NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

June 24, 2024

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-2, Sub 1297 - Application of Duke Energy Carolinas, LLC, for a Certificate of Public Convenience and Necessity to Construct an 850 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Catawba County, North Carolina.

Dear Ms. Dunston:

Attached for filing on behalf of the Public Staff in the above-referenced docket is the **public redacted version** of the joint testimony of Evan D. Lawrence and Dustin R. Metz with the Energy Division of the Public Staff – North Carolina Utilities Commission.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. Confidential information is located on pages 10-12, 16, 31, and 33 of the testimony.

The confidential version has been provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
/s/ William S.F. Freeman
Staff Attorney
william.freeman@psncuc.nc.gov

Attachment

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1297

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for a Certificate of Public Convenience and Necessity to construct an 850 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Catawba County, North Carolina	)))))))	**JOINT TESTIMONY OF EVAN D. LAWRENCE AND DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION**

June 24, 2024

Q. Mr. Lawrence, please state your name, business address, and current position.

A. My name is Evan D. Lawrence. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina, where I work for the Public Staff - North Carolina Utilities Commission (Public Staff). I am an engineer in the Energy Division, specifically the Electric Section – Operations and Planning.

Q. Briefly state your qualifications and experience.

A. My qualifications and experience are attached as Appendix A.

Q. Mr. Metz, please state your name, business address, and current position.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am an engineer and the manager of the Electric Section – Operations and Planning of the Public Staff's Energy Division.

Q. Briefly state your qualifications and experience.

A. My qualifications and experience are attached as Appendix B.

Q. What is the mission of the North Carolina Public Staff?

A. The Public Staff represents the concerns of the using and consuming public in all public utility matters that come before the North Carolina Utilities Commission (Commission). Pursuant to N.C. Gen. Stat. §

62-15(d), it is the Public Staff’s duty and responsibility to review, investigate, and make appropriate recommendations to the Commission with respect to the following utility matters: (1) retail rates charged, service furnished, and complaints filed, regardless of retail customer class; (2) applications for certificates of public convenience and necessity; (3) transfers of franchises, mergers, consolidations, and combinations of public utilities; and (4) contracts of public utilities with affiliates or subsidiaries. The Public Staff is also responsible for appearing before State and federal courts and agencies in matters affecting public utility service.

Q. What is the purpose of your joint testimony in this proceeding?

A. The purpose of our joint testimony is to present the results of our evaluation of the preliminary information and application filed by Duke Energy Carolinas, LLC (DEC), on March 14, 2024, in Docket No. E-7, Sub 1297, for a certificate of public convenience and necessity (CPCN) to construct two 425-megawatt (MW) natural gas-fired simple cycle combustion turbine (CT) electric generating units in Catawba County, North Carolina, at the site of the existing Marshall Steam Station (Marshall) (Marshall CT CPCN Application, or DEC's Application).

Q. What did your evaluation of the Marshall CT CPCN Application include?

A. The Public Staff's evaluation included a review of the Application, the testimonies of DEC witnesses John Robert Smith, Jr., and Michael Quinto, and their accompanying exhibits. Our evaluation also included a review of DEC's responses to Public Staff data requests and participation in multiple meetings with DEC and Duke Energy Progress, LLC (DEP, and collectively with DEC the Companies or Duke) personnel. In addition, we reviewed modeling inputs and outputs used by Duke in Docket No. E-100, Sub 179 (2022 Carbon Plan proceeding), as well as the Commission's December 30, 2022 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Carbon Plan Order) in that proceeding, and modeling inputs and outputs used by Duke in the 2023 Carbon Plan and Integrated Resource Plans (IRP) proceeding in Docket No. E-100, Sub 190 (CPIRP). We also reviewed consumer statements of position filed in the accompanying docket (E-7, Sub 1297CS) and statements made at the June 5, 2024 public hearing in Newton, NC, and June 6, 2024 virtual public hearing held via WebEx.

Finally, as will be further explained in our joint testimony, our review of the Marshall CT CPCN Application was concurrent with our review of the preliminary information and application filed by DEP and North Carolina Electric Membership Corporation (NCEMC) on March 14, 2024, in Docket Nos. E-2, Sub 1318, and EC-67, Sub 55, for a CPCN to construct a 1,360-MW natural gas-fired combined cycle (CC) electric generating facility in Person County, North Carolina, at the site of the existing Roxboro Steam Station (Roxboro) (Roxboro CC CPCN Application, or DEP's Application). Our joint testimony demonstrates that the decision to site a CC in one Duke service territory has inherent planning and analytical links to the decision to site CTs in another Duke service territory, such that our testimony requires discussion and analysis of both CPCN applications and their impacts on North Carolina ratepayers.

Q. Please summarize your findings in this proceeding.

A. There is a need for CC and CT natural gas generation in DEC’s and DEP’s service territories and denial of this CPCN Application could delay interim carbon emissions reduction compliance and coal plant retirements set forth in the Carbon Plan Order.

Q. Based on your evaluation, what do you recommend?

A. We recommend that the Commission grant the requested CPCN for two 425 MW CT units at the Marshall site, subject to certain conditions, including the Company providing updated information through rebuttal that we discuss later in our testimony. In addition, our recommended conditions include necessary protections for ratepayers by requiring appropriate cost allocation of the NC Retail portion of total costs between DEC and DEP retail customers.

Q. Please describe the organization of your joint testimony.

A. Our testimony begins with our evaluation and investigation of preliminary matters in the Application, including the operational characteristics of the proposed facility, the CTs' estimated life, fuel supply, technology challenges, integration with the DEC's electrical system, and other required regulatory permits. We then discuss the estimated project costs; our evaluation and investigation of the need for the project; DEC's evaluation of project sites; and compliance with the United States Environmental Protection Agency's (EPA) recent rulemaking under Section 111(b) and (d) of the Clean Air Act (CAA) entitled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule"[1] (CAA Rule). Finally, we detail our conclusions and make recommendations to the Commission concerning the Application.

[1] 89 FR 39798 (May 9, 2024), *available at*: https://www.federalregister.gov/d/2024-09233.

I. PRELIMINARY MATTERS

Q. Please describe the operational characteristics of the proposed CT facility.

A. The facility, as proposed, consists of two natural gas-fired units with an estimated nominal winter capacity of 425 MW each (850 MW total), and will utilize Number 2 fuel oil as a backup fuel source. The operational characteristics of these proposed units are similar to those of the Lincoln County CT that received a conditional CPCN in Docket No. E-7, Sub 1134.

Q. What is the estimated life of the proposed CT facility?

A. DEC estimates a 35-year life for the proposed facility.

Q. How will this project be supplied with fuel?

A. As proposed, the primary fuel will be natural gas supplied from the existing Piedmont Natural Gas, Inc., (Piedmont) pipeline that currently serves the Marshall site. This existing pipeline will require modifications that are discussed later in our testimony. Duke states that these CTs will be capable of hydrogen firing, should that technology become viable in the future.

Q. Do you have any concerns about Duke's use of natural gas CTs?

A. Generally, no. DEC and DEP, as well as many other utilities, have a fleet of CTs in operation, used primarily for system reliability purposes. However, we do have concerns around the potential future use of hydrogen as a fuel source, as described in detail in the CPIRP testimony of Public Staff witnesses Dustin R. Metz and Blaise C. Michna filed on May 28, 2024. Given the recent finalization of the CAA Rule and DEC's ongoing analysis of the rule's impact, we cannot determine which aspects of DEC's proposed facility may be impacted and to what extent.

Q. How will the project be integrated with DEC's electrical system?

A. A new switchyard is proposed to interconnect the new CT units to the existing onsite substation via two 230 kV buses spanning 1.09 miles. An existing 230 kV transmission line located on the site of the existing Marshall Steam Station will need to be relocated to accommodate the two new buses. No additional transmission lines will be required for facility operation at this time, and only minor upgrades to the existing transmission system will be needed.

Q. Are environmental or other permits required for this project?

A. Yes. In order to operate the facility, DEC must obtain an air quality permit from the North Carolina Department of Environmental

Quality's (DEQ) Division of Air Quality. DEC submitted its application for an air permit on March 28, 2024. Other regulatory permits required are included as Exhibit 2 to the Marshall CT CPCN Application.

Q. Does the Public Staff have any specific recommendations regarding the environmental impact of the proposed facility?

A. No. Environmental impacts fall within the purview of environmental regulators with expertise in this area who are responsible for issuing specific environmental permits for electric generating plants. To that end, the Public Staff recommends that the Commission require compliance with all environmental permitting requirements as a condition for the issuance of the CPCN.

II. PROJECT COSTS

Q. Please discuss the costs of the Marshall CTs.

A. Confidential Exhibit 3 of the Application provides a cost breakdown of the Project, summarized below for ease of reference.

Table 1: Marshall CTs Capital Costs

[BEGIN CONFIDENTIAL]

CATEGORY	**COST**
On-site bus connection to switchyard	[redacted]
Definitive Interconnection System Impact Study network upgrades	[redacted]
Generator Replacement Request upgrades	[redacted]
Engineering, Procurement, and Construction	[redacted]
Other owner costs including major equipment and contingency (but excluding AFUDC)	[redacted]
Total project costs (excluding AFUDC)	[redacted]
Winter output, MW	850 MW (estimated nominal winter capacity)
Summer output, MW	750 MW
Project cost $/kW (winter)	[redacted]
Total Project costs including AFUDC	[redacted]

[END CONFIDENTIAL]

To our knowledge, DEC has not received final bids for the overall project, although our review indicates that DEC appears to have used reasonable cost estimates. History indicates, however, that these cost estimates can vary once contracts for major components are received and the engineering, procurement, and construction (EPC) vendor is selected, neither of which is expected to occur before the second quarter of 2026,[2] approximately two years from now.

[2] See Exhibit 4, Table 4.1 of the Initial Application.

DEC's filed cost estimates, listed above, also exclude the total cost of gas delivery to the facility (i.e., the "pipeline" costs). More specifically, DEC has not included the capital cost of the intrastate pipeline in the capital cost of the facility. Instead, DEC appears to recognize the cost of the intrastate pipeline as an operating cost, presumably to be recovered through the annual fuel rider. Outlined below is a breakdown of DEC's projected annual operating costs.

Table 2: Marshal CT Projected Annual Operating Costs

[BEGIN CONFIDENTIAL]

Category	Total
Fixed Operations & Maintenance (O&M)	[redacted]
Variable O&M	[redacted]
Gas Pipeline Intrastate Firm Transportation	[redacted]
Fuel	[redacted]
Total	[redacted]

[END CONFIDENTIAL]

Q. What is the interstate pipeline capital cost estimate for the proposed facility?

A. Based on the amended confidential natural gas pipeline construction and transportation service agreement between Piedmont and DEC filed in Docket No. G-9, Sub 718, and Exhibit 3 of DEC's Application, the annual cost for the upgrades required by Piedmont is approximately **[BEGIN CONFIDENTIAL]** [redacted].[3] **[END CONFIDENTIAL]**

III. PROJECT NEED

Q. What types of generation resources are generally considered when a need for new generation capacity has been identified?

A. When there is a need for new generation capacity, generally three types of generation resources are considered: peaking units, intermediate or cycling units, and base load units. The selection of the type of unit is an economic decision based on the amount of energy required to meet customer load or the number of hours a unit is expected to operate each year or over a planning period. The process of determining the selection of resources to meet load, also commonly referred to as a load duration curve, optimizes the generation capacity and utilization of assets. Some production plant costs are incurred primarily to provide sufficient capacity during peak periods, while other production plant costs are incurred because of the need to provide significant amounts of low-cost energy to customers. If little energy is required, peaking units are cost-justified

[3] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

due to their lower capital cost as compared to base load units. However, if much energy is needed, the lower energy cost (in cents/kWh) of capital-intensive base load units makes them more appropriate. An integrated system with economic dispatch that serves diversified loads with a least cost mix of diverse generating resources benefits all customers through lower average fuel costs.

Figure 1, below, is an excerpt from page 17 of DEP's[4] 2012 IRP.[5] This figure provides an economic comparison of utility-scale technologies based on estimates of capital, fuel, and O&M cost projections at the time they were developed, inclusive of carbon costs. The costs in this type of analysis are referred to as “busbar” costs and are an estimate of the levelized cost of energy production from each technology represented. A busbar cost is different than the load duration curve analysis but illustrates a similar type of analysis to match future generation assets with system need. These busbar costs allow for a long-term economic comparison over the typical life expectancy of a future unit at varying capacity factor levels. The data used is not site specific, and the final determination of future units must be optimized within an existing system that already contains various resource types. Busbar curves can also be

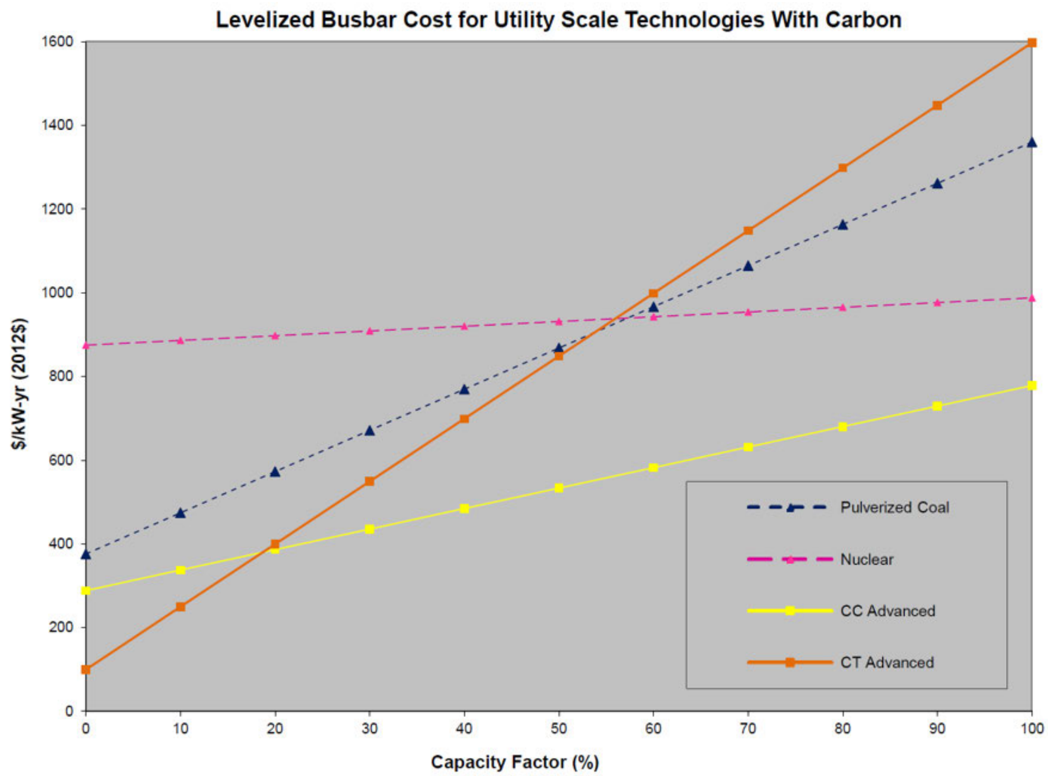
[4] This filing was originally made by Progress Energy Carolinas, Inc., the predecessor to DEP.

[5] Filed in Docket No. E-100, Sub 137 on September 4, 2012.

used as high-level screens to identify technologies that are uneconomic to deploy compared to other technologies and mitigate the need for additional consideration and/or detailed analysis.

The technologies represented in Figure 1 are simple-cycle combustion turbine, combined cycle, pulverized coal, and nuclear. While the cost bases for these technologies have changed, and pulverized coal is no longer considered a viable technology for new generation, the relative representation is illustrative of how generation technologies are compared based on costs ($/kW-year) and capacity factor (%, representing the amount of energy needed per kW).

Figure 1: DEP 2012 IRP Bus Bar Curve



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission or other site specific criteria.

Figure 2 is a levelized busbar cost but with 2022 technologies and updated costs. It is important to note that the levelized busbar costs are not reflective of the updated costs in the CPIRP. The graph is intended for illustrative purposes only.

Figure 2: 2022 Levelized Busbar Cost Curve

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The busbar cost curves provide insight into the reasonableness of one generation source compared to other technologies from both the perspective of cost as well as the technology's ability to meet the total amount of capacity and energy needed to serve load. For example, an advanced class CT will have lower costs than an advanced class CC when operating up to a 40% annual capacity factor, but when the technology is required to operate at an annual capacity factor of approximately 50% or higher, it will be more economic for a CC to be built. When a utility selects new generation technology to meet its needs, it must match both the economic energy and capacity needs.

Q. Describe when the need for a future generation facility is traditionally established.

A. The selection of new capital resources to provide capacity and energy is generally evaluated and determined in an IRP (or equivalent) proceeding. For this Application, the 2022 Carbon Plan proceeding and the Carbon Plan Order are the most relevant starting points to determine the project need. Further, after project need is identified, a utility acting prudently will conduct ongoing assessments of system requirements and continue to monitor and make course corrections to potential plans.

Q. Please describe the 2022 Carbon Plan proceeding's portfolio analysis.

A. In the 2022 Carbon Plan proceeding, Duke presented analysis of multiple portfolios, designated as Portfolios 1-4. Multiple intervenors, including the Public Staff, identified modeling enhancements and refinements (modifications) to the Companies' initial proposed Carbon Plan, which was developed using a new capacity expansion software (i.e., EnCompass). A summary of the modifications to the original Portfolios 1-4 was filed by Duke on July 28, 2022, and are referred to as Supplemental Portfolio 5 (SP5).[6]

The Companies ran the SP5 portfolio with and without a limited Appalachian or Dom Zone South[7] gas supply, which would supply natural gas at a lower cost from the Mountain Valley Pipeline (MVP) or MVP Southgate expansion when compared to the costs of gas from Henry Hub Zone 4. The portfolio with no available Appalachian or Dom Zone South gas was designated as SP5 and the portfolio with presumed access to Appalachian or Dom Zone South gas was designated as $SP5_A$.

The Public Staff found the Companies' approach in these supplementary analyses to be reasonable for planning purposes given the uncertainty of future natural gas supply and its influence on the resource selection outcomes.

[6] In filing this summary of supplemental modeling modifications, Duke noted in its cover letter the "consensus reached" between Duke and the Public Staff and that this supplemental modeling can inform the Commission's assessment of Duke's proposed Near Term Execution Plan as well as the longer-term least cost pathways to achieving House Bill 951's emissions reductions targets, while ensuring the reliability of the system is maintained.

[7] Appalachian and Dom Zone South are gas supply from the general Pennsylvania area.

Q. What did the Carbon Plan Order provide with regard to future natural gas generation assets?

A. In the Carbon Plan Order, the Commission determined that it was reasonable for Duke to plan for approximately 800 MW of CT generation and up to 1,200 MW of CC generation. The Commission went on to specify that planning for this amount of generation:

> **[S]hould include assessing replacement generation options at the sites of retiring coal units on the DEC and DEP systems**. However, as multiple parties note, the availability of interstate pipeline firm transportation capacity is an ongoing concern. If and when Duke applies for a CPCN for any new natural gas-fired generating facility, the Commission will evaluate the need for the facility, **using this 2022 Carbon Plan as one factor in determining the need**. The Commission will also evaluate the projected costs of the facility, including all the costs associated with construction of the facility itself. The Commission will also consider the availability of firm transportation capacity to North Carolina, the status of any necessary pipeline expansion projects, and the availability of firm intrastate pipeline capacity. Due to uncertainty of interstate transportation as well as the very recent enactment of the IRA, **it would not be appropriate to give the Commission's approval for planning purposes of 800 MW of CTs and 1,200 MW of CC dispositive weight in the future related CPCN proceedings**. The Commission directs Duke to include in its initial CPIRP filing a detailed discussion of interstate transportation capacity and modeling analysis to demonstrate that any natural gas resource selected in future plans continues to be part of the least cost path to compliance.

(Emphasis added). Carbon Plan Order, at 79.

Q. Since issuance of the Carbon Plan Order, has the Public Staff conducted additional analysis or modeling?

A. Yes. On May 28, the Public Staff filed testimony in the CPIRP proceeding that discussed extensive modeling runs and analysis the Public Staff conducted in review of Duke's 2023 proposed CPIRP.

Q. Did any of the Public Staff's analysis in the CPIRP change or otherwise reinforce the 2022 Carbon Plan proceeding modeling results?

A. Yes. Generally, the Public Staff's CPIRP model runs identified the same need of each utility.

Listed below are summaries of SP5 and $SP5_A$ modeling results as well as multiple Public Staff model runs for both CC and CTs for DEP and DEC in the CPIRP.

Table 3: DEP CC Number of Units Per Year

	DEP Combined Cycle Number of Units Per Year					
		2028	2029	2030	2031	Total
2022 CPIRP	SP5	-	-	-	-	-
2022 CPIRP	SP5A	-	1	-	-	1
	PS1F 2034	-	-	-	-	-
	PS1F 2035	-	-	-	1	1
	PS1F 2034 Limit OffSW	-	-	-	-	-
	PS1F 2034 Limit OnSW	-	-	-	-	-
	PS1F 2034 Force 2029 DEP CC	-	1	-	-	1
	PS1F 2034 Shared Capacity	-	-	-	-	-
	PS1F 2034 High Gas Cost	-	-	-	-	-
	PS1F 2034 EPA 40%CC Limit	-	-	-	-	-
	PS1F 2034 Low Battery Avail	-	-	-	-	-
	PS1F 2034 NG Cap to 4 CC	-	-	-	-	-
	PS1F 2034 SC CC	-	-	-	-	-
	PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	1	-	1	2

Table 4: DEP CT Number of Units Per Year

	DEP Combustion Turbine Number of Units Per Year					
		2028	2029	2030	2031	Total
2022 CPIRP	SP5	1	1	-	-	2
2022 CPIRP	SP5A	1				1
	PS1F 2034	-	2	-	-	2
	PS1F 2035	-	2	-	-	2
	PS1F 2034 Limit OffSW	-	2	-	-	2
	PS1F 2034 Limit OnSW	-	2	-	-	2
	PS1F 2034 Force 2029 DEP CC	-	-	-	-	-
	PS1F 2034 Shared Capacity	-	2	-	-	2
	PS1F 2034 High Gas Cost	-	3	-	-	3
	PS1F 2034 EPA 40%CC Limit	-	3	-	-	3
	PS1F 2034 Low Battery Avail	-	3	-	-	3
	PS1F 2034 NG Cap to 4 CC	-	2	-	-	2
	PS1F 2034 SC CC	-	3	-	-	3
	PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	-	-	-	-

Table 5: DEC CC Number of Units Per Year

	DEC Combined Cycle Number of Units Per Year					
		2028	2029	2030	2031	Total
2022 CPIRP	SP5	-	1	1	-	2
2022 CPIRP	SP5A	-	1			1
	PS1F 2034	-	1	1	1	3
	PS1F 2035	-	1	-	1	2
	PS1F 2034 Limit OffSW	-	1	1	1	3
	PS1F 2034 Limit OnSW	-	1	-	1	2
	PS1F 2034 Force 2029 DEP CC	-	-	-	1	1
	PS1F 2034 Shared Capacity	-	1	-	1	2
	PS1F 2034 High Gas Cost	-	1	1	1	3
	PS1F 2034 EPA 40%CC Limit	-	1	-	1	2
	PS1F 2034 Low Battery Avail	-	1	-	1	2
	PS1F 2034 NG Cap to 4 CC	-	1	-	1	2
	PS1F 2034 SC CC	-	1	-	1	2
	PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	-	-	1	1

Table 6: DEC CT Number of Units Per Year

	DEC Combustion Turbine Number of Units Per Year					
		2028	2029	2030	2031	Total
2022 CPIRP	SP5	1	1			2
2022 CPIRP	SP5A	2	-	-	1	3
	PS1F 2034	-	-	-	1	1
	PS1F 2035	-	-	-	1	1
	PS1F 2034 Limit OffSW	-	-	-	-	-
	PS1F 2034 Limit OnSW	-	-	-	-	-
	PS1F 2034 Force 2029 DEP CC	-	3	-	1	4
	PS1F 2034 Shared Capacity	-	-	-	-	-
	PS1F 2034 High Gas Cost	-	-	-	-	-
	PS1F 2034 EPA 40%CC Limit	-	1	-	-	1
	PS1F 2034 Low Battery Avail	-	-	-	-	-
	PS1F 2034 NG Cap to 4 CC	-	-	-	1	1
	PS1F 2034 SC CC	-	1	-	-	1
	PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	-	3	1	-	4

Collectively, these tables show a general trend of the generation assets needed for each service area.

In testimony filed in the CPIRP proceeding, the Public Staff found that the Companies' CPIRP natural gas assumptions did not present any concerns.[8]

Q. Has DEC identified any errors in its CPIRP Supplemental Planning Analysis (SPA) (i.e. Fall Base Update) analysis relating to firm supply of natural gas to generation plants?

A. Yes. Based on discussions with the Company, we were informed that Company-provided EnCompass files included an inadvertent data set input error in the annual fixed fuel costs for new generic DEP combined cycle units related to the firm transportation costs for new natural gas. The Company subsequently corrected the error in CPIRP discovery on June 5th, 2024 and identified that the uncorrected error increased costs for DEP-specific CC plants and that the correct FT rate would only decrease the cost of new generic DEP CCs and reduce the costs to customers.

Q. How does this error impact the Public Staff's CPIRP analysis and investigation of need for a new natural gas plant in DEC?

A. The Public Staff's CPIRP portfolios included multiple portfolios over a range of potential outcomes. We identified an inflection of CT and CC generation resources were selected based on economics and underlying assumptions that produced the annual fixed fuel costs for

[8] Testimony of Public Staff witness Michna, p. 18, lines 1-3.

firm transportation of new natural gas generation units. Given the decrease in firm transportation costs for combined cycle generation in DEP's service territory, the Company confirmed that rerunning the Public Staff's base 2034 portfolio with the correct FT rate, thereby decreasing the overall costs of a CC in DEP will cause a change in the resource selection between DEC and DEP.

Q. Were you able to confirm or re-run any additional model runs to verify that a change in resources occurred.

A. No. The Public Staff sets forth below a series of additional model runs which we request the Company provide in rebuttal testimony.

Q. Is there a need for new natural gas generation in both the DEC and DEP territories?

A. Yes, the Public Staff believes that there is a need for new natural gas generation in the DEC and DEP service territories. However, the need must reflect requirements for capacity and energy specific to each service territory. As described in more detail in Section IV, the Public Staff has concerns about the long-term use of natural gas generation in light of new regulatory requirements set forth in the CAA Rule, which could reduce the extent to which these plants are available to meet load needs in the future.

It is also noteworthy that significantly more load growth is forecasted in the CPIRP in comparison to the 2022 Carbon Plan proceeding, affecting the DEC service area the most.

IV. PROJECT SITING

Q. What sites did DEC evaluate in its decision to locate the CT generation at Marshall?

A. DEC stated that the first criteria for site selection was the retirement dates of the Marshall units, which aligned with the need for new generation in the 2028-2029 time frame. The retirement dates were listed in the Carbon Plan Order as well as DEC's most recent general rate case in Docket No. E-7, Sub 1276. For reference, the retirement dates of the coal-fired generating units in the DEC and DEP BAs, as shown on page 64 of the Carbon Plan Order, are included in Table 7, below:

Table 7: Coal retirements as presented in the 2022 Carbon Plan Order

Table E-47: Coal Unit Retirements (effective by January 1st of year shown)

Unit	Utility	Winter Capacity [MW]	Effective Year (Jan 1)
Allen 1[2]	**DEC**	167	2024
Allen 5[2]	**DEC**	259	2024
Belews Creek 1	**DEC**	1,110	2036
Belews Creek 2	**DEC**	1,110	2036
Cliffside 5	**DEC**	546	2026
Marshall 1	**DEC**	380	2029
Marshall 2	**DEC**	380	2029
Marshall 3	**DEC**	658	2033
Marshall 4	**DEC**	660	2033
Mayo 1	**DEP**	713	2029
Roxboro 1	**DEP**	380	2029
Roxboro 2	**DEP**	673	2029
Roxboro 3	**DEP**	698	2028-2034[3]
Roxboro 4	**DEP**	711	2028-2034[3]

Note 1: Cliffside 6 is assumed to cease coal operations by the beginning of 2036 and was not included in the Carbon Plan's Coal Retirement Analysis because the unit is capable of operating 100% on natural gas.

Note 2: Allen 1 and 5 retirements are planned by 2024 and were not re-optimized in the Carbon Plan's Coal Retirement Analysis.

Note 3: Retirement year for Roxboro Units 3 and 4 vary by portfolio, with retirement of those units effective 2028 in P1, 2032 in P2, and 2034 in P3 and P4.

As this table shows, the projected retirement dates for Marshall Units 1 and 2 are end-of-year 2028.[9]

These timeframes for the planned retirement of coal generation result in the availability of the Generator Replacement Request (GRR) process (a streamlined replacement generation process for new generation that does not cause a material adverse impact on the transmission system at existing generation sites of retiring generation assets)[10] for the Marshall site (Units 1 and 2), the Allen

[9] These projected retirements dates are for general planning purposes. The overall dates may be updated/changed to serve dynamic system conditions and plant health.

[10] For more information about the GRR, see http://www.oasis.oati.com/woa/docs/DUK/DUKdocs/May_11,_2022_DEC_&_DEP_Stakeholder_Meeting_Presentation.pdf

site (Units 1 and 5), and the Cliffside site (Unit 5), which had the effect of eliminating any greenfield sites from its consideration. The Company has also stated that, compared to Marshall Units 1 and 2, Allen Units 1 and 5 and Cliffside Unit 5 have less existing capacity, thus increasing the likelihood that transmission system upgrades will be required. Additionally, the Company stated that the Cliffside and Allen sites will require additional natural gas pipeline construction, which was not needed at Marshall.

In Duke's view, these factors, among others, make Marshall the most desirable of the three DEC sites that were evaluated.

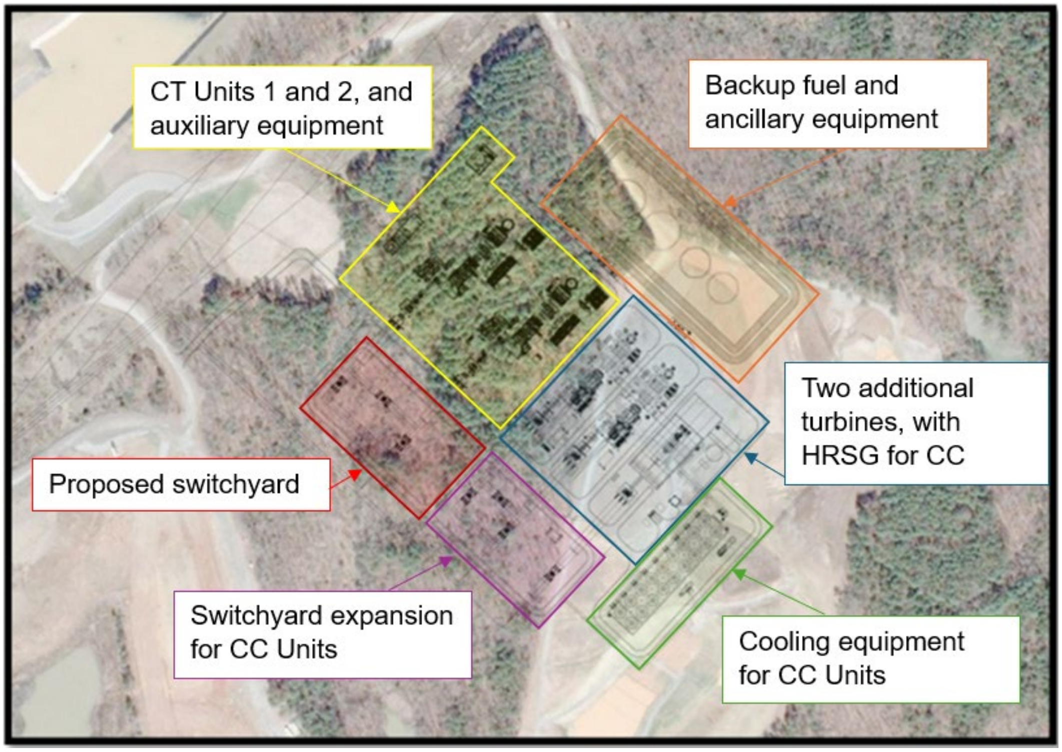
Q. Do you agree with DEC's conclusion that an additional natural gas pipeline was not needed at Marshall?

A. Yes. However, it is important to note that the existing pipeline was constructed relatively recently, along with the upgrades that are needed for the proposed CTs. While DEC is technically correct that a "new" natural gas pipeline is not needed at Marshall, there is the need for new natural gas equipment to provide service to the Marshall CTs and that new equipment will require piping and piping modification to intertie into the existing system. The proposed new natural gas equipment, discussed earlier in our testimony, will cost more than the existing pipeline that was installed recently for DEC's dual fuel operation conversion of the existing four coal generation units at Marshall. We discussed earlier in our testimony the required natural gas pipeline investments to provide service to the facility.

Q. Please identify the aspects of the Application that identify the location of CT Units 1 and 2.

A. Shown in Figure 3 ,below, is a map that shows the general location of the CT units, as well as other aspects of the overall proposed facility. We modified this figure from the one included in the Application by adding the labels and colored boxes.

Figure 3: Proposed Marshall CTs site layout with additional CC.



Q. Do you believe that Duke followed the Commission's directives in its Carbon Plan Order with regard to future natural gas generation assets?

A. Generally, no. Although the Commission's directive included an assessment of replacement generation options at the sites of retiring coal units on the DEC and DEP systems, its directive was not exclusive to such sites and Duke should have evaluated other potential sites in its planning process. In other words, the Carbon Plan Order did not address the site or service territory where CTs or CCs should be located, and, therefore, DEC was not precluded from evaluating greenfield sites, technologies other than a CT, or other brownfield sites. Similarly, while the Commission stated that the Carbon Plan Order should serve as one factor in Duke's analysis of the need for new natural gas plants, the Commission did not state that such consideration should be conducted in isolation of other important factors.

Q. Please list other factors you considered in your evaluation of the siting of this project.

A. In addition to the numerous discovery requests and discussions with DEC staff, we took into account DEC and DEP's historic reserve margins, power transfers from DEP to DEC, and probable transmission constraints.

Q. Have you compared DEC's and DEP's historic reserve margins?

A. Yes. DEC and DEP provide weekly reserve margin reports to the Public Staff. Listed below, in Figure 4, are the 2022 and 2023 DEC and DEP weekly reserve margins.

Figure 4: 2022 and 2023 DEC and DEP weekly reserve margins

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Did you identify any trends or correlations with the reserve margins?

A. Yes. DEP, in aggregate, maintains higher reserve margins than DEC for the majority of the year. Notably, DEP's overall higher reserve margin is, in part, more significant during the summer and shoulder seasons because of the amount of solar interconnected in DEP's territory relative to DEC's territory.

Q. Have you calculated the energy transfers between the Companies?

A. Yes. My calculations and analysis can be found in Table 7 of my testimony filed in DEP's most recent general rate case in Docket No.

E-2, Sub 1300. This table, shown below as Table 8, provides a snapshot of DEP to DEC energy transfers per hour in 2022.

Table 8: Hourly Energy Transfers from DEP to DEC

2022									
DEP to DEC Net Transfers per Hour									
MWh									
8	9	10	11	12	13	14	15	16	17
148,941	237,906	334,802	411,512	466,612	492,634	493,521	473,781	431,134	335,882

Q. Have you compared the weekly reserve margins to weekly power flows between the Companies?

A. Yes. Figure 5, below, overlays DEC's and DEP's weekly reserve margins with the total gigawatt hour (GWh) transfers during the same period.

Figure 5: 2022 DEC and DEP reserve margin compared to energy transfers

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What conclusions do you draw from the graph?

A. The key observation from this graph is that the energy transfers (identified as the dashed line in the above graph) are very one-sided. DEP clearly provides more energy to DEC over the course of the year, regardless of whether DEC has adequate reserves to serve its own load. This ongoing and escalating use of DEP resources (both generation and transmission) to serve DEC load leads to growing equity concerns. DEP ratepayers bear costs without receiving adequate compensation for DEC's usage of the DEP system. This is particularly significant insofar as a CC is more expensive to construct than a CT on a $/kW basis, with the capital cost difference being balanced by the lower energy cost.

Q. Hypothetically, if DEP builds a CC and DEC builds a CT, given the DEC-DEP joint dispatch agreement, which resource will be dispatched for its energy?

A. All else equal, a CC will be dispatched before a CT due to its economics, assuming available transmission transfer capacity between DEP and DEC. Dispatching a lower cost resource located in DEP will increase the total energy flows from DEP to DEC. However, DEP ratepayers will be burdened with the capital and ongoing O&M costs of the CC facility, to which DEC will not contribute under the DEC-DEP joint dispatch agreement. Such a scenario will only increase the DEP to DEC power flows discussed above at the expense of DEP ratepayers.

Q. Did the Public Staff complete any additional energy transfer analysis as part of its review of the proposed Marshall CTs or Roxboro CC?

A. Yes. We used some of the portfolios from the CPIRP for illustrative purposes to show the energy transfers between DEP and DEC that will occur over time and are reflective of certain portfolios.

Table 9, below shows that the present 2022 values of energy transfers will almost double by 2028 across all portfolios. This rapid increase is caused, in part, by the addition of solar photovoltaic generation in DEP. However, a review of the hourly power flows from Duke's P3 Fall Base indicates that DEP to DEC net energy transfers are also occurring at night and not just when solar is producing energy. In addition, this table shows the GWh energy transfers from DEP to DEC each year and how they will change over time as discrete CC and offshore wind resources are added.

Table 9: Annual Energy Transfers from DEP to DEC

	GWh Transfers from DEP to DEC						
Portfolio	2022 Net (Present)	2028	2029	2030	2031	2032	2033
PS1F 2034	6,953	12,840	10,921	11,558	10,147	12,686	15,031
PS1F 2035	6,953	12,796	9,900	10,682	12,382	12,274	11,208
PS1F 2034 Shared Capacity	6,953	12,626	11,265	11,945	11,034	13,182	15,974
PS1F_2034_2035OSW	6,953	12,840	10,966	11,731	12,915	12,647	7,849
PS3F_2037_Force DEP CC, 2035 OffSW, EPA 40% CF	6,953	12,786	13,402	13,722	14,910	17,869	15,531
Duke P3 FB 2035	6,953	12,885	13,550	18,500	17,295	17,809	16,009

Table 9, illustrates a key concept: there is an increase in the amount of expected energy transfers from DEP to DEC, increasing the utilization of both new and existing DEP generation plants as well as DEP's transmission system to serve DEC.

Q. Do you believe that the evaluation completed by Duke for the site and technology selection was sufficient to conclude these were the least cost options?

A. No. Duke completed site evaluations that confirmed that construction of a CC at Roxboro and CTs at Marshall is feasible, but Duke did not complete a sufficient evaluation to determine the ideal site for these resources. While there are several benefits of locating new generation at the Marshall site as discussed in more detail below, it may not be the least cost option. Because of the incomplete analysis performed by Duke, we simply cannot say that Marshall is the least cost option to locate the first new CT units. Ideally, Duke should have continued to re-evaluate which technology will best serve each BA and where. Instead, Duke failed to consider the costs and benefits of all potential sites as well as identifying the amount of energy transfers that are occurring from DEP to DEC.

Q. Was the Public Staff able to discern how the Company made the decision to move forward with the Marshall CTs?

A. Duke's discovery responses reflect that the decision to move forward with the Marshall CTs became interlinked with the Roxboro CC decision. A key insight into the timing and decisions was found in the Companies' board and committee processes, which indicate that the decisions to move forward with Roxboro and Marshall had been made prior to the issuance of the Commission's 2022 Carbon Plan.

Q. Does the timing of the investigation of this Application limit the ability to evaluate and pursue other options that may produce a more equitable outcome for ratepayers, or develop a resource that would mitigate the DEP to DEC energy transfers?

A. Yes. In light of the planned retirement dates of the existing coal generating units, it is simply too late, from a planning or implementation perspective, to go back to the drawing board and evaluate placing a CC at Marshall given the energy needs of DEC.

Q. Are there benefits to siting new generation at the existing Marshall Steam Station site?

A. Yes. Marshall is comprised of four generating units, originally constructed to burn, and still primarily fueled by, coal with the ability to co-fire using natural gas. Siting new generation where there is existing coal generation that will cease operations upon energization of generation fueled by other sources has several benefits.

One such benefit is the ability to utilize the GRR process,[11] which allows a streamlined review of a new generation resource that will be directly taking the place of an existing resource. This process largely focuses on interconnection facilities, and the characteristics of the type of generation that will serve as a replacement. In this case, the planned retirement of Marshall Units 1 and 2 will create 760 MW of

[11] *See* DEC/DEP LGIP/LGIA – Joint OATT, Attachment K.

capacity availability on the transmission system. The GRR process allows the proposed CTs (or any other replacement resource) to have the right of first access to the 760 MW of transmission capacity. A comprehensive transmission study is still required for all generation above the replacement level, which in this particular case is an incremental (nominal) 90 MW of capacity.[12] This interconnection study request was submitted to the 2023 definitive interconnection system impact study (DISIS) cluster study process (Phase II). The DISIS Phase II study was completed on May 20, 2024.[13]

A second benefit, albeit minor in this instance, of utilizing the Marshall site for the replacement generation is that it defers an approximately $52 million transmission upgrade for five years (until 2034), which otherwise would be required upon retirement of Marshall Units 1 and 2 to support grid stability and prevent overloading on the McGuire-Marshall 230 kV line that would result from the retirement of the Marshall generation if not replaced in whole.

[12] The 2023 definitive interconnection system impact study listed 136 MW of incremental capacity.

[13] The 2023 DISIS Phase II results for the proposed Marshall incremental capacity was $45,000 (i.e., near zero costs) with a project in service date of June 1, 2029. The 2023 DISIS Phase II Report is available at: http://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2023_DEC_Definitive_Interconnection_System_Impact_Study_Cluster_(Phase_2)_Report.pdf.

A third benefit of locating the proposed replacement generation at Marshall is the utilization of recently installed natural gas infrastructure, though it will nonetheless require significant upgrades. In 2020, DEC completed a project that allowed up to 50% natural gas co-firing for Marshall Units 3 and 4, with 40% co-firing for Units 1 and 2 in 2021. However, the existing natural gas delivery infrastructure for the dual fuel optionality (DFO) of these Marshall Units is not sufficiently sized to handle the increased flow and pressure requirements of the proposed CTs. To serve the proposed Marshall CTs, Duke will be required to build a new electric compressor station with five electric natural gas compressors (totaling six compressors), located at the nearby Lincoln County Combustion Turbine site.[14]

Additionally, new metering and regulation equipment will be needed, as the remaining DFO units will continue to operate at current pressure. DEC has executed an amendment to its existing natural gas agreement with Piedmont for the incremental firm supply of natural gas and respective pipeline upgrades to the proposed Marshall CT, filed December 15, 2023, in Docket No. G-9, Sub 718, and included as Confidential Exhibit 1.

[14] Multiple compressors are required because the new Marshall CTs will require higher gas pressure than what is currently available at the Marshall site.

Q. Are the benefits you highlighted above specific to CT generation technology?

A. The benefits discussed above are not specific to CT generation and would largely apply if the site had been chosen for a CC generation facility.

V. EPA COMPLIANCE

Q. Should the EPA's recent finalization of its rule limiting emissions from certain electric generating facilities impact this proceeding?

A. Yes. Although the EPA's CAA Rule was only issued several weeks ago, our reading of the CAA Rule indicates that it is likely to impact the operation of the proposed Marshall CTs.

Q. What is the effect of the CAA Rule on the Marshall CTs?

A. Any new natural gas unit that operates at a more than 40% capacity factor will be required to have a greenhouse gas mitigation plan under the CAA Rule. The Company states that the expected average annual capacity factor for the first five years of operation is approximately 20%; however, this operation is based on assumptions within EnCompass modeling in the CPIRP. However, the Company may need to constrain the generation output of the facility should it exceed the current 40% target set in the CAA Rule.

Q. Has DEC proposed a plan for compliance with the CAA Rule for the Marshall CT CPCN Application?

A. No. At this time, DEC has not proposed a plan for compliance with the CAA Rule, nor provided an analysis of how the CTs will be impacted by it.

The Companies have indicated in discovery that Duke is conducting a sensitivity analysis within the CPIRP proceeding, the results of which will be ready, at the earliest, in early July. The Companies have stated that they do not intend to address the impact of the CAA Rule in this docket, but rather in rebuttal testimony filed in the CPIRP proceeding.

VI. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q. Please summarize your findings.

A. The summary of our findings is as follows:

- The Company identified a modeling error associated with the annual fixed fuel costs for new combined cycle units within EnCompass for the firm transportation costs for new natural gas. It is likely that a correction of this error will modify many of the Public Staff's CPIRP portfolio outcomes and identify a need that aligns with the Company's proposed Marshall CT Application.

- Given the interrelationship of the proposed Marshall CTs and Roxboro CC, any decision to approve or disapprove either proposal should not be made in isolation. Commission approval of the Marshall CTs will essentially "force" a Roxboro CC to be built and vice versa.
- The modeling results in the 2022 Carbon Plan proceeding completed by the Companies, and the results from the CPIRP identify the capacity and energy needs of DEC. The increasing power transfers from DEP to DEC illustrate that DEC requires significant amounts of additional energy.
- The Public Staff cannot say definitively that the proposed Marshall CT project is least cost for DEC's ratepayers.
- Duke decided to site CTs at Marshall and a CC at Roxboro prior to the Commission issuing the 2022 Carbon Plan.
- DEC has not determined or proposed a CAA Rule compliance plan for the Marshall CTs.

- The Companies have made no proposal to address the worsening cost allocation issues caused by the uncompensated building and use of assets in DEP to serve DEC load requirements.

Q. What should DEC provide and or respond to in rebuttal testimony?

A. We request that the Company respond in rebuttal by addressing the error associated with the annual fixed fuel costs for new combined cycle units within EnCompass for the firm transportation costs for new natural gas combined cycle plants. The response should also include a summary of the resource additions in DEC and DEP with only the annual fixed fuel cost correction to the Public Staff's capacity expansion plans for the PS1F 2034 model run as well as an additional capacity expansion plan to the PS3F 2037 with a Duke proposed CAA Rule variant.

To the extent that DEC files the information in rebuttal, and if discrete changes to only the annual fixed fuel costs are made to the portfolios identified above, we will be able to discuss any findings or observations during the hearing.

Should the Company not provide this level of additional information in rebuttal, we request that the Commission order the Company to complete, and file said analysis given that the need for this request results from the Companies unintentional modeling error. We further request that the Public Staff be allowed two weeks from the Company's filing of this analysis to provide the Commission with a brief summary that outlines our conclusions from the Company's filing.

In aggregate, these additional capacity expansion plans will further clarify the reasonableness of the proposed Marshall CT, while addressing Duke's embedded modeling error discussed earlier in our testimony.

Q. What conditions should the Commission impose in conjunction with granting the CPCN?

A. We recommend the following conditions, contingent on the revised modeling provided by the Company in rebuttal:

1) That DEC shall file within 60 days of the Commission's final order in the CPIRP proceeding a detailed report on how DEC intends to comply with the CAA Rule.

2) That DEC shall not recover any interstate or intrastate pipeline costs in annual fuel riders or general rate cases until the generation plant is placed in service and released to the energy control center (or equivalent) for economic dispatch for a minimum of 24 hours while operating under full load without interruption (commercial operation), with the exception of necessary testing and

commissioning of the facility prior to commercial operation, recovery of which will be based on a proration of the natural gas consumed.[15] Further, the Commission should require DEC to attest to compliance with this condition in future fuel rider proceedings.

3) That recovery of fuel and fuel-related costs associated with the Marshall CTs is subject to adjustment in future fuel rider proceedings should the Commission find that operation of this facility, or operation of the remaining generation fleet in support of this facility, causes extra fuel costs to be incurred.

Q. In the event that Duke's revised modeling affirms the reasonableness of the proposed locations of both the Marshall CTs and the Roxboro CC, do any of these recommendations become unnecessary?

A. Yes, Conditions 2 and 3 as listed above become unnecessary.

Q. Please list any other requirements recommended by the Public Staff.

A. In addition to the finding and conditions listed above, the Public Staff recommends the following:

[15] For example: if the annual cost for an interstate pipeline is $100M a year, and it was designed to operate at 250,000 Dkthms a day (250,000 Dkthm * 365 days a year = 91,250,000 Dkthm/year), then total annual costs divided by the annual usage ($1.096 per Dkthm of natural gas consumed in this case ($100,000,000 / 91,250,000 Dkthm)) would be the total costs that could be recovered during commissioning and testing, but prior to commercial operation.

1) That the Commission require Duke to file semiannual (twice per year) reports on how it is evaluating, selecting, developing, or taking any other actions related to future resource additions. The report should clearly identify what actions the respective utility has taken with regard to its most recently approved near-term action plan and should identify specific locations, technology types, and capacities of future resource additions that have been recommended to or approved by senior management or the corporate board, including any committee or subcommittee of the board.

2) While the Public Staff is optimistic about a potential DEC and DEP merger, it remains uncertain whether or when it will occur. It is imperative therefore that an alternate solution to cost allocation or cost sharing between DEC and DEP should be developed in the event that the merger does not occur, or even if it is delayed. New generation and transmission additions will be completed between now and the proposed merger date, inclusive of decisions made for longer lead time resources, discussed extensively in Public Staff witness Metz's CPIRP testimony (Docket No. E-100, Sub 190).

The Public Staff recommends that the Commission require DEC and DEP to work with the Public Staff to propose a mandatory and enforceable cost allocation mechanism that addresses equity issues for generation and other rate-based resources (e.g., transmission), including incremental additions, sited in one BA and used to serve load in another BA. The plan and cost allocation mechanism would be solely for NC Retail allocation purposes. Progress updates on plan development should be filed quarterly until complete, with the first report due 60 days after the Commission's final order in the CPIRP proceeding. The plan should also account for the dynamic year-over-year change in annual power flows between DEC and DEP. The purpose of the proposal will be to determine a methodology and not a set dollar value amount. The Public Staff further proposes that DEP and DEC be obligated to work with the Public Staff–regarding the cost allocation mechanism. Given the magnitude and complexity of such a methodology, it will likely require significant time to complete and cannot be resolved without input from both the Companies and the Public Staff.

For future cost sharing methodologies, we propose that the Companies complete modeling sensitivities showing the cost and benefits of DEP located resources, both carbon and non-carbon emitting, to provide energy, even if non-firm, to serve DEC load. For example, from a capacity expansion and production cost modeling analysis, one could "turn off" the ability to transfer energy from DEP East to DEC and determine the incremental resources that would be needed in each utility service area and evaluate the incremental costs. Given the magnitude of energy transfers currently taking place in both the Public Staff and Duke modeling, if transfers were disabled, there would more likely than not be more incremental generation, inclusive of transmission, built in DEC. Public Staff will work with Duke to further refine the scope of this modeling and post analysis and provide results in the quarterly filings discussed above.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

EVAN D. LAWRENCE

I graduated from East Carolina University in Greenville, North Carolina in May 2016, earning a Bachelor of Science degree in Engineering with a concentration in Electrical Engineering. I started my current position with the Public Staff in September 2016. Since that time, my duties and responsibilities have focused on reviewing renewable energy projects, rate design, and renewable energy portfolio standards (REPS) compliance. I have filed an affidavit or testimony in DENC, DEP, and DEC REPS and fuel proceedings, testimony in New River Light and Power's 2017 rate case proceeding, testimony in Western Carolina University's 2020 rate case proceeding, and testimony in multiple dockets for requests for CPCNs. Additionally, I previously served as a co-chair of the National Association of State Utility and Consumer Advocates' Distributed Energy Resources and Energy Efficiency Committee from 2019 to 2021.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (*Magna Cum Laude*) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (*Cum Laude*) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 at North Carolina State University.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion. I also worked for six years for an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on both electric and natural gas matters including general rate cases, fuel cases, annual gas cost reviews, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

CONFIDENTIAL

DOCKET NO. E-7, Sub 1297

LAWRENCE EXHIBIT 1

CERTIFICATE OF SERVICE

I certify that I have caused to be served a copy of the foregoing on all the parties of record on the date set forth below in the manner set forth below on the person(s) set forth below and in accordance with the applicable jurisprudence, especially Commission Rule R1-39.

The unredacted (confidential) version was served on June 24, 2024, via email electronic delivery by agreement of the receiving party, upon those persons identified in the filed documents or in the Commission's online docket's service list at the following addresses:

Anne.Keyworth@psncuc.nc.gov
bbreitschwerdt@mcguirewoods.com
bfranklin@mcguirewoods.com
bwsmith@kilpatricktownsend.com
ccress@bdixon.com
cdodd@brookspierce.com
dconant@bdixon.com
gina.freeman@duke-energy.com
Jack.Jirak@duke-energy.com
jason.higginbotham@duke-energy.com
kathleen.richard@duke-energy.com
lucy.edmondson@psncuc.nc.gov
mmaney@mcguirewoods.com
mtrathen@brookspierce.com
nadia.luhr@psncuc.nc.gov
robert.josey@psncuc.nc.gov

The redacted (public) version was served on June 24, 2024, via email electronic delivery by agreement of the receiving party, upon those persons identified in the filed documents or in the Commission's online docket's service list at the following addresses:

bkaylor@rwkaylorlaw.com
charles.bayless@ncemcs.com
dneal@selcnc.org
kmartin@cucainc.org
mmagarira@selcnc.org
michael.youth@ncemcs.com

/s/ William Freeman, by electronic filling
William S. F. Freeman
Staff Attorney