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 Nos. E-2, Sub 1318, EC-67, Sub 55 – Joint Application of Duke Energy Progress, LLC, and North Carolina Electric Membership Corporation for a Certificate of Public Convenience and Necessity to Construct a 1,360 MW Natural Gas-Fueled Combined Cycle Electric Generating Facility in Person 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 14-18, 22, 34, 36-37, 39, 41, and 48 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-2, SUB 1318
DOCKET NO. EC-67, SUB 55

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Application of Duke Energy Progress, LLC, and North Carolina Electric Membership Corporation for a Certificate of Public Convenience and Necessity to Construct a 1,360 MW Natural Gas-Fueled Combined Cycle Electric Generating Facility in Person 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 of the 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 joint application filed by Duke Energy Progress, LLC (DEP), and North Carolina Electric Membership Corporation (NCEMC) (together, Joint Applicants) on March 28, 2024, in Docket Nos. E-2, Sub 1318, and EC-67, Sub 55, for a certificate of public convenience and necessity (CPCN) to construct a 1,360 megawatt (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 Joint Application).

Q. What did your evaluation of the Roxboro CC CPCN Application include?

A. The Public Staff's evaluation included a review of the Joint Application; the testimonies of DEP witnesses Michael Quinto, Daniel Donochod, H. Lee Mitchell, IV, and John Robert Smith, Jr., as well as NCEMC witness Amadou Fall; and the respective exhibits to those testimonies.

Our evaluation also included a review of responses by NCEMC and DEP to Public Staff and intervenor data requests; multiple meetings with Duke Energy Carolinas, LLC (DEC), DEP, and NCEMC personnel; modeling inputs and outputs used by DEC and DEP (DEC and DEP together, Duke or the Companies) in Docket No. E-100, Sub 179 (2022 Carbon Plan proceeding); the Commission's December 30, 2022 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Carbon Plan Order) in the 2022 Carbon Plan proceeding; and modeling inputs and outputs used by Duke in the 2023 Carbon Plan and Integrated Resource Plans proceeding in Docket No. E-100, Sub 190 (CPIRP).

We also reviewed consumer statements of position filed in the accompanying dockets (Docket Nos. E-2, Sub 1318CS, and EC-67, Sub 55CS); the testimony from the June 12, 2024 virtual public hearing held via WebEx; and the testimony from the June 13, 2024 public hearing held in Roxboro, North Carolina.

Finally, as will be further explained in our joint testimony, our review of the Roxboro CC CPCN Application was concurrent with our review of the preliminary information and application filed by DEC on March 14, 2024, in Docket No. E-7, Sub 1297, for a CPCN to construct two 425-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). 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 disapproval 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 Roxboro CC CPCN subject to 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 DEP and DEC 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 Roxboro CC CPCN Application including the operational characteristics of the proposed facility, the CC's estimated life, fuel supply, technology challenges, integration with DEP's electrical system, and required regulatory permits. We then discuss the estimated project costs; our evaluation and investigation of the need for the project; DEP's evaluation of project sites; 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" (CAA Rule); and the nature of the proposed joint ownership arrangement between DEP and NCEMC. Finally, we detail our conclusions and make recommendations to the Commission concerning the Roxboro CC CPCN Application.

I. PRELIMINARY MATTERS

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

A. The facility will be a natural gas-fueled CC that will have an estimated nominal winter capacity of 1,360 MW. The proposed facility will be a "2x1" CC generating facility comprised of two combustion turbines with bypass stacks, two heat recovery steam generators, and one steam turbine generator and will utilize Number 2 fuel oil as a backup fuel source.

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

A. The Joint Applicants estimate a 35-year life for the proposed facility.

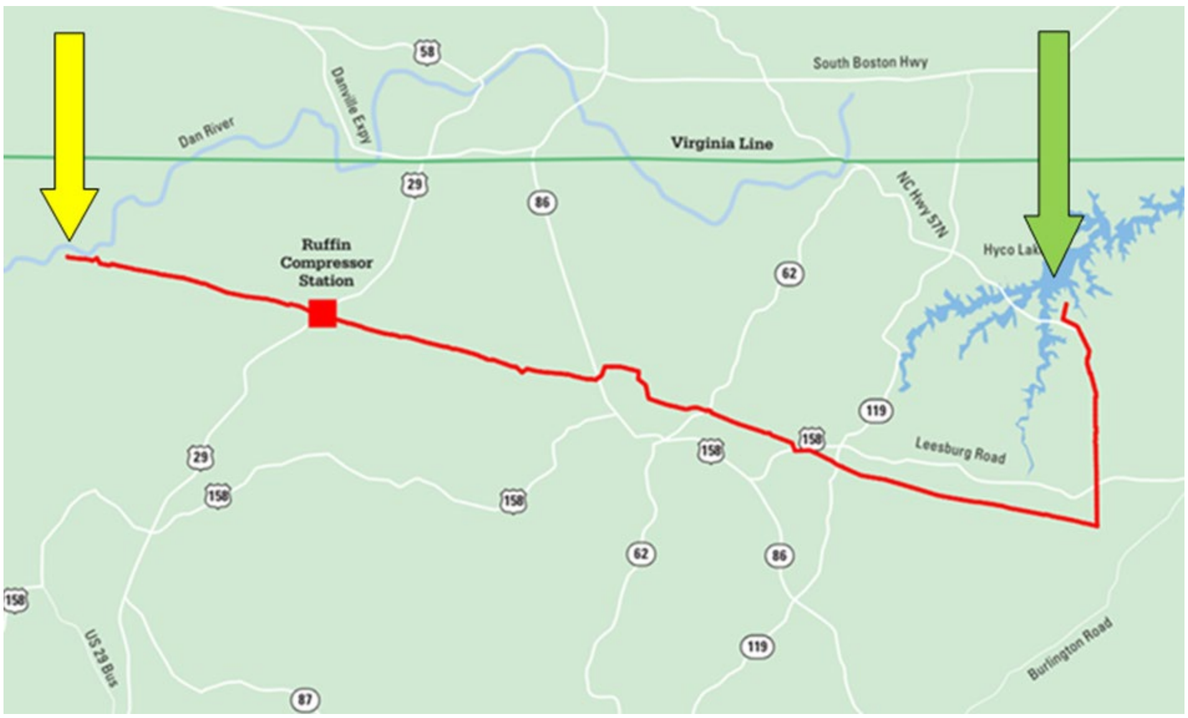
Q. How will this project be supplied with fuel?

A. The primary fuel for the Roxboro CC will be natural gas redelivered from the Williams Transco interstate pipeline (Transco) through a Public Service Company of North Carolina, Inc. (PSNC) pipeline proposed to be constructed to the Roxboro site. In a separate docket, G-6, Sub 668, PSNC filed documents describing the agreement "under which PSNC would construct incremental facilities to provide natural gas transportation and redelivery service to DEP's Person County Electric Generation Facility." PSNC May 30, 2024, cover letter.

The routing of the proposed PSNC pipeline is shown in Figure 1, below, and is represented by the red line. At far left (near the Dan

River), the yellow arrow indicates the proposed PSNC intertie with Transco. The green arrow at the right northerly portion of the red line that terminates near Hyco Lake shows the offtake point for the Roxboro proposed facility.

Figure 1: Proposed PSNC pipeline routing map.



The proposed Roxboro facility will also have limited onsite Number 2 fuel oil as a back-up fuel source should there be an interruption in the natural gas supply. The Joint Applicants indicate that the facility would be capable of hydrogen firing (hydrogen blending), should that technology become viable in the future.

Q. Does the natural gas supply have firm transportation?

A. DEP indicates that the natural gas supply will have firm transportation and will not be interruptible, absent reliability issues on the Transco or PSNC pipelines.

Q. Do you have any concerns about the technology of the proposed facility?

A. Generally, no. DEP and DEC, as well as many other utilities, operate a fleet of combined cycles. Overall, we consider the technology to be mature; however, we do have concerns around the use and potential future need for 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. We also have concerns regarding the viability of carbon capture and sequestration in North Carolina as well as the costs and impacts to the operation of the proposed CC.

Related to these points, we have concerns about the impact and implementation of the recently issued CAA Rule. Given DEP's ongoing analysis of how it will comply with the CAA Rule, we cannot yet identify how DEP's proposed Roxboro facility may be impacted and to what extent.

Q. Has DEP proposed any system design or system configuration that helps address any of the Public Staff's findings and recommendations from its investigation of 2022 Winter Storm Elliott?

A. Yes. The proposed base design indicates the Roxboro CC will be equipped with bypass stacks. This improvement will allow for limited operation in situations where a facility would otherwise be entirely offline.

For example, based on the Public Staff's Winter Storm Elliott investigation in Docket No. M-100, Sub 163, DEC's W.S. Lee natural gas generation plant was out of service from December 11, 2022, through January 13, 2023, due to an issue with the steam turbine. W.S. Lee was constructed without a bypass stack, and therefore these issues with the heat recovery steam generator (HRSG or steam turbine) prevented operation of the entire plant. As a result of this lesson learned, the inclusion of a bypass stack,[1] which allows one or more of the CTs to operate independent of the HRSG, enables flexibility for system operators and removes single points of failure.

[1] A simple cycle CT has an exhaust stack as part of its base design, but in a CC configuration, the final exhaust of combustion gases occurs at the very end of the energy conversion process, post HRSG. A bypass stack allows the exhaust gases to avoid the HRSG (bypass it), enabling the exhaust gases to be released to the atmosphere. In a CC configuration, a bypass stack is installed after each CT but before the HRSG.

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

A. Two new onsite 230 kV transmission lines, measuring less than one mile long, will be required to connect the proposed Roxboro CC to the existing switchyard. To prevent crossing these new 230 kV transmission lines, portions of the existing 230 kV transmission lines must be rerouted. The proposed facility will likely require expansion of the existing Roxboro Steam Station switchyard given the location of the existing switchyard and as a result of design specifications evolving since the switchyard was originally constructed.

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

A. No. Review of the environmental impacts fall within the purview of environmental regulators with expertise in this area, and they 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 relationship between the Joint Applicants.

A. NCEMC is a wholesale power supply customer of DEP. Under the wholesale power supply and coordination agreement between NCEMC and DEP (Power Supply Contract), NCEMC has the right to co-own new baseload generation that DEP plans for development and construction to serve customer load in DEP. On March 14, 2024, NCEMC exercised its right to jointly own the maximum amount of allowable capacity under the Power Supply Contract – approximately 225 MW of the proposed 1,360 MW Roxboro CC.

Although NCEMC exercised its right to ownership, the Joint Applicants have not yet entered into a binding agreement regarding any of their respective rights and obligations. The Public Staff has not received finalized contracts, a term sheet, terms or conditions, or any additional information that would confirm a binding agreement or contract between NCEMC and DEP. In addition, due to the CAA Rule, the proposed Roxboro CC may be operated as an intermediate load plant (i.e., up to 40% annual capacity factor) and not as a baseload plant. Thus, since the Power Supply Contract specifically applies to "new baseload," it is unclear if or how the joint ownership would be impacted. In addition, it is not clear if or how any must run (i.e., generation that must be dispatched regardless of economic dispatch order) requirements will be impacted by NCEMC's ownership.

Although we are not attorneys, we have been advised by counsel that N.C.G.S. § 62-110.1(e) provides in part as follows: "As a condition for receiving a certificate, the applicant shall file an estimate of construction costs in such detail as the Commission may require.... In making its determination, the Commission shall consider … reasonably anticipated future operating costs." Because the respective rights and obligations between NCEMC and DEP have not been agreed upon and due to the uncertainty as to the impact of the CAA Rule, the Public Staff is unable at this time to provide the Commission with either the construction costs or anticipated future operating costs of the proposed Roxboro facility that will be borne by DEP ratepayers. Instead, the Public Staff can only comment on total costs and expenses of the project with the understanding that DEP ratepayer allocations should decrease if or when the Joint Applicants reach a firm agreement.

Q. Please discuss the total costs of the Roxboro CC project.

A. Confidential Exhibit 3 of the Application provides a cost breakdown of the project, which is summarized in Table 1, below. This table represents the total costs of construction for the overall facility.

Table 1: Roxboro CC Projected Capital Cost

[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	1,360 MW (estimated nominal winter capacity)
Summer output, MW	1,220 MW
Project cost $/kW (winter)	[redacted]
Total Project costs including AFUDC	[redacted]

[END CONFIDENTIAL]

As noted above, there is no indication of the portion of costs to be borne by the ratepayers of either of the Joint Applicants since the respective rights and responsibilities of the Joint Applicants have not been agreed to at this time.

To our knowledge, DEP, which is supervising the construction of the project, has not received final bids on the overall project, although our review indicates that DEP appears to have used reasonable cost estimates. Based on Confidential Exhibit 3 of the Application, the project estimate is between a Class 3 and Class 4 estimate,[2] and DEP currently projects that the total cost to construct the Roxboro CC is in the predictability range of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

The cost estimating practice used to determine the range of potential project costs appears to be reasonable from an industry perspective; however, the potential for the project to come in at the upper end of the cost band is concerning given the unknowns surrounding the project's CAA Rule compliance and longer-term risk to DEP ratepayers. To the extent that hydrogen fuel use or carbon capture and sequestration is required, the costs to operate the Roxboro CC will increase.

Additionally, while the total cost estimate does not include the costs for capital spare parts, based on information provided in discovery, the addition of the costs of capital spare parts will most likely not cause the estimate to exceed the upper band of the overall estimate.

DEP's filed confidential cost estimates, listed above, also exclude the total cost of gas delivery to the facility (i.e., the "pipeline" costs). More specifically, DEP has not included the capital cost of the intrastate pipeline in the capital cost of the facility. Instead, DEP appears to

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[2] www.costengineering.eu/Downloads/articles/AACE_CLASSIFICATION_SYSTEM.pdf

recognize the cost of the intrastate pipeline as an operating cost, presumably to be recovered through the annual fuel rider. Outlined in Table 2, below, is a breakdown of the DEP's projected annual operating costs.

Table 2: DEP's Projected Annual Operating Cost

[BEGIN CONFIDENTIAL]

Category	**Total**
Fixed O&M	[redacted]
Variable O&M	[redacted]
Gas Pipeline Intrastate Firm Transportation	[redacted]
Fuel	[redacted]
Total	[redacted]

[END CONFIDENTIAL]

Q. Table 2, above, lists the intrastate pipeline costs. If the annual capacity factor of the Roxboro CC facility were reduced to 40% in order to be CAA Rule compliant, would the total annual operating costs, including pipeline costs, be reduced proportionally as well?

A. No. Prior to the CAA Rule, the Public Staff's CPIRP modeling and our analysis of Duke's modeling results indicated that the proposed CC facility would have likely operated at a near 80% annual capacity factor. It is possible that DEP could comply with the CAA Rule by reducing the Roxboro CC's output to a capacity factor of no more than 40%, or half of the expected 80% annual capacity factor. While the total fuel costs may, in this instance, also be reduced by half given that energy output has a direct correlation to fuel consumption, the total transportation charges would mostly be unchanged within the “Fuel” category because of the significant pipeline costs that would be necessary to provide natural gas service to the Roxboro site. For this reason, even if the proposed output of the facility is halved, the total costs shown in Table 2 would not be reduced proportionally because of the magnitude of total fixed costs.

Q. What is PSNC’s estimated interstate pipeline capital cost for the proposed facility?

A. Based on the confidential natural gas pipeline construction and transportation service agreement filed by PSNC on October 16, 2023, and later updated on May, 30, 2024, in Docket No. G-5, Sub 668, along with DEP’s responses to discovery, these costs are anticipated to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** subject to true up once the pipeline is complete. We use a nominal price of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for purposes of further discussion in this testimony.

Q. Is it your understanding that PSNC's estimated interstate pipeline costs do not include future larger volumes of hydrogen blending on the PSNC pipeline?

A. Yes, that is our understanding. It is entirely unknown what the longer-term impacts will be for larger volumes of hydrogen blending on the intrastate pipeline system.

Q. Why are intrastate pipeline costs identified in the operating cost table but not interstate pipeline costs?

A. We understand that the interstate pipeline costs are included in the "Fuel" cost category in Table 2.

Q. What are the total annual costs for this plant to secure a firm transportation supply of natural gas on both intrastate and interstate pipelines?

A. The Company estimates the combined intra and interstate costs to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** a year, depending on whether post processing analysis or the direct EnCompass inputs are used.[3] The Company will likely seek to recover these costs in its annual fuel rider. As a result, these costs will be essentially fixed over the contract period, regardless of the capacity factor at which the CC operates. In addition,

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[3] See testimony of Public Staff witness Blaise Michna filed May 28, 2024, in Docket No. E-100, Sub 190, page 25, Confidential Table 1: Annual Fixed Fuel Costs of new CC units in EnCompass, DEP Resource.

the annual costs of the intrastate pipeline will likely be directly assigned to DEP ratepayers, as the pipeline delivery costs will be allocated to this single generation plant.

III. PROJECT NEED

Q. What types of generation resources are generally considered to meet an identified need for new generation capacity?

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 baseload 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 selecting the most appropriate 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 to provide significant amounts of low-cost energy to customers. If little energy is required, peaking units are cost-justified due to their lower capital cost as compared to baseload units. However, if much energy is needed, the lower energy cost (in cents/kWh) of capital-intensive baseload 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.

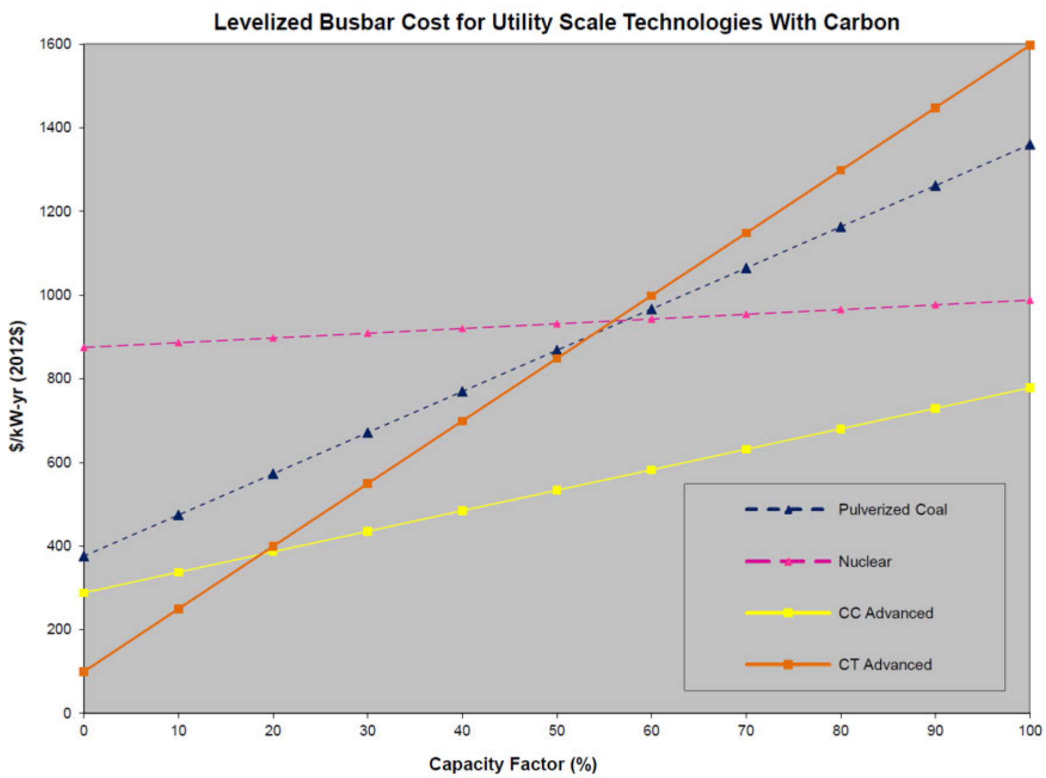
Figure 2, below, is an excerpt from page 17 of DEP's[4] 2012 IRP.[5] This figure provides an economic comparison of utility-scale technologies based on estimates of capital, fuel, and O&M cost projections at the time they were developed, inclusive of carbon costs. The costs in this type of analysis are 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 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.

[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.

The technologies represented in Figure 2 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 2: 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.

The following confidential graph, shown in Figure 3, is a levelized busbar cost but with 2022 technologies and updated costs from 2012. It is important to note that the levelized busbar costs are not reflective of the updated costs in the CPIRP. The graph is for illustrative purposes only.

Figure 3: 2022 Levelized Busbar Cost Curve

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

This busbar graph provides 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 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 future need for resource selection of new capital resources to provide capacity and energy is evaluated and determined in an integrated resource plan (or equivalent) proceeding. For this Application, the 2022 Carbon Plan proceeding and the Carbon Plan Order are the relevant starting points to determine the project need. Further, after project need is identified, a utility acting prudently would 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 through 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, EnCompass. A summary of the modifications to the original Portfolios 1 to 4 was filed by Duke on July 28, 2022, and is 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, both of 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. Did the Companies' CPIRP P3 FB portfolio retirement schedule match the discovery responses in the Roxboro CPCN Application?

A. Yes. Shown below in Figure 4, and Table 3, are the proposed retirement dates used in the CPIRP EnCompass files for DEC and DEP coal units.

Figure 4: CPIRP P3 Fall Base projected coal capacity, and capacity factors

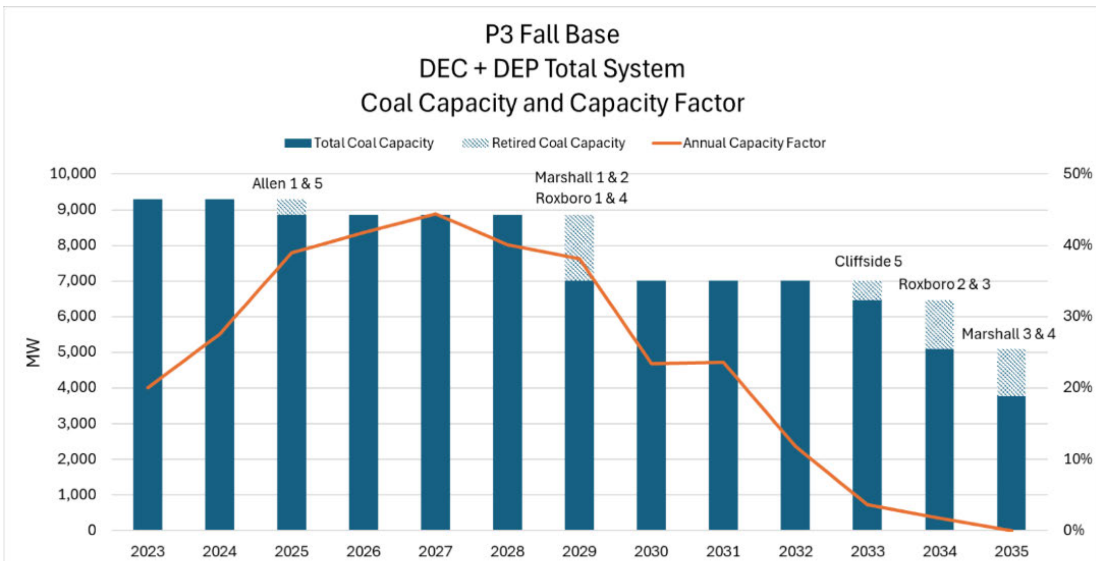


Table 3: Coal retirements as presented in the 2022 Carbon Plan Order

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.

Q. In the Companies' CPIRP, did Duke impose modeling constraints on future CCs?

A. Yes. The Companies limited the model to only allow CCs to be built in 2029 and 2030 in the DEP service area.

Q. If the Commission were to approve the Roxboro CPCN as filed, when do you expect the CC to come online?

A. If the Commission were to approve the Roxboro CPCN Application as filed, the CC should come online in 2029, pending construction delays, equipment failure, or other unforeseen circumstances.

Q. If the Commission were to approve the Roxboro CPCN as filed, will the in-service date of this first CC (CC1) align with the retirement of Roxboro Units 1 and 4?

A. Yes, subject to compliance with CAA Rule.

Q. Why did Duke limit the CPIRP's EnCompass modeling to CCs in DEP's BA for 2029 and 2030 when Roxboro Units 2 and 3 retire five years after Roxboro Units 1 and 4?

A. These modeling assumptions do not seem logical, and as a result, we cannot explain why these limits were placed on the model.

Our investigation did not reveal that the Companies took any other actions to evaluate alternate options other than building Roxboro CC1, and ultimately CC2. Our investigation concludes that the Companies constrained the model in such a way as to accelerate deployment of a second CC, which DEP will likely seek to be located at Roxboro as well, given what the Public Staff learned through discovery, as discussed throughout our testimony.

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

A. Yes. On May 28, 2024, the Public Staff filed testimony in the CPIRP proceeding that discussed extensive modeling runs and analysis the Public Staff conducted in its 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 SP5 modeling results?

A. Yes. Generally, the Public Staff's CPIRP model runs identified the same resource needs 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 4: 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 5: 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 6: 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 7: DEC CT Number of Units Per Year

	DEC Combustion Turbine Number of Units Per Year					
		2028	2029	2030	2031	Total
2022 CPIRP	SP 5	1	1			2
2022 CPIRP	SP 5A	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 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 DEP identified any errors in its CPIRP Supplemental Planning Analysis (SPA) (i.e., Fall Base Update) 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

[8] Testimony of Public Staff witness Michna filed May 28, 2024, p. 18, lines 1-3.

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 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 solidify if 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. How did DEP select this site for the proposed CC facility?

A. DEP performed a “preliminary” review of select brownfield locations. It did not fully evaluate new greenfield sites for the proposed CC. The Company did not provide any objective analyses of its site selection process in the Application, nor any additional insights in discovery related to either greenfield or brownfield site selection.

Q. Was the Company's decision not to evaluate greenfield sites reasonable?

A. No. While a brownfield site can leverage the synergies of existing electrical infrastructure at an existing plant, thus reducing risk and costs to ratepayers, the Company's failure to conduct any analysis is concerning given the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in costs associated with expanding the PSNC pipeline to the Roxboro site.

Q. How did the Company evaluate brownfield sites for the proposed facility?

A. Other than Roxboro, DEP explained in discovery that all other brownfield sites "were not comprehensively evaluated for siting CC1 to support the planned replacement of retiring units at Roxboro by January 1, 2029".[9] Other brownfield sites were considered preliminarily [Blewett, Harris, Richmond, or other DEP locations], but each had impediments to development compared to replacing Roxboro retiring units with on-site CC. For example, the Blewett CTs are diesel-only and existing gas infrastructure is insufficient to meet the CC1 requirements, Richmond has transmission constraints in the

[9] Company response to PS DR 6-1.

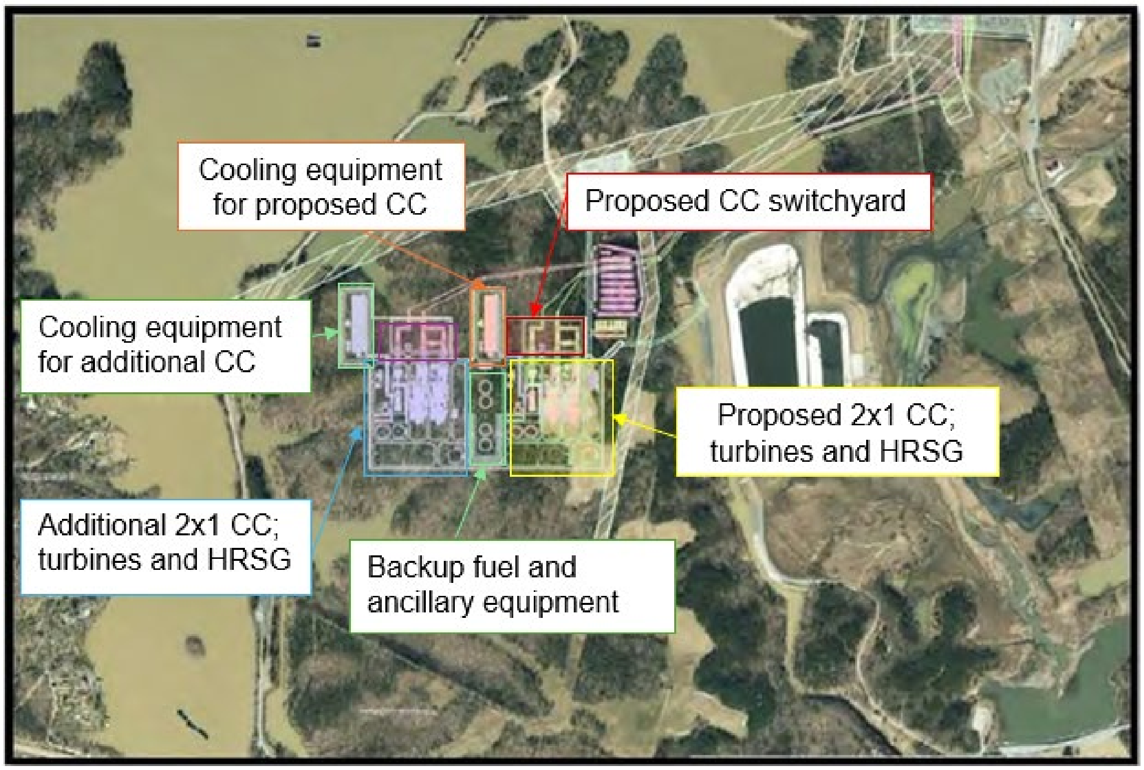
area, while Company-owned land at the Harris nuclear plan[t] has been identified as favorable site for future nuclear use."[10]

Q. Do you know why the Company describes the Roxboro proposed facility as CC1 in discovery?

A. As shown on page 270 of Exhibit 2 of the Application, the response to PSDR 6-1, and other discovery responses, it appears that the Company intends to build two CCs at Roxboro as identified below in Figure 5. A proposed 2x1 CC (CC1) is outlined in yellow and the additional 2x1 CC (CC2) is outlined in blue. We modified this figure from the one included in the Application by adding the labels and colored boxes.

[10] *Id*.

Figure 5: Person County CC site layout with second CC



Q. Will a second CC require additional natural gas pipeline upgrades?

A. Yes. The total PSNC pipeline costs to provide service to CC1 and CC2 at Roxboro are estimated to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, or an incremental amount of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, beyond the pipeline costs projected to provide service to CC1.

Q. How did the Company determine the size (MW) of the proposed CC?

A. It is unclear how the Company determined the size of the proposed Roxboro CC. The Company was planning for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

The sizing of this proposed facility appears to be linked to the retirement of two coal units at Roxboro as opposed to retiring three or all four units at Roxboro. DEP's data request responses state that "[t]he Company only filed for GRR to support the DEP combined cycle (CC1) that was included in the NTAP and which the Commission determined was reasonable to plan for in the 2022 Carbon Plan Order. The CPIRP continues to show Roxboro Units 2 and 3 retiring in 2034, so submitting a GRR for the entire coal plant will dramatically accelerate coal retirements relative to the current 2023 CPIRP."[12] It appears that DEP also predetermined the size of the CC. The Company did not produce any substantive information on whether it analyzed sizing alternatives to its proposed facility with a nominal

[11] Company response to PS DR 3-4.

[12] Company response to PS DR 3-4.

1,360 MW capacity. While a larger CC may require higher capital expenditures, it may also leverage a more efficient heat rate with the retirement of additional Roxboro units.

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 DEP staff, we took into account DEP and DEC's historic reserve margins, power transfers from DEP to DEC, and probable transmission constraints.

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

A. Yes. DEP and DEC provide weekly reserve margin reports to the Public Staff. Listed in Figure 6, below, are the 2022 and 2023 DEP and DEC weekly reserve margins.

Figure 6: 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 a table located on page 47 of my testimony filed in DEP's most recent general rate case in Docket No. E-2, Sub 1300, on March 27, 2024. It is shown below as

Table 8 and 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. The graph below, in Figure 7, overlays DEP's and DEC's weekly reserve margins with the total gigawatt hour (GWh) transfers during the same period.

Figure 7: 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 meet 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 would 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 Applications?

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 benefits of locating new generation at the Roxboro site, especially Duke's ownership of the land and the existing transmission, it may not be the least cost option. Because of the incomplete analysis performed by Duke, we simply cannot say that Roxboro is the least cost option to locate the first new CC. 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 Roxboro CC?

A. Duke's discovery responses reflect that the decision to move forward with the Roxboro CC became interlinked with the Marshall CTs 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.

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 Roxboro CC facility.

Q. What is the effect of the CAA Rule on the Roxboro CC?

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. Absent a CAA Rule, as discussed earlier in our testimony, a new CC would operate at around a 70%-80% annual capacity factor. The CAA Rule will reduce the ability of a new CC to leverage the economic benefits of lower cost generation compared to older or less efficient generation technologies.

Q. Has DEP proposed a plan for compliance with the CAA Rule for the Roxboro CC CPCN Application?

A. No. At this time, DEP has not proposed a plan for compliance with the CAA Rule, nor provided an analysis of how the CC 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. DEP AND NCEMC JOINT OWNERSHIP

Q. Were you able to evaluate the joint ownership proposal between DEP and NCEMC for the Roxboro CC?

A. No. At the time of filing of this testimony, neither DEP nor NCEMC had provided a term sheet or executed contracts regarding the joint ownership of the proposed CC. Therefore, we were unable to evaluate the proposed joint ownership arrangement.

Q. In regard to the proposed joint ownership of the facility by DEP and NCEMC, have the parties agreed to commercial terms of ownership?

A. Not to our knowledge.

Q. Is it appropriate for NCEMC to own a part of the proposed facility?

A. NCEMC's ownership will serve native wholesale load in DEP's BA that DEP is currently, or will be, serving. The Public Staff does not take issue with this general proposition but will need to review the finalized commercial terms of ownership to provide a complete answer to this question.

Q. What is the impact of NCEMC's partial ownership of the Roxboro CC on DEP's operation of the facility and carbon emission reduction requirements?

A. This information is unknown at this time because the joint applicants have not provided information on dispatch priority and whether the plant will be designated as a "must run" resource. However, commercial terms reached by DEP and NCEMC could affect how DEP will operate the facility and how carbon emission reduction requirements will be met.

Q. What other questions are unanswered without an executed joint ownership agreement?

A. Other issues that are unclear without an agreement are:

- Assignment of fuel cost responsibility, inclusive of intrastate and interstate annual fixed costs, and ownership;
- NCEMC's obligation to pay for a share of carbon capture and sequestration costs if found to be a reasonable way to comply with the CAA Rule;
- Uncertainty on long-term operation and maintenance expenses and or capital replacements; and
- Whether NCEMC's agreement is required for DEP's ultimate CAA Rule compliance strategy.

This last issue raises a serious concern. If DEP finds a need to make a capital investment to allow the CC to continue to provide service to ratepayers, for example hydrogen blending or carbon capture, DEP may have to seek agreement from NCEMC prior to implementing the technology solution. This uncertain and unknown risk makes it challenging to determine whether the proposed facility should be approved by the Commission in the first place, and it may cause financial harm to DEP ratepayers if NCEMC does not agree with DEP's proposal to incur certain future capital costs.

Q. Why have DEP and NCEMC not provided this information?

A. It is the Public Staff's understanding that DEP and NCEMC have not agreed to or finalized the terms of their relationship (if any) or contracts that address these issues. Since no agreement exists, neither DEP nor NCEMC was able to provide an executed contract to the Public Staff for its review. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

VII. CONCLUSION AND RECOMMENDATIONS

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 in DEP that aligns with the Company's proposed CC generation.

- 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 Marshal 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 DEP, noting 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 Roxboro CC project is least cost for DEP's ratepayers.

- Duke decided to site CTs at Marshall and a CC at Roxboro prior to the Commission issuing the 2022 Carbon Plan.

- DEP has not determined a CAA Rule compliance plan for the Roxboro CC.

- 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.
- The lack of a joint ownership agreement between DEP and NCEMC prevents the Public Staff from having a sufficient opportunity to review the potential impacts.

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 DEP and DEC 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 DEP 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 Roxboro CC, 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. The Public Staff recommends the imposition of the following conditions:

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

(2) That DEP 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.[13] Further, the Commission should require DEP to attest to compliance with this condition in future fuel rider proceedings.

(3) That recovery of fuel and fuel-related costs from the Roxboro CC units 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 listed above become unnecessary.

[13] 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.

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:

(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 given the complexities associated therewith. It is imperative therefore that an alternate solution to cost allocation or cost sharing between DEP and DEC 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 filed in Docket No. E-100, Sub 190.

The Public Staff recommends the Commission require DEP and DEC 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 DEP and DEC. 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 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. The 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.

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.

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:

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