September 15, 2025

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RE: Comments on Preliminary MVST Solutions and Proposed Alternatives

Dear Rich,

The Southern Environmental Law Center, North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, and Sierra Club submit these comments in response to the Carolinas Transmission Planning Collaborative's (CTPC) Multi-Value Strategic Transmission (MVST) draft solutions, as sent via email on August 8, 2025; presented during the August 22, 2025, Transmission Advisory Group (TAG) meeting; and supplemented on August 29, 2025.

We appreciate the opportunity to provide feedback on the CTPC's draft solutions. However, our comments below focus less on the tentative solutions the CTPC has proposed and more on the process that produced them. We and many other stakeholders had high hopes for the potential of the MVST process. To our knowledge, it promised to represent the only example nationally of proactive, multi-value transmission planning conducted on a purely local level. The MVST appeared to be a perfect complement to the resource planning processes in Duke Energy's service territories in North and South Carolina, as it seemed poised to enable co-optimized transmission expansion alongside the substantial generation investments identified by the North Carolina Utilities Commission (NCUC) and South Carolina Public Service Commission (PSCSC). Only a true integration of generation and transmission planning can achieve the necessary systemwide build-out in an efficient, cost-effective manner.

The initial returns of the first MVST cycle do not appear to have met this potential. The draft solutions proposed by the CTPC largely resemble those that the traditional reliability planning process would have produced. Indeed, representatives from Duke confirmed that some percentage of these solutions had been previously vetted either in the reliability planning process or the Definitive Interconnection System Impact Study process. And although the CTPC clearly assessed numerous alternatives, it has declined to conduct a detailed benefit-cost analysis of these alternatives to demonstrate whether they are less suited to meet the identified needs than the CTPC's preferred solutions.

Some of the flaws in the process can be explained by the CTPC's lack of experience with this type of planning, which is understandable for the inaugural cycle. But others are more systemic and will persist unless addressed in advance of the next cycle. Among other things, these include (1) a 10-year planning horizon that is indistinguishable from the reliability planning process; (2) the lack of a nodal production cost model to identify needs and compare and vet the economic benefits of solutions and alternatives; (3) overly restrictive criteria guiding the identification of both needs and solutions; (4) the insistence on scenarios that are tied to previously proposed resource portfolios; and (5) a willingness to disregard disfavored or uncertain aspects of the chosen scenarios at the solution stage, such as offshore wind after Duke's Acquisition Request for Information did not recommend moving forward with an offshore wind Request for Proposals.

Taken together, these issues have resulted in a process that looks a lot like the CTPC's traditional reliability planning approach. Resource planning comes first, and transmission planning follows. So long as these processes proceed in succession rather than working in tandem, they will produce inefficient results and ratepayers will bear the unnecessary burden. Correcting the flaws identified above and explained in greater detail below would go a long way towards synchronizing transmission and resource planning efforts. Failure to do so in the next cycle will impose excessive costs on customers, waste the resources of planners and stakeholders who have engaged in this time-intensive process, and undermine the NCUC's purpose in directing these changes. Using the MVST to justify the status quo does not reflect the spirit of proactive transmission planning or the recent changes to Attachment N.

Below, we highlight some of these shortcomings in the CTPC's solution identification process.

The Proposed Solutions Neither Reflect a Multi-Value Planning Process Nor Proactively Meet Needs in an Optimal Manner

Since Duke first proposed the MVST process, it has consistently held up the process as a proactive, multi-value transmission planning process that would allow Duke to cost-effectively meet multiple needs at once. For example, in its filing to the Federal Energy Regulatory Commission (FERC), Duke stated that the MVST process would "ensure alignment of transmission planning and resource planning" and "enable a holistic review of [] various transmission drivers."[1] Likewise, before the PSCSC, Duke witness Sammy Roberts testified that "[i]ntegrating transmission planning with resource planning through the [CTPC] [MVST] study process aligned with the IRP process will also support identification of 'no regrets' long term strategic transmission projects for executing future IRPs."[2]

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[1] Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Proposed Revisions to Local Transmission Planning Process in Attachment N-1 of Joint OATT, Transmittal Letter at 8-9, FERC Docket No. ER24-314-000 (Nov. 1, 2023).

[2] Duke Energy Progress, LLC's & Duke Energy Carolinas, LLC's 2023 Integrated Resource Plans, Rebuttal Testimony of Dewey S. Roberts II at 5:5-9, S.C. Pub. Serv. Comm'n Docket Nos. 2023-8-E & 2023-10-E (Aug. 14, 2024). *See also id*. at 24:8-13 ("Key Attachment N-1 revisions include the creation of an MVST scenario-based planning process and multiple paths for stakeholder engagement that will allow for identifying

But rather than evaluate the reliability, economic, and public policy needs that transmission solutions can meet and the benefits they provide in doing so, the CTPC applied a narrow reliability lens to identifying needs and developing solutions. This focus appears to have removed high-capacity solutions from consideration, even though they tend to represent the optimal solution due to the economies of scale transmission provides.

First, Duke failed to truly conduct "multi-value strategic transmission" planning, as it has focused solely on upgrades needed to address NERC reliability requirements and failed to assess how those solutions provide other benefits, including by addressing economic drivers. As discussed below, Duke's transmission planning efforts should use nodal production cost modeling to assess the benefits of potential solutions and identify solutions that maximize net benefits.

Second, by focusing almost exclusively on solutions that reduce system loading without introducing new issues, Duke's approach essentially rules out greenfield and higher-capacity transmission solutions. These larger solutions have a larger impact on the transmission system, which allows them to provide larger benefits and realize economies of scale. But it also means they may trigger overloads on other parts of the system that may require additional system reinforcement. Duke's prioritization of solutions that reduced system loading without introducing new issues thus likely screened out greenfield or higher capacity solutions that could introduce new needs but still reduce loading overall, providing the broadest benefits.

In addition, it is unclear how the CTPC evaluated and prioritized solutions. For example, it is not apparent whether, when developing solutions, the CTPC targeted a specific reduction in loading for a solution to achieve (i.e., 70% of violations). Similarly, the CTPC has not articulated any criteria it used to decide between potential solutions where multiple solutions reduced loading to a similar degree. The CTPC must clarify its approach to evaluating solutions at this stage to ensure it does not limit the range of possible solutions or constrain the ability to evaluate projects that could deliver long-term value to consumers.

A more balanced framework for solution development and prioritization is needed to ensure other benefits to ratepayers are properly considered while maintaining reliability. While it is appropriate for reduction in loading, cost, and development risks to be considered during solutions development, consideration should also be given to the

transmission needs and solutions that cover multiple scenarios where quantified benefits are greater than costs. The MVST study cycle is intended to be aligned with the IRP cycle to holistically consider resource plan implications with the MVST transmission planning scenarios."); 30:25-27 ("The Companies will continue to work through the CTPC process to identify cost-beneficial transmission solutions for all customers and appreciate the input and involvement of all participants in that process.").

potential economic benefits and long-term value to ratepayers. The CTPC has proposed only to consider the economic and other benefits of its preferred solutions without examining the potential benefits of the alternative solutions it considered. Leaving benefits evaluation out of the initial solutions evaluation risks undervaluing options that could provide significant net benefits to ratepayers over time.

The CTPC's proposed solutions also lack clarity as to whether initial solutions were reviewed on a project-by-project basis or as a part of a portfolio of solutions. Evaluating solutions project-by-project, or even cluster-by-cluster, typically misses opportunities to identify larger projects or combinations of projects that can collectively unlock greater economic benefits and may also reduce overall loading more efficiently. As we have discussed in previous comments, transmission planning works best when portfolios of solutions are considered, as they allow for economies of scale and broader system improvements. Evaluating projects in isolation narrows the scope and reduces their effectiveness in efficiently meeting identified needs.

The CTPC has Not Clearly Described its Development and Prioritization of Needs, Clusters, and Solutions

In the March 20, 2025, TAG meeting, the CTPC outlined a proposed methodology to "screen" identified needs. In subsequent comments, stakeholders proposed "clustering" as an additional approach for screening needs. At the time, the CTPC suggested it would use a combination of both methods to develop solutions. However, based on the draft solutions, it is not clear that the CTPC has consistently applied either methodology when developing solutions.

For example, across both the DEP and DEC territories, multiple "high-scoring" needs that would support the addition of multiple gigawatts of new generation if addressed were left unaddressed in the draft solutions. Specifically, the Woodruff and Wateree clusters were the only clusters to address needs that scored higher than a 5. However, DEC had 40 constraints that scored a 5 or higher and DEP had over 60 constraints that scored a 5 or higher. In addition, some of the highest scoring constraints were on the 230kV and 500kV systems, but despite these high scores, many of these needs were not addressed by the draft solutions.

The draft solutions also did not fully address the needs identified within clusters. First, the draft solutions identified two offshore wind clusters with a significant number of needs but did not propose any solutions within those clusters. Even if offshore wind is pushed beyond the ten-year planning horizon, there are still likely to be needs within those clusters that should be addressed. Beyond the offshore wind cluster, it appears that other clusters for which solutions were developed did not address all the needs that appeared within the cluster. For example, several of the highest scoring constraints within DEP, which were all associated with the Lilesville - DPC Oakboro 230kV line, were not addressed within the Badin Tie Cluster.

Ignoring the highest scoring needs in both DEC and DEP and inconsistently addressing needs within clusters suggests an ill-defined and arbitrary solution development process. The CTPC should provide additional clarity on the methodology used to develop solutions and further explanation as to why some constraints remain unaddressed despite having the highest scores or appearing in CTPC-developed clusters.

Nodal Production Cost Modeling Is Essential to an Effective Multi-Value Planning Process

We continue to strongly urge the CTPC to develop and use nodal production cost modeling to quantify transmission benefits and differentiate between proposed solutions and alternatives. Nodal production cost modeling is necessary to properly quantify transmission benefits and allows for comparison between proposed solutions. As we have discussed in previous comments, zonal production cost simulation models lack the necessary granularity to accurately reflect the operation of Duke's transmission system, the dispatch of generation resources, and how both will change with the addition of proposed transmission solutions or alternatives. Zonal production cost models can only capture the impacts of upgrades between the zones as defined by the CTPC, such that any solutions and alternatives within the same zone will be unable to demonstrate different benefits. This renders comparison of production cost savings between alternatives impossible.

We appreciate the CTPC's suggestion during the March 20, 2025, TAG meeting that it will use nodal production cost modeling for benefit quantification. We would welcome an update on the status of CTPC's progress on its nodal production cost modeling being developed in EnCompass, and request confirmation that the CTPC plans to incorporate nodal production cost modeling into its evaluation of alternatives.

The Draft Solutions Demonstrate the Limitations of a Ten-Year Planning Horizon

As we have discussed in previous comments, transmission solutions should be optimized over a 20-year planning horizon. We have noted that limiting the planning horizon for scenarios to 10 years may limit the feasibility of executing identified transmission solutions in a 10-year timeframe. Indeed, Duke has previously explained that developing greenfield transmission can require 10 to 15 years from the project start date.[3] Large infrastructure projects such as offshore wind, new nuclear units, and high-voltage transmission lines are complex projects that often experience numerous sources of delay. Using a 10-year planning horizon for these large but highly beneficial projects introduces a significant

[3] Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, App. P: Transmission System Planning and Grid Transformation at 21, N.C. Utils. Comm'n Docket No. E-100, Sub 179 (May 16, 2022).

amount of uncertainty into the process as 10 years may not capture the amount of time needed to plan for and develop these projects.

Moreover, despite the uncertainty surrounding long-lead resources like offshore wind, such resources and the transmission needed to support them may represent broadly beneficial investments. In order to maintain optionality for future generation resources, the MVST process should transparently show regulators the costs of future transmission that may be built over this 20-year horizon, including facilities designed to support generation that may ultimately not be selected. Having this information ahead of time will accelerate bringing new generation online if and when it is ultimately needed.

The CTPC Should Consider Additional Alternatives and Subject them to a Detailed Cost-Benefit Analysis

Since the beginning of this process, we have proposed numerous solutions that the CTPC has declined to consider. We will not repeat all of those here but will nevertheless highlight some that have the potential to provide substantial benefits.

First, the CTPC should assess complete integration of the DEC and DEP systems under a "Consolidated System Operations" model and, if needed, the transmission required to optimize flows between the two systems. Now that Duke has filed for approval of its "One Utility" at FERC, the NCUC, and the PSCSC, planning for a future in which the Balancing Authority Areas (BAA) remain separate provides an inaccurate picture of future system needs. Indeed, as Duke's witness Nelson Peeler has acknowledged to the NCUC, consolidation of the DEC and DEP systems allows Duke to "plan its investment in generation and transmission resources more efficiently, resulting in the ability to optimize the timing and sequencing of construction and in-service dates for future resources."[4]

For the Carbon Plan/Integrated Resource Planning (CPIRP) process, Duke assumes consolidation of DEC and DEP where the NERC Balancing Authority, Transmission Service Provider, and Transmission Operator functions are combined. Duke noted in its most recent CPIRP filing that a "consolidated approach allows for economically dispatching the system, and furthermore, allows for optimization of meeting operating services requirements, such as balancing and regulating reserves."[5] Similarly, Duke has explained to the NCUC and PSCSC that the One Utility model "will create operational efficiencies

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[4] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Application to Engage in a Business Combination, Address Regulatory Conditions and Code of Conduct, and Request Accounting Order, Direct Testimony of Nelson Peeler, at 11:17-21, N.C. Utils. Comm'n Docket Nos. E-2, Sub 1383 & E-7, Sub 1332 (Aug 14, 2025) (Peeler Test.).

[5] *See* Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, 2023 Biennial Carbon Plan and Integrated Resource Plans, Ch. 2: Methodology and Key Assumptions, at 17, N.C. Utils. Comm'n Docket No. E-100, Sub 190 (Aug. 17, 2023).

that achieve substantial system-wide cost savings."[6] These operational benefits should be reflected in a transmission planning process designed to simulate future conditions.

Moreover, Duke's 2022 Carbon Plan proposed closing the hole between the DEC and DEP systems on the northeastern end of Duke's 500kV network. This could be achieved by building the long-discussed Durham - Parkwood 500kV line, or other potential upgrades in the Durham area and between Roxboro and Sadler, North Carolina.

Second, we have submitted the following solution types for the CTPC to consider when developing solutions:

1. Greenfield high-voltage transmission expansion, within Duke's footprint and with neighboring Balancing Authorities.

2. Moving to higher-voltage transmission along existing corridors.

3. To meet shorter-term needs in the interim:

    a. Grid-enhancing technologies including dynamic line ratings, topology optimization, and power flow control devices;

    b. Reconductoring or rebuilding transmission lines using High Performance Conductors, specifically consideration of Carbon Fiber or Composite Core Conductors or Superconductors alongside ACSS, on existing rights-of-way and upgrading terminal equipment (which was included as a sensitivity in the *Benefits Whitepaper*); and

    c. Strategically siting batteries to defer the need for transmission upgrades and alleviate identified transmission constraints and voltage and stability concerns.

While the CTPC has studied some of these solution types as alternatives to its preferred solutions, it has declined to subject them to a detailed cost-benefit analysis. We urge the CTPC to transparently assess the costs and benefits of the alternatives it has reviewed (or at least a subset of them) in order to quantitatively compare them to the preferred solutions. Otherwise, stakeholders and regulators will have no way of knowing whether a preferred solution is the optimal one. Qualitative concerns like constructability should factor in to selection decisions, but not to the exclusion of quantifiable costs and benefits.

[6] Peeler Test. at. 17:7-8.

Structural Changes Are Required for the MVST to Comply with its Mandate

It may be too late to make any substantial changes to the MVST process that would meaningfully affect this initial cycle. And, as noted above, some of the deficiencies in this first iteration of the MVST can be attributed to the CTPC's lack of familiarity with proactive, multi-value planning, such as the truncated planning horizon and narrow solution set. That will not be the case next time. Going forward, the MVST requires certain fundamental changes in order to comply with the NCUC's directive that Duke "integrate transmission planning with resource planning to maintain the reliability of the electric system and to ensure a least cost path."[7]

At a minimum, and as discussed in greater detail above and in prior comments, these changes should include:

1. A 20-year planning horizon;
2. Nodal production cost modeling;
3. Clearer and less restrictive identification and prioritization of needs and solutions;
4. Application of a detailed cost-benefit analysis to both preferred solutions and alternatives;
5. Evaluation of the single, combined DEC and DEP BAA, consistent with the proposed One Utility model;
6. Flexibility to depart from CPIRP portfolios when developing scenarios including by using capacity expansion modeling;
7. Commitment to maintaining the integrity of scenarios throughout the needs and solutions identification process, despite resource uncertainty.

These modifications would better integrate transmission and generation planning, thereby ensuring selection of optimal solutions and limiting impacts to ratepayers. We would be happy to discuss any of these reforms in greater detail.

[7] Order Adopting Initial Carbon Plan and Providing Further Direction for Future Planning, N.C. Utils. Comm'n Docket No. E-100, Sub 179, at 121 (Dec. 31, 2022).

Sincerely,

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