Form to Identify the Public Policy Driving Local Transmission

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Submitting Company (TAG participant)	North Carolina Public Staff
Company Contact	Dustin Metz
Contact Phone Number	919-733-1513
Contact E-Mail Address	dustin.metz@psncuc.nc.gov
Identify the Public Policy – Identify the specific state, federal, or local law or regulation (including order of a state, federal, or local agency) that is driving a local transmission need.	North Carolina Gen. Stat. 62-110.9 § (HB 951) and Section 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA), as well as NCUC regulation of safe and reliable service, and long-term planning.
Supporting Facts – Identification of any supporting facts that would show that the identified need cannot be met absent the construction of additional transmission facilities.	A recent Duke and NREL study released in 2022 illustrated transmission power flow shifts with increasing renewable generation across the State, notably the southeastern North Carolina area of DEP's service territory. Duke has also identified, informally, a potential need for a greenfield 500 kV transmission line in the longer term planning horizon. If cost effective generation is to be built in certain areas of the state or balancing area, a primary focus should be on evaluation of transmission facilities timelines and evaluation to maintain reliable service, at lowest reasonable cost.

See following pages for additional information

The Public Staff requests a study of the following public policy impacts regarding transmission upgrades required for the DEC and DEP systems.

Objective: Use transmission planning to identify potential transmission impacts from the retirement of older generation assets and integration of new resources. Notably, evaluate impacts of the need to build new 230 kV and/or 500 kV transmission to manage the bulk energy system, to support meeting the carbon reduction objectives codified in State law, ensure economic dispatch, and maintain or improve reliability.

The NCUC issued its initial Carbon Plan in Docket No. E-100, Sub 179 on December 30, 2022. In addition, the NCUC has established a framework for the 2023 Carbon Plan or Carbon Plan Integrated Resource Plan (CPIRP) to start this year. To balance the risk, reliability and costs, further evaluation of the transmission system is needed; the transmission system is the essential component to implement incremental generation, retire existing fossil generation, and enable the economic transformation of the electrical system.

The Public Staff proposes the following for purposes of evaluation:

- Use the Company's assumptions of coal asset retirement dates of the most recent Company filed Carbon Plan with a 2030 mass cap compliance.
- Use the current transfer limits for DEC to DEP balancing areas, or vice versa, for purposes of the study.
- Evaluate transfer limit set points between DEC and DEP and establish thresholds for modeling limits.
- Evaluate contingency analysis (TPL-001 P1-P7) of a Cumberland to Richmond failure.
- Evaluate solutions to resolve the potential Cumberland to Richmond failure event, notably the time needed for those solutions.
- A scenario based approach may be used for generation assumptions.
- A power flow study should be conducted similar to that of an interconnection study and NRIS.

The Public Staff acknowledges that for purposes of the power flow study, a balance of generation and load needs to take place. The work product of this request also needs to consider the impacts of the winter morning peak, summer peaks, and the shoulder season, inclusive of generation location. Because multiple assumptions will need to be discussed with the NCTPC's appropriate committees, collaboration is essential to resolve any open modeling input requirements. The Public Staff is also open to other Public Policy requests that could be leveraged into a common study. Locational guidance of new generation is a critical step of this evaluation.

The Public Staff proposes a generation portfolio of the existing system while using the Carbon Plan P1 coal retirement dates; known new generation and generation uprates can be included (e.g., LC CT 17, Bad Creek uprates, etc.).

For purposes of new generation, an average portfolio mix by ratio of resource types of the Carbon Plan's P1/SP5 can be used, and added in the appropriate year with a proxy of the aforementioned portfolios by balancing area.

For purposes of this study only, any new incremental generation need to resolve load requirements should be solar generation, with 70% located in the DEP service area, notably in the southeast region of the DEP East balancing area. In the event that the model needs to solve for winter peak loads after taking all the prior steps, only battery storage may be used, with 50% located in the DEP service area and 50% in the DEC service area, relying on transmission transfer limits to maximize the system dispatch to load between the service areas. Stand-alone battery storage can be deployed on the primary transmission voltages, 100 kV thru 230 kV, and distributed across major load centers (e.g., Raleigh, Wilmington, Charlotte, Spartanburg, Asheville, etc.)

In the event that the system still cannot meet load requirements, the Company may deploy Combustion Turbines as a stopgap measure, by locating the CTs in DEC at Marshall, and in DEP at HF Lee.

No more than one ~1200 MW combined cycle generating plant can be added in the power flow analysis. Duke may choose the location for purposes of this evaluation but likely at either Marshall or Roxboro.

Locational guidance for new renewable generation, notably solar and solar plus storage, should be added proximate to the locational results of the 2022 DISIS competitive tier projects that were pulled forward.

All generation will need to be evaluated in an NRIS, firm service, methodology.

The Public Staff is open to making modifications to these assumptions via the NCPTC committee and public policy process.

For purposes of simplification of the model runs, the Public Staff proposes:

- Focus on the DEP balancing area and evaluate in more detail the Cumberland to Richmond 500 kV section of the line using contingency analysis.

- Scenario based approach for new incremental generation (e.g., stand-alone solar case, implementation of a battery case, 2400 MW of offshore wind, etc.).
- Potential evaluation of delay of onshore and offshore wind resources.
- Looking out over a longer time horizon, like 2035 or 2040.
- All non-utility owned short-term market purchases from fossil generators providing energy and capacity to DEP, for purposes of power flow modeling, should terminate and not assume to be resumed/renewed. Any lost generation from fossil short-term market purchases may be replaced with the proxy method of P1/SP5.
- Replacement generation can be assumed to be located at brownfield locations of retired coal generation.