NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

October 30, 2024

Carolinas Transmission Planning Collaborative
Attn: Rich Wodyka
Independent Administrator and
Secretary to the Oversight/Steering Committee

Re: Duke's Proposed Red Zone Expansion Plan (RZEP) 2.0 Projects

Dear Rich:

The RZEP 2.0 projects (RZEP 2.0 Projects) are being considered as part of the current 2024 CTPC cycle, as discussed in the September 18, 2024, TAG stakeholder meeting.

Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (collectively, Duke or the Companies), requested acknowledgement of the RZEP 2.0 Projects from the North Carolina Utilities Commission (Commission) in the recent Docket No. E-100, Sub 190 Carbon Plan and Integrated Resource Plan (2023 CPIRP) proceeding.

Duke is proposing the RZEP 2.0 Projects, which are discrete transmission upgrades located in both North Carolina and South Carolina, and in both DEC and DEP territories. These projects follow the RZEP 1.0 projects proposed by the Companies in the 2022 Carbon Plan proceeding in Docket No. E-100, Sub 179. The RZEP 2.0 Projects are not designed to address any current reliability issue; rather, Duke has indicated they are public policy projects intended to interconnect new generation, primarily solar.

The Public Staff is cognizant of the need for and strongly supports holistic transmission planning to meet the needs of the future and provides the following comments as the CTPC considers approval of the Companies' proposed RZEP 2.0 Projects:

1) The Companies did not provide alternatives analyses in the 2023 CPIRP during discovery as requested by the Public Staff. Absent any such alternatives analyses, when coupled with item 2 immediately below, it is impossible to credibly and

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reliably determine if the Companies' proposed projects are reasonable and prudent as long-term transmission investments and solutions.

2) The Companies' proposals, notably the DEC projects, do not reflect sensitivities for the proposed DEC natural gas combined cycle plant, or potential multiple natural gas generation plants.

3) Significant amounts of generation are projected to be built in DEP to serve, in part, the energy needs of DEC. This situation creates a gross imbalance for DEP customers and is in violation of fundamental ratemaking principles.

Detailed discussion:

Issue #1: Alternatives Analysis

The Public Staff has two separate concerns about the Companies' analysis of the RZEP 2.0 Projects.

First, as far as the Public Staff is aware, based upon extensive due diligence and negotiation, the Companies did not conduct an analysis of alternatives to the RZEP 2.0 Projects. In the 2023 CPRIP proceeding, the Companies requested Commission "acknowledgement" of the RZEP 2.0 Projects as being in the public interest and part of the necessary and reasonable steps to execute the CPIRP during the near-term; the Companies made this request despite the CTPC being the proper forum for vetting and ultimately approving such projects. The Public Staff investigated the Companies' proposals as part of its due diligence in that proceeding and raised numerous concerns as articulated in the direct testimony of Public Staff witness Dustin Metz, filed on May 28, 2024, and via in-person expert witness testimony before the Commission.[1] As part of the discovery process in the 2023 CPIRP docket, the Public Staff and the Companies engaged in significant discussion and correspondence related to the need for alternatives analyses and for Public Staff requests for specific line segments to be studied. The Companies did not complete the requested alternatives analyses; as a result, the Public Staff cannot ascertain whether the proposed projects are indeed holistic and reasonable technical solutions for the issues they are meant to resolve. Having investigated this issue for multiple months, the Public Staff does not understand the Companies' basis for asserting that the RZEP 2.0 Projects are in the public interest when they performed no systematic analysis of alternatives.

Second, the Companies have relied heavily on their cost benefit analysis (CBA) as conclusively demonstrating that the RZEP 2.0 Projects are beneficial to customers. The CBA used by the Companies only assesses reliability and resilience benefits. However, the Public Staff believes that the Companies' current CBA approach and project scoring

[1] Metz direct testimony: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=1a11ad50-5671-4eb8-befc-8f1b67daa87f. Also see Docket No. E-100, Sub 190 general: https://starw1.ncuc.gov/NCUC/page/docket-docs/PSC/DocketDetails.aspx?DocketId=7409648d-c9c2-4f42-8709-a0830971812d

is seriously flawed and requires revision. The overall interruption cost estimate (ICE) CBA scoring is partly subjective in nature given the underlying assumptions used in the ICE Excel workbooks. As such, the ICE CBA should not be the sole or disproportionate determinant for deeming a project to be in the public interest, nor should it be the single metric for determining if the benefits outweigh the costs.

For instance, a critical flaw in the Companies' use of the ICE CBA is the Companies' failure to properly account for the fact that older assets <u>will not</u> be replaced in kind. The result of this flaw is that as older assets reach their end of life, they will be designed and built to newer standards that may not match the design or functionality of the transmission upgrade projects being implemented at this time. This has the effect of causing projects to score overly positive in terms of reliability and resilience but provides no information about their relative or incremental benefits as public policy projects. This erodes the benefits – and distorts the value – of the CBA scoring for assessing the RZEP 2.0 projects for their intended purpose, and effectively invalidates the CBA score.

In addition, certain cost categories should be scrutinized to determine whether the proposed transmission line is merely reducing the costs of a specific customer as opposed to providing system benefits, much like the installation of "backup equipment" or "power conditioning" equipment versus equipment that is normally installed or maintained by individual customers regardless of the transmission project (as listed in the ICE Excel workbooks), or is being treated by the Companies as "extra facilities."

Continued sole reliance on the ICE CBA as the basis of and/or support for a project will require increased scrutiny of the ICE CBA. To the extent that the Companies continue utilizing the ICE CBA as the rationale to support public policy transmission projects, the Companies should investigate the appropriateness and the extent to which the benefits emulate plausible actual conditions. Thereafter, the Companies should report their findings in the CTPC and other forums in which the Companies' filings rely upon the ICE CBA for project justification.

Issue #2: Failure to identify future generation assets

The Public Staff and the Companies worked together to identify an analysis methodology for identifying transmission project candidates in RZEP 1.0. However, the Companies' load forecasts have changed, and there is more certainty as to where new natural gas generation resources, and potentially onshore wind, will be located than when the methodology was developed for use in RZEP 1.0.

Specifically, the Companies have filed applications for, or announced their intent to file for, Certificates of Public Convenience and Necessity (CPCNs) for three natural gas plants to be located in North Carolina, one at the existing Marshall Steam Station in

Catawba County,[2] and two at the existing Roxboro Steam Station in Person County.[3] Based upon discovery, meetings, and testimony in these two proceedings, while the Public Staff ultimately recommended approval of two of the requested CPCNs, the Public Staff identified numerous issues with the Companies' decisions to move forward with these proposed natural gas generation plants at Marshall and Roxboro. Notwithstanding these issues and the fact that the scope of that investigation is outside the purview of the CTPC, there exists a level of debate as to where future natural gas generation assets should be located in the DEC and DEP service areas given system needs.

Importantly, the power flow modeling assumptions used in support of the RZEP 2.0 Projects are not reflective of the Companies' current plans to locate at least one combined cycle plant in South Carolina. Also, there is uncertainty as to how many additional natural gas generation plants will be built in the DEC service area, inclusive of both combined cycles and combustion turbines. Interconnection of new natural gas generation assets in the southern and southwestern portions of the DEC system along the Williams Transco pipeline will likely result in interconnections to the 230kV system and/or segments of the 100kV system. As a result, the addition of significant natural gas generation may materially alter Duke's modeling results for its proposed RZEP 2.0 Projects.

Issue #3: Inequity

The Companies have made material changes to their integrated resource plan modeling. Historically, before S.L. 2021-165 (in which the Carbon Plan was required) and the use of EnCompass software for resource planning, DEC and DEP modeled their balancing areas as island cases for purposes of capacity expansion plans. However, the utilization of EnCompass, which coincided with the passage of the Carbon Plan legislation, resulted in modifying the Companies' modeling approaches.

Presently, as allowed by the EnCompass model, Duke models the exchange of energy between DEC and DEP, while using the least cost optimization algorithm to solve for a total system (DEC and DEP combined) cost. The exchange of energy within the modeling software acts as a proxy for the Companies' pre-existing Joint Dispatch Agreement that resulted from the 2012 merger of DEC and DEP (then Progress Energy Carolinas, Inc.).[4] While the overall least cost modeling framework that is being used today is informative, it is not used for rate setting, nor does it consider cost causation.

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[2] Docket No. E-7, Sub 1297.

[3] Docket No. E-2, Sub 1318, Docket No. EC-67, Sub 55, and Docket No. E-2, Sub 1349.

[4] Docket Nos. E-7, Sub 986, and E-2, Sub 998.

In proceedings before the Commission (most recently in the Companies' last general rate cases,[5] CPCN applications,[6] and CPIRP comments and testimony), the Public Staff has repeatedly raised a two-fold concern of ensuring that rates are just and equitable and that cost causation principles have been utilized.[7] The Public Staff has identified both the magnitude of and increase in energy transfers from DEP to DEC, as well as future trends of the same, in both the Companies' modeling and the Public Staff's independent modeling.

The Companies have not challenged the Public Staff's finding that total energy transfers are trending upward from DEP to DEC. Significant generation and transmission projects are being planned, built, and operated in the DEP service territory for, at least in part, the energy needs of DEC customers, while being funded solely by DEP customers.

The RZEP 2.0 Projects being constructed in the DEP service area for the purpose (in whole or in part) of transferring power to DEC will compound the equity issues and cause a further increase in DEP's retail rates without commensurate compensation from DEC. Continued incremental build out of DEP's transmission assets to accommodate generation built to serve DEC load requires scrutiny when an entity, in this case Duke, is proposing proactive transmission projects. Note that DEC's proposed RZEP 2.0 Projects do not have this issue of inequity; only those proposed for DEP.

The Public Staff urges the OSC to require Duke to demonstrate that the RZEP 2.0 Projects have been selected through a holistic planning process that includes robust alternatives analysis and modeling of known sensitivities, such as potential new gas generation plants, and to require that such analysis be shared with TAG participants.

Sincerely,

Dustin R. Metz
Manager, Electric Division
Operations and Planning

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[5] Docket Nos. E-7, Sub 1276, and E-2, Sub 1300.

[6] Docket Nos. E-7, Sub 1297, E-2, Sub 1318, and EC-67, Sub 55.

[7] Docket Nos. E-100, Sub 179, and E-100, Sub 190.