: NCTPC Planning Study Process Changes Timeline



To facilitate a transparent and coordinated approach, the revisions to the Local Transmission Planning process will include: 1) an Assumptions Meeting with the TAG Stakeholders to review the criteria,

[18] Carbon Plan Order at 121.

[19] North Carolina Transmission Planning Collaborative, Transmission Advisory Group Meeting, March 2023, available at http://www.nctpc.org/nctpc/document/TAG/2023-03-15/M_Mat/TAG_Meeting_Presentation_for_03-15_2023_FINAL.pdf; North Carolina Transmission Planning Collaborative, Transmission Advisory Group Meeting, June 2023, available at http://www.nctpc.org/nctpc/listDocument.do?catId=TAG&date=2023-06-21.

assumptions and models NCTPC plans to use to study and identify local transmission system needs; 2) a Needs Meeting with TAG Stakeholders to review identified transmission system constraints and associated transmission system needs; and 3) a Solutions Meeting with TAG Stakeholders to review the identification of potential solutions to the transmission system constraints and system needs, as well as alternative solutions considered. These meetings will provide more opportunities for engagement and input from stakeholders on Local Economic Projects, Local Public Policy Projects and a newly proposed category of Strategic Multi-Value Projects, subject to the new planning processes.

For the new proposed category of Strategic Multi-Value Projects, a planning study would consider different scenarios for evaluation of new resource supply options, changing load dynamics, transmission solutions requiring longer lead times and/or economic development opportunities. TAG Stakeholders will also have the opportunity to propose scenarios to study as part of the multi-value strategic planning process. Potential solutions to the transmission system constraints identified by this scenario analysis would be developed and the benefits of each solution evaluated. Potential solutions will consider the use of Grid Enhancing Technologies ("GETs") and non-wires alternatives as discussed further in the next section. Potential benefits to be evaluated and quantified for transmission solutions could include reliability, asset replacement, production cost and avoided transmission project benefits. In addition, the multi-value strategic transmission plan will evaluate transmission planning solutions with longer lead times.

While Duke Energy considers these planned revisions to the Local Transmission Planning process to be necessary for effective planning for future transmission needs and identifying the best solutions to meet those needs, there is a risk that FERC's final rule associated with the NOPR[20] on Transmission Planning and Cost Allocation issued in April 2022 may specify materially different transmission planning process requirements. These different requirements may impact both the Local and Regional Transmission Planning processes. Duke Energy and the NCTPC are trying to adopt attributes from the FERC NOPR into the revised Local Transmission Planning process. Duke Energy and the NCTPC will keep this risk under consideration as the Companies move forward with planned revisions to the Local Transmission Planning process.

Use of Grid Enhancing Technologies and Consideration of Non-Wires Alternatives

Duke Energy has utilized GETs as alternative solutions to identified transmission needs in the past and will continue to evaluate and utilize these potential alternative solutions where evaluated to be a sustainable and reliable solution for addressing identified transmission needs. Duke Energy has utilized phase shifting transformers, switchable reactors and remedial action schemes as alternative solutions to reconductoring transmission lines or constructing new transmission lines. Duke Energy continues to consider different technologies for solutions to transmission needs as evidenced in the DEC and DEP 2022 Definitive Interconnection System Impact Study ("DISIS") Phase 2 Study

[20] Notice of Proposed Rulemaking, available at https://ferc.gov/media/rm21-17-000.

Reports[21] reflecting identified transmission network upgrade needs. These reports show that five transmission line loading issues are being resolved through application of switchable reactors and eight transmission lines requiring reconductoring are utilizing High Temperature Low Sag Aluminum Conductor Steel Supported/ Trapezoidal Wire conductor. An overall assessment methodology and summary of analytical results evaluating non-wires alternatives such as battery storage being considered to defer or avoid traditional transmission upgrades is provided in Appendix G (Integrated System and Operations Planning).

Duke Energy will continue to consider GETs as potential alternative solutions to transmission needs. However, alternative solutions must not create conditions that are so complex that system operators are no longer able to maintain local and wide area situational awareness. Over-reliance on GETs can lead to circumstances where operators cannot successfully assess potential risks, hazards, or system events that might occur. Duke Energy will continue to use due diligence when considering application of GETs and non-wires alternatives to ensure any operational complexity is minimized and operator situational awareness of system configuration is not lost.

Regional and Interregional Transmission Planning Process

On July 11, 2011, FERC issued Order No. 1000, which built on principles of transmission planning established in FERC Order No. 890. Order No. 1000 adopted regional transmission planning and cost allocation requirements, requiring that transmission-owning and -operating public utilities, among other things, participate in a regional transmission planning process that produces a regional transmission plan, amend their OATTs to describe procedures providing for consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes and improve coordination between neighboring transmission planning regions for interregional transmission facilities.

In compliance with these requirements, the Companies participate in the SERTP process. SERTP provides an open and transparent transmission planning forum for transmission providers to engage with stakeholders regarding transmission plans in the region. The SERTP was originally developed to comply with FERC Order No. 890 and was expanded in 2014 to implement Order No. 1000 directives.

The SERTP has expanded several times, both in scope and size of the region, since its initial formation. SERTP now includes the following Sponsors (Transmission Owners and Transmission Providers that participate in SERTP) in addition to DEC and DEP: Southern Company, Dalton Utilities, Georgia Transmission Corporation, Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company, Associated Electric Cooperative Inc. and

[21] Duke Energy Carolinas, LLC, 2022 Definitive Interconnection System Impact Study, March 2023, available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report.pdf; Duke Energy Progress, LLC, 2022 Definitive Interconnection System Impact Study, March 2023, available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022_DEP_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report.pdf.

the Tennessee Valley Authority ("TVA"). As a result of this expanded size and scope, the SERTP region has become one of the largest regional transmission planning processes in the United States.

The Companies also participate in other local and regional planning and working groups as a primary participant or as requested, including:

1. Carolinas Transmission Coordination Arrangement between DEC, DEP, Dominion Energy South Carolina and the South Carolina Public Service Authority ("Santee Cooper") – a forum for coordinating certain transmission planning assessment and operating activities among the participants.

2. South Carolina Regional Transmission Planning group – established by Dominion Energy South Carolina and Santee Cooper to meet the transmission planning requirements of FERC Orders 890 and 1000.

3. SERC Intra-Regional Long-Term Power Flow Working Group: Updates SERC Regional power flow base cases and conducts longer-term intra-regional reliability assessment studies to assist SERC in performing its delegated functions.

4. SERC Near-Term Power Flow Working Group: Conducts near-term intra-regional seasonal reliability studies to assist SERC in performing its delegated functions and builds Open Access OASIS study models.

5. Eastern Interconnection Planning Collaborative ("EIPC"): Provides coordinated interregional analysis for the entire Eastern Interconnection based on the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities.

6. Eastern Interconnection Reliability Assessment Group: Oversees NERC's MMWG, which develops all Eastern Interconnection power flow and dynamic base case models, including seasonal updates to summer and winter power flow study cases.

The NCUC encouraged DEC and DEP to participate in a coordinated manner with SERTP and PJM Interconnection, L.L.C. ("PJM") to ensure least cost paths for resource plan resources were identified.[22] Several Public Policy Requests were submitted to SERTP for evaluation of regional impacts from the initial 2022 proposed Carbon Plan. The submitted requests identified the Carbon Plan Order as the basis for the requests. In the Order, the NCUC encouraged Duke Energy "to explore all possible efficiencies and to be vigilant in its participation in SERTP . . . to assure a least cost path to achieve the carbon dioxide emissions reduction requirements while maintaining and improving reliability."[23]

SERTP's response to the Public Policy Requests indicated that in accordance with the NCUC Order, the Carbon Plan Order is currently being considered by Duke Energy and in its local planning activities

[22] Carbon Plan Order at 121.

[23] Id.

with the NCTPC. Regarding SERTP's response, in addition to Local Transmission Planning process changes to address FERC Transmission Planning Notice of Proposed Rulemaking suggestions and incorporating a process for multi-value strategic transmission planning, as part of its 2023 plan, the NCTPC is studying a portfolio of resources suggested by the 2022 resource plan. Any resulting transmission plans will subsequently be made part of the SERTP process.

With respect to DEC and DEP participation in interregional transfer studies, SERTP is conducting an interregional transfer study to assess transfer capability with neighboring regions. EIPC is also developing a road map and schedule for conducting an interregional transfer capability study in 2024. Furthermore, Duke Energy has engaged with PJM through submission of a 1,000 MW transmission service request, which is pending study under PJM's revised queue reform process. The status of this request is discussed later in this Appendix.

Engagement with SERTP and other Regional Transmission Planning Groups such as SCRTP will continue to be important to assure power supply reliability for South Carolina and North Carolina customers.

Definitive Interconnection System Impact Studies and Generator Interconnection Impact on Transmission Upgrades

Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures contained in the OATT and the South Carolina and North Carolina state generator interconnection procedures applicable to qualifying facilities selling their output to DEC or DEP under the Public Utility Regulatory Policies Act of 1978. In 2021, DEC and DEP obtained regulatory approvals from the NCUC, Public Service Commission of South Carolina and the FERC to transition from the serial "first-come, first-served" queuing process to a "first-ready, first-served" cluster study approach. In fall 2021, the Companies initiated the transition process for existing interconnection requests in the generator interconnection queue, providing an expedited window and study process for those projects to either proceed to interconnection or to withdraw with the option to reenter the new annual DISIS cluster study process. Projects that met transition process readiness requirements and completed study in the transitional serial or transitional cluster study process have now completed interconnection study and received IAs.

Definitive Interconnection System Impact Study Cluster Process

The first annual DISIS cluster commenced in August 2022 ("2022 DISIS") and is ongoing. Phase 1 and phase 2 studies for the 2022 DISIS cluster study are now complete and were an integral part of the joint systemwide 2022 Solar Procurement RFP process. The 2022 Solar Procurement RFP resulted in approximately 1 GW of new, controllable solar facilities selected on a highest-ranked, least-cost basis in DEC and DEP. In July 2023, the Companies determined that the 2022 DISIS requires restudy ("Phase 3 restudy") due to participants exiting the 2022 DISIS after 2022 DISIS phase 2 concluded. The Phase 3 restudy commenced on July 10, 2023. Table L-3 below summarizes the projects remaining in 2022 DISIS cluster.

Table L-3: Resources Remaining in 2022 DISIS Resources Phase 3 Cluster Study

Transmission Area	# of Projects	Total MW
DEC	15	2,607
DEP	23	1,514

Among the 15 DEC projects, five are FERC jurisdictional, six are state jurisdictional connected to transmission and four are state jurisdictional connected to distribution. Among the 23 DEP projects five are FERC jurisdictional, 16 are state jurisdictional connected to transmission and two are state jurisdictional connected to distribution. 12 of 15 projects in DEC and 19 of 23 projects in DEP are progressing as commercially ready projects, while three and four (or approximately 20% and 17%) in DEC and DEP, respectively, are progressing as non-ready projects that have provided increased financial security to remain in 2022 DISIS. As the Companies complete the Phase 3 restudies, the Companies will also monitor the risks of termination by the remaining projects and the potential need for further restudies.

The 2023 DISIS Cluster enrollment window closed on June 29, 2023, and the Phase 1 Study will commence on August 29, 2023. The Companies are also planning a resource solicitation cluster for studying proposals bid into the 2023 solar and SPS RFP to commence after 2023 DISIS. This Resource Solicitation Cluster will be designed to mitigate risks of restudy associated with the late-stage participant exits that the Companies recently witnessed in the 2022 DISIS.

Since undertaking the queue reform transition in 2021, all study phases in the Transitional and DISIS Cluster process have been completed in compliance with the required time frames of the FERC and state generator interconnection procedures. The average time to deliver an IA improved from more than four years under the serial process to two years under the cluster study if no restudy is required.

The cluster study process is superior to the serial study process, as the new study process has helped the goals of improving the study timelines for interconnection customers, incentivizing commercially ready projects in the queues, reducing the negative impact of speculative projects to other projects in the queue, as well as easing administrative burdens associated with processing significant volumes of Interconnection Requests in the prior serial study process. Interconnection customers benefit from a transparent and predictable process that is similar and aligned in each state and at the federal level.

On July 28, 2023, FERC issued its Final Rule on Improvements to Generator Interconnection Procedures and Agreements.[24] Order No. 2023 includes three broad categories of reforms to apply to all transmission providers: 1) transition to a “First Ready, First Served” cluster process; 2) reforms to increase the speed of generator interconnection queue processing; and 3) reforms to incorporate technological advancements into the interconnection process. DEC and DEP were early adopters of the First Ready, First Served Cluster Study process that FERC is now requiring each Transmission

[24] Improvements to Generator Interconnection Procedures and Agreements, Order No. 2023, 184 FERC ¶ 61,054 (2023) (“Order No. 2023”).

Service Provider to adopt in accordance with the Final Rule. With FERC changing the pro forma Large Generator Interconnection Procedure ("LGIP"), Large Generator Interconnection Agreement ("LGIA") and Small Generator Interconnection Agreement ("SGIA"), DEC and DEP will need to review Order No. 2023 carefully to determine what, if any, revisions will be needed to the current DEC and DEP Joint OATT to comply with Order No. 2023's directives. Currently, it is not yet clear whether or how the changes being imposed by the Final Rule could potentially impact the proceeding DISIS or Resource Solicitation Cluster schedules. The Companies will know and share more about the impacts of the Final Rule as they work to meet the schedule for implementation of the Final Rule. The Final Rule will be effective 60 days after publication in the Federal Register (likely early October), and DEC's and DEP's compliance filing is currently due 90 days after publication (likely early November).

Generator Replacement Request Process

In addition to queue reform associated with the Cluster Study process, DEC and DEP filed a request in June 2022 for FERC approval to revise the Large Generator Interconnection Procedure contained in their OATT to establish more efficient interconnection processes for certain replacement generation. This request was approved by FERC with an effective date of August 1, 2022, and the new generator replacement process was implemented for DEC and DEP. This new process will be critical to efficient, timely, and cost-effective replacement of retired coal-fired generation with new generation that interconnects at the same switchyard where the retiring generation is located. Utilization of the same switchyard for interconnection will save the cost of potentially expensive interconnection facilities that would be required if the same replacement generation was constructed at a greenfield site. DEC and DEP are already leveraging this new process for the benefit of DEC and DEP customers for replacing retiring coal generation at the DEC Marshall Plant and the DEP Roxboro Plant. More discussion on how this generation replacement process is being used for facilitating coal generation retirements is provided later in this Appendix.

Impacts for Solar and Solar Paired with Storage Interconnections and Allowable Capacity

The pace at which Duke Energy can interconnect renewables to the transmission grid is a result of a number of different factors, including the location of new generating facilities, size of facility (MW), interconnection requested, resource/load characteristics and prior queued requests, both individually and in aggregate. One such factor is reliability of the transmission grid and the ability to maintain single contingency operations with outage coordination as discussed further below. Another factor is the availability of solar and SPS projects that will be discussed further in the interconnection risk section. Finally, the number of annual interconnections to the system is dependent on the following additional key factors:

- **Expected Project Size** - One of the major evolving factors that will influence the achievable amount of MW of interconnections is the size of the solar projects procured under future competitive solar RFPs. Looking forward, the Companies will primarily procure substantially larger, transmission-connected projects. Third-party-owned projects are expected to be 50 to 80 MW and utility-owned projects could be substantially larger.

- **Need for Transmission Upgrades** - The influx of solar into the Carolinas has created a continued need for significant transmission system upgrades to allow for additional resource interconnections. These areas have been communicated through guidance documents and maps showing constrained transmission areas and are posted on the DEC and DEP OASIS sites for developers. These constrained transmission areas are associated with large, flat land parcels, ideal for solar development. These areas will become more attractive for solar development as Resource Plan implementation moves forward. Based on the timeline to complete these projects, the Companies project interconnected solar increases over time as network upgrades are completed.

- **Increasingly Complex Interconnections** - Not only will more complex system upgrades be required to interconnect solar, but the average cost for direct interconnection facilities will also increase in the future. This cost increase results from the fact that most prime real estate close to existing transmission infrastructure has been or is already being developed. New solar facilities seeking to interconnect will, on average, be built further from existing infrastructure than historical developments. Building farther from existing infrastructure requires larger direct interconnection facilities, which will further consume available resources and limit the maximum achievable annual interconnections.

Transmission Outage Coordination Impacts

The 2022 DISIS Phase 2 study results, shown below in Table L-4, revealed the average sizes for solar facilities requesting interconnection in DEC and DEP.

Table L-4: 2022 DISIS Phase 2 Solar Resources Requesting Interconnection

DEC/DEP	Avg Solar MW	Jurisdiction	# of Facilities	Total MW
DEP	73	State	19	1,393
DEP	78	FERC	2	155
DEC	85	FERC	2	171
DEC	52	State	11	570
		Total	34	2,289

Deriving an "average" project from the solar facilities requesting interconnection in DISIS as reflected in Table L-4 above would imply the number of annual interconnections shown below in Table L-5 at a given aggregate level of solar and solar paired with storage.

Table L-5: Number of Interconnections Needed to Meet Solar and Solar Paired with Storage Targets

		Resource Plan Annual Solar Target (MW)				
		750	1000	1350	1500	1800
DEP Interconnections	UOT	4	5	7	7	9
	PPA	3	4	6	6	8
DEC Interconnections	UOT	1	2	3	3	3
	PPA	2	3	4	4	5
Total Interconnections		**10**	**14**	**19**	**21**	**25**

Note : Assume 70%/30% DEP/DEC split, UOT – Utility-owned track, PPA – Power Purchase Agreement

Annually, Transmission Outages, shown below in Table L-6, are needed for a variety of reasons including maintenance, NERC preventive maintenance requirements, asset management programs, NERC TPL-001 Standard Upgrade projects, new retail and wholesale delivery points, outage restoration, resource interconnections and associated Network Upgrades. Outage coordination groups currently accommodate about as many outages as can be accommodated and maintain reliable, single contingency operations in accordance with NERC Reliability Standards and prudent outage planning. Outages to accommodate interconnections of resources are additive to the line outages needed in a given year, which are scheduled to occur primarily in the spring and fall.

Table L-6: Transmission Outages (37-42% Annually are Line Outages)

	2019	2020	2021	2022	2023
DEC Outages	895	1,352	1,214	1,204	276
DEP Outages	786	1,308	1,086	1,168	132
Data Available	May 1 - Dec 31	Full Year	Full Year	Full Year	Jan 1 - Mar 15

Note : Each Interconnection can add up to four line outages per year with two additional outages for each associated network upgrade, e.g., eight interconnections could add 48 line outages per year assuming one network upgrade per interconnection.

From information provided above in Tables L-4, L-5 and L-6, ten interconnections for 750 MW could add an estimated 60 line outages (~+6%) per year and for 25 interconnections for 1,800 MW, an additional 150 line outages (~+15%) per year could be expected. This increase in line outages needed to meet higher levels of annual solar and SPS resource interconnections significantly increases execution risks and requires a fine balance between outages for interconnection and those required to preserve system operational reliability. One possible solution to decrease the number of annual interconnections required to meet Carolinas Resource Plan specified volumes would be to increase the size of the PPA (closer to the 80-MW limit) and Duke Energy-owned solar facilities (greater than 120 MW on average) as compared to the average sizes of solar facilities reflected in Table L-4.

As further addressed below, the Companies are designing process improvements to achieve increased resource interconnections; however, the Companies are doing so prudently with the objective of ensuring interconnecting new resources does not in any way negatively impact the adequacy or reliability of the existing grid across the Carolinas in accordance with NERC Reliability Guidelines and Institute of Electrical and Electronics Engineers ("IEEE") Standards.

Interconnection Process Improvements – From Fully Executed Generator Interconnection Agreement to Permission to Operate

DEC and DEP continue to develop new practices to advance interconnection timelines. Accordingly, a team was formed in 2022 to review options and actions to accelerate the interconnection timeline with an objective to complete interconnection activity in as few as 20 months from a fully executed IA for resources that can connect with a standard design and for which developers can partner to meet carefully aligned construction and commissioning milestones. The team consists of multi-function subject matter experts, stakeholders and process element owners for the interconnection queue, customer interface, interconnection study work, project planning and management, engineering, construction and facility commissioning. To date, those efforts have identified the following enhancements:

- Development of standard interconnection engineering designs
- Options for early ordering of equipment with long lead times
- Ability to parallel certain engineering design activities when developers can provide timely facility information
- Steps to accelerate timing for certain construction activities
- Definition of more visible program level performance measurement and tracking
- Identification of critical commissioning steps to ensure facility operational reliability

These efforts and initiatives will continue to improve interconnection timeline efficiencies, thereby enabling interconnection of solar and SPS resources on the timeline necessary to meet Resource Plan objectives for resource supply additions and coal retirements.

Improvements include increased developer coordination, industry learnings and application, improved commissioning coordination from industry best practices, DEC and DEP construction phase process improvements and visible interconnection and project financial performance metrics.

Working with Inverter Based Resources ("IBR") developers from the transitional cluster, DEC and DEP piloted a commissioning process and used learnings of the pilot to implement the new transmission IBR Technical Requirements and commissioning process released in March 2023. DEC and DEP have incorporated additional developer meetings at key points in the construction process to ensure both parties understand the timing of upcoming requirements and align new interconnection milestones. Obtaining cooperation and coordination with solar developers for commissioning of IBRs will be imperative to preserving the reliability of the transmission grid now and in the future as highlighted by several NERC Event Reports and associated Reliability Guidelines addressing IBR reliability during grid disturbances.

As evidenced by the Companies' past interconnection performance of the process improvements, Duke Energy is an industry leader in IBR interconnections and this initiative reflects the Companies' continued constructive efforts to achieve increased annual generator interconnections while ensuring transmission system reliability is not adversely impacted. Through the generation transition, the Companies will continue to check and adjust the interconnection process to ensure timely interconnection of all generators, as well as to maintain the reliability of the transmission grid.

With respect to industry learnings and application, Duke Energy is working with NERC, IEEE and other industry regulatory agencies, as well as coordinating with peer utilities to ensure interconnection/commissioning processes are effective at promoting grid resilience while not being overly burdensome to developers or the utilities.

Internally, Duke Energy is focused on efficient procurement of materials and resources for the interconnection process given the increased time in obtaining key transmission interconnection materials from vendors. Duke Energy holds monthly internal meetings to ensure interconnection milestones are being met and to review the status of developer milestones. In addition, Duke Energy has aligned IA milestones and project management tools for increased visibility, coordination and focus on Duke Energy and developer milestones. Also, Duke Energy has developed a standard engineering design for single-breaker interconnections to make the design and construction phase more efficient where this standard design can be applied.

Interconnection Risks – Customer Delays and Transmission Upgrades

Duke Energy continues to see risks to meeting interconnection milestones as developer in-service dates are being pushed out and not pulled in to the 20-month timeline from signed generator IA to construction completion due to permitting issues, the ability to obtain materials in a timely manner due to global supply chain disruptions and other unforeseen developer realizations such as material and labor cost inflation occurring between bid acceptance and construction phases. This trend introduces the risk of solar and SPS resources not interconnecting at the pace needed to meet Resource Plan objectives. Another risk is being able to coordinate transmission system outages needed to accommodate the construction of network upgrades and interconnection facilities to meet Resource Plan objectives. As highlighted by Table L-4 and Table L-5, larger-sized solar and SPS facilities would result in a lower number of interconnections for a given amount of MW being interconnected and thus, could result in fewer outages needed per interconnected MW. Furthermore, addressing transmission network upgrades in a proactive manner would help to lower the risk and accelerate the path from executed IA to commercial operations.

Transmission Network Upgrades Keeping Pace with Solar and Solar Paired with Storage Interconnections

Multi-value strategic transmission planning that includes studying scenarios of different grid conditions results in identifying transmission needs and solutions that have multiple benefits for transmission customers and are cost-effective and sustainable solutions. This type of transmission planning avoids the piecemeal practice of identifying transmission needs and solving transmission constraints in an isolated manner. In accordance with FERC Orders on transmission planning, these planning methods have to address local and regional transmission planning for reliability, economic studies and public policy requirements; however, FERC does not require that these studies be conducted in an isolated manner. As mentioned earlier in this Appendix, Duke Energy is working to expand local transmission planning processes to adopt this type of planning method. Duke Energy's first step with proactive transmission planning and determination of multiple benefits associated with local transmission projects was introduced with the RZEP projects in the NCTPC 2022–2032 Local Transmission Plan.

In the summer of 2022, DEC and DEP conducted cluster-type studies and presented these studies to the NCTPC TAG stakeholders for input and feedback. The studies were performed in a cluster study manner modeling the transmission system impacts of interconnecting 5.4 GW of historical solar generator interconnection requests. It revealed that even under changing assumptions about location, MW size, resource characteristics and queue order, a common set of transmission upgrades was needed in order to unlock a transmission-constrained area that has high viability for solar and SPS facilities known as a red zone region. These studies validated a set of identified recurrent transmission upgrades that were impeding solar facilities in the high solar viability areas of the DEC and DEP systems from moving forward to IAs.

From the results of the cluster-type studies, 14 transmission upgrade projects were identified. The NCUC acknowledged in the Carbon Plan Order that the results of the studies showed that the 14 RZEP projects were needed to execute the Companies' Resource Plan. The NCTPC OSC reviewed the cluster-type study analysis, agreed with the study results and supported inclusion of the RZEP projects in the 2022 Plan.[25] As noted in the Report on the NCTPC 2022–2032 Collaborative Transmission Plan,[26] the aforementioned cluster-type studies show that completion of the 2022 RZEP projects should enable the interconnection of approximately 3,759 MW of solar-generating facilities in Duke Energy's territory – 2,778 MW in DEP and 981 MW in DEC. Furthermore, the Interruption Cost Estimate tool considering asset replacement value revealed each of the 14 projects had a benefit-to-cost ratio of at least 5.1. This cost-benefit analysis excludes any benefit associated with carbon reduction.

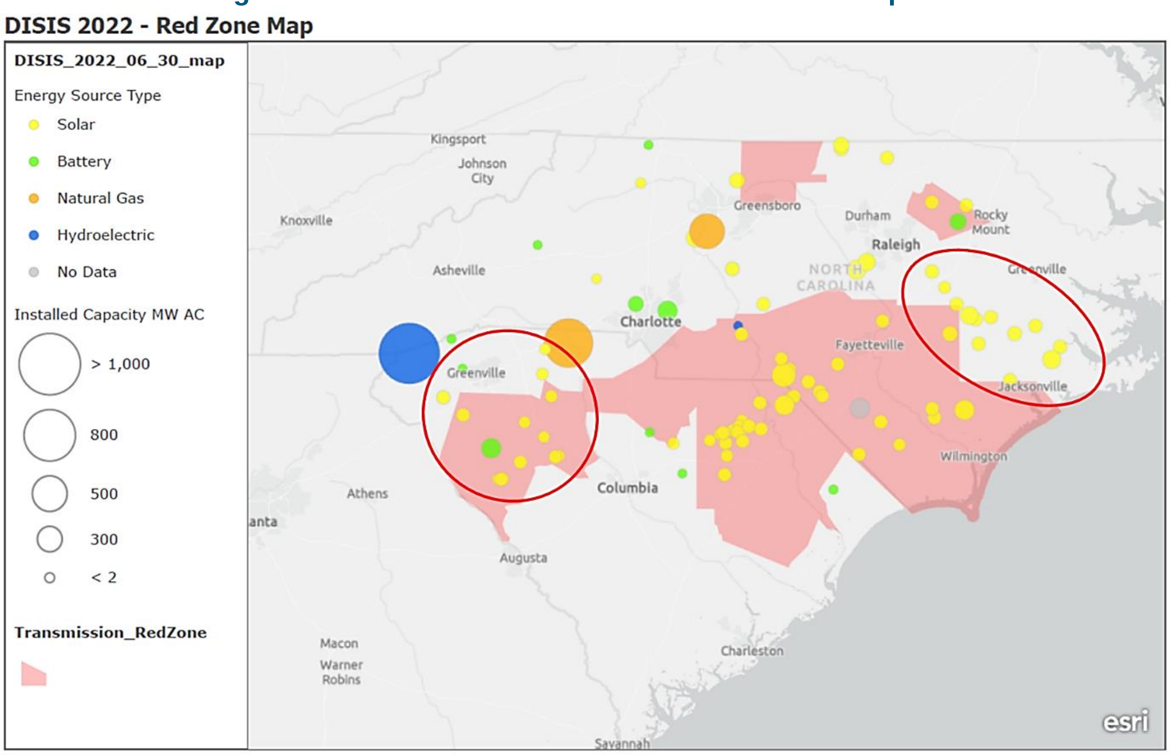
Since the inclusion of the 14 RZEP projects into the 2022-2032 Plan, new 2022 DISIS Phase 1 and Phase 2 studies were completed for DEC and DEP. For DEC, the Phase 1 study identified multiple upgrades needed for the 5.1 GW of differing resource types (solar, battery storage, pumped storage hydro and gas generation) proposing to interconnect in those studies. In evaluating the 2022 DISIS in a similar manner to the prior supplemental study assessment of solar resources, it was identified that transmission upgrades that are complementary with the initial four DEC RZEP projects are needed for interconnecting additional solar and SPS facilities in DEC's South Carolina area (red circle on Figure L-2). For DEP, the Phase 1 study identified multiple upgrades needed primarily for the 4.6 GW of solar

[25] North Carolina Transmission Planning Collaborative, Report on the NCTPC 2022-2032 Collaborative Transmission Plan, February 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf p. 27.

[26] North Carolina Transmission Planning Collaborative, Report on the NCTPC 2022-2032 Collaborative Transmission Plan, February 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf p. 26-28.

facilities requesting interconnection. With the 4.8 GW of all resource types requesting interconnection, the DEP Phase 1 study revealed that more transfer capability is needed between the eastern and western areas of the DEC and DEP systems as more of the Resource Plan-identified resources are integrated into the systems. This additional transfer capability should enable reliable and efficient economic dispatch of these resources. In addition, new transmission-constrained areas on the DEP transmission system were identified, primarily with solar facilities requesting interconnection along the Jacksonville to New Bern to Goldsboro corridor (red ellipse on Figure L-2). Evaluating the results of the 2022 DISIS Phase 1 Studies, a second phase of RZEP projects, shown below in Table L-7, has been identified that are longer duration and start to address these constraints. It should be noted that some of the proposed RZEP 2.0 projects are still being reflected in the 2022 DISIS Phase 2 study results. Ultimately, the results of the 2022 DISIS studies, as well as the results of the 2023 NCTPC study will determine the network transmission upgrade projects that need to be proactively pursued and the projects that will be approved in the 2024-2034 NCTPC Plan.

Figure L-2: 2022 DISIS Phase 1 Interconnection Requests



Transmission Red Zone

Table L-7: Proposed Red Zone Expansion Plan (RZEP 2.0) Upgrades

Project	Owner	Project Description	Cost Estimate[1,2]	Potential In-Service Date
Broadway B/W 100 kV (Belton Tie-W.S. Lee Combined Cycle)	DEC	Rebuild	$19,749,000	May 2028
Bush River 115/100 kV Transformers	DEC	Upgrade	$8,523,000	May 2028
Champion B/W 100 kV (Bush River-New Berry PV)	DEC	Rebuild	$29,114,000	May 2028
Clayton Industrial - Selma 115 kV	DEP	Rebuild	$27,741,000	Sep 2028
Lilesville-Oakboro 230 kV Black[3]	DEP	Rebuild	$54,470,000	Dec 2029
Lilesville-Oakboro 230 kV White[3]	DEP	Rebuild	$54,470,000	Dec 2029

Note 1 : Class 5 Cost Estimate from the DEC 2022 DISIS Phase 2 Study Report.[27]
Note 2 : Class 5 Cost Estimate from the DEP 2022 DISIS Phase 1 Study Report.[28]
Note 3 : Cost Estimate includes upgrading the entire tie-line but excludes any upgrades to be identified as needed in the DEC Oakboro 230 kV substation.

Status Update on Transmission Expansion Plan Projects and Benefits from These Upgrades

Table L-8 below reflects the 14 RZEP projects approved through the Local Transmission Planning process as outlined in the DEC and DEP Joint OATT, Attachment N-1. For the 2022 DISIS, there were 11 solar facilities representing over 760 MW in the Phase 1 study that identified dependencies on one or more of the four DEC RZEP projects. There were nine solar facilities representing over 530 MW in the Phase 2 study that identified dependencies on one or more of the four RZEP projects. For the 2022 DISIS, there were 30 solar facilities representing over 2.4 GW in the Phase 1 study that identified dependencies on four of the 10 DEP RZEP projects. There were 12 solar facilities representing over 830 MW in the Phase 2 study that identified dependencies on four of the 10 DEP RZEP projects. Included in Table L-8 is the July 2023 status of all 14 RZEP projects including an updated cost estimate reflecting a fully burdened cost with contingency included. It should be noted that all 14 RZEP projects are on or ahead of the original planned in-service date schedule. The aggregated cost estimates for the projects, inclusive of burdens and contingency, have increased from $554 million to $576 million. Additionally, the Camden-Camden Dupont 115 kV upgrade, one of the original 18 recommended RZEP upgrades and supported by the summer 2022 DEP cluster-type study results, is included in Table L-8 as being proposed for inclusion in the 2023 Local Transmission Plan as presented in the 2022 Plan Mid-Year Update Report. All of the project status updates were provided in the Semi-Annual

[27] Duke Energy Carolinas, LLC 2022 Definitive Interconnection System Impact Study Phase 2 Report – Rev. 1 July 7, 2023, available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report_rev1.pdf.

[28] Duke Energy Progress, LLC 2022 Definitive Interconnection System Impact Study Phase 1 Report November 23, 2022, available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022_DEP_DISIS_Phase_1_study_report_11-23.pdf.

Report on Status of Transmission Upgrades and Status Report on NCTPC Process under NCUC Docket No. E-100, Sub 190T.

Table L-8: Proposed Red Zone Expansion Plan (RZEP 1.0) Project Status

Project	Owner	Project Description	Cost Estimate[1]	Planned In-Service Date
Lee 100 kV (Lee-Shady Grove)	DEC	Rebuild	$39,660,000	Aug 2025
Piedmont 100 kV (Lee-Shady Grove)	DEC	Rebuild	$40,080,000	Aug 2026
Newberry 115 kV (Bush River-DESC)	DEC	Rebuild	$34,583,000	Apr 2025
Clinton 100 kV (Bush River-Laurens)	DEC	Rebuild	$86,091,000	Oct 2026
Cape Fear Plant-West End 230 kV Line	DEP	Rebuild	$83,033,000	Jun 2026
Erwin-Fayetteville East 230 kV Line	DEP	Rebuild	$95,826,000	Jun 2026
Erwin-Fayetteville 115 kV Line	DEP	Rebuild	$24,083,000	Jun 2025
Fayetteville-Fayetteville Dupont 115 kV Line – 3.2-mile section	DEP	Rebuild	$15,574,000	Dec 2024
Milburnie 230 kV Substation	DEP	Redundant Bus Protection	$5,205,000	Apr 2026
Weatherspoon-Marion 115 kV Line	DEP	Rebuild	$21,167,000	Dec 2025
Camden Junction-DPC Wateree 115 kV Line	DEP	Rebuild	$15,909,000	Dec 2026
Robinson Plant-Rockingham 115 kV Line	DEP	Rebuild	$42,293,000	Jun 2027
Robinson Plant-Rockingham 230 kV Line	DEP	Rebuild	$49,020,000	Jun 2026
Fayetteville-Fayetteville Dupont 115 kV Line – 4.9-mile section	DEP	Rebuild	$15,574,000	Apr 2026
Camden-Camden Dupont 115 kV Line[2]	DEP	Rebuild	$9,372,000	Nov 2024

Note 1 : Cost Estimate is fully burdened with contingency and can change over the project life cycle due to labor and materials costs.
Note 2 : Upgrade proposed to be included in NCTPC 2023 Local Transmission Plan.

Impacts for Standalone Storage Interconnections

Large scale standalone storage will continue to migrate to proactively selected sites such as retired coal sites that should minimize network upgrades relative to early projects and potentially garner the additional 10% Inflation Reduction Act of 2022[29] ("IRA") energy community tax credit. Additionally, locating standalone battery storage at transmission substations near load centers where the land availability for solar is not required should reduce the need for transmission network upgrades as well. In addition, the existing communications infrastructure can be leveraged at these locations.

[29] Inflation Reduction Act, S. Con. Res., 117th Cong. (2022).

Transmission Planning for Enabling an Orderly Transition with Coal Plant Retirements

The Companies must plan the transmission system to enable and execute an orderly utility system transition and achieve the Plan's target schedule for retiring the Companies' coal-fired generating units in North Carolina. The schedule for coal unit retirements is further addressed in Appendix F (Coal Retirement Analysis) and Chapter 4 (Execution Plan). The transmission planning team works closely with the Companies' Generation and Transmission Strategy team to ensure coordinated and executable planning for coal unit retirements and potential replacement generation. DEC and DEP transmission planning groups perform coal unit retirement assessments based on assumptions for replacement generation in order to analyze potential impacts to the DEC and DEP transmission systems. Critical to the results of the assessments are: 1) location and size of the coal-fired generation being retired; 2) the year of retirement or sequence with other generators retiring; and 3) the size and location of replacement generation. If the replacement generation can be located at the site of the retiring coal generation and utilize the existing interconnection to the same electrical point of interconnection, there will likely be minimal to no network upgrades required for the replacement generation and the schedule for interconnecting the replacement generation will be more certain. Enabling this efficient, timely, and cost-effective replacement of retired coal units is the objective of the aforementioned Generation Replacement queue process that DEC and DEP designed and FERC approved for implementation in 2022. If replacement generation cannot be interconnected to the same electrical point of interconnection as the retiring generation, network upgrades, due to thermal overload issues or voltage support issues, may be required.

DEC

- Allen Station Units 1 and 5: Transmission upgrades will be completed to enable retirement of the remaining Allen Station Units 1 and 5 are planned to be retired by the end of 2024.

- Cliffside Unit 5 (earliest planned retirement date December 2030): Planning analysis does not identify any major transmission upgrades to be required from Cliffside Unit 5 retirement.

- Marshall Station Units 1-4 (earliest planned retirement date Marshall 1-2 December 2028; Marshall 3-4 December 2031): Retirement of any Marshall coal units, if by the end of 2028, will require replacement generation on site coincident with retirement. If any Marshall coal units are retired and not replaced with new generation on-site, then significant transmission projects will be needed (i.e., upgrade McGuire to Marshall 230 kV lines currently shown in Table L-2 to be in-service in 2031 coincident with retirement of Marshall 3-4) and in service by December 2028. The project will also allow removal of Marshall generation from reliability must run status if performed earlier than the planned retirement date. A Generation Replacement Request for Marshall Plant Units 1 and 2 replacement generation (780 MW of advanced CT generation) has been submitted to the Generation Replacement Coordinator for study in accordance with the Generation Replacement queue process approved by FERC and provided in the OATT. Also, in accordance with the OATT, the 140 incremental MW above the 780 MW replacement generation necessary to achieve Network Resource Interconnection Service for the full 920 MW capacity[30] of the 2 advanced CTs has been submitted as an interconnection request into the 2023 DISIS.

- Belews Creek Units 1-2 (earliest planned retirement date December 2035): Belews Creek units will continue to operate into the 2030s and DEC plans to evaluate transmission upgrades to enable retirements as the planned retirement date approaches. However, preliminary analysis does suggest that transmission upgrades will be required to retire the 2,220 MW of capacity at Belews Creek if not replaced with new generation on-site and coincident with the retirements.

DEP

- Roxboro Station Units 1-4 and Mayo Unit 1 (earliest planned retirement dates Roxboro 3-4 December 2033; Roxboro 1-2 December 2028; Mayo 1 December 2030) will cause the need for additional transmission projects if the generation is not replaced sufficiently at the Roxboro and/or Mayo sites coincident with the retirements. If the Roxboro/Mayo generation is not replaced by new generation at the same location, but within DEP, then some transmission projects will be required. It is likely that a static var compensator would be needed in the DEP northern region along with some other moderately small transmission upgrades with an estimated cost of less than $100 million. A Generation Replacement Request for Roxboro Plant Units 1 and 2 replacement generation (1,053 MW of gas fired CC generation) has been submitted to the Generation Replacement Coordinator for study in accordance with the Generation Replacement queue process approved by FERC and provided in the OATT. Also, in accordance with the OATT, the 313 incremental MW above the 1,053 MW replacement generation necessary to achieve Network Resource Interconnection Service for the full 1,366 MW capacity[31] of the gas-fired CC has been submitted as an interconnection request into the 2023 DISIS.

- Currently, there is no available long-term firm import capability from DEC to DEP. Thus, if the Roxboro/Mayo replacement generation is located in DEC and requires import into DEP, then additional upgrades would be required. Conceptual transmission projects that would likely be needed would be a Durham-Parkwood Tie 500 kV interconnection, a Bynum 500/230 kV Switching Station interconnection along with associated line upgrades, and potentially a Roxboro Plant-Sadler Tie 230 kV interconnection.

Actual retirement dates may extend beyond the planned retirement dates identified in the Plan to avoid power system reliability issues. Generation retirement reliability assessments will continue to be updated with results provided in future iterations of the Carolinas Resource Plan.

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[30] 920 MW capacity represents the maximum winter output capacity for coldest ambient temperatures.

[31] 1,366 MW capacity represents the maximum winter output capacity for coldest ambient temperatures.

Transmission Needed to Enable Additional Pumped Storage Hydro Capacity at Bad Creek

As described in Appendix I (Renewables and Energy Storage), the planned Bad Creek II project will increase the capacity of the Bad Creek pumped storage hydro facility from 1,640 MW to approximately 3,320 MW with an 80-year asset life resource. To determine the transmission needs for injecting an additional 1,680 MW of energy into the transmission system at the Bad Creek point of interconnection, a generator interconnection request was submitted into the 2022 DISIS. The recent 2022 Phase 2 DISIS study report[32] identifies that approximately $455 million of network upgrades are assigned to the Bad Creek II project, which is a significant portion of the total upgrades in the DEC 2022 Cluster. Approximately $153 million of the $455 million of network upgrades are identified solely for the Bad Creek II project. However, several solar and battery projects in 2022 DISIS are also contributing to certain of the same network upgrades identified as needed to interconnect the Bad Creek II project. Specifically, approximately 645 MW of standalone solar and 534 MW of standalone battery resources are dependent on several of the same network upgrades as the Bad Creek II project. It is also notable that the $455 million of network upgrades identified as needed in 2022 DISIS Phase 2 is less than the $627 million assumed to develop the network upgrade cost proxy for this resource utilized for capacity expansion modeling.

Near-Term Transmission Needed to Enable Onshore and Potential Offshore Wind Resources

Appendix I addresses feasibility, technology and other considerations associated with planning, siting and installing onshore and offshore wind resources in the Carolinas. This section addresses the transmission required to support onshore and offshore wind as a resource in the Carolinas. The transmission needed to interconnect offshore wind was evaluated through a 2020 NCTPC planning study, dated June 7, 2021, which Duke Energy has used along with its own internal analysis to inform the Companies' strategy around installing offshore wind as a resource plan resource. In addition, for onshore wind, the results of a siting feasibility study are key inputs to assessing potential transmission upgrade needs for this resource type.

Onshore Wind

From Appendix I, the Companies do not currently have onshore wind generation installed in the Carolinas, but the U.S. onshore wind market continues to grow with approximately 146 GW operational nationwide and approximately 40 GW coming online in the last three years. The Companies are expecting to develop onshore wind capacity, with 1,200 MW identified in Chapter 4 as needed to come

[32] Duke Energy Carolinas, LLC 2022 Definitive Interconnection System Impact Study Phase 2 Report – Rev. 1 July 7, 2023, available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DRAFT_2022_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report_rev1.pdf.

online by 2033 to transition to a diverse and reliable clean energy portfolio. Additionally, the Companies have initiated a siting feasibility study to understand areas suitable for onshore wind development within the Carolinas.

Interconnection of onshore wind facilities will be another variable the Companies will continue to monitor. Once an appropriate site is identified and site control established for the development of an onshore wind facility, the next critical risk is interconnection of that generator. Similar to other generation resources needed to execute the capacity additions identified in the Resource Plan, interconnection is also a critical path item for the execution of onshore wind. In addition to the fact that there are a limited number of interconnection projects that can be constructed and interconnected in a given year, onshore wind resources could be located farther from population centers than other generation resources, resulting in more complex and expensive interconnection projects, which further exacerbates this constraint.

As stated in Appendix I, proximity to existing transmission infrastructure was used in the siting feasibility study. However, actual transmission impacts associated with developing onshore wind projects will need to be evaluated in future DISIS clusters and may be impacted by other generator interconnection requests in an earlier cluster or the same cluster.

Offshore Wind

For offshore wind, the first step to address the transmission infrastructure challenge was to determine the best point of interconnection of the offshore wind generation to the DEP transmission network. Based on the 2020 NCTPC study and Duke Energy's own internal analysis, the Companies determined that the New Bern 230 kV substation would be the most appropriate point of interconnection for both the Kitty Hawk and the Carolina Long Bay Wind Energy Areas, due to having higher MW capability at relatively lower cost. However, Duke Energy continues to assess alternate points of interconnection for offshore wind to consider IRA benefits and cost of infrastructure changes for interconnection and bulk power transfer of appreciable offshore wind energy into the Carolinas and impacts to transmission system power flows.

The 2020 NCTPC study screened 32 potential injection sites and based on the injection capability and cost results of that screening analysis, further analyzed the feasibility and costs of injecting up to 5,000 MW of offshore wind power at the three most promising sites based on those criteria in eastern DEP. The power from the offshore wind plants was delivered 40% to DEP and 60% to DEC. Rather than studying pre-determined MW levels, it was requested that NCTPC find the MW breakpoints at which transmission upgrades would be needed. As reflected in the 2020 NCTPC Offshore Wind Study Report,[33] the New Bern 230 kV substation would be one of the three most promising sites to inject up to 3.2 GW of offshore wind based on cost and feasibility. No other site stood out for both high MW capability and relatively lower cost, but two additional sites were selected to provide geographic diversity — the Greenville 230 kV (selected for high initial MW screening levels, though with higher

[33] North Carolina Transmission Planning Collaborative, Report on the NCTPC 2020 Offshore Wind Study, June 2021, available at http://www.nctpc.org/nctpc/document/REF/2021-06-07/W_Doc/2020_NCTPC_Offshore_Wind_Report_06_07_2021-FINAL%20Rev%202.pdf.

cost per watt) and the Sutton North 230 kV switching station (relatively low cost per watt but only up to 2,500 MW). After the power flow screening of 32 potential injection sites, the site that stood out for high MW injection capability at relatively lower cost was DEP's New Bern 230 kV substation. The New Bern 230 kV substation benefits from already having five 230 kV lines, two of which head in the direction of the DEP Raleigh load center. In addition, DEP has a partial 500 kV right-of-way ("ROW") available from New Bern 230 kV to Wommack 230 kV and a full 500 kV ROW from Wommack 230 kV to Wake 500 kV, which is located just east of Raleigh. These unused ROWs were used in the study to add new 500 kV lines to maximize the injection capability at New Bern 230 kV. The study indicated that no new network transmission was required in DEC to import a share of the offshore wind output.

Additional internal analysis estimated the full transmission cost for a landing area commensurate with sourcing offshore wind from Kitty Hawk or Carolina Long Bay (see Figure L-3 below[34]) and injecting from 800 MW up to 1.6 GW of offshore wind into a New Bern 230 kV point of interconnection.[35] These estimates reflect the cost of radial transmission interconnection facilities from the offshore wind source to the New Bern point of interconnection and then transmission network upgrades from New Bern to the Wake 500 kV substation of $1.3 billion to $2.7 billion for injection of 800 MW up to 1.6 GW of offshore wind into New Bern, respectively. Under the existing generator interconnection cost allocation rules, the cost of the radial transmission interconnection facilities from the offshore wind source to the New Bern substation would be assigned to the wind generation developer. The schedule associated with siting, permitting and constructing this transmission is dependent on public engagement, routing, scoping and acquisition of new ROW for new 500 kV DC and 500 kV AC transmission lines that will be required to import up to 1.6 GW of wind. Delays in these schedule dependencies are key risks in meeting any timeline for importing offshore wind energy. Seeking to mitigate this risk, as well as lowering cost for customers for this resource, DEP has collaborated with the NC Department of Environmental Quality ("NCDEQ") State Energy Office to submit an application for $250 million of Department of Energy ("DOE") funding for a 500 kV line from New Bern to Raleigh needed to support the import of offshore wind energy into the Carolinas. This networked transmission line will also support new interconnections of solar, solar paired with storage and potential onshore wind sites. The 2023 NCTPC study scope includes 800 MW of offshore wind, in addition to 12.5GW of solar and solar paired with storage, which will provide a clearer picture of what network upgrades may be needed to accommodate these resources injecting power into the eastern DEP transmission system.

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[34] Carolina Long Bay formerly known as Wilmington East.

[35] Kitty Hawk offshore wind will be viable prior to Carolina Long Bay offshore wind due to being further along in the process of having leased OSW area as well as its Construction and Operations Plan with BOEM.

Figure L-3: BOEM – North Carolina Designated Wind Energy Areas

Figure source: Bureau of Ocean Energy Management

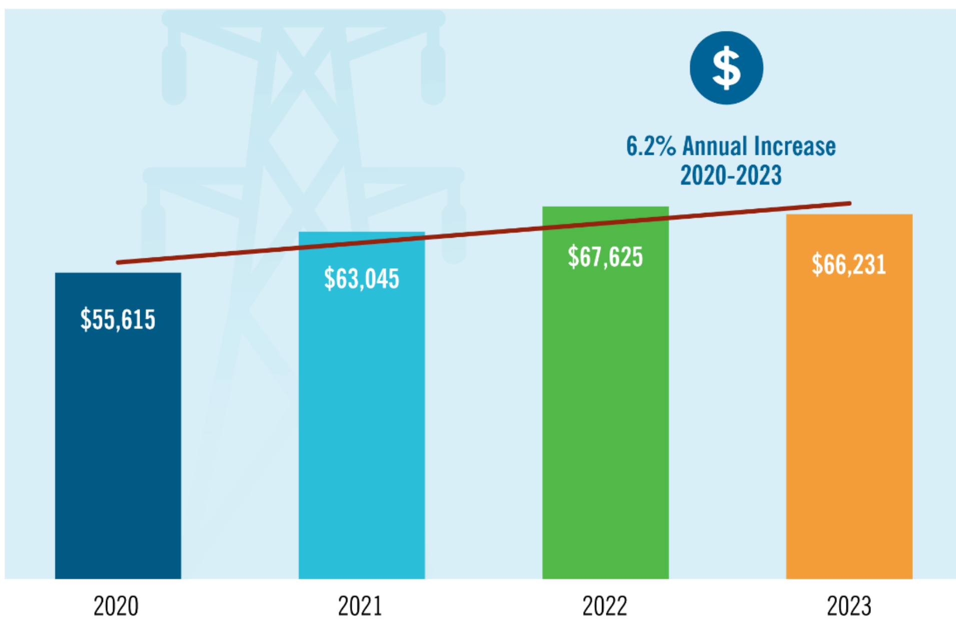
Transmission Needed to Support Importing Capacity and/or Energy from Neighboring Systems (Southern Co, TVA, PJM)

DEC and DEP continue to explore import capabilities for alternative capacity resources to consider in the Carolinas Resource Plan. In the 2022 resource plans, Duke Energy performed import capability studies specifically for a capacity purchase from PJM and to continue to assess costs, risks and reliability aspects of potential off-system purchases. Duke Energy conducted the analysis in a manner that would ensure reliability of the bulk electric system, both through the execution of the proposed transmission upgrades, as well as the coordinated timing of an off-system purchase with proposed generation retirements.

Import Capability from PJM

The process to study a capacity purchase from PJM to DEP involves submitting the applicable Transmission Service Reservation or Network Integrated Transmission Service request on the PJM and DEP OASIS sites, respectively. The request must be for firm transmission service to ensure the continued reliable operation and deliverability of energy from PJM to DEP. PJM's current Border Rate is $66,231/MW-year to purchase Long-Term Firm Point-to-Point transmission service. At the current rate, a 1,000 MW service request would cost approximately $66 million/year to reserve the transmission service. This cost excludes the cost of the capacity resource(s) and energy cost utilizing the transmission service and any identified upgrades on the Duke Energy transmission system needed to enable the imported capacity and energy. The PJM Border Rate has increased 6.2% annually on average since 2020, as illustrated in Figure L-4 below. The PJM Border Rate is based on transmission investment in PJM. As the entire country is focused on the transmission buildout necessary to support the ongoing energy transition resulting in significant coal retirements and distributed resource additions, the level of transmission investment in PJM and thus, the PJM Border Rate, is likely to continue to increase in future years.

Figure L-4: PJM Border Charge, 2020–2023



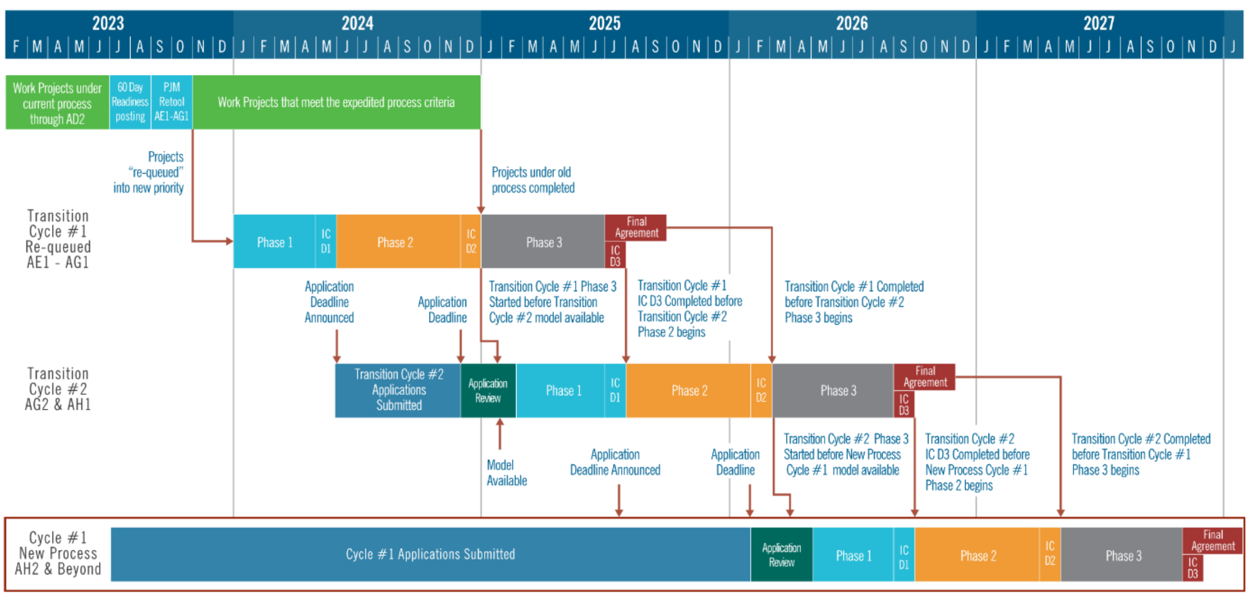
As Transmission Service Providers, PJM and DEP each study transmission service requests consistent with their respective OATT provisions and approve the requests accordingly, subject to the completion of transmission facility upgrades or modifications. Presently, there is no Long-Term Firm Point-to-Point Transmission Service available from PJM to DEP unless several costly transmission network upgrades are implemented. In the initial 2022 proposed Carbon Plan, it was estimated that significant system reinforcement projects are needed on both the PJM and DEP transmission systems to enable such import capacity with initial cost estimates starting at approximately $700 million. This is consistent with previous transmission service requests submitted to PJM[36] by DEP, as well as DEP's own Affected System studies and supported by DEP's own analysis of PJM system limits utilizing the PJM Generator Deliverability tool developed by Power-GEM. The PJM Generator Deliverability tool is

[36] PJM Feasibility Study Report – Long-Term Firm Transmission Service/OASIS Assignment Reference 4966477, 4966479, and 4966484 Queue Project AE1-110/AE1-111/AE1-112 — to be provided upon request.

utilized by PJM in the analysis of the PJM Generator Interconnection Queue, including the analysis of Long-Term Firm Transmission Service requests.

Upon evaluation of previous PJM and DEP feasibility studies and Affected System Studies, as well as utilizing the same study tools and PJM queue data, a 1,500 MW transfer was studied from PJM to DEP. The results of this study indicate the need to upgrade transmission facilities in both PJM and DEP, both requiring significant time and expense. The PJM queue reform process presents additional uncertainty with predicting the timing of implementing a new Transmission Service Request. DEP has submitted a request for 1,000 MW for Firm Point-to-Point Transmission Service from PJM to DEP. This request was submitted into the queue window AH2 and is expected to be processed in accordance with the dark red outlined transition process shown in the revised process flow diagram Figure L-5 below. The expected milestone dates for the Firm Transmission Feasibility Study based upon the below timeline for DEP's transmission service request ("TSR") submittal into queue window AH2 is for the Transmission Service Request to be studied sometime within 2026 with Final Agreements made in late 2027. The revised queue reform transition process flow diagram is found in PJM's redlined Manual 14H – New Service Requests Cycle Process.[37]

Figure L-5: PJM Revised Queue Process Flow Diagram



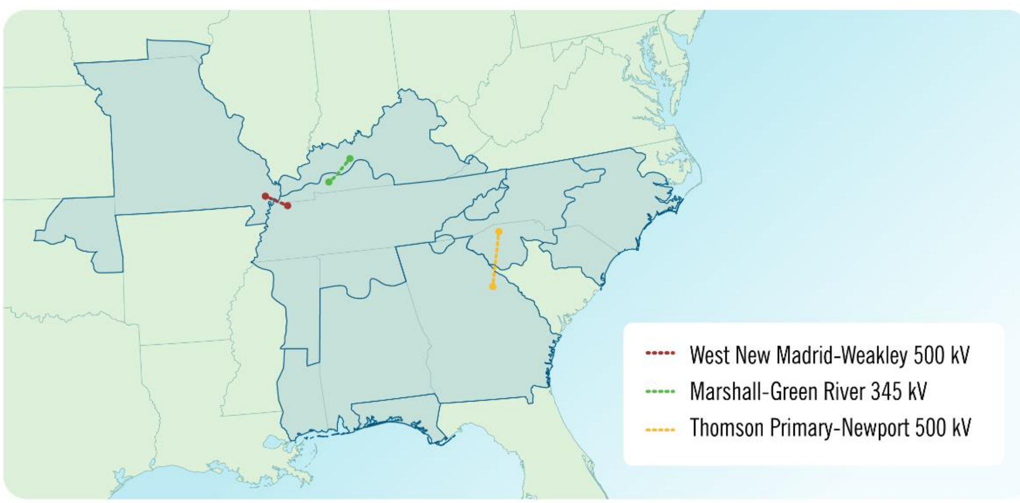
[37] PJM Manual 14H: New Service Requests Cycle Process, available at https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230525/20230525-item-06c---m14h-redlined.ashx.

Import Capability from Southern Company

The 2021 SERTP Regional Transmission Planning Analysis[38] performed Regional Analysis of Potential Transmission Project Alternatives between the Southern Company and DEC areas, shown below in Figure L-6. A transmission project was evaluated as a 140-mile, 500 kV transmission line with one termination point at the Thomson Primary 500 kV substation in Georgia within the Southern Balancing Authority Area and the other termination point at the Newport 500 kV substation in South Carolina within the DEC Balancing Authority Area.

Although the project alternative did not reveal any local projects that it would displace, the project would add single contingency transfer capability between Southern Company and DEC since the main contingency between the two areas, currently the Oconee-South Hall 500 kV line, would no longer be the sole 500 kV path between the two areas.

Figure L-6: SERTP Regional Analysis of Potential Transmission Project Alternatives



The planning level estimate for the Thomson Primary-Newport 500 kV transmission line is approximately $792.5 million. Additional underlying 500 kV, 230 kV and 100 kV upgrades could be necessary and would be identified in a TSR study if submitted on each Company's OASIS site. Other potential options would be to study a Thomson Primary-Richmond 500 kV transmission line possibly looping through a new substation in the Dominion Energy South Carolina VC Summer Plant area.

Import Capability from TVA

Current import capability into DEC and DEP from TVA is subject to contract path limitations. The contract path limit for DEC is 692 MW and for DEP is 276 MW. The primary concern with the DEP

[38] Southeastern Regional Transmission Planning, Regional Transmission Planning Analysis, November 2021, available at http://www.southeasternrtp.com/docs/general/2021/2021-SERTP-Regional-Transmission-Planning-Analyses-Summary-Final.pdf.

path is there is only one tie-line between DEP and TVA. Another risk with a purchase from TVA is that TVA's system experiences a high level of transmission congestion and curtailments as referenced in the 2022–2023 SERC Regional Risk Report.[39] Furthermore, as indicated in Winter Storm Elliott, TVA most likely does not have any surplus winter capacity.[40]

Risks Associated with Off-System Capacity Purchases

The system risks associated with relying on significant incremental off-system capacity purchases for resource plan needs include, but are not limited to:

- Delay in resource availability: If required transmission network upgrades on the DEC/DEP transmission systems or neighboring transmission systems are delayed due to siting, permitting or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource.

- Loss of local ancillary benefits that are inherent with an on-system resource (e.g., Voltage/Reactive Support, Inertia/Frequency Response, Automatic Generation Control/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding static var compensators for voltage support.

- Curtailment due to transmission constraints and/or capacity emergencies in neighboring areas such as occurred on December 24, 2022.

- Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

- Other systems have aging coal generators and are retiring units at the same time as Duke Energy. For example, TVA plans to retire its 865 MW Bull Run plant at the end of 2023, its 2,470 MW Cumberland coal-fired plant by 2028 and all remaining coal-fired generation will be retired by 2035.[41]

Southeast Energy Exchange Market

The Southeast Energy Exchange Market ("SEEM") is a unique regionally coordinated approach to enhancing sharing of economic energy through automation of the bilateral market. The SEEM platform facilitates sub-hourly, bilateral trading, allowing participants to buy and sell power close to the time the energy is consumed, utilizing available unreserved transmission. Participation in SEEM is open to any

[39] SERC Reliability Corporation, 2022-2023 Reginal Risk Report, available at https://www.serc1.org/docs/default-source/committee/ec-reliability-risk-working-group/2022-23-serc_regional_risk_report_final.pdf page 40.

[40] Tennessee Valley Authority, After Action Report / Winter Storm Elliott, available at https://bloximages.newyork1.vip.townnews.com/local3news.com/content/tncms/assets/v3/editorial/4/3e/43e4b436-eb67-11ed-a87a-530b1c4c2bd9/645537f5cd9d7.pdf.pdf.

[41] Tennessee Valley Authority, Power System (Coal), available at https://www.tva.com/energy/our-power-system/coal/.

entity that meets the criteria. DEC and DEP customers will see cost and environmental benefits because of the platform.

The current SEEM Members are Associated Electric Cooperative Inc., Dalton Utilities, Dominion Energy South Carolina, DEC, Duke Energy Florida, DEP, Georgia System Operations Corporation, Georgia Transmission Corporation, JEA, Louisville Gas & Electric Company and Kentucky Utilities Energy, Municipal Electric Authority of Georgia Power, N.C. Municipal Power Agency No. 1, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Seminole Electric Cooperative, Southern Company, Tampa Electric Company and TVA. These SEEM members represent 23 entities in parts of 12 states with more than 180,000 MW (summer capacity; winter capacity is nearly 200,000 MW) across two time zones. These companies serve the energy needs of more than 36 million retail customers (nearly 60 million people).

DEC and DEP started executing purchase and sales of economic energy matched through the SEEM platform on November 9, 2022. SEEM facilitates as-available economic energy exchanges that optimize benefits and rely on available non-firm transmission capability provided by all SEEM Members. This available non-firm transmission capability is transmission capability utilized on a 15-minute period basis that would otherwise not be utilized. From inception through May 2023, DEC and DEP have entered into over 16,000 SEEM trades with an estimated benefit of over $1 million. These benefits are expected to grow as the market matures and as new SEEM members and participants — Duke Energy Florida, Tampa Electric, JEA and Gainesville Regional Utilities — are integrated into the SEEM platform with the ability to participate in SEEM transactions.

On July 14, 2023, the D.C. Circuit Court of Appeals issued its opinion on appeals of the FERC's orders accepting the SEEM Agreement and certain Member's related OATT revisions. The 2-1 majority opinion granted certain aspects of the appeals, denied others and ordered that the case be remanded back to the FERC for further explanation. Parties have the opportunity to seek rehearing of the Court's opinion until August 28, 2023. If there are no rehearing requests filed, the Court is expected to issue an order remanding the case back to the FERC. During the rehearing period, SEEM remains operational and the SEEM Members are continuing to evaluate next steps to support SEEM's operation and preserve the customer benefits that SEEM generates.

New Greenfield Transmission Needed to Achieve Long-Term Transmission System Transformation

The 2023 NCTPC Public Policy Request Study will study retirement of 6,200 MW of coal generation by 2033, as well as the transmission system needs to reliably interconnect and deliver to load almost 24,000 nameplate MW of additional resources by summer 2033. The 2023 NCTPC Public Policy Request Study Scope Document[42] states that the study is intended to identify the future year(s) that it is projected that greenfield 230 kV and/or 500 kV transmission lines would be needed. The study

[42] North Carolina Transmission Planning Collaborative, 2023 NCTPC Public Policy Request Study Scope Document, June 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-06-12/2023_NCTPC_Study_Scope_06_12_2023%20_FINAL_DRAFT.pdf.

would also utilize the 2033 Summer case and 2033/2034 Winter case with resource additions and generation retirements to be aligned with the initial 2022 proposed Carbon Plan P1 Portfolio for DEC and DEP. The study results and any identified greenfield 230 kV and/or 500 kV transmission line needs will be discussed and included in the NCTPC study report and will be included in future Carolinas Resource Plans along with recommendations for potential transmission expansion projects.

Assessment of Transmission System Upgrade Cost Impacts of Carolinas Resource Plan Portfolios

In this section, the estimated transmission network upgrade cost for the Carolinas Resource Plan Portfolio P3 Base is provided. These network upgrade costs are determined using representative proxy costs for network upgrades with the capacity expansion plan modeling selection of resources. These proxy costs for network upgrades are representative of the upgrades that would be required for interconnecting solar, SPS, standalone storage, combustion turbine generators, combined cycle generators, wind generation and small modular reactors to each of the DEC and DEP transmission systems. The proxy costs are derived from the results of the 2022 DISIS Phase 1 Study or assessments of transmission upgrades needed to enable interconnection of the particular resource type.

The identification of required transmission network upgrades is highly dependent upon assumptions of location, MW capacity of the interconnection requested, resource/load characteristics and other queued requests evaluated in the cluster. Also, consistent with current requirements of the OATT, actual network upgrades and transmission projects necessary to support the various resource plan portfolios will need to be planned and developed either in response to specific generator interconnection requests or through the other FERC-approved transmission planning processes such as the local transmission planning process discussed in this Appendix.

Applying the transmission network upgrade proxy costs to transmission network upgrades needed to enable the interconnection of new resources for Portfolio P3 Base resulted in the cumulative transmission network upgrade cost estimates reflected in Table L-9 below.

Table L-9: Portfolio P3 Base Transmission Upgrade Cost Estimate ($M)

Transmission Area	2030	2035
DEC	$1,489	$5,397
DEP	$1,323	$3,378

Execution and Risk Management

Integrated transmission planning and timely construction of the significant transmission projects that will be needed to retire coal generation and interconnect new resources selected in the Carolinas Resource Plan present a key interdependency and timing risk.

Iterative interconnection study process: Location, MW of the interconnection requested, resource/load characteristics and other clustered queued requests, both individually and in aggregate, are inputs that are determinativeso of the transmission network upgrades required to reliably accommodate interconnection requests. While requests for transmission service and generator interconnection provide definitive details for these inputs, as some requests move forward while others do not, the aggregate impact of these modeling inputs change, thus yielding a range of results — both in terms of cost and time to interconnection — for required transmission network upgrades. For this reason, transmission planning must be a continual and iterative process to calibrate transmission plans to objective and verifiable transmission needs.

Red zone constraints: Several common transmission upgrades on the DEC and DEP transmission systems were repeatedly shown to be needed for the interconnection of new solar resources identified in the resource plans through past interconnection studies such as the Transitional Cluster Study, as well as the aforementioned supplemental studies identifying the need for the RZEP 1.0 projects. The Local Transmission Planning Process was utilized in assessing and including these common transmission upgrades in the 2022–2032 NCTPC Plan. Utilization of the Local Transmission Planning process will continue to be needed to identify transmission needs and solutions to those needs to relieve these high solar viability region transmission constraints.

Strategic transmission planning: If the pathway for planning, development and construction of all transmission projects is limited to the traditionally reactive generator interconnection process, the timeline for interconnecting resource plan-identified resources is likely to be adversely impacted. The proposed revisions to the NCTPC local transmission planning process that are under development will offer a more strategic route to transmission planning needed to interconnect resource plan-identified resources in a timely manner. The first group of strategic transmission planning projects to resolve red-zone constraints was supported through past generator interconnection studies, such as the Transitional Cluster Study and the validating supplemental studies. Likewise, the second phase of RZEP projects has been identified through the 2022 Phase 1 DISIS studies. Future transmission expansion plans and resulting projects will most likely be identified or validated through a revised local transmission planning process framework based on scenario analysis and identification of projects with multiple benefit streams. The Companies are planning to participate with the NCTPC in a more comprehensive 2023 study of the long-term transmission needs to meet the needs of the resource plans. Furthermore, upon FERC approval of the revisions planned for the local transmission planning process, a more robust, transparent and coordinated strategic planning process will be available for identification and validation of future transmission projects.

Long-term greenfield needs: Upgrades of existing transmission lines, although very successful with enabling interconnections of near-term identified resource plan resources, will not be sufficient to interconnect later phases of incremental resources associated with resource plan implementation. New transmission infrastructure with new rights-of-way will likely be required toward 2030 and through the 2030s to enable resource interconnections and economic energy transfers. The 2023 NCTPC Study[43] should assist the Companies with identifying potential future greenfield needs.

Coal retirement replacement: Potentially significant transmission upgrades could be required to facilitate the retirement of coal units if replacement generation is not developed commensurate with the retirement of the coal units and interconnected at the retiring generation brownfield site. In 2022, FERC accepted DEC and DEP's filing for a revised interconnection process for replacement generation. This new generation replacement queue process will be critical to efficient, timely and cost-effective replacement of retired coal-fired generation with new generation that interconnects at the same electrical point of interconnection where the retiring generation is located, thereby saving the cost of potentially expensive interconnection facilities that would be required if the same replacement generation was constructed at a greenfield site. DEC and DEP are already leveraging this new process with requests to replace retiring coal generation at the DEC Marshall Plant and at the DEP Roxboro Plant.

Pumped Storage Hydro: Completing the significant number of transmission projects to support interconnection of Bad Creek II, a 1,680 MW expansion of the current Bad Creek capacity and staying on schedule with the year the resource has been selected in the Resource Plan will require starting these transmission projects in 2024. As noted previously in this Appendix, several solar and battery projects in 2022 DISIS are also dependent on certain of the same network upgrades identified as needed to interconnect the Bad Creek II project.

Offshore wind: Completing transmission projects to support interconnection of offshore wind as a diverse resource in the resource plan portfolio will be challenging from a timing and scheduling standpoint. To enable offshore wind interconnection to the DEP system, new ROW and major transmission construction will be required, involving supply chain, siting, permitting and construction risks, as well as risks associated with acquiring the new ROW. Delays in these schedule dependencies are key risks in meeting any timeline for importing offshore wind energy. Seeking to mitigate some of the scheduling risk, as well as lowering cost for customers for this resource, DEP has collaborated with the NCDEQ to submit an application for $250 million of DOE funding for a 500 kV line from New Bern to Raleigh needed to support the import of offshore wind energy into the Carolinas. This new 500 kV line would also support solar and SPS, as well as potential onshore wind resources.

Off-system purchases: System risks associated with relying on significant incremental off-system capacity purchases for resource plan needs include, but are not limited to, delay in resource availability, loss of local ancillary benefits that are inherent with an on-system resource, thus requiring more on-system transmission upgrades, curtailment due to transmission constraints and/or capacity emergencies in neighboring areas and transmission system stability issues.

[43] North Carolina Transmission Planning Collaborative, 2023 NCTPC Public Policy Request Study Scope Document, June 2023, available at http://www.nctpc.org/nctpc/document/REF/2023-06-12/2023_NCTPC_Study_Scope_06_12_2023%20_FINAL_DRAFT.pdf.