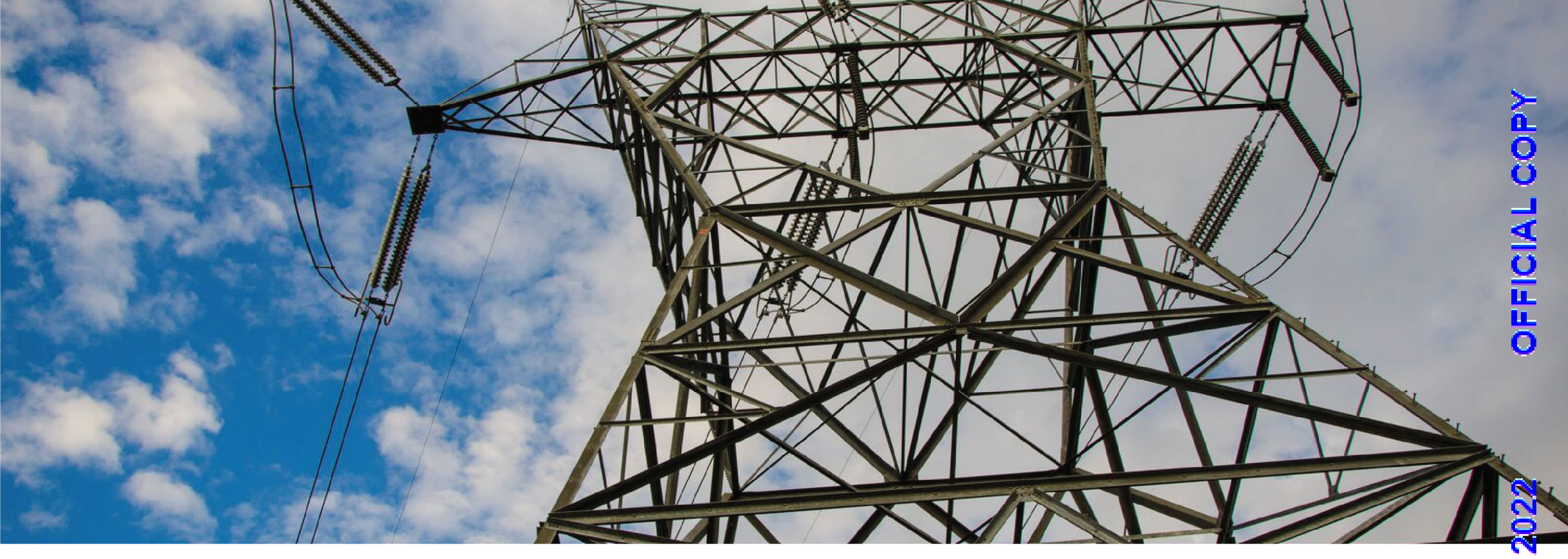

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Transmission System Planning and Grid Transformation

This Appendix discusses transmission requirements and associated cost estimates related to the Carolinas Carbon Plan (the "Plan" or "Carbon Plan") four portfolios proposed to meet the CO_2 emissions reductions and carbon neutrality targets set out by North Carolina Session Law 2021-165 ("HB 951"). Grid edge and distribution requirements are separately discussed in Appendix G (Grid Edge and Customer Programs).

Executing the Carbon Plan requires a transformation of the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke Energy" or the "Companies") transmission system in the near-term and long-term to interconnect the unprecedented amounts of new supply-side resources that will be needed to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets.

As the Companies have discussed with stakeholders, the Carbon Plan will require significant investment in the transmission system on an aggressive timeline to interconnect the significant amounts of incremental new solar, solar plus storage, stand-alone storage, wind, small modular reactors and new natural gas generation resources identified as needed in the Carbon Plan and to reliably retire the coal units that currently support the grid. To meet the challenge of interconnecting the significant supply-side resources required by the Plan while ensuring that the adequacy and reliability of the existing grid is maintained or improved, Duke Energy will both utilize the new annual Definitive Interconnection System Impact Study ("DISIS") Cluster Study process and work through the Federal Energy Regulatory Commission ("FERC") jurisdictional transmission planning process to build out the transmission grid over time. As evidenced by recent generator interconnection study reports, including the recent Transitional Cluster Study,[1] Duke Energy has identified several common transmission upgrades on the DEC and DEP transmission systems that are needed for the interconnection of new clean energy resources. These upgrades need to be implemented in order to meet the Carbon Plan's CO_2 emissions reductions targets in a least-cost manner that ensures system reliability is maintained. Duke Energy and other stakeholders are currently evaluating how best to

[1] DEP OASIS, Generator Interconnection Information, Generator Studies, https://www.oasis.oati.com/cpl/index.html; DEC OASIS, Generator Interconnection Information, Generator Studies, https://www.oasis.oati.com/duk/index.html.

solve these common "red zone" constraints through the North Carolina Transmission Planning Collaborative ("NCTPC") Local Transmission Planning process. The Companies are proposing $560 million in transmission network upgrades for consideration by the NCTPC as needed to achieve the near-term energy transition and CO_2 emissions reductions targets of HB 951.

Another key component to a successful transmission system transformation required by the Carbon Plan is enabling the connection of generation to replace retiring coal units. 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. To enable needed replacement generation to be sited in locations that provide the grid support necessary to ensure continued system reliability, and to be connected efficiently and in a timely and cost-effective manner at the site of the retiring generation, Duke Energy plans to seek FERC approval of a generation replacement queue process.

Existing Transmission Systems of DEC and DEP

DEC and DEP are each Transmission Owners[2] and Transmission Service Providers that independently own and operate transmission systems and provide transmission service under their Open Access Transmission Tariff ("OATT"), which is filed with FERC. DEC has approximately 12,957 miles of transmission and subtransmission lines[3] in North Carolina and South Carolina at voltages ranging from 44 kilovolts ("kV") to 500 kV. DEP has approximately 6,302 miles of transmission lines in North Carolina and South Carolina at voltages ranging from 69 kV to 500 kV. Table P-1 below provides DEC's and DEP's installed transmission by voltage.

Table P-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	3,429	292

Table P-2 below identifies DEC's and DEP's transmission lines and associated facilities 161 kV and above or 100 kV and above networked lines that are under construction or for which DEC or DEP have approved specific plans for construction. In addition, Table P-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 public policy requirements, which are defined as "transmission needs driven by public policy requirements

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

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

established by state or federal laws or regulations."[4] The Companies also identify the need for construction of new or upgraded transmission facilities in response to generator interconnection studies and transmission service requests.

Table P-2: DEC and DEP Transmission Under Construction or Approved for Construction[5]

DEC/ DEP	Year	From	To	Capacity MVA	Voltage KV	Comments
DEC	2023	Mocksville	Idols	450	100	Upgrade
DEC	2023	Allen 230/100 kV Transformer (2)		448	230/100	Upgrade
DEC	2024	Sadler	Dan River	550	100	Upgrade
DEC	2024	Wilkes 230/100 kV Transformer		448	230/100	New
DEC	2025	North Greenville 230/100 kV Transformer		448	230/100	Upgrade
DEC	2026	Hodges	Coronaca	450	100	Upgrade
DEC	2026	North Greenville	Marietta	484	100	Upgrade
DEC	2027	Winecoff	Conley	484	100	Upgrade
DEC	2027	Morning Star 230/100 kV Transformer (3)		448	230/100	Upgrade
DEC	2027	Lancaster	Monroe	700	100	Upgrade
DEC	2028	Wylie	Woodlawn	500	100	Upgrade
DEC	2029	Creto	Coronaca	404	100	New
DEC	2029	Newport Tie	Morning Star Tie	421	230	New
DEP	2022	Asheboro	Asheboro East North Line	307	115	Upgrade

[4] FERC Order No. 1000, at P2. "State or federal laws or regulations" is defined as "enacted statutes (*i.e.*, passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level." *Id.*

[5] Table P-2 includes projects above 161 kV pursuant to Rule R8-60(I)(5) that are under construction or approved by Duke Energy for construction.

DEC/ DEP	Year	From	To	Capacity MVA	Voltage KV	Comments
DEP	2022	Brunswick Plant #1	Jacksonville	1490	230	Upgrade
DEP	2022	LOF	Maxton	202	115	Upgrade
DEP	2022	Wateree (DEC)	Elgin Tap	119	115	Upgrade
DEP	2022	Cumberland	Delco	512	230	Upgrade
DEP	2023	Chestnut Hills	Milburnie	202	115	Upgrade
DEP	2023	Porters Neck Tap	Porters Neck	442	230	New
DEP	2025	Carthage 230/115 kV Transformer Substation		336	230/115	New
DEP	2025	Craggy	Enka	644	230	New
DEP	2026	Arden Tap	Arden	209	115	New
DEP	2026	Castle Hayne	Folkstone	594	115	Upgrade
DEP	2026	Holly Ridge North 115kV Switching Station	JOEMC Folkstone POD	178	115	New

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 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 high-quality 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[6] 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 that 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 TPL-001-4 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 transmission planning ("TPL") assessments and have been studied in the past. 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. Future 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.

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 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") 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 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.

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.

[6] Transmission_Planning_Summary: This document contains an overview of the fundamental guidelines followed by Duke Energy Carolinas, LLC's (DEC) Power Delivery employees to plan Duke'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 Duke Carolinas transmission planning practices and provides links to other Duke Carolinas documents that contain additional detail.

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. DEC and DEP are required to meet mandatory FERC, NERC and SERC reliability standards and planning requirements.

Pursuant to the Energy Policy Act of 2005 ("EPACT 2005"),[7] FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the Bulk Electric System 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 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[8] and internal 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,[9] 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.[10]

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[7] 16 U.S.C. 824o.

[8] *See* SERC Reliability Corp, Standards & Regional Criteria, https://www.serc1.org/program-areas/standards-regional-criteria (last visited May 14, 2022).

[9] A Transmission Service Provder ("TSP") is "[t]he entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements. N. Am. Elec. Reliability Corp., Glossary of Terms Used in NERC Reliability Standards, at 32 (Mar. 2022), *available at* https://www.nerc.com/files/glossary_of_terms.pdf.

[10] https://www.ferc.gov/sites/default/files/2020-06/OrderNo.1000-B.pdf.

Attachment N-1 of the Companies' OATT[11] contains the local, regional and interregional processes by which the Companies meet these requirements. Attachment N-1 has been approved by FERC and requires DEC and DEP to participate in local and regional transmission planning processes that satisfy the transmission planning principles of FERC Order Nos. 890 and 1000 and produce local and regional transmission plans. To meet these requirements DEC and DEP are members of the NCTPC local transmission planning process and the Southeastern Regional Transmission Planning ("SERTP") organization regional transmission planning process. As discussed further below, the development of local and regional transmission plans ensure reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving DEC's and DEP's customers.

On April 21, 2022, FERC issued a Notice of Proposed Rulemaking, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," that proposed revisions to the *pro forma* OATT and LGIA.[12] The Companies are tracking the progress of FERC's proposals through the NOPR process and will continue to implement the transmission planning and generator interconnection procedures discussed here while the proposed rule is under consideration.

Transmission Planning Process

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 is effectuated through the NCTPC. North Carolina's major electric load-serving entities ("LSE"), 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 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. 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.*, lowest overall cost to consumers) transmission system.

As reflected in Attachment N-1, Part I of the OATT,[13] the Local Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or

[11] Joint Open Access Tariff of Duke Energy Carolinas, LLC, Duke Energy Florida, LLC, and Duke Energy Progress, LLC, at 846, *available at* http://www.ferc.duke-energy.com/Tariffs/Joint_OATT.pdf ("Joint OATT").

[12] Fed. Energy. Reg. Comm'n, Notice of Proposed Rulememaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022).

[13] Joint OATT.

loads. 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 customers, whose needs are reflected in their transmission contracts and reservations. A resource supply 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.[14] One Public Policy Request submitted in 2021 is currently being studied by the NCTPC with the draft and final reports expected by June 2022[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.

The NCTPC comprises three main groups that carry 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 advice 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

- **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 of the State of North Carolina and South Carolina served by the NCTPC Participants, include the following:

[14] Joint OATT, Section 5.7.1, p. 801.

[15] N.C. Transmission Collaborative, 2021 NCTPC Study Scope Document (Jun. 7, 2021), *available at* http://www.nctpc.org/nctpc/document/REF/2021-06-07/2021_NCTPC_Study_Scope_06_07_2021_FINAL.pdf

- 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 North Carolina Utilities Commission ("NCUC") and non-LSE stakeholders informed concerning the work undertaken by the NCTPC process;
- Forward the draft Local Transmission Plan Report to the TAG participants for their review and discussion; and
- 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.[16]

This Local Transmission Planning process will be utilized to resolve transmission issues such as those discussed in the "Near Term Challenge: Solving "Red Zone" Upgrades to Interconnect Incremental Resources" section of this Appendix, where other FERC approved pathways are not successful with enabling the transmission network upgrades required to meet a public policy requirement.

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.

[16] Joint OATT, at p. 860.

In compliance with these requirements, the Companies participate in the Southeastern Regional Transmission Planning ("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 the scope and in the 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, the Municipal Electric Authority of Georgia, PowerSouth Energy Cooperative, Louisville Gas & Electric Company and Kentucky Utilities Company, Associated Electric Cooperative Inc., and the Tennessee Valley Authority. 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 regional working groups, including:

- Carolinas Transmission Coordination Arrangement ("CTCA") between DEC, DEP, DESC and SCPSA - a forum for coordinating certain transmission planning assessment and operating activities among the participants;

- 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;

- 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;

- Eastern Interconnection Planning Collaborative: 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; and

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

Generator Interconnection Queue Reform

Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures contained in the OATT and the North Carolina and South 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 ("PURPA"). In 2021, DEC and DEP obtained regulatory approvals from the NCUC, Public Service Commission of South Carolina, and 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. The Transitional Cluster Study is now in phase 2 of the study process and it is expected that by the end of 2022 transition projects will have completed the Transitional System Impact Cluster Study and executed Facilities Study Agreements. The enrollment window for the first annual 2022 DISIS cluster study is now open, and the DISIS Cluster phase 1 study is planned to commence in August 2022. In addition, DEC is completing a Resource Solicitation Cluster queued after the Transitional Cluster Study and ahead of the 2022 DISIS cluster study for purposes of studying and interconnecting solar resources that are bid into the Competitive Procurement of Renewable Energy Program ("CPRE") Tranche 3 request for proposals.

As outlined in the following section, the location of new generating facilities, MW interconnection requested, resource/load characteristics, and prior queued requests, both individually and in aggregate are determinative inputs for the transmission network upgrades required to reliably accommodate an interconnection request, and changes in those inputs can have wide ranging impacts on the required upgrades. Several projects requesting interconnection in the recent Transitional Cluster Study for DEP withdrew their requests due to the allocation of expensive network upgrades that DEP knows will be needed in order to interconnect the volume of solar indicated in each of the potential portfolios presented in this Carbon Plan. Several of these expensive network upgrades revealed in the Transitional Cluster Study were common to those revealed through generator interconnection studies performed under the prior serial queue process, which reinforces the fact that, even under changing assumptions about location, MW size, resource characteristics, and queue order, this set of "red zone" projects will need to accommodate the generation needed to meet the CO_2 emissions reductions targets set by HB 951.

In addition to queue reform associated with the Cluster Study process, DEC and DEP plan to file an additional request in 2022 for FERC approval to revise the Large Generator Interconnection Procedure ("LGIP") contained in their OATT to establish more efficient interconnection processes for certain replacement generation. Dominion Energy South Carolina and Public Service Company of Colorado received FERC approval of similar new generator interconnection replacement queuing process revisions on November 24, 2020, and May 4, 2021, respectively. DEC and DEP's proposed process will be similar to the process authorized for Dominion Energy South Carolina and Public Service Company of Colorado.

FERC approval of a revised interconnection process for replacement generation 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.

Near-Term Challenge: Solving “Red Zone” Upgrades to Interconnect Incremental Resources

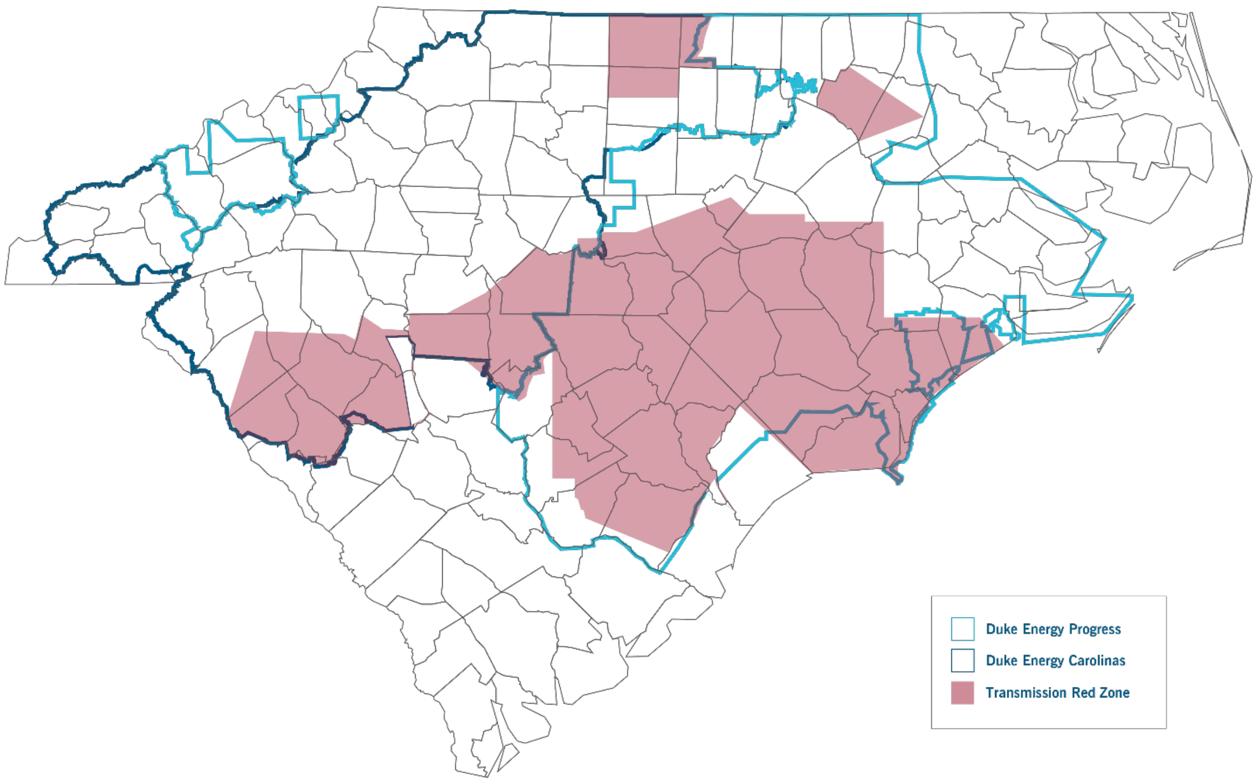
As noted above, both prior serial-queued resource interconnection requests, as well as the recent resource interconnection requests in the Transitional Cluster Study,[17] point to common transmission constraints needing resolution to enable reliable interconnection to the DEC and DEP systems. For example, in the recent DEP Transitional Cluster Study, 35 out of 43 resources requesting interconnection, representing 1,445.9 MW, showed some level of dependency on what are known as the Friesian projects (now withdrawn queue number Q380) network upgrades. These transmission network upgrades consist of a group of five separate transmission lines needing to be upgraded to allow for substantial incremental resource interconnections in the southern and southeastern portions of North Carolina and the Pee Dee region of South Carolina. The Transitional Cluster Study Report (located on the DEC and DEP OASIS sites) reflects that these five projects will take 36 months for the shortest duration project and 66 months for the longest duration project to be placed in-service at a cost of approximately $191 million to enable the generating resources that are dependent on these upgrades to interconnect. As of the commencement of Transitional Cluster Study Phase 2 in April 2022, only 180 MW of DEP-East projects remain in the Transitional Cluster Study process. Thirty projects requesting 1,860 MW of interconnection service withdrew after receiving Phase1 Transitional Cluster Study results that showed an average network upgrade cost allocation around $.17/W.

This scenario is typical for incremental resources requesting interconnection in what is known as the red zone of North and South Carolina for DEC and DEP. Recognizing the importance of procuring new solar resources for the Carbon Plan and mitigating commonly encountered red zone thermal issues, DEP has recently presented the red zone transmission upgrades, indicated in Table P-3 below, to the NCTPC for assessment. These red zone transmission upgrades include the network upgrades that were triggered by the Friesian project, described above, as well as other network upgrades that were often triggered by recent generator interconnection requests.

Figure P-1 below reflects a map of this red zone where significant transmission network upgrades are needed to enable interconnection of certain incremental resources identified in the four portfolios described in Chapter 3 (Portfolios). The red zone is consistent with the location of expensive network upgrades that were identified in the Transmission Cluster Study, as well as several generator interconnection studies performed under the prior serial queue process. As indicated in the 2022 Solar Procurement filing, DEC and DEP intend to continue to provide this type of guidance on the OASIS sites in order to indicate incremental resource locations that will likely incur significant network upgrades to facilitate interconnection to the grid.

[17] Duke Energy Carolinas, LLC Transitional Cluster Study Phase 1 Report (Feb. 28, 2022), *available at* https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-02-28_DEC_TC_Phase_1_Study_Report.pdf; Duke Energy Progress, LLC Transitional Cluster Study Phase 1 Report (Feb. 28, 2022), *available at* https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022-02-28_DEP_TC_Phase_1_Study_Report.pdf.

Figure P-1: DEC/DEP Transmission Red-Zone Map



The Companies intend to move forward to present these initial red zone upgrades to the various NCTPC stakeholder groups discussed above for their input. Subject to following the required process for TAG stakeholder input and coordination and OSC approval as required by the OATT's local transmission planning process, the Companies hope to be able to incorporate this initial set of red zone upgrades into the Local Transmission Plan by mid-year 2022. The Companies will continue to evaluate other transmission system constraints and transmission needs identified through recent generator interconnection studies that need to be solved to achieve near-term public policy goals established by HB 951.

The Companies recognize that a more proactive approach to transmission planning and expansion is needed to meet the Carbon Plan objectives. As stated in the introduction to this Appendix, DEC and DEP have a significant number of generator interconnection studies that point to the same transmission constraints and resulting common transmission network upgrades. If the pathway for planning, development and construction of these transmission projects, which have repeatedly been shown to be needed to support renewable generation, is limited to the traditionally reactive generator interconnection process, the timeline for implementing the Carbon Plan is likely to be adversely impacted. Past experience has shown that generation interconnection requests often withdraw from the interconnection queue after studies are completed and the required network upgrades are not constructed. With HB 951 now providing legislative public policy requirements, the NCTPC process can offer a more proactive route to transmission planning. To that end, the Companies are proposing to the NCTPC and its stakeholder groups that the proactive upgrades listed in Table P-3 below be added to the NCTPC Collaborative Plan by mid-year 2022. The Companies are also planning to participate with the NCTPC in a more comprehensive 2022 Public Policy Request study of the long-term transmission needs to meet the targets of the Carbon Plan.

The upgrades of existing transmission lines reflected in Table P-3 below, although very successful with enabling interconnections of the first phase of Carbon Plan resources, will not be sufficient to interconnect later phases of incremental resources associated with Carbon Plan implementation. Continued iterations of proactive transmission planning within the NCTPC annual process provides the means to identify cost-effective and consensus-driven transmission solutions for future phases of Carbon Plan implementation. The need for greenfield transmission to move beyond 2030 toward the carbon neutrality target in 2050 is discussed later in this Appendix.

Table P-3: Red Zone Upgrades Under Assessment by the NCTPC

Project	Owner	Project Description	Total Cost (FB, w/ contingency)	Estimate Class
Lee 100 kV (Lee-Shady Grove)	DEC	Upgrade	$45,000,000	5
Piedmont 100 kV (Lee-Shady Grove)	DEC	Upgrade	$45,000,000	5
Newberry 115 kV (Bush River-DESC)	DEC	Upgrade	$42,000,000	5
Clinton 100 kV (Bush River-Laurens)	DEC	Upgrade	$109,000,000	5
Cape Fear Plant – West End 230kV Line	DEP	Rebuild	$70,349,010	4
Erwin – Fayetteville East 230kV Line	DEP	Rebuild	$83,933,750	4
Erwin – Fayetteville 115kV Line	DEP	Rebuild	$21,288,975	4
Fayetteville-Fayetteville Dupont 115kV Line – 3.2 mile section	DEP	Rebuild	$14,106,625	4
Rockingham – West End 230kV West Line	DEP	Upgrade	$1,457,875	4
Milburnie 230kV Substation	DEP	Redundant Bus Protection	$4,324,127	4
Erwin-Milburnie 230kV Line	DEP	Rebuild	$5,300,000	5
Sutton Plant-Wallace 230kV Line	DEP	Upgrade	$500,000	5
Weatherspoon-Marion 115kV Line	DEP	Rebuild	$13,000,000	5
Camden-Camden Dupont 115kV Line	DEP	Rebuild	$2,600,000	5
Camden Junction-DPC Wateree 115kV Line	DEP	Rebuild	$10,000,000	5
Robinson Plant-Rockingham 115kV Line	DEP	Rebuild	$38,000,000	5
Robinson Plant-Rockingham 230kV Line	DEP	Rebuild	$43,100,000	5

Project	Owner	Project Description	Total Cost (FB, w/ contingency)	Estimate Class
Fayetteville-Fayetteville Dupont 115kV Line – 4.9 mile section	**DEP**	Rebuild	$11,600,000	5
		Total	$560,560,362	

Transmission Planning for Enabling Coal Generation Retirements

DEC and DEP transmission planning groups have performed 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 generation and utilize the interconnection to the same switchyard, there will likely be 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 intend to file with FERC in 2022. If replacement generation cannot be interconnected to the same switchyard 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 (Planned retirement date December 2023): Transmission planning studies have determined that retiring Allen Units 1 and 5 in December 2023 can be completed with the transmission upgrades (new switching station) already in progress. Note that if the switching station is completed sooner, it would also accelerate the retirement of Units 1 and 5.

- Cliffside Unit 5 (Earliest planned retirement date December 2025): 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 2032): 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) 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.

- 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 2027; Roxboro 1,2 December 2028; Mayo December 2028) will cause the need for additional transmission projects if the generation is not replaced sufficiently at the Roxboro and/or Mayo sites, and 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 300 MVAR 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.

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

Actual retirement dates may extend beyond earliest planned retirement dates identified in the Plan based on system reliability needs or other factors. Generation retirement reliability assessments will continue to be updated and the results will be provided in future Carbon Plan updates.

Near-Term Transmission Needed to Enable Offshore Wind

Appendix J (Wind) addresses feasibility, cost, technology, and other considerations associated with installing offshore wind resources in the Carolinas to meet the 70% CO_2 emissions reductions target. This section addresses the transmission required to support offshore wind in the portfolios included in the Carbon Plan. Portfolio P1 proposes to develop 800 MW of offshore wind by 2030, while Portfolio P2 and Portfolio P4 identify 1,600 MW and 800 MW of offshore wind to be installed by 2032 or 2034, respectively. It is emphasized that the Portfolio P1 timeline is a very aggressive interconnection timeline with supply chain, siting, permitting and construction risks. Completing the required transmission to support these offshore wind injections will be challenging from a timing and scheduling standpoint as new right-of-way and major construction will be required. The transmission needed to interconnect offshore wind has recently been 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 under the Carbon Plan.

The first step to address this challenge is 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 parcels, due to having higher MW capability at relatively lower cost.

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 up to 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,[18] 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 - Greenville 230 kV (selected for high initial MW screening levels, though with higher cost per watt), and the Sutton North 230 kV switching station (relatively low cost per watt but only up 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. 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 its share of the offshore wind output.

Additional internal analysis has estimated the full transmission cost for a landing area commensurate with sourcing offshore wind from Kitty Hawk or Carolina Long Bay (See Figure P-2 below[19]) and injecting from 800 MW up to 1.6 GW of offshore wind into a New Bern 230 kV point of interconnection.[20] 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 $2.39 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. Also concerning schedule risks, any offshore wind seeking to interconnect with the DEP transmission

[18] Report on the NCTPC 2020 Offshore Wind Study (Jun. 7, 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.

[19] Carolina Long Bay was formerly known as Wilmington East.

[20] 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 offshore wind area as well as its Construction and Operations Plan with BOEM.

system will need to submit a generator interconnection request and be studied in the annual DISIS Cluster Study process.

Figure P-2: BOEM - North Carolina Designated Wind Energy Areas ("WEA")

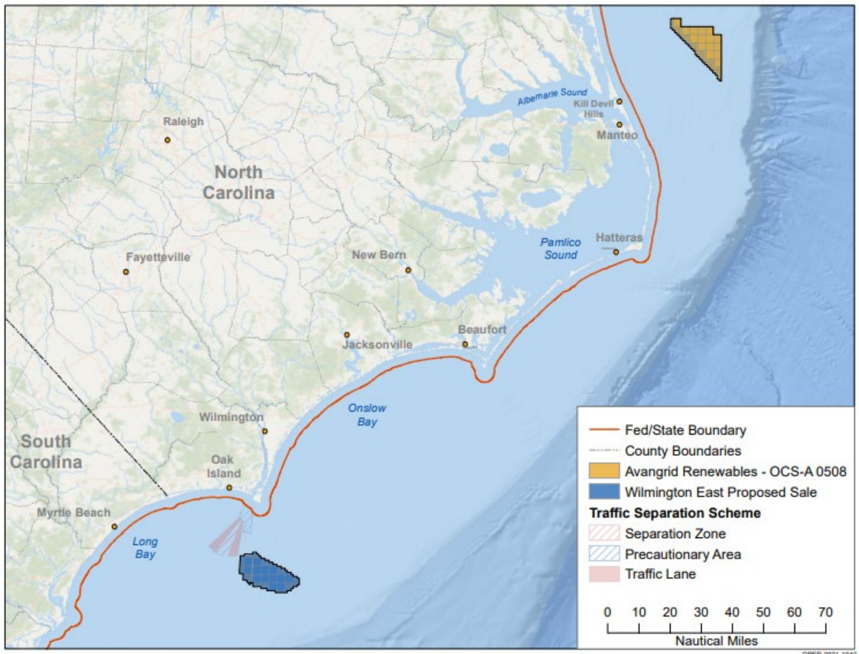


Figure source: BOEM

The screening studies performed to date as part of the 2020 NCTPC study have indicated that 800 MW of offshore wind can be injected at New Bern 230 kV without the addition of major new network transmission lines but with some significant upgrades to the existing system in the New Bern area. The New Bern area transmission upgrades as well as the radial transmission interconnection facilities from the offshore wind generation site to the New Bern 230 kV substation would have to be completed before the 2030 requested date. Under the existing generator interconnection cost allocation rules, the cost of the radial transmission facilities up to the point of interconnection at the New Bern substation will be assigned to the resource. Completing this required transmission construction by the requested date will be challenging.

Studies have also indicated that, to inject 1,600 MW or more of offshore wind at New Bern 230 kV, it is likely that new 500 kV network lines would need to be constructed. The construction of the new 500 kV network lines, in addition to the local upgrades and radial interconnection facilities from the offshore wind generation site to New Bern 230 kV will be quite challenging to complete by the proposed 2032 in-service date in Portfolio P2.

Assessment of Transmission System Upgrade Cost Impacts of Carbon Plan Portfolios

In this section the estimated transmission network upgrade cost for each of the Carbon Plan portfolios is provided. These network upgrade costs are determined using representative generator interconnection system impact studies where possible and transmission planning assessments where representative system impact studies do not exist (e.g., offshore wind) to represent a proxy cost for network upgrades that would be required for interconnecting solar, solar plus storage, standalone storage, combustion turbine generators, combined cycle generators, onshore wind, offshore wind and small modular reactors to each of the DEC and DEP transmission systems.

However, as discussed above, the identification of required transmission network upgrades is highly dependent upon assumptions about location, MW of the interconnection requested, resource/load characteristics, and other clustered queued requests, both individually and in aggregate. Also, consistent with current requirements of the OATT, actual network upgrades and transmission projects necessary to construct to support the various Carbon Plan portfolios will need to be planned and developed either in response to specific generator interconnection requests and the approved generation interconnection process or through the proactive transmission planning processes discussed above.

Estimated Cost of Future Transmission Needs to Facilitate Portfolio P1 (70% by 2030 With Offshore Wind)

Applying the transmission network upgrade proxy costs to transmission network upgrades needed to enable the interconnection of new resources for Portfolio P1 resulted in the cumulative transmission network upgrade cost estimates reflected in Table P-4 below.

Table P-4: Portfolio P1 Transmission Upgrade Cost Estimate ($M)

Year Ending	2030	2035
DEC	$777 M	$1,686 M
DEP	$1,847 M	$2,743 M

Estimated Cost of Future Transmission Needs to Facilitate Portfolio P2 (70% by 2032 With Offshore Wind)

Applying the transmission network upgrade proxy costs to transmission network upgrades needed to enable the interconnection of new resources for Portfolio P2 resulted in the cumulative transmission network upgrade cost estimates reflected in Table P-5 below.

Table P-5: Portfolio P2 Transmission Upgrade Cost Estimate ($M)

Year Ending	2030	2035
DEC	$626 M	$1,663 M
DEP	$1,561 M	$3,098 M

Estimated Cost of Future Transmission Needs to Facilitate Portfolio P3 (70% by 2034 With Small Modular Reactors)

Applying the transmission network upgrade proxy costs to transmission network upgrades needed to enable the interconnection of new resources for Portfolio P3 resulted in the cumulative transmission network upgrade cost estimates reflected in Table P-6 below.

Table P-6: Portfolio P3 Transmission Upgrade Cost Estimate ($M)

Year Ending	2030	2035
DEC	$581 M	$1,630 M
DEP	$1,115 M	$2,132 M

Estimated Cost of Future Transmission Needs to Facilitate Portfolio P4 (70% by 2034 With Offshore Wind and Small Modular Reactors)

Applying the transmission network upgrade proxy costs to transmission network upgrades needed to enable the interconnection of new resources for future transmission needs to facilitate Portfolio P4 resulted in the cumulative transmission network upgrade cost estimates reflected in Table P-7 below.

Table P-7: Portfolio P4 Transmission Upgrade Cost Estimate ($M)

Year Ending	2030	2035
DEC	$480 M	$1,460 M
DEP	$1,285 M	$2,403 M

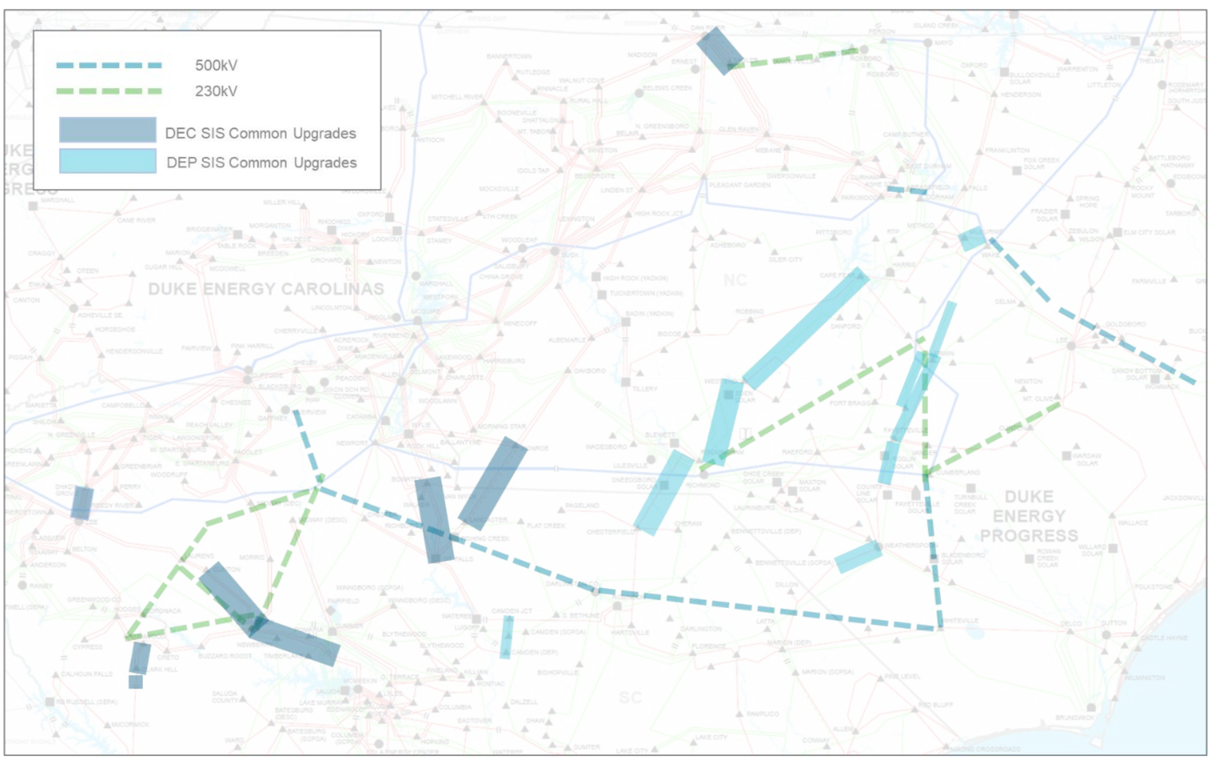
New Greenfield Transmission Needed to Achieve Long-Term Transmission System Transformation

As interconnection of incremental resources and coal-fired generation retirements progress with implementation of the Carbon Plan, more extensive transmission network upgrades will be required to ensure more remote interconnected resources can safely and reliably deliver energy to load centers under various stressed grid conditions (e.g., extreme cold weather, extreme hot weather, summer solar peak output). Upgrades of existing transmission lines, although very successful with enabling interconnections of the first phase of Carbon Plan resources, will not be sufficient to interconnect later phases of incremental resources associated with Carbon Plan implementation. New transmission infrastructure with new rights-of-way will likely be required toward 2030 and through the 2030s to enable Carbon Plan resource implementation. Coordination in forums like NCTPC will help Duke Energy work through how to achieve the Carbon Plan targets of 70% CO_2 emissions reductions and carbon neutrality by 2050.

An example of where this need has already been reflected is shown in the System Impact Study - Partial[21] results associated with DEP Generator Interconnection Requests, Q389 - Q393, for 375 MW of solar facilities in Richmond and Scotland Counties, NC. Analysis of the network upgrades needed to interconnect these facilities revealed the need for a new 75-mile Erwin - Richmond 230kV transmission line at a cost estimated at $225 million. This study result was a driver in the solar facilities' generator interconnection requests being withdrawn.

Figure P-3 below represents a hypothetical example of significant greenfield transmission (represented by the dashed lines) that will be needed as the Companies move beyond 2030 toward carbon-neutral CO_2 emissions. The highlighted transmission on this map likely represents over $7 billion of greenfield transmission and system impact study identified common upgrades needed for interconnecting Carbon Plan resources. Also, it should be noted that greenfield transmission requiring new rights of way can require 10 to 15 years from project start date to in-service date.

Figure P-3: Long-term Transmission Expansion Planning - Example



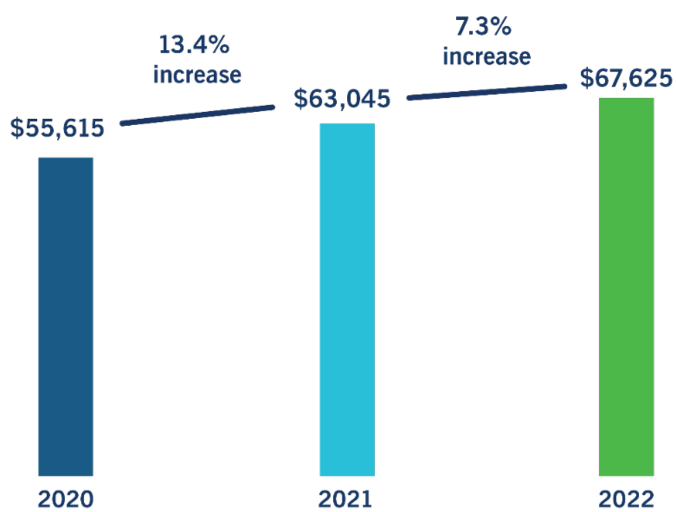
[21] Duke Energy Progress, LLC, Generator Interconnection Impact Study Report: Power Flow Only, *available at* https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/GenImpactStudy_Q389-393_Interim_Power_Flow.pdf.

Assessment of Transmission Needed to Enable a Capacity Purchase from PJM

The Commission's 2020 IRP order directed DEC and DEP to refine 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. In complying with this directive, the Companies must maintain the 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.

The process to study a capacity purchase from PJM to DEP involves submitting the applicable Transmission Service Reservation or Network Integrated Transmission Service ("NITS") 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 $67,625/MW-year to purchase Long-Term Firm Point-to-Point transmission service. At the current rate, a 1,000 MW service request would cost ~$67 million/year to reserve the capacity, plus the cost of the energy provided from the identified capacity resource. The PJM Border Rate has increased 21.5% since 2020, as illustrated in Figure P-4 below and is updated annually. The PJM Border Rate is based off transmission investment in PJM. As the entire country is focused on the transmission buildout necessary to support the clean energy future, the level of transmission investment in PJM, and thus the PJM Border Rate, is likely to continue to increase.

Figure P-4: PJM Border Charge, 2020 - 2022



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. It is 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[22] 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 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 with such upgrades 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. The expected completion date of the Firm Transmission Feasibility Study is pending the outcome of the Interconnection Process Reform Task Force ("IPRTF"). For information, please see the PJM Interconnection Reform Task Force site.[23] For the current PJM Generation and Transmission Interconnection Planning Process Flow Diagram, see PJM Manual 14A, Attachment A.[24]

The system risks associated with relying on significant incremental off-system capacity purchases for Carbon Plan resource 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, AGC/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 in neighboring areas; and

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

[22] ftp://www.pjm.com/planning/project-queues/ltf-phase-1/4966477_ltf1%20(2).pdf.

[23] PJM, Interconnection Process Reform Task Force, https://pjm.com/committees-and-groups/task-forces/iprtf (last visited May 14, 2022).

[24] PJM Manual 14A: New Services Request Process, Revision 29, at 58 (Aug. 24, 2021), *available at* https://www.pjm.com/-/media/documents/manuals/m14a.ashx#page=58.

Execution and Risk Management

Coordinated proactive transmission planning and timely construction of the significant transmission that will be needed to interconnect new resources selected in the Carbon Plan presents a key interdependency and timing risk.

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 determinative 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 have repeatedly been shown to be needed for the interconnection of new solar resources needed to meet the Carbon Plan's CO_2 emissions reductions targets in a least-cost manner that ensures system reliability is maintained. The NCTPC will be considering $560 million of proposed transmission network upgrades to address these constraints in 2022.

Proactive transmission planning: If the pathway for planning, development, and construction of red zone transmission projects is limited to the traditionally reactive generator interconnection process, the timeline for implementing the Carbon Plan is likely to be adversely impacted. The NCTPC local transmission planning process can offer a more proactive route to transmission planning needed to meet carbon reduction objectives. The first group of proactive transmission planning projects to resolve red-zone constraints is supported through past generator interconnection studies. Future transmission expansion plans and resulting projects may need different sources of inputs to be studied within the local transmission planning process framework. The Companies are planning to participate with the NCTPC in a more comprehensive 2022 Public Policy Request study of the long-term transmission needs to meet the targets of the Carbon Plan.

Long-term greenfield needs: Upgrades of existing transmission lines, although very successful with enabling interconnections of the first phase of Carbon Plan resources, will not be sufficient to interconnect later phases of incremental resources associated with Carbon Plan implementation. New transmission infrastructure with new rights-of-way will likely be required toward 2030 and through the 2030s to enable Carbon Plan resource implementation.

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. FERC approval of a revised interconnection process for replacement generation 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, thereby saving the cost of potentially expensive interconnection facilities that would be required if the same replacement generation was constructed at a greenfield site.

Offshore wind: Completing the required transmission to support the offshore wind injections needed to achieve the Portfolio P1 (800 MW block in 2029) and P2 (800 MW block in 2029 and 800 MW block in 2031) timelines will be challenging from a timing and scheduling standpoint as new right-of-way and major construction will be required, involving supply chain, siting, permitting and construction risks, and risk associated with acquiring new ROW. Delays in these schedule dependencies are key risks in meeting any timeline for importing offshore wind energy. An additional schedule risk is presented by the need for any offshore wind seeking to interconnect with the DEP transmission system to submit a generator interconnection request and be studied in the annual DISIS Cluster Study process.

Off-system purchases: System risks associated with relying on significant incremental off-system capacity purchases for Carbon Plan resource 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 in neighboring areas, and transmission system stability issues.

Conclusion

As discussed in this Appendix, significant investment in the transmission system will be needed on an aggressive timeline to interconnect the significant amounts of incremental resources identified as needed in the Carbon Plan and to reliably retire the coal units that currently support the grid. To meet the challenge of interconnecting the significant supply-side resources required by the Plan while ensuring that the adequacy and reliability of the existing grid is maintained or improved, Duke Energy will both utilize the new annual DISIS Cluster Study process and work through the FERC jurisdictional transmission planning process to build out the transmission grid over time to facilitate Carbon Plan and reliability needs.