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)	)))))	**TESTIMONY OF S. LEE RAGSDALE, JR. ON BEHALF OF NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is S. Lee Ragsdale, Jr. My business address is 3400 Sumner Boulevard, Raleigh, North Carolina, 27616.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I have been employed by North Carolina's Electric Cooperatives, the family of three organizations supporting 26 electric cooperatives which includes North Carolina Electric Membership Corporation, which I will refer to as "NCEMC," for the past 17 years, where I currently serve as the Senior Vice President, Energy Delivery in the Power Supply Division. My primary responsibility is to ensure that NCEMC provides a brighter future for the 26 electric cooperatives across the State through innovative edge of grid programs such as our Distribution Operator and the integrated transmission & distribution planning effort to ensure reliable transmission delivery to NCEMC's member cooperatives. I have further responsibility for the development, deployment, and integration of Distributed Energy Resources ("DER") and Microgrids, including solar and energy storage on our members' grid infrastructure.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND, AND IDENTIFY ANY OTHER ACTIVITIES WHICH YOU BELIEVE INFORM YOUR TESTIMONY IN THIS PROCEEDING.

A. I hold a Bachelor of Electrical Engineering from the Georgia Institute of Technology and a Master of Business Administration from Georgia State University. I am also a licensed professional engineer in the State of North Carolina. I have been in the electric utility and energy industry for over thirty-three (33) years in various areas of utility operations and management, risk management, resource planning, portfolio management, modeling, and grid operations. Prior to joining NCEMC in 2007, I held various positions with Progress Energy Ventures (now Duke Energy) in portfolio and asset management, NewEnergy Associates (now Hitachi) in production modeling and long-term planning, and the Southern Company.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY IN THIS DOCKET.

A. Consistent with the Commission's, January 17, 2024, *Order Scheduling Public Hearings, Establishing Interventions and Testimony Due Dates and Discovery Guidelines, Requiring Public Notice, and Providing Direction Regarding Duke's Supplemental Modeling* in this Docket, my testimony is intended to provide the Commission with NCEMC's perspective on the Carbon Plan/Integrated Resource Plan ("CPIRP") filings submitted by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Duke") in this proceeding, including but not necessary limited to CPIRP-related topics such as how the pace of work required of Duke to achieve compliance by 2030 with the carbon reduction goals established in Section 1 of House Bill 951 ("H951"), codified as N.C. Gen. Stat. § 62-110.9, is affecting transmission system planning, the adequacy of the transmission system and, by extension, the maintenance of reliability of the existing grid at least cost; as well as to provide perspective on how grid edge resources of wholesale customers such as

NCEMC can and should be implemented in a coordinated fashion with Duke to maintain and improve system reliability for all customers in North Carolina.

My testimony is also intended to support and supplement the testimony of Amadou Fall also being filed on behalf of NCEMC in this proceeding that further discusses issues related to the critical importance of ensuring reliability is maintained in a least cost manner as Duke and the Commission work towards compliance with the carbon reduction goals established in H951.

II. THE PACE OF WORK REQUIRED OF DUKE TO ACHIEVE COMPLIANCE BY 2030 WITH H951'S CARBON REDUCTION GOALS AND THE IMPACT ON THE LOCAL TRANSMISSION SYSTEM PLANNING PROCESS AND THE ADEQUACY OF THE TRANSMISSION SYSTEM

Q. TO ASSIST THE COMMISSION IN FULFILLING ITS STATUTORY OBLIGATION TO MAKE AN ANALYSIS AND DEVELOP A PLAN FOR THE FUTURE REQUIREMENTS OF ELECTRICITY FOR NORTH CAROLINA, COMMISSION RULE R8-60A DIRECTS DUKE TO DISCUSS THE ADEQUACY OF THE TRANSMISSION SYSTEM. CAN YOU SHARE NCEMC'S CURRENT PERSPECTIVE ON THE ADEQUACY OF THE TRANSMISSION SYSTEM?

A. Yes. Generally speaking, the transmission system is adequate for today's needs, but NCEMC is becoming increasingly concerned about Duke's ability, in its role as transmission planner, to maintain the adequacy of the transmission system during the CPIRP planning period.

H951 directs the Commission and, by extension, Duke to take "all reasonable steps" to achieve targeted, aggressive carbon dioxide ("CO2") emissions reductions in 2030 and 2050 ("Attainment"). NCEMC ascribes to the view that what is reasonable must be informed by what constitutes the least cost path consistent with N.C. Gen. Stat. § 62-110.9, including the section's express authorization to delay Attainment in the event necessary to maintain the adequacy and reliability of the existing grid.

As I cautioned in my testimony nearly two years ago, as a transmission-dependent utility, NCEMC is becoming increasingly concerned that the pace of work required of Duke to achieve Attainment is driving deployment of Duke's limited resources toward work that focuses inordinately on readying the grid for interconnection of new DER to the detriment of wholesale network customers and the adequacy and reliability of the existing grid, including but not limited to the transmission system.

Three examples of how the pace of work required of Duke to achieve Attainment is affecting transmission system planning and the adequacy of the transmission system may help illustrate the basis for NCEMC's increasing concern.

Q. PLEASE PROVIDE YOUR FIRST EXAMPLE.

A. Subsection (f)(6) of Commission Rule R8-60A, what I will refer to as the "CPIRP Rule", contemplates an orderly process in which the CPIRP development process is informed by "the identified needs, as well as planned transmission lines and facilities, appearing in the most recent local transmission planning report that, as identified in that report, could reasonably be placed into service during the Base Planning Period."

The most recent local transmission planning report, entitled "Report on the NCTPC 2023-2033 Collaborative Transmission Plan" ("the 2023 Plan"), was issued by the North Carolina Transmission Planning Collaborative ("NCTPC") on February 22, 2024. The 2023 Plan included 15 first-generation Red-Zone Expansion Plan ("RZEP 1.0") projects as "Public Policy Projects" needing to be placed in service by 2033. The 2023 Plan was the culmination of a local transmission planning process that enabled the NCTPC's Participants, including NCEMC, to consider and vet multiple proposed transmission projects, each of which exceeded a $10 million project cost threshold. NCEMC believes use of the 2023 Plan, in a manner consistent with the CPIRP Rule, is appropriate in this proceeding.

NCEMC believes it is appropriate for any second-generation RZEP ("RZEP 2.0") projects to be presented to the Commission for identification in the CPIRP only after the RZEP 2.0 projects have been fully vetted by the now CTPC process. The CTPC has not yet issued a local transmission planning report addressing any RZEP 2.0 projects.[1] It is anticipated that the 2024 Plan to be issued later this year or in 2025 will include some RZEP 2.0 projects.

The pace of work required of Duke to achieve Attainment has led to injection into this proceeding of several RZEP 2.0 projects for Commission consideration. For example,

[1] As noted in the April 30, 2024 supplemental testimony of Dewey S. Roberts II on behalf of DEC and DEP in this proceeding, Duke filed with the Federal Energy Regulatory Commission ("FERC") on January 12, 2024, modifications to Attachment N-1 of the Duke Joint Open Access Transmission Tariff ("Joint OATT") to rename the NCTPC as the Carolinas Transmission Planning Collaborative, or "CTPC", established a process to study a new category of local transmission projects referred to as Multi-Value Strategic Transmission, or "MVST" Projects; and modified the stakeholder review elements of the transmission planning process. FERC approved the proposed revisions to Attachment N-1 on March 12, 2024.

Duke recently pre-filed the supplemental testimony of Dewey S. Roberts II on April 30, 2024, requesting that the $137 million, 40-mile Lee-Milburnie 230 kV line rebuild be added to the list of RZEP 2.0 projects, stating that the "Lee-Milburnie 230 kV rebuild project is needed to integrate solar, solar paired with storage, and standalone batteries within the DEP East Balancing Authority Area" and tying this RZEP 2.0 project to Duke's ability to "enable the integration of over 1,600 MW of new solar and other generation with the DEP-East transmission system." (Roberts Supplemental Testimony at 3-5).

However, Attainment ought not propel the Commission – especially prior to a project's having been considered by, vetted by, and reported on by the local transmission planning process – to take the unreasonable step of identifying a particular RZEP 2.0 project as necessary in this CPIRP[2]. Taking such a step could have unintended and detrimental impacts on maintaining reliability at least cost and result in piecemeal transmission expansion that could result in development of inefficiently sized or designed, duplicative, or unnecessary transmission facilities that increase costs to customers.

In addition, the pace of Attainment is limiting Duke's ability to study alternatives to the projects, including RZEP 1.0, in the NCTPC report. NCEMC has advocated for

[2] As noted in the April 30, 2024, supplemental testimony of Dewey S. Roberts II on behalf of DEC and DEP in this proceeding "The Companies identified six RZEP 2.0 project, which were informed by the results of the 2022 Definitive Interconnection System Impact Study ("DISIS") Phase 1 Studies. The CPIRP presented the identified RZEP 2.0 projects in Table L-7, which was sponsored by the Transmission and Interconnection Panel's direct testimony. Appendix L also noted that ongoing studies, including the Carolinas Transmission Planning Collaborative's ("CTPC") 2023 public policy study, would further inform the need for the second phase of RZEP projects. (Roberts Supplemental Testimony at 2)

years that a more holistic view is needed rather than a serial break/fix approach that has been done. There is also a need to consider alternatives such as new greenfield line development, coordination with regional transmission planning processes, and consideration of resources such as grid-enhancing technologies ("GETs"). NCEMC recognizes the importance of visibility to grid operators and that FERC provides the transmission providers discretion on whether it should be used, but at a minimum the end-of-year study report should include a detailed discussion of the results. Instead, NCEMC recommends the Commission permit the local transmission planning process to proceed apace with considering, vetting, and reporting on proposed projects, including RZEP 2.0 projects, consistent with the orderly process contemplated by the CPIRP Rule.

Q. PLEASE PROVIDE YOUR SECOND EXAMPLE.

A. Like the Commission, NCEMC and its member cooperatives prioritize maintaining reliability at least cost. Traditionally, the costs of DEC and DEP transmission projects have been assigned to any cost-causer (for example, an interconnection customer or a large load customer) to the extent such direct cost assignment is fair, with the remainder of the costs being allocated to Duke's network transmission customers, including NCEMC, on a load ratio share ("LRS") basis.[3]

[3] For State-jurisdictional interconnections, the directly assigned network upgrade costs remain the responsibility of the interconnecting customer pursuant to Section 5.2 of the North Carolina Interconnection Agreement, adopted as part of the North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections in Docket No. E-100, Sub 101 (October 29, 2021). However, the network upgrade costs for DEC and DEP FERC-Jurisdictional interconnection customers are subject to repayment of the costs of the network upgrades under Duke's Joint OATT, including Section 11.4.1 of the Duke's Large Generator Interconnection Agreement.

NCEMC has long abided by this cost allocation methodology based on a belief that the methodology fairly assigned costs for a reliability-driven or economically- driven project and that said costs were roughly commensurate with the reliability and/or economic benefits.

NCEMC has grave doubts that this cost allocation methodology will fairly assign costs for H951-driven projects and is unconvinced that costs assigned to NCEMC for such projects will be commensurate with the benefits NCEMC enjoys as a result of these projects. NCEMC is particularly troubled by any calculation and assignment of benefits to NCEMC and its members that are based on quantifications of concepts such as avoidance of the social cost of carbon, concepts that this Commission has long deemed unknown and unmeasurable in the absence of a specifically applicable policy, which H951 – vis-à-vis NCEMC – is not.

Duke is the only electric power supplier subject to H951. H951 is prompting Duke to execute a fleet transition; and, as touched upon in the first example above, the fleet transition is prompting Duke to propose local transmission projects such as the RZEP 2.0 projects in addition to the 15 H951-driven first generation RZEP 1.0 projects already included in the 2023 Plan.

H951-driven transmission projects are costly. As articulated in the press release that accompanied publication of the 2023 Plan, “The 2023 Plan, relative to the 2022 Plan, includes one new DEP project resulting from the Public Policy Planning Process. This new project added to the previously identified 14 projects brings the total to around $500 million in new transmission investments for Public Policy projects.”

NCEMC does not question that Duke may "need" a local transmission project to position itself for Attainment; but Duke's need (and the associated benefit Duke enjoys by positioning itself for Attainment) should not be conflated with what NCEMC, or other network transmission customers, which are not subject to H951, needs or benefits from.

Once H951-driven projects are constructed and become used and useful, Duke will seek to recover costs from NCEMC (and Duke's other network transmission customers) on a LRS basis. At that time, NCEMC is likely to challenge the blanket allocation of these policy-driven costs to NCEMC on a LRS basis. At NCEMC's request, and in an effort to ensure proper notice is given of potential future challenges and their possible impact on Duke retail rate risks, the 2023 Plan contains the following caveat: "Inclusion of th[e 15] RZEP projects in the 2023 Plan should not be viewed as an indication of any NCTPC OSC member's position on cost recovery or support for any specific cost allocation approach. … Each [load-serving entity] reserves the right to continue to advocate that the allocation of costs is done in a fair and equitable manner, and to ensure that only reasonable costs are eligible for recovery."

NCEMC would prefer a more robust up-front cost allocation discussion take place prior to the transmission projects being placed in-service and included in the transmission rate base. The Commission and Public Staff, in their February 2, 2024 comments filed with the Federal Energy Regulatory Commission ("FERC") in Docket No. ER24-874 agreed on the importance of appropriate cost allocation, stating that "[t]o ensure that customers in North Carolina pay just and reasonable rates that reflect only the costs caused by those customers, planning and investment by utilities in North Carolina must be laser-focused on, and limited to, the needs of the system to serve those customers adequately and reliably."[4]

As part of its approval of Duke's Attachment N-1 revisions, FERC declined to require Duke to integrate an up-front discussion about cost allocation, finding that Duke's decision to not propose revisions to the default cost allocation under Attachment 1 and instead allow the costs to be recovered under the existing rolled-in rate structure was "sufficient to satisfy Order No. 890's requirement that applicable transmission planning processes 'address the allocation of costs of new facilities,'"[5] FERC further stated that:

> "Duke's FPA section 205 filing does not propose any changes to the Joint OATT sections providing for the costs of Local Projects to be recovered from local transmission customers under the existing rolled-in rate structure. Therefore, we believe that the existing method for assigning the costs of Local Projects among Duke's transmission customers is beyond the scope of Duke's proposal. (*Id.* at Paragraph 64)

However, to NCEMC's knowledge, there is no jurisdictional or other legal impediment to the Commission directing Duke to: (i) integrate an up-front cost allocation discussion into the local transmission planning process; (ii) summarize the discussion in the local transmission planning report shared with the Commission in advance of recurring CPIRP proceedings; and (iii) to ensure that [all] customers in North Carolina pay just and reasonable rates that reflect only the costs caused by those customers.

[4] Joint Comments of the North Carolina Utilities Commission and Public Staff – North Carolina Utilities Commission in FERC Docket No. ER-24-874, at p. 10 (February 2, 2024).
[5] Duke Energy Carolinas, LLC, *Order Accepting Filing*, 186 FERC ¶ 61,178 (March 12, 2024)., at paragraph 60.

As the Commission noted in its December 30, 2022, *Order Adopting Initial Carbon Plan and Providing Direction for Future Planning* in Docket No. E-100, Sub 179 ("2022 Carbon Plan Order"), the "Commission retains certain jurisdiction over transmission facilities under N.C.G.S. § 62-101, over bundled retail rates, and over resource adequacy and generation mix, which is dependent on transmission facilities needed to interconnect generation resources." Recognizing the increasing significance of transmission and potential increased investment in transmission resulting from CPIRP activities, the Commission availed itself of Section 2.5 of Attachment N-1 of Duke's OATT to require periodic status updates and progress reports on the NCTPC process in Docket No. E-100, Sub 190T.

The inclusion of such information in the local transmission planning report and in the updates provided to the Commission in Docket No. E-100, Sub 190T would assist the Commission in assessing the Duke retail rate risks associated with H951-driven projects. For example, such a summary might provide the Commission, in this proceeding, with additional insight into which, if any, H951-driven projects included in the most recent local transmission planning report were preliminarily found by NCEMC (or other transmission customers) to appear to be fair for allocation on a LRS basis and which were not.

The pace of work required of Duke to achieve Attainment should not serve as justification for avoiding an up-front cost allocation discussion. Avoiding such a reasonable step could have unintended and detrimental impacts on maintaining reliability at least cost.

Q. PLEASE PROVIDE YOUR THIRD EXAMPLE.

A. My third example builds upon the testimony I gave in the last CPIRP proceeding, to wit: "RZEP projects should not … be[] prioritized over other transmission projects needed for reliability and maintaining service quality for retail and wholesale customers. To the extent that RZEP projects are accelerated, there should be no delays to Duke's traditional transmission provider obligations, including managing the network reliably, serving current load, and expanding the network to meet load growth and long-term service requests. NCEMC has multiple delivery point repairs and upgrade requests to serve its member-consumers currently being coordinated with Duke that if delayed could result in impacts to the service quality and reliability of service to our member-consumers. Consistent with the requirement in H951 that any resource changes 'maintain or improve upon the adequacy and reliability of the existing grid,' these existing obligations must continue to be met in a timely fashion while additional measures for Carbon Plan compliance are undertaken." (September 2, 2022, Testimony of Lee Ragsdale on Behalf of NCEMC filed in Docket No. E-100, Sub 179, at p. 5).

As illustrated by the first two examples above, the pace of work required of Duke to achieve Attainment is impacting the local transmission planning process and the types of projects being proposed for inclusion in the most recent local transmission planning report.

While NCEMC and Duke are collaborating on seven new delivery points requests, it is NCEMC's opinion that the pace of work required of Duke is also having an impact on other aspects of transmission system planning that fall outside the official scope of the local transmission planning process but nonetheless affect the adequacy of the transmission system. NCEMC believes the pace of work required of Duke to achieve Attainment is contributing to Duke decisions to allocate resources and capital away from certain maintenance and modernization efforts that would benefit NCEMC's members and contribute to greater transmission system adequacy. Over the past two years, Duke has communicated to NCEMC on numerous occasions that its requests have not made it high enough on the priority list to be selected for completion due to Duke's constrained resources, time, and money.

Q. DOES NCEMC HAVE ANY ADDITIONAL PERSPECTIVE ON THE ADEQUACY OF THE TRANSMISSION SYSTEM THAT IT WOULD LIKE TO SHARE?

A. Yes. Maintaining the reliability and adequacy of the transmission system at least cost requires communication and coordination, both of which take time. While public filings such as this one expose gaps in the communication and coordination between Duke and NCEMC, NCEMC would nonetheless like to commend Duke for consistently responding to such filings with renewed attentiveness to the concerns of NCEMC and its members.

By way of example, during the last CPIRP proceeding, I testified that, "When conducting an affected system study Duke must coordinate not only with other transmission providers but also with [load serving entities, such as NCEMC,] to ensure that all affected systems are considered." Since that filing Duke and NCEMC have communicated regarding affected system studies and Duke, in coordinating with NCEMC in advance of a recent FERC Order 2023 compliance filing, did make the following commitment which NCEMC appreciates: "We will notify NCEMC of affected system issues in cases in which our studies show that there may be adverse impacts to NCEMC's system as a result of generator interconnection on the DEC/DEP systems."

III. THE DISTRIBUTION OPERATOR, GRID EDGE TECHNOLOGIES, AND THE USE OF DISTRIBUTED ENERGY RESOURCES

Q. AS BACKGROUND, PLEASE DESCRIBE THE COMMISSION'S CONSIDERATION OF THE GRID EDGE RESOURCES OF DUKE'S WHOLESALE CUSTOMERS IN THE 2022 CARBON PLAN PROCEEDING?

A: In its 2022 Carbon Plan Order, the Commission emphasized the important interrelationships between DEP, DEC, and their wholesale customers from both a reliability and cost perspective. The Commission stated that:

> The Commission recognizes that contractual arrangements between Duke and its wholesale customers associated with the operation of DER, demand reduction measures, and any compensation mechanisms associated with such resources are FERC-jurisdictional. However, the Commission acknowledges the very real potential that coordinated use of these resources has to influence a lower-cost path to compliance with N.C.G.S. § 62-110.9. Therefore, the Commission directs Duke to continue to coordinate with NCEMC and other LSEs in both its ISOP process and the Carbon Plan stakeholder process regarding the utilization of the capabilities of their DER programs and the ability of such programs to contribute to Duke's ability to comply with the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 in a least cost manner that at a minimum maintains or improves the reliability of the entire grid network in North Carolina. (2022 Carbon Plan Order at 112).

In the rulemaking proceeding in Docket No. E-100, Sub 191 that followed the 2022 Carbon Plan Order, the Commission adopted Commission Rule R8-60A(f)(7)(ii) to include the following requirement:

> (ii) The electric public utilities shall discuss the results that are expected from integrated (generation, transmission and/or distribution) systems planning processes, how integrated systems planning is used in the CPIRP process, and the impact of it and their wholesale customers' distributed energy resources and non-traditional solutions on resource planning and load forecasting.

Q. DID DUKE ADDRESS THIS REQUIREMENT AS PART OF ITS 2023 CARBON PLAN FILING?

A: Yes. Duke outlined some of the coordination between NCEMC in its September 2023 CPIRP Filing Appendix G - Integrated System and Operations Planning. NCEMC appreciates the effort and coordination that Duke continues to make, and we look forward to seeing this collaboration continue to mature. It is our hope that these efforts not only complement but inform the long-term transmission system planning to support the adequacy of the transmission system.

Q. HOW HAS NCEMC CONTINUED TO ADVANCE ITS DISTRIBUTION OPERATOR AND COORDINATION OF GRID EDGE TECHNOLOGY TO CONTRIBUTE RELIABILITY BENEFITS TO DUKE'S SYSTEM?

A: NCEMC has made great progress over the last two years with its Distribution Operator, or "DO" platform. These capabilities and coordination were demonstrated during Winter Storm Elliott to deploy DER and participate in load shed to support DEC's and

DEP's system. After the event, NCEMC worked collaboratively with Duke to develop lessons learned and strengthen our coordination efforts.

NCEMC continues to further develop the visibility and coordination with Duke. This includes enhancing load and grid edge resource forecasting to enable the integration of these resources into their reliability and contingency planning efforts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.