STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	))))))	**DIRECT TESTIMONY OF DEWEY S. ROBERTS II AND JING SHI ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND OVERVIEW

Q. MR. ROBERTS, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Dewey S. Roberts II (Sammy) and my business address is 3401 Hillsborough Street, Raleigh, North Carolina. I am employed by Duke Energy as General Manager, Transmission Planning and Operations Strategy.

Q. BEFORE INTRODUCING YOURSELF FURTHER, WOULD YOU PLEASE INTRODUCE THE PANEL?

A. Yes. I am appearing on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy") together with Jing Shi on the "Transmission and Interconnection Panel." Witness Shi will introduce herself.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from North Carolina State University in 1987 with a Bachelor of Science Degree in Electrical Engineering. I also obtained a Master of Science Degree in Electrical Engineering from North Carolina State University in 1990 and a Master of Business Administration Degree from North Carolina State University in 2004. I am also a registered Professional Engineer in the state of North Carolina, and I was a Certified System Operator by the North American Electric Reliability Corporation through 2021.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I joined Carolina Power & Light Company, a predecessor of DEP, in 1990 and have held several engineering and management positions in Nuclear Engineering, Engineering and Technical Services, System Operator Training, Portfolio Management, Transmission Services, and System Operations. These positions include Project Engineer, Manager – Transmission Services, Manager – Power System Operations, Director – System Operations, and General Manager – System Operations. In July 2020, I assumed my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I have primary responsibility for the development of mid-term and long-term strategy for Transmission Planning and Operations. This responsibility includes mid-term and long-term planning to support reliable transmission system transformation needed to enable coal plant retirements and to integrate resource plan resources. This responsibility also includes developing strategies and standards for transformed system operations necessary to reliably operate the Duke Energy power systems to facilitate a smooth transition through planned coal plant retirements and integrating increasing amounts of renewable energy resources and storage.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I have testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") and the Public Service Commission of South Carolina ("PSCSC") on several occasions in the Progress Energy Carolinas (now DEP) annual fuel proceedings. I have also testified before the PSCSC in the Companies' 2020 South Carolina IRP proceedings. Most recently, I have testified before this Commission in the 2022 Carbon Plan proceeding in Docket No. E-100, Sub 179 ("2022 Carbon Plan Proceeding").

Q. MS. SHI, PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Jing Shi, and my business address is 411 Fayetteville Street, Raleigh, North Carolina. I am currently employed as Managing Director-Renewable Integration.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Shanghai International Studies University in 1993 with a Bachelor of Art Degree in English. I also obtained a Master of Accounting Degree from Kenan Flagler Business School at University of North Carolina - Chapel Hill in 1998. I am a Certified Public Accountant licensed in North Carolina and have been practicing in the industry since 2000. I am also a member of the American Institute of Certified Public Accountants.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I joined Carolina Power & Light Company, a predecessor of DEP, in 1998 and have held financial, planning, regulatory and renewable energy accounting and management positions of increasing responsibility at Duke Energy. These positions include: Financial Analyst roles in Accounting or Planning to support business planning, acquisitions and divestitures, internal controls, financial reporting, nuclear decommissioning, and implementation of NC Senate Bill 3, Manager - Disbursement Services managing DEP's Accounts Payable services, Lead Renewable Analyst – Distributed Energy Technologies ("DET") leading renewable compliance and analytics, Lead Rates and Regulatory Analyst – Rates supporting Cost of Service and revenue requirement modeling, Manager – DET Data Systems leading the development of renewable database and applications and the deployment of second solar generation meters for the Private Solar Study Project, Director – DET Business Controls and Data Systems leading interconnection system support, financial governance and process readiness for the Company's transition to the cluster study process. In August 2022, I assumed my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I have primary responsibility to manage the interconnection process for the Carolinas and Florida jurisdictions. This responsibility includes administering utility scale interconnection enrollment, studies, interconnection agreements ("IA"), construction and commissioning. This responsibility also includes back-office support for study cost allocation, construction cost allocation, final accounting report, billing, compliance reporting and continuous process improvement.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No.

Q. IS THE PANEL SPONSORING ANY EXHIBITS?

A. No. The Panel is not.

Q. MR. ROBERTS, PLEASE BRIEFLY DESCRIBE THE PURPOSE OF THE PANEL'S TESTIMONY.

A. The purpose of the Panel's testimony is to sponsor one section of Chapter 4 (Execution Plan) and Appendix L – Transmission System Planning and Grid Transformation of the 2023-2024 Carbon Plan and Integrated Resource Plan ("CPIRP" or the "Plan") and to highlight several key transmission and interconnection planning and execution issues addressed in the Plan. Appendix L provides a comprehensive overview and update on transmission system transformation and expansion needed to execute the near-term plan and enable execution of mid-term to long-term plans presented in the CPIRP. It also updates the Commission on the Companies' progress on strategic transmission planning, transmission planning processes, interconnection processes, and utilization of the Federal Energy Regulatory Commission ("FERC")-accepted generation replacement process since the 2022 Carbon Plan was filed. This testimony also addresses specific directives from the Commission's December 30, 2022 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning issued in Docket No. E-100, Sub 179 ("Carbon Plan Order"). As Appendix L explains and this testimony highlights, executing the CPIRP requires transformation of the DEC and DEP transmission systems in the near-term and long-term to retire large amounts of coal-fired generation and to interconnect unprecedented amounts of new supply-side resources while maintaining or improving power system reliability for customers. Safely and efficiently interconnecting these significant amounts of renewable and other resources to the transmission grid is critical to successfully managing the generation fleet transition presented in the Plan.

Q. PLEASE EXPLAIN HOW THE PANEL'S TESTIMONY IS ORGANIZED.

A. Section II of the Panel's testimony identifies the portions of the Plan and the Companies' Requests for Relief presented to the Commission for approval in support of the Plan that this Panel sponsors.

Section III of the testimony addresses how the Companies are meeting specific directives from the Commission's Carbon Plan Order.

Section IV of the testimony discusses the Companies' response to generator interconnection challenges caused by significant anticipated CPIRP resource additions.

II. SPONSORSHIP OF THE PLAN

Q. MR. ROBERTS, ON BEHALF OF THE PANEL, PLEASE IDENTIFY WHICH SECTIONS OF THE PLAN THE PANEL IS SPONSORING WITH ITS DIRECT TESTIMONY.

A. The Transmission and Interconnection Panel adopts and sponsors those parts of the CPIRP describing the Companies' 1) grid transformation in progress to integrate planned resource additions and retirements; 2) updates to the transmission planning processes to ensure FERC accepted processes are in place to evaluate and approve strategic transmission plans that are cost effective, ensure reliability for customers, and enable execution of the resource plan; and 3) interconnection process efficiencies and technical requirements that enable near term action plans to be executed to ensure inverter-based resources ("IBRs") are interconnected without adversely impacting reliability. Specifically, the Panel is sponsoring the following portions of the CPIRP as follows:

- Chapter 4, (Execution Plan) – section on Transmission Planning and Grid Transformation and Table 4-15. This section outlines the Companies' near-term and intermediate-term execution plans related to Transmission System Planning and Grid Transformation.
- Appendix L, Transmission System Planning and Grid Transformation. Appendix L discusses transmission system requirements and associated cost estimates related to the CPIRP for the Companies. Appendix L covers the following topics:
  - 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.
  - Revision of the Local Transmission Planning Process to meet

the changing energy landscape.

- Impact of transmission constraints on ability for solar and solar plus storage ("SPS interconnections").
- The status of current Red Zone Expansion Plan ("RZEP") projects and proposed future projects as well as the need to continue to proactively identify and construct transmission network upgrades that will improve the ability to execute the CPIRP.
- How the RZEP projects and the FERC-accepted Generation Replacement Request process are being leveraged in the execution of the CPIRP for the benefit of customers.
- Interconnection processes and challenges associated with the increasing number of resources planned to be interconnected to the DEC and DEP transmission systems, and the Companies' actions being taken to manage these challenges and risks in a manner that maintains or improves reliability.
- Transmission considerations for coal generation retirements, planned resource supply additions, including pumped storage hydro capacity, offshore and onshore wind, and the potential for off-system resources.
- Execution risks and management of these risks for meeting the transmission needs for executing the CPIRP.

Q. PLEASE IDENTIFY THE REQUESTS FOR RELIEF PRESENTED IN THE COMPANIES' CPIRP PETITION AND BOWMAN EXHIBIT 1 THAT THE PANEL IS SUPPORTING THROUGH ITS TESTIMONY.

A. The Panel supports the CPIRP Petition's Request for Relief 6, which seeks acknowledgement of the proposed RZEP 2.0 projects identified in Table L-7 of Appendix L as in the public interest and part of the necessary and reasonable steps to execute the CPIRP during the near-term.

III. PROGRESS ADDRESSING CARBON PLAN ORDER DIRECTIVES

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. The Carbon Plan Order specifically requires the Companies to take certain actions or provide designated information in future filings. This testimony identifies transmission planning-related requirements and refers to applicable portions of Appendix L of the Plan that address them.

A. Local Transmission Planning Process

Q. THE CARBON PLAN ORDER DIRECTED THE COMPANIES TO TAKE REASONABLE EFFORTS IN ACCORDANCE WITH STATE AND FEDERAL LAW TO UPDATE AND IMPROVE THE LOCAL TRANSMISSION PLANNING PROCESS, INCLUDING INCREASING TRANSPARENCY AND COORDINATION.[1] PLEASE DESCRIBE THE

[1] Carbon Plan Order at 134 (Ordering Paragraph No. 34).

COMPANIES' RECENT EFFORTS RELATED TO THE LOCAL TRANSMISSION PLANNING PROCESS.

A. Appendix L describes the Companies' Local Transmission Planning Process and identifies recent and proposed revisions to the process.[2]

In short, through the development of the 2022 Local Transmission Plan and discussions with the Transmission Advisory Group ("TAG") Stakeholders, the Companies recognized that the Local Transmission Planning Process should be revised to increase transparency and coordination with stakeholders and improve processes to address the challenges of the ongoing generation transition. Accordingly, the Companies, in coordination with the North Carolina Transmission Planning Collaborative ("NCTPC") Oversight/Steering Committee ("OSC"), established a plan to revise Attachment N-1 to the OATT (Local Transmission Planning Process) to accomplish those objectives. Following completion of stakeholder processes, the Companies plan to file the proposed revisions 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 as Figure 1 below.

[2] CPIRP Appendix L at 8-15.

Figure 1: NCTPC Planning Study Process Changes Timeline[3]

These efforts are consistent with the Commission's stated support for NCTPC changes and recommendation to "initiate a review of its processes and quickly implement any improvements that FERC may require in a final rule resulting from the Notice of Proposed Rulemaking in FERC Docket RM21-17-000."[4]

Q. HOW ARE THE COMPANIES AND THE OSC REVISING THE LOCAL TRANSMISSION PLANNING PROCESS TO INCREASE TRANSPARENCY AND COORDINATION?

A. The Companies' efforts to facilitate a transparent and coordinated approach are discussed in Appendix L at pages 13-15.

Q. ASIDE FROM TRANSPARENCY AND COORDINATION IMPROVEMENTS, ARE THERE OTHER REVISIONS TO THE PROCESS THAT WILL BE BENEFICIAL TO CUSTOMERS?

A. Yes. Specifically, as part of the reforms under development, the Local Transmission Planning process would also adopt a muti-value strategic transmission planning approach. This approach is discussed in greater detail on pages 14-15 of Appendix L.

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[3] CPIRP Appendix L at 13 (Figure L-1).

[4] Carbon Plan Order at 121.

Q. AT THIS STAGE IN THE GENERATION TRANSITION, WHY IS DUKE ENERGY MORE FOCUSED ON LOCAL TRANSMISSION PLANNING AND PROJECTS COMPARED WITH REGIONAL OR INTERREGIONAL TRANSMISSION PROJECTS?

A. The Companies' regional and interregional planning efforts are discussed in Appendix L at pages 15-17. The Companies continue to stay engaged with Southeastern Regional Transmission Planning ("SERTP")[5] and will elevate scenarios that are regional in nature to be studied at the SERTP regional level. The current Attachment N-1 Local Transmission Planning process states: "[t]he PWG will determine if it would be efficient to combine and/or cluster any of the proposed scenarios and will also determine if any of the proposed scenarios are of a Regional nature. The OSC will direct the TAG participants to submit the Regional study requests to the SERTP."[6] However, the majority of transmission upgrades identified through the 2022 Definitive Interconnection System Impact Study ("DISIS") Interconnection Studies for enabling resource interconnections are local upgrades (i.e. within the DEC and DEP transmission system boundaries).

Q. THE CARBON PLAN ORDER DIRECTED THE COMPANIES TO "MAKE SEMI-ANNUAL REPORTS IN THE CPIRP SUB-DOCKET

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[5]Attachment N-1, Transmission Planning Process at Section 4.5.4, *available at* oasis.oati.com/woa/docs/DUK/DUKdocs/REDLINE_ATTACHMENT_N-1_with_Proposed_Revisions_to_10.0.0_(8.8.2023)_(for_posting).pdf.

[6] *Id*.

REGARDING THE STATUS OF TRANSMISSION UPGRADES[,] INCLUDING TIMING[,] MILESTONE COMPLETION, AND COST ESTIMATES TO THE COMMISSION PURSUANT TO SECTION 2.5 OF ATTACHMENT N-1 OF THE OATT."[7] HAVE THE COMPANIES PROVIDED THIS UPDATE?

A. Yes. For reference, Section 2.6 of Attachment N-1 of the OATT states: "State public utility regulatory commissions also may seek to receive periodic status updates and the progress reports on the NCTPC Process." In response to the Carbon Plan Order and consistent with this provision of Attachment N-1, DEC and DEP filed their first Semi-Annual Report on Status of Transmission Upgrades and Status Report on NCTPC Process on July 6, 2023 in Docket No. E-100, Sub 190T ("Semi-Annual Transmission Report").

Q. WHAT INFORMATION WAS INCLUDED IN THE SEMI-ANNUAL TRANSMISSION REPORT?

A. The Semi-Annual Transmission Report included three separate, but related items with respect to status of the RZEP upgrades and the aforementioned proposed revisions to the Local Transmission Planning process. First, the Companies reported that all DEP and DEC RZEP projects are proceeding through the project management, engineering, and construction process towards achieving their planned in-service dates. Three RZEP projects' planned in-service dates were accelerated, while none were delayed. In total, the 2022-2032 Plan RZEP 1.0 project cost estimates increased from $554M to $576M,

[7] Carbon Plan Order at 134 (Ordering Paragraph No. 35).

with nine project cost estimates increasing and five decreasing as more refined estimates were developed since the initial proposed Carbon Plan was approved. Second, the Semi-Annual Transmission Report described the Companies' recommendation to NCTPC that a DEP RZEP candidate project, the $9 million, 0.73-mile upgrade Camden – Camden Dupont 115 kV line project ("Camden Dupont Line Upgrade"), be included in the 2023-2033 Local Transmission Plan ("2023 Plan") as a Public Policy Project. The Camden Dupont Line Upgrade has a planned in-service date of December 1, 2024, and has been presented to TAG as part of the 2023 Mid-Year Update to the initial proposed Carbon Plan. Third, the Companies provided an update on the status of the proposed revisions to the Local Transmission Planning process discussed above.

Q. WILL THE COMPANIES CONTINUE TO PROVIDE SIMILAR UPDATES TO THE COMMISSION ON A SEMI-ANNUAL BASIS?

A. Yes.

B. Planning for Strategic Transmission in the NCTPC

Q. HAVE THE COMPANIES BEEN WORKING WITH THE NCTPC REGARDING THE IMPACTS OF PROPOSED TRANSMISSION UPGRADES ON ITS SYSTEM AND THE SYSTEMS OF OTHER LOAD SERVING ENTITIES ("LSEs")?[8]

[8] Carbon Plan Order at 134-135 (Ordering Paragraph No. 37).

A. Yes. Duke Energy has been discussing proposed future network upgrades and associated benefits through NCTPC meetings with the Planning Working Group ("PWG"), the OSC, as well as the TAG stakeholders. Appendix L describes these efforts and proposed projects.[9]

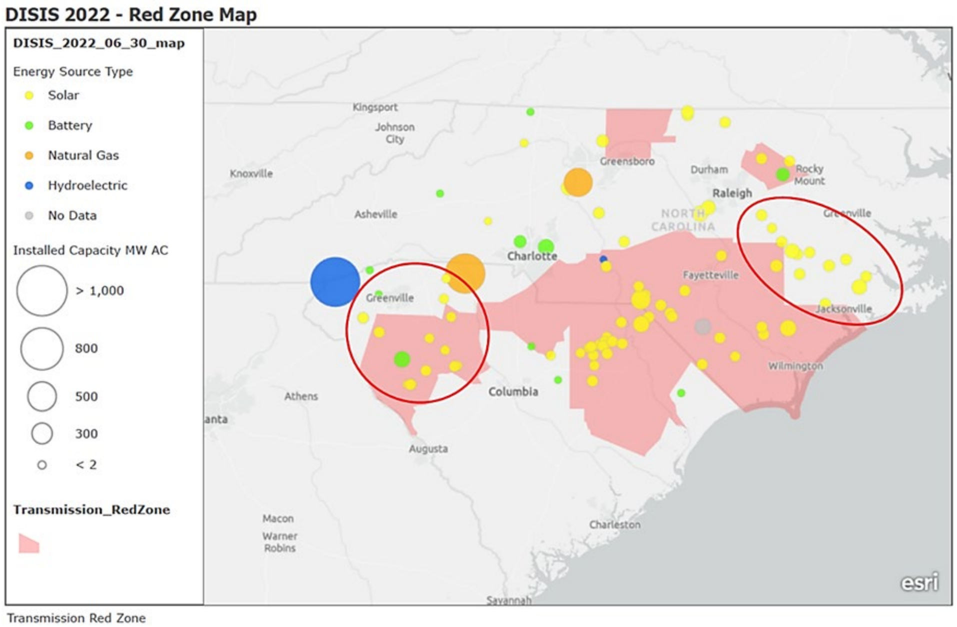
Q. ARE THE COMPANIES REQUESTING COMMISSION ACKNOWLEDGEMENT OF NEW TRANSMISSION PROJECTS IN THE CPIRP AS NEEDED TO EXECUTE THE CARBON PLAN?

A. Yes. As further described in Appendix L, Duke Energy is proposing six new Network Upgrades, referred to as "RZEP 2.0 Upgrades," in the 2023 CPIRP in light of DEC's and DEP's completed 2022 DISIS Phase 1 and Phase 2 studies.[10] For DEC, the Phase 1 study identified multiple upgrades needed to interconnect additional solar and SPS facilities in DEC's South Carolina area (red circle on Figure 2). For DEP, the Phase 1 study identified multiple upgrades, primarily to accommodate solar facilities requesting interconnection along the Jacksonville to New Bern to Goldsboro corridor (red ellipse on Figure 2, below). Based upon the results of the 2022 DISIS Phase 1 Studies, the Companies are proposing a second phase of RZEP projects, shown as Table 1 below, to begin addressing these constraints.

[9] *See* CPIRP Appendix L at 8-10 (describing the NCTPC process); 11-12 (describing results of the 2022-2032 Local Transmission Plan and 2023-2033 plan through the NCTPC); 23-26 (describing projects identified through the NCPTC 2022-2032 Local Transmission Plan, including RZEP 2.0); and 26-27 (providing update on RZEP 1.0 projects).

[10] *See* CPIRP Appendix L at 24-26.

Figure 2: 2022 DISIS Phase 1 Interconnection Requests[11]



Based upon the results of the 2022 DISIS Phase 1 Studies, the Companies are proposing a second phase of RZEP projects, as further supported in Appendix L and shown in Table 1 below, to begin to address these constraints.

[11] CPIRP Appendix L at 25 (Figure L-2).

Table 1: Proposed Red Zone Expansion Plan (RZEP 2.0) Upgrades[12]

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.[13]

Note 2: Class 5 Cost Estimate from the DEP 2022 DISIS Phase 1 Study Report.[14]

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.

Q. PLEASE EXPLAIN THE PROCESS FOR THE NCTPC TO EVALUATE THESE PROPOSED RZEP 2.0 PROJECTS.

A. As presented to OSC, the PWG, as well as the TAG stakeholders, the 2022 DISIS Studies reflected the need for these upgrades. As further validation for these proposed future network upgrades, the NCTPC is conducting a 2023 study

[12] CPIRP Appendix L at 26 (Table L-7).

[13] 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.

[14] 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.

with increased solar and SPS resources in the 2033 summer and 2023/2024 winter timeframes to evaluate the potential transmission needs for executing the interconnection of additional supply resources. Ultimately, the results of the completed 2022 DISIS studies as well as the results of the in progress 2023 NCTPC study will be used to identify the network transmission upgrade projects that are necessary to facilitate additional supply resources, and such projects would then be approved in the 2024-2034 NCTPC Plan.

Q. HAS DUKE ENERGY COORDINATED WITH ALL LSES IN NORTH CAROLINA ON THESE UPGRADES?

A. Yes. The NCTPC local transmission planning process is the mechanism that the Companies utilize to coordinate transmission network upgrades, such as the proposed RZEP 2.0 upgrades, with the LSEs in North Carolina. OSC meeting highlights[15] and the June 21 TAG presentation[16] document Duke Energy's efforts to coordinate with all LSEs in North Carolina on the need for and benefits of the RZEP 2.0 upgrades. As reflected in these meeting minutes and presentation, timing, costs, and benefits have been and continue to be coordinated with the other LSEs in North Carolina.[17]

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[15] *See* North Carolina Dept. of Envt'l Quality, Onshore Wind Energy Program http://www.nctpc.org /nctpc/listDate.do?category=OSC (last visited Sept. 1, 2023).

[16] *See* NCTPC, TAG Meeting Webinar (June 21, 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] Carbon Plan Order at 134-135 (Ordering Paragraph No. 37).

C. Maintaining or Improving Transmission System Reliability

Q. THE CARBON PLAN ORDER DIRECTED THAT, IN EXECUTING THE REQUIREMENTS OF N.C. Gen. Stat. § 62-110.9, THE COMPANIES SHALL NOT ALTER, DELAY OR MODIFY SCHEDULED MAINTENANCE, ASSET MANAGEMENT OR OPERATIONS OR UPGRADES ON ITS SYSTEMS THAT WOULD NEGATIVELY IMPACT THE RELIABILITY OR SERVICE QUALITY TO THE CUSTOMERS OF OTHER LSES.[18] PLEASE DESCRIBE THE COMPANIES' COMPLIANCE WITH THIS DIRECTIVE.

A. As directed by the Commission, the Companies are integrating transmission planning with resource planning to maintain the reliability of the electric system and ensure a least cost path to compliance.[19] As part of the Companies' orderly energy transition to meet HB 951's emissions reductions targets while maintaining or improving reliability, the Commission recognized that power system reliability is non-negotiable for its customers.[20] As stated in Appendix L, outage coordination for scheduled maintenance, asset management programs, or upgrades on its system or to the delivery points of other LSE is a given.[21] For this reason, it is necessary that a limitation on the number of interconnections the Companies can accommodate in a given year and maintain reliability must be a primary factor in determining the addition of resource sizes

[18] Carbon Plan Order at 134 (Ordering Paragraph No. 36).

[19] CPIRP Appendix L at 6-7.

[20] Carbon Plan Order at 36.

[21] CPIRP Appendix L at 20-22.

and locations needed to execute the CPIRP. The real-world limitations on generator interconnections required to execute the resource additions identified in the Plan can be reduced through interconnecting larger facilities and through strategic identification and proactive construction of transmission network upgrades that enable a more efficient interconnection process.

Q. MR. ROBERTS, PLEASE EXPLAIN WHAT TRANSMISSION PLANNING APPROACHES DUKE ENERGY MUST CONSIDER AND IMPLEMENT FOR THE TRANSMISSION SYSTEM TRANSFORMATION NEEDED TO IMPLEMENT THE RESOURCE PLAN.

A. As more fully discussed in Appendix L as well as described above and by witness Shi's testimony that follows, Duke Energy is planning to execute a number of important transmission planning approaches to successfully execute the CPIRP:

1) integrate a multi-value strategic transmission planning approach into the local transmission planning process;
2) continue to identify and proactively construct needed transmission upgrades and consider potential alternatives to traditional upgrades to be able to maintain or improve reliability and to execute the CPIRP through effective planning studies such as the 2023 NCTPC study;
3) transition out of coal generation in a paced and reliable manner and leverage the Generation Replacement process with this transition; and

4) continue to identify and implement interconnection process efficiencies as well as ensure reliability of interconnected resources through initiatives such as the IBR commissioning and monitoring process.

IV. GENERATOR INTERCONNECTION QUEUE IMPACTS TO TRANSMISSION DEVELOPMENT

Q. MS. SHI, HOW DOES THE COMPANIES' GENERATOR INTERCONNECTION PROCESS IMPACT THEIR TRANSMISSION PLANNING PROCESS EXECUTION PLAN?

A. In coordination with proactively planning to meet future needs through the local, regional, and interregional transmission processes as discussed by Mr. Roberts above and as detailed in Appendix L,[22] the Companies also anticipate that the pace, scope, and scale of the significant resource additions identified as needed in the CPIRP will drive increasingly complex interconnections and the need for significant transmission upgrades to enable these generator interconnections. As DEC and DEP continue to implement "first-ready, first-served" cluster studies and develop new practices to advance interconnection timelines and IBR commissioning technical requirements, it has become clear that cooperation and coordination between utilities and third parties is one of the key success factors to progress CPIRP execution while maintaining reliability, as further detailed in Appendix L.[23] This portion of my testimony highlights three issues related to interconnection in more detail: (1) the status

[22] *See* CPIRP Appendix L at 8-17 (describing local, regional, and interregional transmission planning processes).

[23] CPIRP Appendix L at 19-23.

of the process and timing issues caused by market challenges; (2) the Companies' increased focus on reliably interconnecting IBRs; and (3) the Companies' planning for increased transmission outages to meet the generator interconnection needs of the CPIRP while maintaining reliability.

A. <u>Update on Process and Timing Concerns</u>

Q. CAN YOU PROVIDE AN UPDATE ON THE CURRENT INTERCONNECTION PROCESS?

A. As described in Appendix L at pages 17-19, the Companies have successfully completed their transition to the "first ready, first served" cluster study process. Following the transition process, the first annual DISIS cluster commenced in August 2022 and is ongoing. The second annual 2023 DISIS cluster is also in process. Since undertaking the queue reform transition in 2021, all study phases have been completed within required time frames, and the average time to deliver an IA has improved from more than four years under the serial process to two years under the cluster study process (if no restudy is required). In short, the queue reform undertaken by the Companies and approved by the Commission has accomplished a more coordinated and efficient generator interconnection process, as intended.

The Companies are also evaluating process changes to the generator interconnection study process in response to the FERC's July 28, 2023 Final Rule on Generator Interconnection Procedures and Agreements as further described in Appendix L.[24] The Companies are evaluating the Final Rule to determine potential impact, if any, to the DEC and DEP DISIS process and anticipate that their FERC compliance filing will be due in late November. The Companies will provide any necessary updates to the Commission on impacts to the state-jurisdictional North Carolina Interconnection Procedures after the Companies' compliance filing with FERC is made.

Q. HAVE THESE PROCESS REFORMS COMPLETELY ELIMINATED RISKS OF FAILURE TO MEET INTERCONNECTION PROCESSING, STUDY AND CONSTRUCTION MILESTONES?

A. No. While queue reform has promoted project readiness, improved study process efficiency, and reduced speculation in the generator interconnection process, some risk remains both for efficiently processing and studying generator interconnection requests prior to IA execution, as well as for post-IA planning and constructing of the interconnection facilities and network upgrades required to bring new generating facilities online. As described in Appendix L, the Companies continue to see risks to meeting interconnection milestones in this post-IA process based on developer requests to extend project in-service dates due to supply chain disruption, cost inflation, permit issues or change of off-taker dynamics.[25]

[24] CPIRP Appendix L at 18-19.

[25] CPIRP Appendix L at 23.

B. Interconnection and Parallel Operation of IBRs

Q. PLEASE UPDATE THE COMMISSION ON THE COMPANIES' PROCESS FOR ENSURING THE RELIABILITY OF THE TRANSMISSION GRID WITH CONNECTED IBR PLANTS, AS DISCUSSED IN THE COMMISSION'S ORDER IN DOCKET NO. E-100, SUB 101.[26]

A. Appendix L[27] and Appendix M[28] summarize the Companies' efforts to reduce the duration to interconnect facilities, while still ensuring reliable integration of IBRs. The Companies are now implementing a new "Interconnection Life Cycle" verification and validation program for transmission-connected IBR plants.

The Companies released the new IBR interconnection technical requirements on the Companies' OASIS sites in March 2023, and new milestones are now being included in projects' IA (*e.g.*, capability and performance review, plant verification walkdown, and commissioning tests) to facilitate verification during the design and construction phase. To ensure IBR plant model and design reflect what is being commissioned, a new as-built requirement will be completed by the developers to facilitate final validation

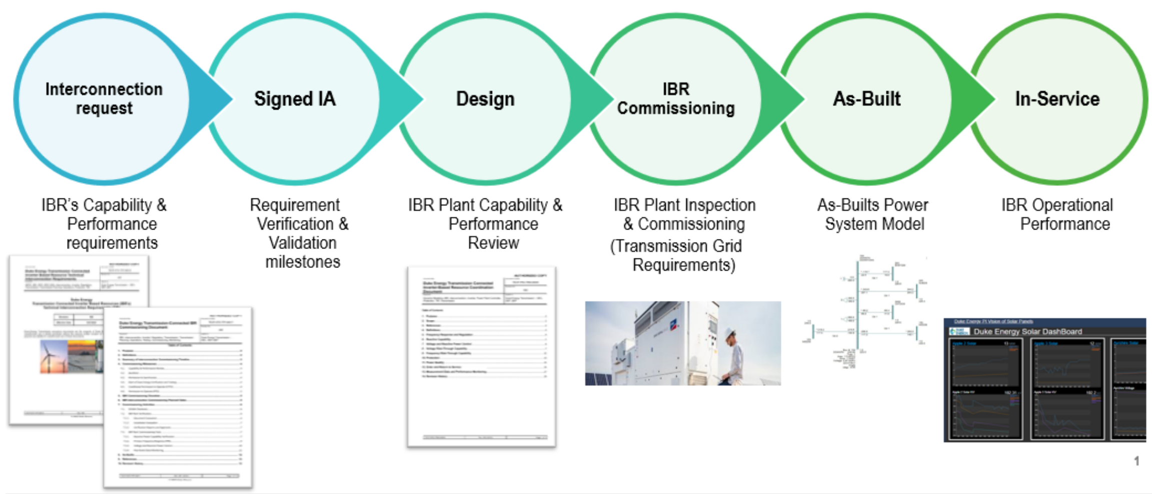
[26] Order Clarifying Generator Interconnection Standards and Requiring Periodic Filing of Information Regarding Risks Posed By Inverter-Based Resources, Docket No. E-100, Sub 101, at 7 (Ordering Paragraph No. 3) (Apr. 13, 2023).

[27] CPIRP Appendix L at 22.

[28] CPIRP Appendix M at 17-19.

before the IBR facility receives full permission to operate ("PTO") status. Post PTO, various operational performance metrics will be used to monitor IBR plants for compliance with these technical requirements. Reliable interconnection and parallel operations of IBRs to the Companies' transmission systems will require collaboration between the Interconnection Customer and Duke Energy to ensure appropriate verification and validation steps are completed throughout the interconnection life cycle. Figure 3 illustrates the new the interconnection life cycle requirements and process improvements.

Figure 3: Transmission-Connected IBR Interconnection Life Cycle Verification and Validation



Q. WHY IS DUKE ENERGY PUTTING SO MUCH EFFORT INTO THE VERIFICATION AND VALIDATION (COMMISSIONING) PROCESS OF SOLAR AND STORAGE TRANSMISSION-CONNECTED IBR FACILITIES?

A. The Companies' efforts are consistent with NERC's and FERC's recognition that interconnection of IBRs can pose reliability risks if not properly considered and carefully integrated. NERC's *Reliability Guideline*: *Improvements to Interconnection Requirements for Bulk Power System ("BPS")-Connected Inverter-Based Resources ("IBR")*, published in September 2019, recommends significant enhancements to transmission owner interconnection requirements per NERC FAC-001 and the modeling and study requirements per NERC FAC-002-4. This guideline served as a pillar for development of the Institute of Electrical and Electronics Engineers ("IEEE") Standard 2800-2022 released in April 2022, which Duke Energy team members helped develop. IEEE 2800-2022 outlines performance and capability requirements for IBR plants connected to the transmission grid. Other peer utilities in the region also have developed and released similar new technical standards and interconnection requirements for IBRs interconnecting to their transmission systems. NERC and FERC have released a number of analyses, recommendations, and rule changes related to IBR integration to the BPS, including the following:

- In June of 2022, NERC released an IBR strategy document outlining the following issues and action plan:[29]
  - The rapid interconnection of BPS-connected IBR is the most significant driver of grid transformation and poses a high risk to BPS reliability.

[29] NERC, Inverter-Based Resource Strategy: Ensuring Reliability of the Bulk Power System with Increased Levels of BPS-Connected IBRs at 1 (Sept. 2022), https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf.

- Implemented correctly, inverter technology can provide significant benefits for the BPS; however, the new technology can introduce significant risks if not integrated properly.
- NERC's IBR Risk Mitigation Strategy is designed to proactively identify and address IBR integration challenges through risk assessment, interconnection process improvements, education, and regulatory enhancements.

- In November 2022, the FERC issued three orders that are intended to address the reliability impacts of the rapid integration of IBRs on the BPS.
  - An order directing NERC to develop a plan to register the entities that own and operate IBRs (but are not currently, so that NERC may monitor their compliance with NERC's Reliability Standards.[30]
  - A Notice of Proposed Rulemaking to direct NERC to develop new or modified Reliability Standards that cover data sharing, model validation, planning and operational studies, and performance requirements related to IBRs.[31]
  - An order approving the revisions to two of NERC's FAC Reliability Standards related to IBRs based on recommendations from a 2020 NERC whitepaper.[32]

[30] Registration of Inverter-Based Resources, 181 FERC ¶ 61,124 (2022).

[31] Reliability Standards to Address Inverter-Based Resources, Notice of Proposed Rulemaking, 181 FERC ¶ 61,125 (2022).

[32] NERC, 181 FERC ¶ 61,126 (2022) (approving revised standards FAC-001-1 and FAC-002-4); *see also* NERC IRPTF, IRPTF Review of NERC Reliability Standards (Mar. 2020), *available at* https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf.

- The FERC's Final Rule on Interconnection Processes and Agreements also incorporates new modeling and ride-through capability requirements for IBRs in FERC's pro forma Large Generator Interconnection Procedures.[33]

To achieve the accelerated pace of IBR interconnection to DEC and DEP's transmission systems called for by the CPIRP, Duke Energy is embracing the regulatory requirements and the necessary planning to mitigate the increasing risks to grid reliability.

C. Planning for Increased Transmission Outages While Maintaining or Improving Reliability

Q. HOW DOES DUKE ENERGY BALANCE PLANNED TRANSMISSION OUTAGES FOR INTERCONNECTION OF SIGNIFICANT LEVELS OF IBRS WITH MAINTAINING OR IMPROVING RELIABILITY?

A. Annually, transmission outages 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 transmission upgrades. As further explained in Appendix L, outage coordination groups currently accommodate close to the maximum number of outages that can be accommodated while maintaining reliable, single contingency operations in accordance with NERC Reliability Standards TOP-

[33] Improvements to Generator Interconnection Procedures and Agreements, Order No. 2023, 184 FERC ¶ 61, 054 at 1621-1743 (2023).

001-5 and IRO-008-2, and prudent outage planning.[34] Outages to accommodate interconnections of resources are additive to the line outages needed each year for numerous other reasons including regular maintenance, NERC preventive maintenance requirements, asset management programs, NERC TPL-001 Standard Upgrade projects, new retail and wholesale delivery points, and outage restoration.[35] Planned line outages also occur primarily in the spring and fall. As discussed in CPIRP Appendix L, an increase in line outages directly proportional to the number of interconnections needed to meet higher levels of solar and SPS resource interconnections annually significantly increases execution risks and requires careful consideration in coordinating outages for interconnection with those required to preserve system operational reliability and reliable electric service for customers.[36] Based on the analysis included in Appendix L, execution risks for the CPIRP increases as the Companies try to accommodate more annual interconnections due to the requirements imposed by NERC Reliability Standards to maintain single contingency operations.

CONCLUSION

Q. MR. ROBERTS AND MS. SHI, DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

[34] CPIRP Appendix L at 20-21.

[35] CPIRP Appendix L at 21 (Table L-6).

[36] CPIRP Appendix L at 20-22.