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STATE OF NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
	)	
Joint Application of Duke Energy	)	
Progress, LLC, and North Carolina	)	**DOCKET NOS.**
Electric Membership Corporation	)	**E-2, Sub 1349 and EC-67, Sub 57**
for a Certificate of Public	)	
Convenience and Necessity to	)	
Construct a 1,360 MW Natural	)	
Gas-Fired Combined Cycle	)	
Electric Generating Facility in	)	
Person County, North Carolina	)	
	)	

PUBLIC - REDACTED DIRECT TESTIMONY
OF
LUCY METZ

ON BEHALF OF
THE SOUTHERN ALLIANCE FOR CLEAN ENERGY

June 9, 2025

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lucy Metz. I am a Senior Associate at Synapse Energy Economics, Inc. (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation; transmission and distribution system reliability; ratemaking and rate design; electric industry restructuring and market power; electricity market prices; stranded costs; efficiency; renewable energy; future of gas utilities planning; environmental quality; and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. At Synapse, I conduct analysis and write publications on a variety of topics related to power plant economics and integrated resource planning. I regularly support the development of comments and testimony in litigated dockets across the country, including performing analyses of electric power systems using industry-standard models such as EnCompass and spreadsheet tools. I recently sponsored testimony before the Kansas Corporation Commission and the Public Service

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Commission of Wisconsin, and I co-sponsored testimony before the Georgia Public Service Commission.

I hold a Bachelor of Science in Engineering Science from Smith College. A copy of my current resume is attached as Exhibit LM-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the Southern Alliance for Clean Energy (SACE).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. No, I have not previously testified before the Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In my testimony for this proceeding, I first evaluate whether Duke Energy Progress (DEP or Company, and together with Duke Energy Carolinas, Duke Energy) and the North Carolina Electric Membership Corporation (NCEMC, and together with DEP, the Joint Applicants) have established the need for their proposed addition of a second combined-cycle unit at the Roxboro site (Proposed Facility). I also evaluate the extent to which the Proposed Facility is needed to serve prospective large load customers. Next, I assess whether the Company's analysis demonstrates that it adequately compared the Proposed Facility to alternatives and accounted for the risks posed by continued investment in fossil fuel resources. Finally, I discuss potential ratepayer impacts of the Proposed Facility. I suggest actions the Commission could take to protect

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ratepayers from future rate increases associated with the Proposed Facility that stem from fuel price volatility and prospective large load customer additions.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. In Section II, I summarize my findings and recommendations for the Commission and I describe the Joint Applicants' requests in this docket related to obtaining a Certificate of Public Convenience and Necessity (CPCN) for the Proposed Facility.

In Section III, I assess the extent to which prospective large load customers drive DEP's need for the Proposed Facility.

In Section IV, I describe shortcomings in the Company's Carbon Plan and Integrated Resource Plan (CPIRP) modeling that may have prevented it from identifying the most cost-effective solution for ratepayers. I also outline steps DEP should take to procure alternative capacity and energy resources to reduce or eliminate its need for the Proposed Facility and to enable more rapid renewable buildout in its service area.

In Section V, I recommend measures the Commission could take to protect DEP's existing ratepayers from costs associated with building new resources such as the Proposed Facility to meet load growth, specifically protection from fuel price volatility and cost-shifting from prospective large load customers.

Q. WHAT DOCUMENTS DO YOU RELY UPON FOR YOUR ANALYSIS, FINDINGS, AND OBSERVATIONS?

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A. My analysis relies primarily upon the workpapers, exhibits, and discovery responses provided by the Joint Applicants, as well as publicly available data.

II. FINDINGS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. My primary findings are the following:

- Duke Energy's resource planning shows that the model did not build a second combined-cycle unit in DEP's service area until the Company updated its load growth forecast to include economic development customers. This suggests that, but for these new customers, DEP would not need the Proposed Facility on the current timeline.
- Demand from new customers for capacity on an accelerated timeline will increase costs and risks to all ratepayers, absent action from the Commission to protect existing ratepayers.
- DEP's modeling shows that utilization of the Proposed Facility will decline steadily over its 35-year useful life, beginning at 80 percent in 2030 and decreasing to 46 percent by 2040 and only 13 percent from 2050 on, even in the absence of U.S. Environmental Protection Agency Section 111 rules (111 Rules) capacity factor restrictions.
- Several limitations with Duke Energy's modeling, procurement, and interconnection process likely prevented it from identifying the lowest-cost and lowest-risk resource additions for ratepayers:

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a. The Company has not taken sufficient steps to improve its resource interconnection process and remove barriers to the rapid addition of renewable resources in its service area.

b. As a result, the annual limits on the amount of renewable capacity that the CPIRP model could add were restrictive and caused the model to select gas to serve near-term capacity and energy needs, even though investment in gas assets is risky in the long term.

c. Duke Energy's firm capacity ratings for new resources biased the model towards adding gas capacity over renewables.

d. Duke Energy underestimates the risk that the Proposed Facility will become a stranded asset under state climate law, which requires the Company's generating facilities to achieve carbon neutrality by 2050.

e. Duke Energy did not sufficiently model exposure to fuel price volatility, which is a significant concern for combined-cycle units, especially in the years when the Company projects that the Proposed Facility will run at a high-capacity factor.

DEP has not demonstrated that the Proposed Facility is lower cost than a portfolio of dispatchable capacity (e.g., battery storage or even combustion turbines) paired with solar and wind. Clean energy resources such as solar and battery storage would shield ratepayers from future cost

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risks and can be procured incrementally, allowing DEP greater flexibility to adapt to changing market conditions and supply chain disruptions.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on my findings, I offer the following recommendations:

1. The Commission should not approve the Joint Applicants' request for a CPCN for the Proposed Facility.

    a. If the Commission does approve the CPCN application, it should make approval contingent on the establishment of a fuel cost-sharing mechanism for gas burned at the Proposed Facility, to distribute the risk of fuel price volatility more equitably between the Company and its ratepayers.

2. To support its consideration of resource and fuel diversity, the Commission should instruct DEP to issue an All-Source Request for Proposals (RFP) prior to ruling on this CPCN application to determine whether this yields capacity and energy resources that are less costly than the Proposed Facility.

3. DEP should focus its near-term actions on procurement of no-regrets resource additions that its modeling found to be economic and that are consistent with long-term state policy, primarily solar and battery storage capacity. The Company should also focus on streamlining and removing bottlenecks in its interconnection process.

4. Regardless of whether it grants the CPCN, the Commission can protect DEP's existing ratepayers from future cost increases associated

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with proposed generating facilities by directing DEP to develop tariff proposals in a future large load customer docket. These tariff proposals should commit large load customers to paying their full cost of service before DEP builds assets to serve them and/or enable DEP to develop renewable generation to meet load.

Q. WHAT ARE THE JOINT APPLICANTS REQUESTING IN THIS DOCKET?

A. In this docket, the Joint Applicants request a CPCN to construct a 1,360 megawatt (MW) combined-cycle unit in Person County at the site of the Roxboro Steam Plant. The resource will be co-owned, with DEP owning 1,135 MW (83 percent) and NCEMC owning the remaining 225 MW (17 percent).[1] The anticipated commercial operation date of the facility is January 1, 2030.[2] The Proposed Facility, together with the first combined-cycle unit at the Roxboro site, for which DEP has already obtained a CPCN, will be known as the Person County Energy Complex.[3]

Q. WHAT IS THE COMPANY'S ESTIMATE FOR THE COST OF THE PROPOSED FACILITY?

A. As detailed in Confidential Table 1 below, the Joint Applicants estimate the total cost of the Proposed Facility to be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (including Allowance for Funds Used During Construction (AFUDC)), which is equivalent to **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This cost

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[1] Joint Application of Duke Energy Progress, LLC and North Carolina Electric Membership Corporation for a Certificate of Public Convenience and Necessity, at 2.

[2] Joint Application at 3.

[3] Joint Application at 2.

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estimate includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for transmission network upgrades. It does not include the cost to obtain firm gas service at the facility. DEP projects that intrastate firm gas transport will cost **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[4] It has not calculated incremental interstate pipeline costs to serve the Proposed Facility, since it considers these to be a system cost rather than a generator-specific expense.[5]

Confidential Table 1. Project cost estimate for the Proposed Facility

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Source: Joint Application, Confidential Exhibit 3, tables 3.1 and 3.2.

The cost estimate in Confidential Table 1 is between an AACE[6] Class 4 and Class 3 estimate, with a predictability range of **[BEGIN**

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[4] Joint Application for a Certificate of Public Convenience and Necessity, Confidential Exhibit 3: Cost Information, at 6.

[5] DEP Response to PSDR 6-1.

[6] The Association for the Advancement of Cost Engineering (AACE) International publishes a cost estimate classification system that categorizes project cost estimates by their maturity and quality.

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CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**.[7] This means that actual project costs could be between **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[8] Notably, the Company **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[9] Current shortages of gas equipment relative to demand, as well as uncertainty surrounding trade tariffs, create risk that the capital costs of the unit will escalate beyond the Company's current estimate.[10] For example, Duke Energy Indiana filed a CPCN application earlier this year for a pair of combined-cycle units with a combined capacity of 1,476 MW that will cost $2,256 per kW,[11] which is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** higher than DEP's current estimate for the Proposed Facility. The recent surge in demand

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[7] Joint Application Confidential Exhibit 3 at 5.

[8] *Id*.

[9] Confidential DEP Response to SACE DR 2-7.

[10] Kassia Micek & Nushin Huq, *CERAWEEK: Renewables ready to go, labor and parts delays gas plants: NextEra CEO*, S&P Glob. (Mar. 10, 2025), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/031025-ceraweek-renewables-ready-to-go-labor-and-parts-delays-gas-plants-nextera-ceo.

[11] The total project cost including AFUDC is $3.33 billion. *See* Direct Testimony of John Robert Smith, Jr. on Behalf of Duke Energy Indiana, LLC, Petitioner's Exhibit 3, Cause No. 46193, at 18 (I.U.R.C. Feb 13, 2025), *available at* https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/ab0b076a-edea-ef11-be20-001dd80b89f5/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46193_Duke%20Energy%20Indiana_Direct%20Testimony%20of%20Smith_021325.pdf.

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for new gas power plants across the country has also caused a labor shortage, which has the potential to cause construction delays for the Proposed Facility or its supporting pipeline infrastructure and thereby increase project costs.[12] The Joint Application currently does not contain any cost cap provisions or other measures to protect customers in the event of project cost increases.

Q. WHAT IS DEP'S CAPACITY POSITION GOING FORWARD?

A. Figure 1 shows DEP's capacity need and its existing resources. DEP has a small capacity shortfall starting in 2027 that grows in subsequent years. The first combined-cycle unit at the Roxboro site will come online in 2029 and will have a winter rated capacity of 1,360 MW. This addition will reduce the capacity need shown in Figure 1. In summer, DEP does not have a capacity need until 2034 after accounting for the addition of the first combined-cycle unit.

The peak load forecast that DEP uses for planning purposes includes NCEMC's resource needs, so NCEMC's partial ownership of the Proposed Facility will reduce DEP's capacity obligation by a corresponding amount.[13]

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[12] Jason Plautz, *Want to build a gas plant? Get in line*., E&E NEWS (Apr. 22, 2025), https://www.eenews.net/articles/want-to-build-a-gas-plant-get-in-line/.

[13] Joint Application at 10–11.

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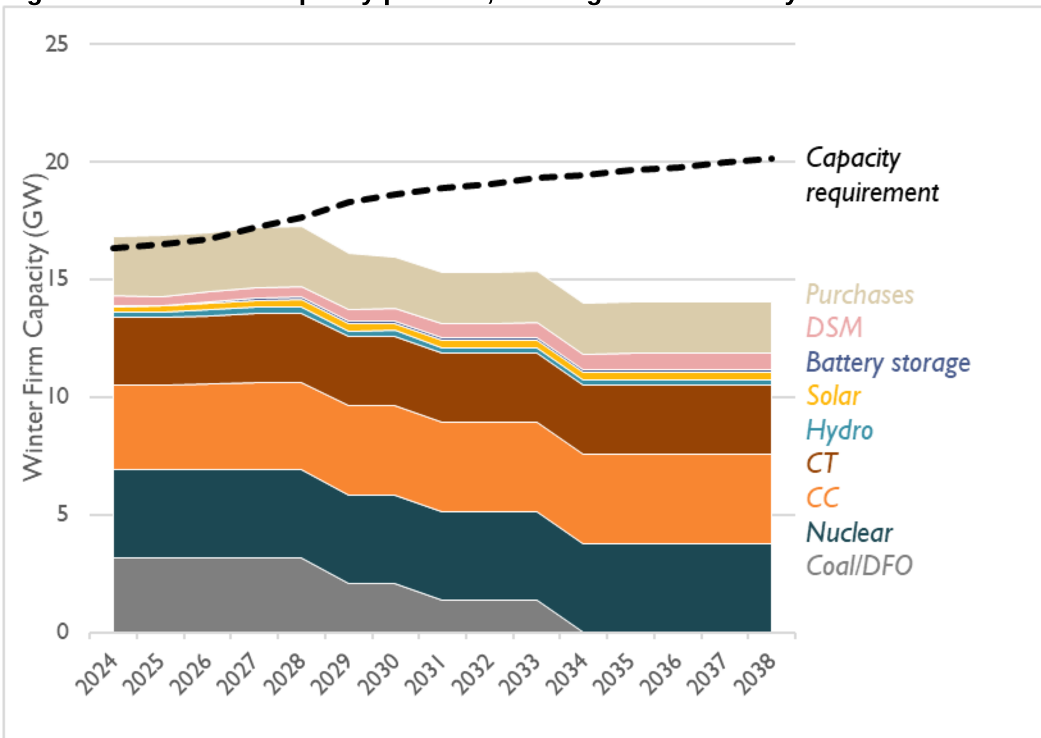
Figure 1. DEP winter capacity position, existing resources only



Source: Supplemental Planning Analysis Technical Appendix, Docket No. E-100, Sub 190, at 12 and DEP Response to SACE DR 4-2.

Q. WHAT FACTORS DRIVE DEP'S NEAR-TERM NEED FOR CAPACITY?

A. There are three main factors driving DEP's capacity need over the next decade. First, DEP projects that its winter peak load will increase 1.5 gigawatts (GW) by 2030 (compared to 2024 levels) and 2.3 GW by 2035, mainly due to large load customer additions. Over the entire study period, DEP projects that its winter peak load will increase by 20 percent from 2024 levels, which is equivalent to a compound annual growth rate of 1.3 percent.

At the same time, DEP is planning to retire its remaining coal units between 2029 and 2034 (Table 2). The Company currently operates 2.5 GW of coal capacity at the Roxboro plant, and an additional 713 MW at

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the Mayo plant. These units are increasingly expensive to maintain due to their age, the environmental regulations they must comply with, and broader declines in the U.S. coal industry.[14]

Finally, the Commission recently approved an increase in DEP's target reserve margin from 17 percent to 22 percent by 2031, based on the results of the Company's 2023 Resource Adequacy Study.[15]

Table 2. DEP scheduled coal unit retirements

Unit Name	Winter Rated Capacity (MW)	Retirement year (effective by Jan 1 of year shown)
Roxboro 1	380	2029
Roxboro 4	711	2029
Mayo 1	713	2031
Roxboro 2	673	2034
Roxboro 3	698	2034

Source: Supplemental Planning Analysis, Docket No. E-100, Sub 190, at 34.

Q. WHAT MODELING DOES DEP USE TO JUSTIFY ITS NEED FOR THE PROPOSED FACILITY?

A. DEP relies upon resource planning that Duke Energy completed for both DEP and Duke Energy Carolinas (DEC) together. Duke Energy's most recent CPIRP involved two main stages of modeling. Duke Energy filed its initial CPIRP analysis in September 2023 and later published a Supplemental Planning Analysis in January 2024 to account for increased load growth since the initial filing.[16]

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[14] *Id.* at 10.

[15] Order Accepting Stipulation, Granting Partial Waiver of Commission Rule R8-60A(d)(4), and Providing Further Direction for Future Planning, In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Docket No. E-100, Sub 190, at 49 (N.C.U.C. Nov. 1, 2024) (2024 CPIRP Order).

[16] *Id.* at 12.

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DEP did not complete any additional analysis for the current docket.[17] Instead, the Company relies on its CPIRP modeling, and in particular the updated Near-Term Action Plan from the Supplemental Planning Analysis, to support the Joint Application.

Q. HOW DOES DUKE ENERGY PLAN TO SERVE ITS NEAR-TERM CAPACITY NEED?

A. Duke Energy primarily plans to serve its near-term capacity needs by building out solar, gas combined-cycle, and combustion turbine plants, and battery storage.[18] In the 2030s, Duke Energy also plans to build out smaller amounts of onshore and offshore wind, pumped storage, and new nuclear capacity.[19] The Proposed Facility is the second of three combined-cycle units Duke Energy plans to construct by 2031. The preferred portfolio from the Supplemental Planning Analysis includes combined-cycle additions in DEP in 2029 and 2030, and a third unit in DEC in 2031.[20]

III. THE PROPOSED FACILITY WILL PRIMARILY SERVE THE NEEDS OF LARGE ECONOMIC DEVELOPMENT CUSTOMERS, AND DEP DOES NOT YET HAVE SUFFICIENT PROCESSES IN PLACE TO ENSURE THAT THESE CUSTOMERS PAY FOR THEIR FULL INCREMENTAL COST OF SERVICE

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[17] DEP Response to PSDR 5-12.

[18] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Supplemental Planning Analysis, Docket No. E-100, Sub 190, at 37 (N.C.U.C. Jan. 31. 2024) (Supplemental Planning Analysis).

[19] *Id.*

[20] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Supplemental Planning Analysis Technical Appendix, Docket No. E-100, Sub 190, at 11-12 (N.C.U.C. Jan. 31. 2024) (Technical Appendix).

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Q. WHAT TRENDS APPEAR IN DUKE ENERGY'S RECENT LOAD FORECASTS?

A. Like many utilities across the United States and particularly in the southeast, Duke Energy has seen dramatically increasing load forecasts over the past few years (Figure 2). These increases are primarily the result of an influx of prospective large load customers, which are customers that have individual peak loads of 20 MW or greater.[21] Approximately 50 percent of the projected demand from prospective large load customers is from manufacturing facilities and 45 percent is from data centers, with the remainder mainly from cryptocurrency mining facilities.[22]

Long term, other contributors to load growth are increases in the number of residential customers and electric vehicle adoption.[23]

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[21] Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC, Semi-Annual Update Report on Large-Load Customer Additions in Advanced States of Development – Spring 2025, In the Matter of 2025 Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. §§ 62-2(a)(3a), 62-110.1, 62-110.9, and Commission Rule R8-60A, Docket No. E-100, Sub 207, at 1 (N.C.U.C. May 15, 2025) (Spring 2025 Semi-Annual Report).

[22] Tr. vol. 24, Docket No. E-100, Sub 190, at 213-14 (N.C.U.C. Aug. 17, 2023).

[23] 2024 CPIRP Order at 27.

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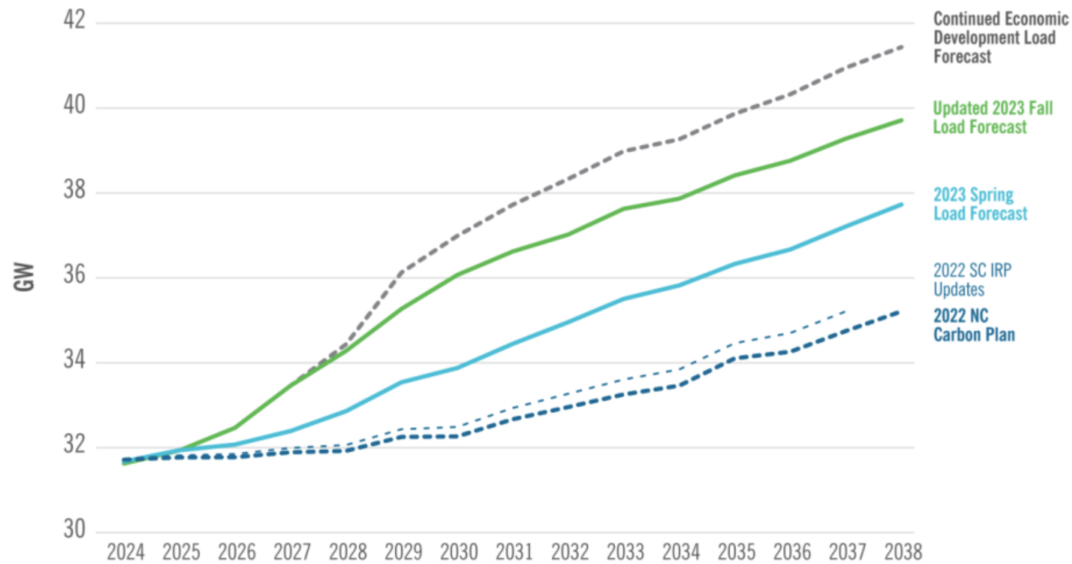
Figure 2. DEP and DEC combined load forecasts from 2022–2023



Source: Supplementary Planning Analysis at 5.

Q. WHAT IS DUKE ENERGY'S CURRENT PROCESS FOR INCORPORATING PROSPECTIVE LARGE LOAD CUSTOMERS INTO ITS LOAD FORECAST?

A. In its 2023 CPIRP, Duke Energy added prospective large load customers for the first time to the aggregated retail load forecast that it used for resource planning. Duke Energy incorporated these manual large additions through a two-step process. First, it identified a list of projects that it deemed sufficiently advanced to be included in the forecast, called Advanced Development Projects. These projects had to meet one of the following criteria:

- Executed Electric Service Agreement (ESA): Project has an agreement in place with DEP detailing the services to be provided, the tariff and riders in effect, any extra facilities and their associated costs, and other terms.

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- Executed Letter of Intent (LOI): Project has a signed agreement with DEP formalizing its size, location, and load ramp timing and committing to reimburse the Company for the money spent designing or constructing facilities on behalf of the customer.
- "90 percent pipeline": Project has progressed to advanced stage discussions with DEP in advance of signing an ESA.[24]

Duke Energy then applied discounting factors to the projected load from the Advanced Development Projects, which begin in the range of 50 percent and later taper off to 20 percent.[25] Duke Energy's rationale for scaling down the projected load was that its base load forecast relies on an econometric model that already accounts for trends in economic development in the state, and as a result, the load forecast would double-count some of the load growth in the absence of a scaling adjustment.[26] Intervenors expressed concern in the most recent CPIRP proceeding that the scaling factors did not accurately account for that double-counting risk, meaning that the resulting load forecast is more uncertain than in previous planning cycles and may still be an overestimate.[27]

Q. HOW MUCH DEMAND DO PROSPECTIVE LARGE LOAD CUSTOMERS CONTRIBUTE TO DUKE ENERGY'S LOAD FORECAST?

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[24] Spring 2025 Semi-Annual Report at 2.

[25] *Id.*

[26] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, 2023 Carolinas Resource Plan, Appendix D – Electric Load Forecast, Docket No. E-100, Sub 190, at 14 (N.C.U.C. Aug. 17, 2023).

[27] *See, e.g.*, Direct Testimony and Exhibits of John R. Hinton and Patrick A. Fahey on Behalf of the Public Staff – North Carolina Utilities Commission, Docket No. E-100, Sub 190, at 22-25 (N.C.U.C. May 28, 2024).

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A. Table 3 shows the contribution of large load customers to Duke Energy's load forecasts over time. The spring 2023 load forecast was the first to include a separate adjustment for prospective large load customers. At that time, Duke Energy included eight prospective customers with a combined load of 1,350 MW in the forecast. The number of prospective large load customers more than quadrupled by the time Duke Energy filed its fall 2023 load forecast, which included 35 large load customers with a total load of 3,883 MW. Duke Energy's most recent large load update, published in spring 2025, shows that the total number of prospective large load customers in the pipeline has not changed, but their total load is 52 percent higher than it was in fall 2023. This suggests that the average size of each project has increased. Customers typically come and go from the queue as a result of changing business plans. So far, new requests have balanced prospective customer departures, leading to no net change in the number of projects in the pipeline since fall 2023.[28]

[28] *See, e.g.*, tr. vol. 24, Docket No. E-100, Sub 190, at 213.

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Table 3. Pipeline of prospective large load customers in Duke Energy resource planning forecasts

Forecast	Number of Projects	Full Load (MW)
Spring 2023 Load Forecast (used in initial CPIRP filing)	8	1,350
Fall 2023 Load Forecast (used in Supplemental Planning Analysis)	35	3,883
Summer 2024 Update	39	4,008
Spring 2025 Update	35	5,914

Source: Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Semi-Annual Update Report on Large-Load Customer Additions in Advanced States of Development – Spring 2025, Docket No. E-100, Sub 207, which was filed May 15, 2025. Load values are the full, non-discounted value from year ten of each projection.

Duke Energy has not published detailed data on these customers, including their year-by-year ramp and the location of the load. It did publish the "Large Site Adjustment" values that it used in its modeling, but these adjustments do not account for the full amount of large customer load, since they include the scaling factors described above. However, these adjustments do give a rough idea of how the load breaks down between the DEP and DEC service areas. At the time of the Supplementary Planning Analysis, approximately 30–40 percent of the total economic development load occurred in DEP's service area, depending on the year, with the remainder in DEC's service area.[29]

Q. HOW DID DUKE ENERGY'S INCREASING LOAD FORECAST CHANGE THE RESOURCES THAT THE MODEL SELECTED?

A. The resource planning model only began to select a second combined-cycle unit in DEP's service area once Duke Energy updated the load forecast to include substantial economic development load growth (Table

[29] Supplemental Planning Analysis at 16.

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4). This suggests that *but for* these new customers, DEP would not need the Proposed Facility on the current accelerated timeline. The Company's testimony in this docket further supports this conclusion. In his direct testimony, Company witness Quinto writes that DEP needs the Proposed Facility "as a resource to meet load growth of the system…when the Proposed Facility comes online, there is no corresponding coal unit retirement, meaning that the capacity is strictly needed for meeting load growth in DEP."[30] In other words, the Proposed Facility will primarily serve new large load customers, rather than directly enabling coal retirements.

Table 4. Combined-cycle additions in DEP Portfolio 3 in the 2022 CPIRP, 2023 CPIRP, and Supplementary Planning Analysis

Analysis	Load Forecast Used	DEP Combined-Cycle Additions	DEC Combined-Cycle Additions
2022 CPIRP*	2022 NC Carbon Plan	1,216 MW in 2029	1,216 MW in 2029
2023 CPIRP, Initial Filing	2023 Spring Load Forecast	1,360 MW in 2029 1,360 MW in 2033	1,360 MW in 2032
Supplemental Planning Analysis	Updated 2023 Fall Load Forecast	1,359 MW in 2029 1,359 MW in 2030	1,359 in 2031

*Sources: Appendix E - Quantitative Analysis, Docket No. E-100, Sub 179; Appendix C - Quantitative Analysis, Docket No. E-100, Sub 190; Technical Appendix. *Note: In the 2022 CPIRP process, the Commission only approved one combined cycle unit, and the location was not specified.*

Q. HOW ARE CONCERNS RELATED TO LARGE LOAD CUSTOMERS RELEVANT TO THE COMPANY'S CURRENT REQUEST FOR A CPCN?

A. As I discuss in more detail below, there is a risk under current rate structures that existing ratepayers may unfairly end up paying for some of the incremental cost of resources constructed to serve large load customers. The Commission cannot protect existing ratepayers and

[30] Direct Testimony of Michael Quinto at 15.

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design fair and effective tariffs if DEP does not first understand the incremental costs and risks of serving new large load customers. Understanding the context for the Company's request in this docket—that the need for the Proposed Facility is primarily a result of large load customers—is important because any decision the Commission makes will need to be accompanied by additional actions to establish safeguards to protect existing ratepayers from being saddled with costs that would not have been necessary to serve them.

IV. VARIOUS SHORTCOMINGS IN DUKE ENERGY'S CPIRP MODELING, PROCUREMENT, AND INTERCONNECTION PROCESSES LIKELY PREVENTED DEP FROM SELECTING THE LOWEST-COST AND LOWEST-RISK OPTION FOR RATEPAYERS

A. Restrictive build limits and insufficient representation of long-term risks caused the model to select near-term combined-cycle capacity that is at risk of becoming a stranded asset

Q. DO YOU HAVE ANY CONCERNS WITH THE PROCESS DUKE ENERGY USED TO DEVELOP ITS MOST RECENT CPIRP ANALYSIS?

A. Yes. I am concerned that Duke Energy has not taken sufficient steps to increase the pace of renewable interconnection in its service area, thereby limiting the resource options available to serve new load growth and causing DEP to request approval for a combined-cycle unit that is not in the best interest of ratepayers. In the CPIRP modeling, a combination of restrictive renewable build limits and high-capacity accreditation for new gas resources led the model to select combined-cycle capacity to serve DEP's near-term capacity and energy needs, despite the

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substantial long-term risks associated with this approach. The CPIRP analysis fails to capture the full forward-going risk of cost increases from environmental regulation and fuel price volatility. Duke Energy should work to address the current limitations on its interconnection processes to enable more rapid procurement of clean energy resources, including solar and battery storage, that will be more robust against these risks in the long term.

Q. WHAT RESTRICTIONS DID DUKE ENERGY PUT ON RESOURCE ADDITIONS IN ITS MODELING?

A. Duke Energy included annual and cumulative build limits on resource additions, as shown in Figure 3. In the Supplemental Planning Analysis, Duke Energy limited solar additions to 1,350 MW per year between 2028 and 2030 and standalone battery storage to only 200 MW in 2027, ramping up to 1,000 MW per year by 2030. The build limits Duke Energy used in the modeling are frequently binding, suggesting that the model would select additional carbon-free resources to serve load if those resources were available.

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Figure 3. Resource build limits in the Initial CPIRP and the Supplemental Planning Analysis modeling

Technology	Initial Plan Assumption		Supplemental Planning Analysis Assumption	
	Annual	Cumulative	Annual	Cumulative
Solar (including SPS)	2028-2030: 1,350 MW 2031+: 1,575 MW	N/a	2028-2030: 1,350 MW 2031: 1,575 MW 2032+: 1,800 MW	N/a
Stand-alone Battery	2027+: 4,400 MW	N/a	2027: 200 MW 2028-2029: 500 MW 2030+: 1,000 MW	N/a
CT	2029+: 4,250 MW	N/a	2029+: 4,250 MW	N/a
CC	2029: 1,360 MW 2030+: 2,720 MW	4,080 MW (3 CC Units)	2029: 1,360 MW 2030+: 2,720 MW	8,160 MW (6 CC Units)
Onshore Wind	2031: 300 MW 2032+: 450 MW	2,250 MW	2031: 300 MW 2032+: 450 MW	2,250 MW
Pumped Storage	2034: 1680 MW	1,680 MW	2034: 1834 MW	1,834 MW
Offshore Wind	2032+: 800 MW	2,400 MW through 2038	2033+: 800 MW	2,400 MW through 2038
Advanced Nuclear	2035: 2 Units	15 Units through 2040	2035: 2 Units	11 Units through 2040

Source: Supplemental Planning Analysis at 28.

Q. WHY DOES DUKE ENERGY IMPOSE LIMITS ON THE QUANTITY OF NEAR-TERM RENEWABLES AND BATTERY STORAGE THAT CAN BE ADDED TO ITS SYSTEM IN ITS CPIRP MODELING?

A. Based on testimony filed in the Company's most recent CPIRP docket, I understand that Duke Energy models limits and costs associated with renewable resource integration to represent real-world interconnection costs and limitations.[31] These limitations stem from a few factors, mainly: (1) the timing and number of transmission outages which may be necessary to interconnect new generation resources to the grid; (2) studies and work to complete transmission upgrades at the point of

[31] *See, e.g.*, Direct Testimony of Michael Goggin on Behalf of the Southern Alliance for Clean Energy, Sierra Club, Natural Resources Defense Council, and North Carolina Sustainable Energy Association, Docket No. E-100, Sub 190, at 10, 24, 26-28 (N.C.U.C. May 28, 2024).

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interconnection; (3) larger transmission expansion projects—such as RZEP 2.0—necessary to build out the Company's transmission grid to increase voltage and capacity; and (4) larger transmission projects to improve ties both between the DEP and DEC systems and between Duke Energy's system and other balancing authorities.

Q. ARE THERE ACTIONS DUKE ENERGY CAN TAKE TO INCREASE THE PACE OF RENEWABLE INTERCONNECTION IN ITS SERVICE AREA?

A. Yes. While there are real challenges with rapidly interconnecting renewables, these are limitations that Duke Energy can study more closely and then work to alleviate. Unlike in an organized market, Duke Energy by and large controls resource interconnection processes in its service area since it is the operator of the local transmission network. More integrated transmission and generation planning would allow Duke Energy to identify where transmission solutions in tandem with generation resources can deliver lower-cost grid resources than just centralized resource additions. Duke Energy has insisted that it is already making significant efforts to improve the interconnection and transmission process over time and that increasing the interconnection assumptions substantially beyond that is unlikely to be achievable.[32] However, given the potential benefits to ratepayers from increased interconnection levels,

[32] *See, e.g.*, Rebuttal Testimony of Dewey S. Roberts II and Jing Shi on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 190, at 3 (N.C.U.C. July 1, 2024).

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Duke Energy should be prioritizing improving its interconnection process and timeline.

Once Duke Energy takes action to improve its interconnection process, it will be able to increase the annual build limits in its modeling. Such an increase will allow the model to select additional clean energy resources early in the study period if doing so would be cost-effective.

Q. HOW DOES DUKE ENERGY CALCULATE FIRM CAPACITY ACCREDITATIONS FOR NEW RESOURCES?

A. Duke Energy uses the effective load carrying capability[33] (ELCC) metric to determine capacity accreditation(s) for solar, wind, and battery storage. It derives the ELCC values from its 2022 Solar and Storage ELCC Report and its 2023 Wind ELCC Report. Battery storage resources begin with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[34] In the summer, the capacity ratings for solar begin at **[BEGIN CONFIDENTIAL]** [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] **[END CONFIDENTIAL]**.[35] In the winter **[BEGIN CONFIDENTIAL]**, [redacted] **[END CONFIDENTIAL]**.[36] Onshore wind has a winter capacity accreditation of

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[33] ELCC measures how well a resource's output aligns with peak, and therefore how much a given resource can contribute to meeting peak load.

[34] Confidential DEP Response to SACE DR 2-10, "SACE DR 2-10 – Battery ELCC (Confidential).xlsx."

[35] Confidential DEP Response to SACE DR 2-10, "SACE DR 2-10 – Solar ELCC (Confidential).xlsx."

[36] *Id.*

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[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**, and offshore wind consistently has winter accreditations of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[37]

In contrast, Duke Energy does not distinguish between the nameplate and winter firm capacity of thermal resources, effectively accrediting them at 100 percent in winter and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. For example, Duke Energy gave each 1,360 MW combined-cycle unit in its modeling a winter rated capacity of 1,360 MW[38] (100 percent) and summer rated capacity of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[39]

This is concerning because over-accrediting thermal resources relative to renewables will result in the model perceiving more value from thermal resources than renewables.[40] No resource is available 100 percent of the time, and it is critical for Duke Energy to accurately calculate capacity de-ratings based on actual unit performance (for existing resources) or based on class averages across the region for new

[37] Confidential DEP Response to SACE DR 2-10, "SACE DR 2-10 – Wind ELCC (Confidential).xlsx."

[38] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, 2023 Carolinas Resource Plan, Appendix C – Quantitative Analysis, Docket No. E-100, Sub 190, at 34, Table C-26 (N.C.U.C. Aug. 17, 2023).

[39] Confidential DEP Response to SACE DR 2-10, "SACE DR 2-10 - 2023 CPIRP Generic Unit Study (Confidential).xlsx."

[40] In the SERVM modeling that Duke relied on for its reserve margin and ELCCs, its consultant Astrapé made adjustments to load to account for the average outage rate of new gas resources. These adjustments do not appear to have been resource-neutral and it is unclear whether and how they would negate the need to adjust thermal resource accreditation levels in EnCompass.

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resources. For example, under PJM's new accreditation methodology, it projects that the class average ELCC for gas combined-cycle units in planning year 2030–2031 will be 83 percent.[41]

Q. WHAT IS THE COMBINED IMPACT OF DUKE ENERGY'S BUILD LIMIT AND RESOURCE ACCREDITATION ASSUMPTIONS?

A. Because of the interconnection limits, the model is unable to add carbon-free resources quickly enough to serve the large amount of load growth that Duke Energy projects. It is forced to select near-term combined-cycle additions, including the 2030 combined-cycle plant that corresponds to the Proposed Facility, to serve this short-term need, even though building new gas capacity is likely not the lowest-cost or lowest-risk option for ratepayers in the long term.

DEP projects that the utilization of the Proposed Facility will decline steadily over its 35-year useful life (Figure 4). The unit's capacity factor begins at 80 percent in 2030 and decreases to 46 percent by 2040 and only 13 percent from 2050 on, even in the absence of the 111 Rules (discussed below). This provides further evidence that the model selects the combined-cycle unit due to short-term constraints and then replaces it as quickly as possible with alternatives. The declining utilization is likely driven by a combination of resource economics—renewables such as solar provide zero-variable-cost energy that displace the gas

[41] *Preliminary ELCC Class Ratings for period Delivery Year 2026/27 – Delivery Year 2034/35*, PJM INTERCONNECTION, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.pdf (last visited June 6, 2025).

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generation—and the carbon limits in the model, which reflect North Carolina's statutory requirement that Duke Energy achieve carbon neutrality by 2050. This declining utilization is particularly concerning given that the plant itself is also displacing energy from—and driving down the utilization of—some of DEP's existing resources.

Building a major power plant with the expectation that its capacity factor will decline by 84 percent over its lifetime is an unusual way to proceed. The Company and Commission should carefully consider whether the Proposed Facility is truly in the best interest of ratepayers or whether there are alternatives that would better serve long-term system needs.

Figure 4. DEP projection of Proposed Facility capacity factor with and without the capacity factor restriction from the 111 Rules

Source: DEP Response to PSDR 2-7, "PS DR 2-7_Projected Annual Capacity Factors.xlsx."

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Q. DID DUKE ENERGY MODEL EXPOSURE TO FUEL PRICE VOLATILITY?

A. No, Duke Energy did not specifically model fuel price volatility in its CPIRP analysis. It did evaluate high and low gas price forecasts as part of its modeling, but volatility is different than sustained higher gas prices. Volatility relates to variation in prices over the course of the year due to weather and demand/supply interactions. Utilities can incorporate volatility into integrated resource planning using stochastic analysis that relies on historical load and weather data. Understanding the risks of fuel price volatility is particularly important for combined-cycle resources that are projected to run at high-capacity factors, as I discuss in more detail below.

Q. WHAT RISKS DO FEDERAL ENVIRONMENTAL REGULATIONS POSE FOR THE PROPOSED FACILITY?

A. The 111 Rules place constraints on existing coal resources and new gas builds. Most relevant to this docket, the rules require that newly built gas generators either maintain a capacity factor below 40 percent or meet emissions standards consistent with 90 percent carbon capture and storage by January 1, 2032. DEP plans to comply with the rules by limiting the Proposed Facility's capacity factor to 40 percent.[42]

The EPA published the final 111 Rules in May 2024, after Duke Energy had already completed modeling for the initial CPIRP and Supplemental Planning Analysis. The core modeling results for the

[42] DEP Response to SACE DR 2-15.

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Supplemental Planning Analysis do not account for the 111 Rules, although Duke Energy did complete an additional modeling sensitivity with the final 111 Rules that it included in rebuttal testimony.[43] In this sensitivity, the model continues to select the 2030 combined-cycle unit in DEP, for the same reasons as it does in the core scenarios—there are not enough carbon-free resources available to it in the short term to replace the Proposed Facility.[44]

This effect is further accentuated by the seven-year optimization window that the Duke Energy used in its capacity expansion modeling.[45] Under this structure, the model optimizes resource additions in seven-year time segments, considering only the environmental regulations and resource costs within each specific time window (often called "limited foresight"). During the first optimization window (2024–2030), there are no operational restrictions on combined-cycle units, and so the model sees these resources as a cost-effective way to serve load. In the next optimization window, the model has no choice but to limit the capacity factor of the already constructed unit. Compared to simple-cycle combustion turbines, combined-cycle units have higher capital costs but also operate more efficiently, so they are designed to be used as baseload resources. With a longer period of foresight, the model would

[43] Rebuttal Testimony of Glen Snider, Michael Quinto, & Thomas Beatty on Behalf of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Docket No. E-100, Sub 190, at 58-68 (N.C.U.C. July 1, 2024).

[44] *Id.* at 62.

[45] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, 2023 Carolinas Resource Plan, Appendix C - Quantitative Analysis, Docket No. E-100, Sub 190, at 6.

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see that a combined-cycle unit added in 2030 will have a limited capacity factor for 33 of 35 years it will be in operation. It would therefore be less likely to add this type of long-lived asset to the system in 2030.

The current U.S. political climate suggests that the 111 Rules may be repealed in their current form. However, while prior administrations have weakened the programs designed by their predecessors under Section 111 of the Clean Air Act, they have nonetheless acknowledged a continuing duty to implement some form of federal carbon regulation.[46] Given that some level of federal carbon regulation is likely during the modeled study period, the current 111 Rules serve as a reasonable proxy for the effect of future carbon regulations, which will likely continue to place operational restrictions on the Proposed Facility over its 35-year useful life.

Q. IS THERE A RISK OF THE PROPOSED FACILITY BECOMING A STRANDED ASSET UNDER STATE LAW?

A. Yes. North Carolina state law requires Duke Energy's generating facilities to achieve carbon-neutrality by 2050, with an interim requirement of a 70 percent emissions reduction from 2005 levels.[47] The Proposed Facility has a book life of 35 years, meaning that it will not be fully depreciated

[46] *See* Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations, 84 Fed. Reg. 32,520 (July 8, 2019) (to be codified at 40 C.F.R. pt. 60).

[47] N.C. Session Law 2021-165. The law requires Duke to achieve the interim target by 2030, but the Commission extended the interim deadline in its order in the 2023 CPIRP proceeding.

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until 2065.[48] When the 2050 carbon neutrality requirement comes into effect, the plant will still have 15 years of its useful lifetime ahead of it.

The Company has not completed a stranded asset risk analysis or an early retirement analysis for the Proposed Facility, because it believes that converting the unit to run on hydrogen (presumably produced using renewable electricity) or retrofitting it with carbon capture and storage (CCS) equipment represents a viable long-term pathway for the unit.[49] In its CPIRP modeling, Duke Energy assumed that all combined-cycle units built in the 2020s and 2030s would convert to 100 percent clean hydrogen in 2050 (i.e., hydrogen produced through non-carbon emitting means, such as electrolysis powered by renewable electricity).[50] While Duke Energy did include some conversion costs in its modeling,[51] there is a significant risk that its modeling assumptions are too optimistic and that neither clean hydrogen nor CCS will be available at a feasible cost or timeline to retrofit Duke Energy's gas resources by 2050, at which point these resources will become stranded assets.

Q. WHAT ARE THE BARRIERS TO DEPLOYMENT OF HYDROGEN AND CCS RETROFITS ON GAS UNITS?

A. Neither conversion to 100 percent hydrogen nor CCS are demonstrated at scale on combined-cycle plants. Both technologies face barriers related

[48] DEP Response to PSDR 2-2.
[49] DEP Response to PSDR 2-6.
[50] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, 2023 Carolinas Resource Plan, Appendix K – Natural Gas, Low Carbon Fuels, and Hydrogen, Docket No. E-100, Sub 190, at 8 (N.C.U.C. Aug. 17, 2023).
[51] DEP Response to PSDR 5-6.

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to the availability of supporting infrastructure and retrofit technologies, as well as uncertainties surrounding cost and technology performance. Hydrogen-firing on gas plants additionally faces barriers related to fuel availability. Given these uncertainties, Duke Energy should test a scenario with accelerated depreciation of emitting resources by 2050, rather than assuming that retrofit technologies will be available.

Specifically, barriers to deployment of hydrogen include the following:

Uncertainty surrounding low-carbon fuel supply: The majority of hydrogen available today is produced through steam methane reforming, which, absent carbon capture, is an emissions-intensive process that would not be compatible with North Carolina's climate law.[52] Production of clean hydrogen using renewable electricity to power electrolysis is energy-intensive, and it would be costly to produce or obtain green hydrogen at the scale needed to supply the Company's gas fleet.

Retrofit technology availability and cost: There are currently no operational combined-cycle units that burn 100 percent hydrogen, leading to uncertainty about the capital costs of this technology in the future. It is unclear whether the technology to retrofit existing gas plants for 100 percent hydrogen firing will become available, and how much this would cost.

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[52] *See generally Pathways to Commercial Liftoff: Clean Hydrogen*, U.S. DEPARTMENT OF ENERGY (2023), https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/review23/ia005_munster_2023_o-pdf.pdf (providing carbon intensity of various hydrogen production pathways).

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Need for supporting infrastructure: Unless green hydrogen is produced on site, it must be transported to the site of each gas unit by truck or through dedicated pipeline infrastructure, which would be costly to construct and would likely face siting barriers.

Barriers to deployment of CCS include the following:

Potential for cost overruns: The level of uncertainty around the cost of installing CCS is much greater than for existing non-emitting technologies such as solar and storage. Given how expensive CCS projects will likely be, that could mean hundreds of millions or even billions in underestimated costs.

Uncertainty surrounding achievable capture levels: Because the technology is not demonstrated at scale on combined-cycle units, there is uncertainty about achievable capture levels. Relying on CCS for state carbon reduction compliance exposes Duke Energy to the risk that the technology performs worse than expected.

Need for supporting infrastructure: Duke Energy cannot operate CCS equipment unless there is adequate supporting infrastructure available to transport and store the captured carbon dioxide.

Existing tax credits are insufficient for cost-effective implementation: The costs of CCS vary by sector, and economics are challenging for combined-cycle units because the carbon dioxide in the exhaust streams is not as concentrated as in other end uses. The federal 45Q tax credit for captured carbon is insufficient to make carbon capture

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cost-effective on combined-cycle units. The current credit, which is set to expire in 2033, offers up to $85 per ton of captured carbon dioxide (if the carbon dioxide is permanently sequestered), compared to an estimated cost of $177 per ton for a first-of-a-kind CCS system installed on a combined-cycle unit, or $123 per ton for a utility-financed nth-of-a-kind project.[53]

B. <u>DEP should take steps to procure alternative resources to reduce or eliminate its need for the Proposed Facility</u>

Q. IS THE PROPOSED FACILITY LIKELY THE LOWEST-COST AND LOWEST-RISK RESOURCE ADDITION AVAILABLE TO THE JOINT APPLICANTS?

A. No. Moving ahead with the Proposed Facility will lock ratepayers into 35 years of capital costs and fuel costs over the resource's lifetime, and it will expose them to future risks from fuel price volatility and environmental regulation. Instead, DEP should work to procure alternative resource options, such as dispatchable capacity (e.g., battery storage or even combustion turbines) paired with solar and wind. Duke Energy should also take steps to increase the amount of renewable capacity and battery storage it can interconnect each year to facilitate more rapid buildout of these resources.

Solar, battery storage, and wind are more modular resource additions than combined cycle units, so DEP can adjust the quantity it

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[53] EFI FOUNDATION, UNLOCKING PRIVATE CAPITAL FOR CARBON CAPTURE AND STORAGE PROJECTS IN INDUSTRY AND POWER 11 (2025), https://efifoundation.org/wp-content/uploads/sites/3/2025/04/Unlocking-Private-Capital-for-CCS-Projects-in-Industry-and-Power.pdf.

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procures in a given year based on current market conditions. This modularity, combined with the fact that solar and wind have zero exposure to fuel price volatility once they are constructed, makes these resources particularly valuable in the face of trade tariff uncertainty.

Q. HOW SHOULD DEP IDENTIFY ALTERNATIVE RESOURCE OPTIONS?

A. As soon as possible—and prior to a final ruling on this CPCN application—DEP should issue an All-Source RFP and evaluate responses based on the grid services each resource would provide (e.g., firm capacity or low-cost energy). This will allow DEP to compare the cost of a range of resources, including solar and battery storage, to the Proposed Facility and proceed with whichever resource is lower cost.

Q. DOES DEP HAVE ENOUGH TIME TO PROCURE ALTERNATIVE RESOURCE OPTIONS?

A. Yes. DEP plans to begin operating the Proposed Facility in 2030. Accordingly, DEP still has five years to construct or otherwise obtain alternatives resources. Renewables and batteries can generally be brought online more quickly than gas resources. The typical construction timeline for utility-scale solar is one year and for onshore wind is three years;[54] siting and permitting can add another two to four years.

Additionally, while DEP has an obligation to serve load in its service area, it does not necessarily have an obligation to serve

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[54] *2024 Electricity Annual Technology Baseline (ATB) Data Download*, NATIONAL RENEWABLE ENERGY LABORATORY (NREL), https://atb.nrel.gov/electricity/2024/data (last visited June 6, 2025).

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prospective large load customers on the timeline that those customers request. If delaying certain customer additions by a few years would give DEP the necessary lead time to procure lower-cost clean energy resources rather than combined-cycle capacity, that is an option the Company should consider.

V. IF IT DECIDES TO APPROVE CONSTRUCTION OF THE PROPOSED FACILITY, THE COMMISSION SHOULD TAKE ACTION TO PROTECT RATEPAYERS FROM FUEL PRICE VOLATILITY RISK AND FROM BEARING COSTS ASSOCIATED WITH THE ADDITION OF LARGE LOAD CUSTOMERS

A. The Commission should consider fuel cost-sharing measures to share the risk of fuel price volatility between the Company and its ratepayers

Q. HOW WILL CONSTRUCTING THE PROPOSED FACILITY EXPOSE RATEPAYERS TO FUEL PRICE RISK?

A. Duke Energy's overall energy mix is currently 46 percent nuclear, 29 percent gas, and 16 percent coal, with the remaining 9 percent of generation coming from solar and other renewables.[55] As another gas-burning resource, the Proposed Facility will increase the exposure of Duke's ratepayers to gas fuel price volatility, especially in the first five to ten years of the plant's useful life, when DEP projects that it will operate at a high capacity factor.

Q. EXPLAIN THE RISKS POSED TO RATEPAYERS BY FUEL PRICE VOLATILITY.

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[55] Direct Testimony of Micheal Quinto at 26.

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A. High reliance on gas resources can expose ratepayers to fuel price volatility for which they cannot plan. Because gas is a global commodity, both domestic and global market forces impact price and demand for the resource. After roughly doubling from 2019 to 2023, North American liquified natural gas (LNG) export capacity is projected to double again by 2028, from current levels of 11.4 billion cubic feet (Bcf) per day to more than 24 Bcf per day in 2028.[56] To put this in perspective, U.S. total gas consumption in 2023 averaged roughly 89 Bcf per day.[57] This leaves domestic markets exposed to global market dynamics.

Recently announced U.S. trade tariffs have injected substantial uncertainty into the global gas market. According to industry analysts, this uncertainty is driven in part by the role of LNG as a tool to rebalance trade with the United States. Nations looking to ease relations with the United States may increase their imports of U.S. LNG in order to reduce trade surpluses, while nations looking to retaliate against the United States for steep tariffs may reduce their imports of U.S. LNG.[58] Sudden changes in demand for LNG exported from the United States will affect the domestic gas supply and could cause dramatic swings in gas prices. For example, market uncertainty caused March 2025 NYMEX gas future contracts and

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[56] Victoria Zaretskaya, *North America's LNG export capacity is on track to more than double by 2028,* U.S. ENERGY INFORMATION ADMINISTRATION (Dec. 31, 2024), https://www.eia.gov/todayinenergy/detail.php?id=64128.

[57] *Natural Gas Consumption by End Use*, U.S. ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm (last visited June 6, 2025).

[58] Gavin Maguire, *US natural gas prices brace for impact from tariff crossfire: Maguire,* REUTERS (Apr. 2, 2025), https://www.reuters.com/business/energy/us-natural-gas-prices-brace-impact-tariff-crossfire-maguire-2025-04-02/ (last visited June 6, 2025).

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gas spot market prices to increase.[59] Regardless of the precise outcome of these trade disputes, domestic gas markets will continue to feel the impacts of global uncertainty.

Q. HOW ARE VOLATILE FUEL COSTS PASSED ON TO RATEPAYERS?

A. When the market is constrained and prices spike, those costs are passed directly to ratepayers. This happened in 2022 when Russia invaded Ukraine and European gas customers turned increasingly to U.S. gas. This drove up domestic gas prices, and those high costs were passed on directly to ratepayers. For example, DTE Electric Company in Michigan filed its 2022 Fuel Reconciliation Docket and noted that gas spending was 74 percent higher than planned. As a result, DTE requested to recover an additional $154 million for 2022 fuel costs alone.[60] Absent action from the Michigan Commission, DTE and its shareholders are not impacted by these gas price spikes—these costs are entirely passed on to ratepayers.

A similar phenomenon occurred in North Carolina during this period. In its 2023 Fuel Charge Adjustment docket, DEP reported that it had under-recovered $445 million in fuel costs for the year ending March

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[59] Kevin Dobbs, *Natural Gas Futures, Spot Prices Soar as Trump Tariff Fallout Awakens Bulls*, NATURAL GAS INTELLIGENCE (Feb. 3, 2025), https://naturalgasintel.com/news/natural-gas-futures-spot-prices-soar-as-trump-tariff-fallout-awakens-bears/.

[60] DTE Electric Company's 2022 PSCR Reconciliation Exhibits A1-A27, 2022 Fuel Expense and Comparison to Plan, Case No. U-21051, at Exhibit A-7 (Mich. Pub. Serv. Comm'n filed Mar. 31, 2023), *available at* https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000007N4mzAAC.

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31, 2023.[61] A major contributing factor to this under-recovery was that gas costs were 50 percent higher than expected.[62]

Q. WHAT STEPS CAN THE COMMISSION TAKE TO PROTECT RATEPAYERS FROM FUEL PRICE VOLATILITY?

A. Current fuel recovery mechanisms create a mismatch of incentives, since the decision about whether to construct the Proposed Facility rests with DEP (subject to Commission approval), while the risk associated with fuel cost volatility rests with ratepayers. A fuel cost-sharing mechanism would help to more accurately align incentives and risks with decision-making authority. If the Commission decides to approve the CPCN for the Proposed Facility, it could make approval contingent on the establishment of a fuel cost-sharing mechanism for fuel costs from the unit. Under a fuel cost-sharing mechanism, only a portion of the discrepancy between actual fuel costs and the base fuel cost rate would be trued-up.[63] Key design considerations include the method used to set the baseline fuel cost, the frequency with which the baseline cost is updated, the level of sharing, and the timing and duration of the true-up.[64] Several states, including Wyoming, Washington, Oregon, Missouri, and Hawaii already

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[61] Order Approving Fuel Charge Adjustment, In the Matter of Application of Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-133.2 and NCUC Rule R8-55 Relating to Fuel and fuel-Related Charge Adjustments for Electric Utilities, Docket No. E-2, Sub 1321, at 4 (N.C.U.C. Nov. 17, 2023).

[62] *Id.* at 11.

[63] JOE DANIEL ET AL., ROCKY MOUNTAIN INSTITUTE, STRATEGIES FOR ENCOURAGING GOOD FUEL-COST MANAGEMENT: A HANDBOOK FOR UTILITY REGULATORS 10 (2023), https://rmi.org/insight/strategies-for-encouraging-good-fuel-cost-management/.

[64] *Id.* at 10-13.

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have fuel cost-sharing mechanisms in place,[65] and North Carolina could build off their experience in designing a mechanism that would apply to the Proposed Facility.

B. DEP should put structures in place to ensure prospective large load customers are paying their full incremental cost of service, including the cost of the Proposed Facility

Q. WHAT RISKS DO PROSPECTIVE LARGE LOAD CUSTOMERS POSE TO DEP'S EXISTING RATEPAYERS?

A. Load growth from large load customers, and in particular data centers, poses several risks to all other ratepayers—both in scenarios where the load materializes, as well as in scenarios where it does not.

First, there is the risk that DEP builds resources and supporting infrastructure for prospective customer load that may not materialize fully or at all. If load does not materialize at the level DEP currently projects, existing ratepayers may be left paying for unneeded assets.

Second, even if the load does materialize, large generation additions and transmission upgrades can increase system costs for all ratepayers under current tariff structures. This can result from increases in energy and capacity market prices, additional transmission and gas infrastructure investments, and general cost-shifting if rates and tariffs are not designed correctly to ensure data center and other large load customers cover their full incremental cost of service.[66]

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[65] *Id*. at 13-14.

[66] A new large load customer's incremental cost includes (1) the increase in variable costs as a result of serving the load, (2) the new customer's share of the existing system's fixed costs, and (3) any new system costs (e.g., investment in new generation assets) incurred to serve the load.

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In addition to these risks, large load customers can also bring benefits. For example, new manufacturing facilities create jobs and are catalysts for economic development. However, it is important to ensure that all large load customers pay their fair share for electricity, as economic development is a separate policy goal that should not be pursued through electric rates.

Q. HOW CAN THE COMMISSION PROTECT DEP'S EXISTING RATEPAYERS FROM THE RISKS POSED BY LARGE LOAD ADDITIONS?

A. The Commission can direct DEP to establish tariffs designed for large load additions that protect existing ratepayers from, at a minimum, incurring any incremental cost resulting from the new large load customers. It is important that DEP ensures tariffs are in place before resource procurement for these customers takes place. A customer's willingness to take service under this type of tariff should be a precursor for Duke Energy planning to serve that large load as part of its resource plan. If a data center customer is not willing to receive service under a tariff that shifts some of the cost and risk to the data center customer, rather than placing it all on existing ratepayers, then Duke Energy should not be building generation and transmission to meet that customer's demand. Well-designed tariffs protect existing ratepayers from high system costs and incent the data center customers to be more flexible. Such tariffs are particularly important today, given the uncertainty surrounding the costs of equipment for new gas plants, and the potential

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for cost overruns caused by equipment shortages and trade tariffs. As discussed in Section III, Duke Energy's CPIRP analysis suggests that there will be no need for the Proposed Facility on the timeline that the Company currently proposes if the projected large load customer growth fails to materialize in whole or part. The new large load customers should be responsible for the full incremental cost of all capacity and fixed pipeline costs (including firm transportation costs and pipeline construction costs) that DEP would not incur but for these customers.

Q. WHAT ARE SOME FEATURES COMMON AMONG LARGE LOAD TARIFFS?

A. Some general principles for large load tariffs include the following:

- Requirement that load over a certain MW threshold—as measured at an individual facility, or across multiple facilities owned by the same company—be on a large load customer tariff.
- Commitment for tariff participants to pay at a minimum the cost of incremental generation not needed "but for" the facility for a substantial portion of the asset life, and in some cases including an additional risk premium.
- Minimum take requirements/minimum monthly demand based on contracted capacity, minimum contract term (years), and exit fees.
- Incentives for demand response, demand flexibility, interruptible load, and energy efficiency, for facilities where these measures are feasible.

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- Commitment on the part of the utility or load-serving entity to develop renewable energy resources consistent with jurisdictional goals as well as the customer's corporate commitments (e.g., through clean energy tariffs).
- Payment from the tariff participants of incremental costs to build out distribution, transmission, and firm gas infrastructure.
- Additional investment in community, economic development, and low-income programs.

Several recent industry and expert reports discuss these and other principles in more detail.[67]

Q. WHY IS IT IMPORTANT THAT DEP AVOID DELAYING THE PLANNED RETIREMENTS OF ITS COAL UNITS?

A. Another potential risk associated with large load additions is that they may cause DEP to delay the retirement of its coal units. Most of the Company's planned retirement dates are not locked in. Based on trends I am seeing elsewhere, I am concerned that those dates could change, especially with the addition of more large load customers to DEP's base load forecast.

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[67] *See* STACY SHERWOOD, ENERGY FUTURES GROUP REVIEW OF LARGE LOAD TARIFFS TO IDENTIFY SAFEGUARDS AND PROTECTIONS FOR EXISTING RATEPAYERS (2025), https://energyfuturesgroup.com/wp-content/uploads/2025/01/Review-of-Large-Load-Tariffs-to-Identify-Safeguards-and-Protections-for-Existing-Ratepayers-Report-Final.pdf (detailing common features and principles in report prepared on behalf of Earthjustice); JOHN D. WILSON ET AL., STRATEGIC INDUSTRIES SURGING: DRIVING US POWER DEMAND. GRID STRATEGIES LLC (2024), https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.

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DEP's current, planned coal unit retirement dates are based on the units' worsening economics and associated commodity pricing risk.[68] However, if DEP is unable to cost-effectively bring new resources online within the timeframe required to serve new load, it may turn to its legacy coal units instead and delay retiring them. The problem with this approach is that new load does not change the cost of operating the coal units, and continued reliance on coal to serve the new load will drive up total system costs. Absent action by the Commission to ensure that the costs are fully allocated to the new customers, existing customers will be subsidizing the cost to maintain legacy coal assets that, but for the new load, would be retired.

Q. WHAT RISKS DOES DEP FACE FROM CONTINUED RELIANCE ON COAL ASSETS?

A. As with gas assets, coal units pose risk to ratepayers related to fuel price volatility. The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[69] There have also been labor challenges both at the mines and the railroad companies that transport the coal, as coal workers demand better pay and have more options in the labor market. Additionally, as coal plants across the United States retire and the demand for coal decreases, coal companies could

[68] Joint Application at 10.

[69] *Coal Markets*, U.S. ENERGY INFORMATION ADMINISTRATION (June 2, 2025), https://www.eia.gov/coal/markets/.

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consolidate. Concentration of the coal supply among fewer companies means less competition, which in turn can lead to higher coal prices.[70]

Electric power sector coal consumption was down in 2023 relative to prior years, with coal accounting for around 15 percent of generating capacity and 16 percent of total utility-scale generation.[71] Preliminary data from the U.S. Energy Information Administration indicates that this trend continued in 2024.[72] This is novel because coal's national market share of electric generation had been around 20 percent each month between 2020–2022; and prior to 2020, coal had never comprised less than 20 percent of the market in any month.[73] Additionally, risks from increased environmental regulation could result in higher costs and higher risks. Higher risk impacts not just resource planning economics but company risk profiles, which can lead to downgraded credit ratings and impact access to capital.

In addition, continued reliance on coal assets poses substantial risks of future environmental compliance costs. The 111 Rules place

[70] *See* Duke Energy Carolinas, LLC & Duke Energy Progress, LLC, 2023 Carolinas Resource Plan, Appendix F - Coal Retirement Analysis, Docket No. E-100, Sub 190, at 2 (N.C.U.C. Aug. 17, 2023).

[71] *Electricity Explained: Electricity Generation, Capacity, and Sales in the United States*, U.S. ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php (last visited June 6, 2025).

[72] *Form EIA-923 Detailed Data with Previous Form Data (EIA-906/920)*, U.S. ENERGY INFORMATION ADMINISTRATION (May 22, 2025), https://www.eia.gov/electricity/data/eia923/.

[73] Seth Feaster, *Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024*, INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS (Nov. 2, 2023), https://ieefa.org/resources/coal-use-us-power-plants-continues-downward-spiral-full-impact-mines-be-felt-2024.

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additional limitations on the future operation of the coal units, requiring them to (1) retire before January 1, 2032, (2) retire before January 1, 2039 and co-fire with at least 40 percent gas starting on January 1, 2030, or (3) install CCS with at least a 90 percent capture rate by January 1, 2032, if they will operate after January 1, 2039.[74] Even if the 111 Rules change in the future, the coal units will continue to face pressure from carbon regulations over the coming years. DEP can protect its ratepayers from unexpected cost increases by procuring zero-emissions replacement resources through the all-source RFP proposed in Section IVB for example, which would enable it to retire the coal units on schedule.

VI. CONCLUSION

Q. IN CONCLUSION, WHAT ARE YOUR RECOMMENDATIONS REGARDING THE JOINT APPLICANTS' REQUEST FOR A CPCN IN THIS DOCKET?

A. I recommend that the Commission not approve the Joint Applicants' request for a CPCN for a second 1,360 MW combined-cycle unit at the Roxboro site. Moving ahead with this combined-cycle plant will lock ratepayers into paying for a long-lived asset that will expose them to future risks from fuel price volatility and environmental regulation. DEP's modeling shows that the utilization of the Proposed Facility will decline steeply over its lifetime, and the resource is at risk of becoming a stranded

[74] *See* 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, 89 Fed. Reg. 39,798, 39,801 (May 9, 2024) (to be codified in 40 C.F.R. pt. 60).

asset under state climate law. Instead of moving ahead with the Proposed Facility, DEP should work to procure alternative resource options, such as battery or combustion-turbine capacity paired with solar and wind. It should also focus on streamlining and removing bottlenecks in its interconnection process.

Because DEP's need for the Proposed Facility is primarily a result of load growth from prospective large load customers, I recommend that the Commission instruct DEP to establish large load tariffs in a future docket. The tariffs should commit these customers to paying their full incremental cost of service before DEP builds assets to serve them and/or should enable DEP to develop renewable generation to meet load. Finally, if the Commission does choose to approve the CPCN, I recommend that it establish a fuel cost-sharing mechanism for the Proposed Facility to distribute the risks of fuel price volatility more fairly between the Company and its ratepayers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Lucy Metz on Behalf of Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 9th day of June, 2025.

s/ Munashe Magarira
Munashe Magarira

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate* April 2025 – Present*; Associate* April 2023 – April 2025; *Research Associate,* July 2022 – April 2023.

- Provides expert research, analysis, and deliverables on energy-sector issues, including electric utility resource planning and power plant economics, building decarbonization, industrial sector emissions, and state and local climate policy
- Supports the development of testimony and comments in integrated resource planning dockets, rate cases, certificates of need, and environmental compliance investment dockets across the country
- Conducts analysis using Synapse's Building Decarbonization Calculator (BDC), a stock turnover model that calculates the emissions and energy impacts of heat pump adoption
- Produces data visualization tools in R, including interactive webtool of U.S. industrial emitters
- Assists with power sector dispatch modeling using EnCompass

Laboratory of Dr. Alexander Barron, Department of Environmental Science and Policy, Smith College, Northampton, MA. *Research Assistant*, June 2020 – May 2022

- Co-authored paper on carbon neutrality initiatives in higher education
- Designed data visualization and analysis for USREP-ReEDS modeling of Clean Air Act policy
- Calculated CO_2 emissions reductions achievable under Massachusetts climate legislation and drafted white paper with results

Co-Equal, Washington, D.C. *Policy Intern*, February 2021 – March 2022.

- Performed analysis on a wide range of policy topics requested by members of Congress
- Finalized economic modeling study for public release and presented results
- Coordinated with research team at MIT and Co-Equal to meet policy-relevant deadlines

EDUCATION

Smith College, Northampton, MA
Bachelor of Science in Engineering Science, *Magna Cum Laude with Highest Honors*, 2022

SKILLS

Computer: Excel, R, EnCompass, MATLAB, Mathematica, ENERGY STAR Portfolio Manager

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Languages: Spanish (proficient)

TESTIMONY

Kansas Corporation Commission (Docket No. 25-EKCE-207-PRE): Direct testimony of Lucy Metz in the matter of the Petition of Evergy Kansas Central, Inc., Evergy Kansas South, Inc., and Evergy Metro, Inc. for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Costs to Be Incurred for Certain Electric Generation Facilities under K.S.A. 66-1239. On behalf of Citizens' Utility Ratepayer Board (CURB). March 14, 2025.

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Public Service Commission of Wisconsin (Docket No. 6690-UR-128): Direct testimony of Lucy Metz in the matter of the Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates. On behalf of Sierra Club. August 19, 2024.

Georgia Public Service Commission (Docket No. 55378): Direct Testimony of Devi Glick and Lucy Metz in re: Georgia Power Company's 2023 Integrated Resource Plan Update. On behalf of Sierra Club. February 15, 2024.

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