BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1349
DOCKET NO. EC-67, SUB 57

In the Matter of:	)	
Joint Application of Duke Energy	)	**POST-HEARING BRIEF OF**
Progress, LLC and North	)	**THE SOUTHERN ALLIANCE**
Carolina Electric Membership	)	**FOR CLEAN ENERGY**
Corporations 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	)	

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The Southern Alliance for Clean Energy (SACE) respectfully submits this post-hearing brief.

I. INTRODUCTION

Duke Energy Progress, LLC (DEP, Duke, or Duke Energy) and the North Carolina Electric Membership Corporation (NCEMC) (collectively, the Applicants) have requested a certificate of public convenience and necessity (CPCN) for a second, costly, carbon-emitting, 1,360-megawatt (MW), natural gas-fired combined cycle power plant at the existing Roxboro coal plant (the Proposed Facility or CC2) to meet a highly uncertain resource need (the Joint Application).

Applicants primarily justify this capital-intensive power plant because of the energy it provides for a handful of years in the 2030s. However, over the long term, the Proposed Facility is fundamentally ill-suited to provide the benefits DEP has alleged it would, as Duke Energy's modeling reveals that it will effectively cease operating as a baseload generation facility in the 2040s, with zero carbon resources increasingly providing more energy in its place. The applicants' assumption that the Proposed Facility will have a 35-year assumed useful life is based on far-too-optimistic assumptions about the development of a green hydrogen infrastructure that is far from certain and highly inefficient. As the Public Staff observed in the most recent CPIRP docket, Duke's unreasonable hydrogen assumptions lead it to a greater dependence on gas plants in the short term, ultimately resulting in stranded asset risk for its captive ratepayers over the long term.

The Applicants have not met their burden of proof and demonstrated that the Proposed Facility is part of the least-cost path to achieve compliance with N.C. Gen. Stat. § 62-110.9. There are cheaper, cleaner, and more nimble alternatives that could provide the foundation for the retirement of Roxboro Units 2 and 3, along with DEP's other proposed coal retirements. Nor have the Applicants met their burden of proof to show that the Proposed Facility will maintain or improve upon the adequacy and reliability of the existing grid, as gas infrastructure can experience significant weather-related constraints during winter peaks. Lastly, the Applicants have failed to demonstrate that issuing a CPCN would be in the public interest, given the high costs DEP customers would be forced to pay for the construction and operation of a generation asset that may not even be needed and will increasingly be underutilized as more zero-carbon resources are integrated into Duke Energy's system.

Accordingly, the Commission should deny the Joint Application. If the Commission were to approve the Joint Application, however, the Commission, among other things, should condition the CPCN to hold ratepayers harmless in future general rate cases or cost recovery proceedings from cost overruns stemming from tariffs and supply chain shortages, require an all source procurement to select a least cost resource, and establish a fuel cost sharing mechanism that would equitably share fuel cost risk from the Proposed Facility between DEP customers and shareholders.

II. LEGAL STANDARDS

State law protects North Carolina ratepayers from excessive power plant construction costs by requiring an adequate showing that a facility is in the public interest before the construction of electric generation facilities. N.C.G.S. § 62-110.1 (a) ("no public utility . . . shall begin the construction of any . . . facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service . . . without first obtaining from the Commission a certificate that public convenience and necessity requires, or will require such construction"). Indeed, "[t]he primary purpose of the statute is to provide for the orderly expansion of the State's electric generating capacity in order to create the most reliable and economical power supply possible *and to avoid the costly overbuilding of generation resources*." *State ex rel. Utils. Comm'n v. Empire Power Co.*, 112 N.C. App. 265, 278, 435 S.E.2d 553, 560 (1993) (emphasis added). *See also State ex rel. Utils. Comm'n v. High Rock Lake Ass'n*, 37 N.C. App. 138, 140, 245 S.E.2d 787, 790 (1978) (explaining that the purpose of the section is "to help curb overexpansion of generating facilities beyond the needs of the service area").

Our Supreme Court has explained that the public convenience and necessity standard in N.C.G.S. § 62-110.1 "is based on an 'element of public need for the proposed service.'" *High Rock Lake Ass'n*, 37 N.C. App. at 140, 245 S.E.2d at 790 (quoting *State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co.*, 267 N.C. 257, 270, 148 S.E.2d 100, 110 (1966)). *Accord Empire Power Co.*, 112 N.C. App. at 279-80, 435 S.E.2d at 561 ("before issuing a CPCN, [the Commission] must establish a public need for a proposed generating facility") (citing *In re Duke Power*

Co., 37 N.C. App. 138, 245 S.E.2d 787).

To assist the Commission in making an informed decision regarding the need for a proposed facility, N.C.G.S. § 62-110.1 directs the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina . . . and [to] consider such analysis in acting upon any petition by any utility for construction." N.C.G.S. § 62-110.1(c). This Integrated Resource Planning process (IRP), which has since been consolidated with the biennial Carbon Plan proceedings established under N.C.G.S. § 62-110.9 (CPIRP) for DEP and Duke Energy Carolinas (DEC)[1] is intended to identify those electric resource options that can be obtained for the least total cost to the ratepayers, reduce carbon emissions on the timeline contemplated by § 62-110.9, and maintain or improve upon grid reliability. *See* N.C.G.S. §§ 62-2, 62-110.9.

However, the fact that a resource need is identified in a CPIRP is not enough to meet the standard for a CPCN for a particular facility. *See, e.g.*, Order Granting Application in Part, with Conditions, and Denying Application in Part, *In the Matter of Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fired Electric Generation Facility in Buncombe County Near the City of Asheville*, Docket No. E-2, Sub 1089 (N.C.U.C. March 28, 2016) ("Asheville Order") at 43 (denying request

[1] This consolidation only applies to DEP and DEC's IRPs. *See* Order Adopting Commission Rule R8-60A and Amending Commission Rules R8-60, R8-67, and R8-71, *In the Matter of Rulemaking Proceeding Related to Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)*, Docket No. E-100, Sub 191, at 10-11 (N.C.U.C. Nov. 20, 2023) (CPIRP Order).

for a CPCN for a combustion turbine (CT) for which DEP's 2015 IRP identified a need eight years after the CPCN application). When considering a certificate for a new generating facility, the Commission has recognized that "[t]he standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, *and the facts of each case must be considered*." Order Granting Certificate of Public Convenience and Necessity with Conditions, *In the Matter of Application of Duke Energy Carolinas, LLC, for Approval for an Electric Generation Certificate of Public Convenience and Necessity to Construct Two 800-MW State-Of-the-Art Coal Units for Cliffside Project*, Docket No. E-7, Sub 790 (N.C.U.C. March 21, 2007) (Cliffside Order) at 10 (citing *State ex rel. Utils. Comm'n v. Casey*, 245 N.C. 297, 302, 96 S.E.2d 8, 12 (1957)) (emphasis added).

The public convenience and necessity standard also entails consideration of the cost of a proposed facility, which, when coupled with N.C.G.S. § 62-110.1(e)'s requirement that the Commission consider resource and fuel diversity, requires consideration of viable, less costly alternatives. As the *High Rock Lake* Court reaffirmed, "it is clear that the purpose of requiring a certificate of public convenience and necessity before a generating facility can be built is to prevent costly overbuilding." 37 N.C. App. at 141, 245 S.E.2d at 790. To this end, the CPCN statute requires the applicant to file "an estimate of construction costs in such detail as the Commission may require" and provides that "no certificate shall be granted unless the Commission has approved the estimated construction costs and made a finding that such construction will be consistent with the Commission's plan for expansion of electric generating capacity." N.C.G.S. § 62-110.1(e).

Our Court of Appeals has elaborated on the meaning of the public convenience and necessity standard, explaining that it must be read together with our State's policies regarding energy resources: "We read this standard *in pari materia* with N.C.G.S. § 62-2, which contains ten specific policies . . . ." *Empire Power Co*., 112 N.C. App. at 274, 435 S.E.2d at 557. These policies include, among others:

> (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs . . .
> ;
> ***
> (5) To encourage and promote harmony between public utilities, their users and the environment.

N.C.G.S. § 62-2 (a)(3a), (5).

In the years since *Empire Power Co.* was decided, N.C.G.S. § 62-2 was amended to include additional policies promoting renewable energy and energy efficiency in the State:

> To promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will do all of the following:
>
> a. Diversify the resources used to reliably meet the energy needs of consumers in the State.
> b. Provide greater energy security through the use of indigenous energy resources available within the State.
> c. Encourage private investment in renewable energy and energy efficiency.
> d. Provide improved air quality and other benefits to energy consumers and citizens of the State.

N.C.G.S. § 62-2 (a)(10).

Additionally, House Bill 951's carbon reduction mandate, specifically the directive that Duke Energy reduce carbon emissions from generation facilities it owns or operates and achieve carbon neutrality by 2050, has since been enacted into law and incorporated by reference in a newly modified N.C.G.S. § 62-110.1. Accordingly, a covered applicant under N.C.G.S. § 62-110.9 seeking a CPCN must demonstrate that its proposed generation facility would help reduce carbon emissions at the least cost. In sum, since the public convenience and necessity standard must be read with reference to state laws that both require Duke Energy to reduce its power plant carbon emissions and promote the general adoption of clean energy resources, it follows that the standard here is inextricably linked to whether Duke Energy has reduced its power plant carbon emissions and maximized its use of clean energy resources. If not, the standard has not been met.

The burden is on the applicant to show that its proposed generating facility is required by the public convenience and necessity. An applicant's failure to show that public convenience and necessity require the construction of a generating facility is grounds for denial of a certificate or even dismissal of a certificate application. *Empire Power Co*., 112 N.C. App. at 279, 435 S.E.2d at 560-61 (finding that the Commission's dismissal of an application was proper where the application's initial showing or forecast of evidence on the issue of need was inadequate).

Finally, when the Commission grants a certificate, it has the authority to impose conditions it deems necessary to ensure compliance with the public convenience and necessity standard. The Commission has exercised this authority in several recent proceedings. For example, in granting a CPCN to DEP for a new gas plant in Asheville, the Commission required DEP to, among other things, retire the existing coal units at the site, report on its efforts to work with customers to reduce peak load, and its efforts to site solar and storage capacity, and investigate retrofitting its four Roxboro coal units to improve their efficiency. Asheville Order at 43-44. *See also, e.g.*, Order Granting Certificate of Public Convenience and Necessity Subject to Conditions, *In the Matter of Application of Progress Energy Carolinas, Inc. for a Certificate of Public Convenience and Necessity to Construct a 950 Megawatt Combined Cycle Natural Gas Fueled Electric Generation Facility in Wayne County Near the City of Goldsboro and Motion for Waiver of Commission Rule R8-61*, Docket No. E-2, Sub 960 (N.C.U.C. Oct. 22, 2009) at 11 (attaching conditions to CPCN requiring DEP to "permanently cease operation of the three coal-fired generating units at its Wayne County facility" upon completion of new facility and to submit "a plan to retire additional unscrubbed coal-fired generating capacity reasonably proportionate to the amount of incremental generating capacity authorized by the certificate above 400 MW," the approximate capacity being retired at the site.); Cliffside Order at 34-35 (attaching conditions to CPCN requiring DEC to retire four existing units at the Cliffside site; retire additional coal capacity up to 800 MW; invest a certain percentage of its annual revenues in demand-side management and energy efficiency programs and submit those programs for Commission approval, along with specific annual reporting requirements).

III. ARGUMENT

A. DEP has not met its burden of proof to demonstrate that the Proposed Facility is part of the least-cost path to achieving compliance with N.C.G.S. § 62-110.9.

DEP has not met its burden of proving that the Proposed Facility "is part of the least cost path to achieve compliance" with N.C.G.S. § 62-110.9. Specifically, DEP has not adequately shown that the Proposed Facility, which is envisioned as a baseload power plant, is needed as the foundation to support the retirement of Roxboro units 2 and 3. Moreover, DEP's current modeling indicates that the Proposed Facility would operate far less often than a typical baseload resource, with ratepayers facing higher costs as a result. Lastly, DEP has not demonstrated that the risks attendant to (and resulting ratepayer costs associated with) gas power plants and tariffs would result in least cost compliance with N.C.G.S. § 62-110.9.

i. The Proposed Facility—a Baseload Resource—is a Poor Replacement for Roxboro Coal Units 2 and 3, Which Operate as Peaking Resources.

DEP argues that the Proposed Facility is needed to help reduce the costs of retiring and replacing Roxboro coal units 2 and 3. Joint Application for a CPCN ¶ 26 at 15 (Official Ex. Vol. 3, 38) ("Constructing the Proposed Facility also provides additional benefits to customers because, in the absence of replacement generation in the vicinity of Roxboro's coal-fired Units 2 and 3 that DEP plans to retire on January 1, 2034, expensive transmission upgrades would be necessary to maintain system reliability and provide for replacement capacity and energy from a greenfield resource"). *See also* tr. vol. 3, 109 ("It certainly provides a foundation for the future retirement of those [coal] resources."). But DEP's recent low utilization of those aging coal units is a strong indication that a suitable replacement resource would not need to be the kind of "baseload" resource that can generate the large volumes of megawatt hours of electricity that the Proposed Facility would provide initially. *See* Joint Application for a CPCN, Person County Energy Complex, Combined-Cycle Combustion Turbine Addition Project 2, Ex. 1B: DEP Statement of Need at 12 (Joint Application Ex. 1B) (Official Ex. vol. 3, 56).

The winter nameplate capacity of Roxboro Unit 2 is 673 MW, while the capacity of Unit 3 is 689 MW. *Id.* at 2 (Official Ex. vol. 3, 46). In 2023, Roxboro Unit 2 had a 21.2% capacity factor, with a capacity factor range of 21.2% to 36.1% since 2017. Unit 3 had a 21.8% capacity factor last year and a capacity factor range of 21.8% to 38.8% since 2017. SACE Cross Quinto Direct Ex. 1 (Official Ex. vol. 3, 100). In other words, with limited exceptions, these two coal units have shifted to operating as peaking units rather than baseload units on an annual basis. Tr. vol. 3, 111 ("[T]ypically, our gas units . . . are dispatched first with those coal units operating more as a – needed to run as a peaking or ramping type of resource[.]").

The total electricity generated by Roxboro Units 2 and 3 in 2023 was about 2,568 GWh.[2] In contrast, the Proposed Facility, at its original 80.4% capacity factor, would generate about 9,579 GWh—more than 3 times the amount of energy the current Roxboro coal units produced in 2023. *See* tr. vol. 3, 68; SACE Cross Quinto Direct Ex. 2 at 2 (Official Ex. Vol. 3, 102). Even under the constrained 40% capacity factor limitation that would be required for the Proposed Facility to comply with the Clean Air Act Section 111 Rule (CAA 111 Rule),[3] it would still generate about 4,765 GWh, almost double the amount of energy the Roxboro coal units generated in 2023.

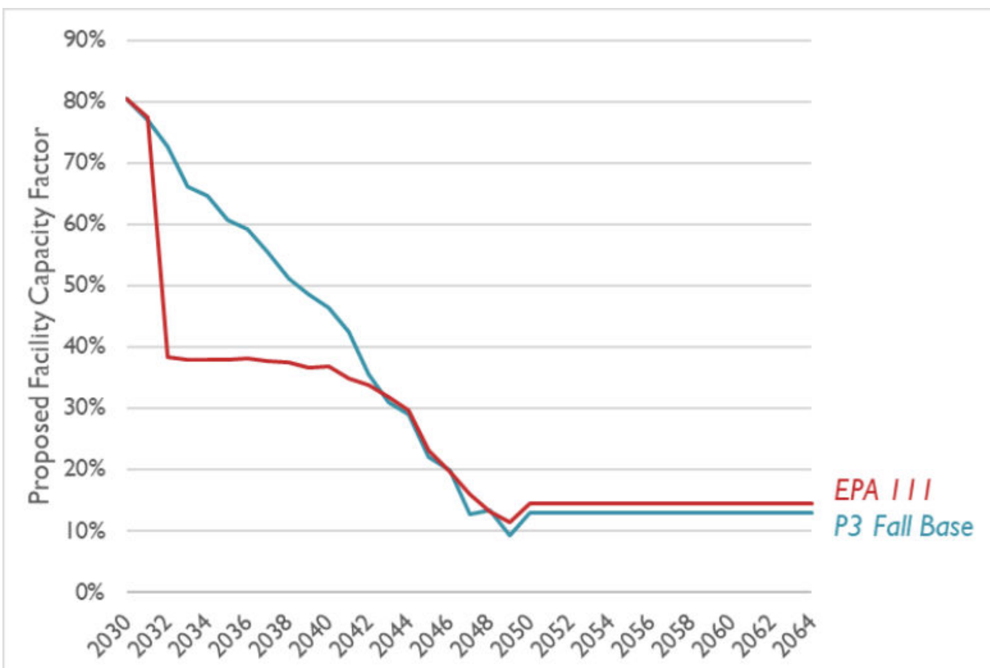
Retiring DEP's remaining coal units is necessary to comply with N.C.G.S. § 62-110.9. However, DEP should exercise more forethought about how its proposed resource portfolio fits into the long-term carbon neutrality requirement under state law before committing to a fleet of new combined cycle plants, including the Proposed Facility. Under its "replace before retire" rubric, DEP should consider the actual amount of annual megawatt hours needed to replace, while also considering the overall sufficiency of peaking resources to meet critical system demands.

[2] Each unit's nameplate capacity (MW) is multiplied by its annual capacity factor and then multiplied by 8760, the number of hours in a year, and then divided by 1,000 to convert the capacity into GWh. Tr. vol. 3, 66.

[3] While the EPA has announced plans to remove the more stringent carbon reduction requirements that would apply to new baseload gas plants, the CAA 111 Rule is still currently in effect. *See* tr. vol. 3, 103.

ii. DEP's Modeling Shows that the Proposed Facility Will be Underutilized.

DEP's preferred modeling pathway in support of the Proposed Facility indicates that this asset would meet a transitory need for energy in the 2030s. *See* tr. vol. 3, 44-47 (positing that the Proposed Facility would function similarly to Roxboro CC1 and would help facilitate the addition of renewables and other zero carbon resources, which will comprise a growing percentage of Duke Energy's generation mix in the 2030s and 2040s). As depicted in the graph below, after being in service for 10 years, Duke Energy projects that the capacity factor of the Proposed Facility will drop from an initial high of about 80.4% in 2030 to less than 50% by 2039, and down to 22% by 2045. SACE Cross Quinto Direct Ex. 2 at 2-3 (Official Ex. vol. 3, 102-03).



Source: Figure 4 from SACE witness Lucy Metz's direct testimony[4]

[4] Tr. vol. 4, 218.

These rapidly declining annual capacity factors demonstrate that the Proposed Facility would not be fully utilized for the large majority of its 35-year amortization period.

DEP argues that the Proposed Facility helps to meet energy needs in the early 2030s and that it was economically selected by its models even with steeply declining usage before the end of its assumed useful life. Tr. vol. 4, 365. In response to concerns that the Proposed Facility would essentially become a stranded asset in the face of declining utilization, DEP has argued that it could still provide some amount of peaking capacity and aid in reliability, even if it rarely runs after its first 15 years in service. *Id.* at 390-91. But the question is not whether the Proposed Facility could possibly be put to some conceivable use in the future. The question for the Commission is whether the Proposed Facility is the right resource to build based on what we know now. Given its projected limited future use after its first decade in service, it is not.

Rather than consider a peaking resource or a combination of peaking and renewable resources to replace those retiring coal units, DEP selected a baseload resource. Joint Application Ex. 1B at 5, 12 (Official Ex. vol. 3, 49, 56). While DEP argued that this choice was informed by its increased load forecast, the key criterion for this CPCN should be whether the Proposed Facility is an adequate, least-cost resource that is in the public interest.

The Public Staff provided testimony about the trade-offs between different generating resources at different capacity factors. In particular, Public Staff witnesses Evan Lawrence and Blaise Michna testified that, under the Public Staff's

2022 Carbon Plan analysis, "an advanced class CT will have lower costs than an advanced class CC when operating up to a 40% annual CF" and an advanced class CC will "be more economic to build" and operate "at an annual CF of approximately 50% or higher." Tr. vol. 4, 288, 289.

Importantly, under a scenario in which the Proposed Facility is limited to a 40% annual capacity factor, its total annual operating costs, including pipeline costs, would not be reduced proportionally. *Id.* at 281. Witnesses Lawrence and Michna testified that "even if the proposed output of the facility is halved, the total costs shown in Table 2 [DEP's Projected Annual Operating Cost] would not be reduced proportionally because of the magnitude of total fixed costs." *Id.* at 282. These operating costs include the firm transportation (FT), which "would persist for the life of that firm transportation contract." *Id.* at 323. Given the existing Roxboro coal units' low utilization, the large, fixed costs DEP customers would be forced to pay even as the Proposed Facility's capacity factor declines, and DEP's assertion in its pre-filed testimony that the Proposed Facility ""is strictly needed for meeting load growth in DEP," tr. vol. 3, 42, there is an argument to be made that Roxboro CC1 could generate the same energy that the Roxboro coal units currently provide through 2041,[5] with battery storage and other low-carbon peaking resources covering any incremental system capacity needs.

[5] The total electricity generated by all four Roxboro coal units in 2023 was approximately 4,028 MWh. *See* SACE Cross Quinto Direct Ex. 1. Under the constrained 40% capacity factor required under the CAA 111 rule, Roxboro CC1 would generate 4,765 GWh. *See* SACE Cross Quinto Direct Ex. 2 at 1 (Official Ex. vol. 3, 101) (confirming that the annual capacity factors for both Roxboro CC1 and the Proposed Facility are the same over time beginning in 2030).

iii. DEP Has Failed to Fully Account for Gas Volatility, Supply Chain, Tariff, and Retrofit Risks.

Among other things, SACE witness Lucy Metz identified the following risks that were absent from, or insufficiently addressed by Duke Energy that have the effect of biasing its analysis and modeling in favor of the Proposed Facility: (1) gas price volatility; (2) supply chain shortages and tariffs; and (3) challenges retrofitting the Proposed Facility and other gas assets to burn green hydrogen or capture and sequester carbon emissions. Tr. vol. 4, 200-01, 219, 221-25, 227-29.

a. Gas price volatility

The Proposed Facility would increase DEP's already heavy reliance on gas, exposing its customers to increased price volatility risks through the fuel adjustment clause; however, DEP's analysis and modeling fail to account for this risk properly.

Gas prices are shaped by domestic and international supply and demand considerations, with constrained supply and/or increased demand exacerbating gas price volatility, and all else being equal, raising the likelihood of higher gas prices. Of particular significance, expansion of liquified natural gas (LNG) capacity will increase domestic market "expos[ure] to global market dynamics," with North American LNG capacity 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." *Id.* at 228. In response to U.S. trade tariffs, nations "looking to ease relations with the United States may increase their imports of U.S. LNG in order to reduce trade surpluses." *Id.* Conversely, other nations may assume a retaliatory posture and import less U.S. LNG in response to U.S. trade policy. *Id.*

Taken in the aggregate, LNG export demand fluctuations could sharply increase gas price volatility.

Domestic issues can also contribute to gas price volatility. During the Commission's investigation into the utility service disruptions stemming from Winter Storm Elliott, PSNC testified that "when prices posted for that day . . . we contacted 17 suppliers before we could go find any amount of gas to purchase, and the price of that gas was so high . . . then you started seeing shippers that were overtaking Transco's system."[6] In this instance, extreme price volatility had the additional consequence of inducing shippers with interruptible contracts to ignore their contractual obligations.

Increased gas price volatility will have a significant impact on DEP ratepayers. DEP's current "firm winter capacity mix consists of approximately 38% gas-fired generating capacity," with the Proposed Facility part of a broader plan that would see both DEP and DEC come to rely on a combination of existing gas CC and CT plants, new CC and CT gas plants, and coal plants retrofitted to run on gas. Joint Application Ex. 1B at 9 (Official Ex. vol. 3, 53). If the Proposed Facility is approved, Roxboro Units 1 and 4 retire in 2029, and Roxboro CC1 begins operating in 2029, CCs will grow from 21% to approximately 33% of DEP's overall firm winter capacity mix. *Id.* at 11 (Official Ex. vol. 3, 55). Under DEP's current plans, as laid out in the most recent CPIRP docket, its ratepayers would

[6] Order Making Findings and Directing Actions Related to Impact of Winter Storm Elliott, In the Matter of Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Water/Wastewater Systems to Operate Reliably During Extreme Cold Weather, Docket M-100, Sub 163, at 26 (N.C.U.C. Dec. 22, 2023). (Winter Storm Elliot Order). The Commission took judicial notice of this order at the hearing in this proceeding. Tr. vol. 3, 160.

rely on existing or new gas plants along with coal plants (most of which co-fire gas) for approximately 54% of its anticipated total winter production capacity by 2033. Joint Application for a CPCN, Ex. 1A (Joint Application Ex. 1A) Supplemental Planning Analysis (SPA) Technical Appendix at 12 (Table SPA T-11).[7] In other words, DEP anticipates increased reliance on gas, which will significantly reduce its fuel diversity in the short to mid-term and thereby increase its customers' exposure to gas price volatility as DEP ratepayers will bear that risk (and ultimately pay for those gas costs) through the fuel adjustment clause. In two recent fuel adjustment proceedings, DEP experienced a $445 million under-recovery in fuel costs due to increased U.S. gas exports to Europe following the Russian invasion of Ukraine,[8] while DEC experienced a $998 million under-recovery.[9]

Despite the scale and consequences of gas price volatility risk for DEP customers, "Duke Energy did not specifically model fuel price volatility in its CPIRP analysis" and instead analyzed a collection of "high and low gas price forecasts" and coupled those forecasts with a range of capital cost scenarios in its initial CPIRP filings submitted on August 17, 2023. Tr. vol. 4, 219. *See also* Joint Application Ex. 1A Chapter 3: Portfolios at 17-18, 20 (detailing different gas

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[7] DEP witness Quinto sponsored the CPIRP Order and Duke Energy's CPIRP, including the initial, proposed CPIRP filed on August 17, 2023, in Docket No. E-100, Sub 190, and the Supplemental Planning Analysis filed on January 31, 2024, as Exhibit 1A to his direct testimony. Tr. vol. 4, 32.

[8] *See* 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)

[9] Order Approving Fuel Charge Adjustment, *In the Matter of Application of Duke Energy Carolinas, 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-7, Sub 1282, at 5 (N.C.U.C. Aug. 23, 2023). The Commission took judicial notice of this order at the hearing in this proceeding. Tr. vol. 4, 161.

price portfolio sensitivities). Duke Energy's SPA, which was filed on January 31, 2024, only evaluated a high CC/CT *capital cost* portfolio sensitivity. Joint Application Exhibit 1A SPA Technical Appendix at 7-8. Stochastic modeling of the kind that DEP dismisses would provide the Commission with more tools to better assess the efficacy of the Company's efforts to reduce its "exposure to the more volatile Transco zone 5 delivered fuel." Tr. vol. 4, 394. However, the most surefire strategy to reduce DEP ratepayers' exposure to fuel price volatility is more fuel-free renewable resources, which "remain[] the most cost-competitive form of generation" on an "unsubsidized basis." SACE Cross Mitchell Rebuttal Ex. 1 at 4 (Official Ex. vol. 4, 80).

b. Supply chain and tariffs risks

Supply chain shortages and unprecedented U.S. tariffs threaten to greatly increase the cost of constructing the Proposed Facility, as much of the necessary equipment has yet to be purchased.

SACE witness Metz notes that "[c]urrent 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." Tr. vol. 4, 200. This concern is justified considering Duke Energy Indiana's recent request to build two CC units with an aggregate nameplate capacity of 1,476 MW and a $2,256/kW cost,[10] "which is **[BEGIN CONFIDENTIAL]** [redacted] **[END**

[10] 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-edeaef11-be20-001dd80b89f5/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46193_Duke%20Energy%20Indiana_Direct%20Testimony%20of%20Sm

CONFIDENTIAL] higher" than DEP's comparable cost estimate for the Proposed Facility.

As confirmed at the hearing, the only major equipment for the Proposed Facility for which the Company has secured firm pricing are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Tr. vol. 4, 88-89. Half of all imported power generation, transmission, and distribution parts used in the U.S. are shipped from Mexico and China, which are under heavy tariffs. SACE Cross Smith Direct Ex. 3 at 4 (Official Ex. vol. 4, 23). According to some reports, supply chain shortages, along with other risk factors, have increased the cost of building new combined-cycle gas plants "three-fold." SACE Cross Smith Direct Ex. 5 at 2 (Official Ex. vol. 4, 36). This suggests that the cost of the Proposed Facility, which increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Duke Energy included in its initial 2023 CPIRP filing, SACE CONFIDENTIAL Cross Quinto Direct Exhibit 4 at 2 (Official Confidential Ex. vol. 3, 38), to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the Joint Application, could increase even more.[12] Despite this, **[BEGIN CONFIDENTIAL]** [redacted]

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[11] Joint Application for a CPCN, Person County Energy Complex Combined-Cycle Combustion Turbine Addition Project 2, Ex. 3: Cost Information at 2 (Joint Application Ex. 3) (Official Confidential Ex. vol. 3, 16).

[12] DEP contests the appropriateness of comparing these two cost estimates for the Proposed Facility on unclear grounds, *see, e.g.*, tr. vol. 3, 84, however it conceded in an earlier discovery response that the Proposed Facility's cost has in fact increased since Duke Energy's initial CPIRP filing. SACE CONFIDENTIAL Cross Quinto Direct Ex. 3 at 1 (Official Confidential Ex. vol. 3, 36).

[redacted] **[END CONFIDENTIAL]**. Tr. vol. 4, 89.

Moreover, the Amended Agreement and Stipulation of Settlement (Partial Settlement) fails to adequately address these supply chain and tariff risks, with DEP and Public Staff committing to meet once a quarter, file an annual progress report regarding “the status of the Proposed Facility’s construction cost estimate,” and “keep the Commission apprised of any material changes” to the Proposed Facility’s cost. Amended Agreement and Stipulation of Settlement ¶ 12 at 5 (Official Ex. vol. 3, 94). Importantly, the Partial Settlement does not define “what would constitute a material change” and would not bar DEP from seeking cost recovery if there were a material change to the Proposed Facility’s cost estimate. Tr. vol. 4, 106. Given all this uncertainty and given the current cost estimate for the Proposed Facility is between a Class 4 and Class 3 estimate, it is quite probable that there will be material changes to the Proposed Facility’s cost estimate. Absent further action from DEP or the Commission, DEP ratepayers would bear any material increases in the cost to construct the Proposed Facility.

In the most recent CPIRP Order, the Commission, citing Public Staff testimony, concluded that Duke Energy should not procure offshore wind resources at “any cost.”[13] The same logic applies to any resource under consideration, including combined cycle gas plants. It is important for the Commission to remember that the Proposed Facility was selected in the most recent CPIRP docket at a lower assumed capital cost than current estimates,

[13] CPIRP Order at 143.

which themselves are not final and could continue to increase for the reasons provided above.

c. Retrofitting and stranded asset risks

The Company continues to assume that it can operate the Proposed Facility with green hydrogen or use carbon capture and sequestration (CCS) to justify its assumed 35-year useful life. Joint Application Ex. 1B at 6 (Official Ex. vol. 3, 50). However, the costs and technical feasibility of both are unknown. Tr. vol. 4, 222-25. At bottom, DEP has failed to conduct a robust, standalone stranded asset analysis. Given the Proposed Facility is assumed to operate well past the 2050 carbon neutrality deadline, “there is a significant risk that its modeling assumptions are too optimistic” and the Proposed Facility becomes a stranded asset. *Id.* at 222.

SACE witness Metz testified about DEP’s unaccounted-for hydrogen cost and deliverability risks, noting among other things (1) speculative green hydrogen supply; (2) the unknown cost and feasibility of green hydrogen conversions; and (3) the lack of cost-effective, practical hydrogen transportation options. *Id.* at 222-23. As Metz notes, most hydrogen is created by heating gas, steam, and a catalyst under pressure, with carbon dioxide generated as a byproduct. *See id.* at 223. Accordingly, green hydrogen created using electrolysis or some other method would be needed to comply with N.C.G.S. § 62-110.9. *See id*. However, green hydrogen would either require DEP to build and use significant amounts of renewable energy or secure access to shipped green hydrogen, either of which would be incredibly inefficient. *See id.* Similarly, it is unclear how much it would cost or whether it would even be possible to retrofit the Proposed Facility or other gas plants to burn 100% hydrogen. Tr. vol. 4, 223.

CCS faces similar challenges as well. "The level of uncertainty around the cost of installing CCS . . . could mean hundreds of millions or even billions [of dollars] in underestimated costs." *Id.* at 224. Although the 45Q tax credits can provide up to $85/ton of captured carbon, standing alone, they would not support "first-of-a-kind CCS system[s] installed on" CCs or their utility-financed equivalents, which would cost $177/ton and $123/ton, respectively. *Id.* at 225. Even if these costs could be brought under control, it is unclear how much carbon these systems would capture or whether there would be "adequate supporting infrastructure available to transport and store" that carbon. *Id.* at 224.

The Public Staff's testimony in this proceeding and the recent CPIRP docket[14] echoed many of these concerns. Public Staff witnesses Lawrence and Michna testified in this proceeding that "the hydrogen landscape remains unchanged over the past year" and they remain concerned "regarding the viability of carbon capture and sequestration in North Carolina, including the cost and impacts to the operations of generation facilities." *Id.* at 271. In the recent CPIRP docket, Public Staff witness Michna expounded upon some of the challenges posed by Duke Energy relying on green hydrogen, remarking that "[t]here are *no* CCs in commercial operation that run on 100% hydrogen fuel"[15] and no "utility

[14] At the hearing in this proceeding, the Commission took judicial notice of Public Staff witness Michna's testimony filed in the most recent CPIRP docket. Tr. vol. 4, 327.
[15] Direct Testimony of Blaise C. Michna on behalf of the Public Staff – North Carolina Utilities Commission, *In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)*, Docket No. E-100, Sub 190, at 34 (N.C.U.C. May 28, 2024).

scale hydrogen marketplace or distribution network."[16] Similarly, witness Michna expressed reservations "regarding the sheer quantity of new generation assets [that would be] needed to serve the electric load required to produce and store hydrogen for use in further electric generation."[17] As a result, [t]he costs, and even the reality of plant operation, are unknown at this time.[18]

With regard to modeling 100 percent hydrogen conversion by 2050, witness Michna stated:

> The Public Staff is concerned that this assumption may lead to a greater dependence on natural gas in the short-term ultimately resulting in stranded assets over the long-term. DEP has no plans for how this facility will contribute to meeting the law's 2050 carbon neutrality requirement in the event that a sufficient or cost-effective hydrogen market does not develop.[19]

Ultimately, DEP's declaration that the Proposed Facility is "hydrogen capable" obscures the steep costs and impracticality of acquiring and deploying green hydrogen in a secure manner.

iv. DEP Has Failed to Consider Alternative Replacement Resources for Roxboro Units 2 and 3.

The mismatch between the total energy produced from the retiring Roxboro Units 2 and 3 and the energy that the Proposed Facility would produce is stark. And yet despite this mismatch, DEP failed to adequately consider alternative, cleaner resources, in large part due to methodological deficiencies that biased its modeling in favor of gas assets.

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16 *Id.* at 35.
17 *Id.* at 43.
18 *Id.* at 40.
19 *Id.* at 45-46.

The underlying modeling performed by Duke Energy in the CPIRP docket applied a 20% capital cost premium to all resources selected in its only portfolio designed to reduce carbon emissions 70% by 2030, further distorting any comparison between different pathways. Joint Application Ex. 1A Appendix C: Quantitative Analysis at 86. In addition, 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." Tr. vol. 4, 212. These build limits were "frequently binding," which indicates more zero carbon and fuel free resources would have been selected if those limits did not apply. *Id.* While Duke Energy asserts that these limits are intended to approximate existing renewable interconnection barriers, *id.* at 213, it largely "controls resource interconnection processes in its service area," *id.* at 214. Prioritizing improved integration of transmission and generation planning, along with other measures, would deliver significant ratepayer benefits by supporting the integration of cheaper, zero-carbon resources. *Id.*

In addition, Duke Energy's application of the effective load carrying capability (ELCC) methodology undervalues the capacity value of renewable resources while overestimating the availability (and reliability) of gas. In contrast to solar, wind, and battery storage, which are assigned ELCC values lower than 100 percent, Duke Energy's analysis "does not distinguish between the nameplate and winter firm capacity of thermal resources, effectively accrediting them at 100 percent in the winter." *Id.* at 216. This flies in the face of reason, as no "resource is available 100 percent of the time," and ultimately biases Duke

Energy's model in favor of gas, as it would appear to the model to be more reliable than renewables and battery storage. Tr. vol. 4, 216. These and related choices by Duke Energy had the combined effect of making resource portfolios with gas plants appear more cost-competitive than they are likely to be in the real world. Notably, even with those inflated cost estimates and cost-adders for resources selected in the near term, Duke's modeling selected solar and wind resources as part of its "least-cost" pathway. It stands to reason that portfolios with larger volumes of those resources at more accurate prices would likely result in savings for ratepayers. Indeed, the Public Staff ultimately concluded that it "cannot say definitively that the Person County CC2 is least cost for DEP's ratepayers." *Id.* at 316.

B. The Applicants have not proven that the Proposed Facility would Maintain or Improve Reliability.

The Applicants have failed to meet their burden and demonstrate that the Proposed Facility would help maintain or improve grid reliability. While the Proposed Facility is intended to withstand the coldest temperature observed in the surrounding area, with "[e]nclosures around the HRSG drums . . . installed to provide an additional level of cold hardening,"[20] Commission Rule R8-61(b)(4)(iv)'s requirements only apply to proposed *generating* facilities. However, severe cold weather can impact other gas infrastructure and, by extension, system reliability in the following ways:

> decreased natural gas production [.] . . mechanical problems at production, gathering, processing and

[20] Joint Application for a CPCN, Person County Energy Complex Combined Cycle Combustion Turbine Addition Project 2, Exhibit 4: Construction Information at 9 (Official Ex. vol. 3, 74).

> pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.[21]

Indeed, it is hard to see how any utility's compliance with R8-61(b)(4)(iv) would prevent most of these issues.

During Winter Storm Elliott, "Buck CC and the Dan River CC experienced derates as a result of low gas pressure [caused by the extreme cold weather] on December 25,"[22] with Buck CC and Dan River CC derated by 178 MW and 359 MW respectively.[23] The Buck CC derate in particular was directly attributable to "low pressure on the Transco interstate pipeline."[24] That incident and the decision taken by many shippers "to continue to take [gas] off the [Transco] pipeline even though the supply they had contracted for did not show up"[25] underscore the absence of (and need for) federal oversight of gas pipeline reliability and federal enforcement of interruptible contracts, which has cascading impacts during severe cold weather events like Winter Storm Elliott.

Given the extreme cold weather, precipitation, and high winds, "virtually all of the impacted BAs" during Winter Storm Elliott had offline or derated generation because of pipeline equipment failure, damage impairing gas quality,

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[21] Winter Storm Elliott Order at 24.
[22] *Id.* at 46.
[23] *Id.* at 22.
[24] *Id.*
[25] *Id.* at 26.

or reducing pipeline pressure or other gas supply problems.[26] In addition, Winter Storm Elliott directly impacted gas production at its source "in the Marcellus and Utica basins, which are the predominant source of the natural gas procured by gas generation. . . . This led to significant loss of gas supply for all downstream gas consumers."[27]

And yet, this risk has not driven DEP to modify its ELCC or reliability contribution methodology for traditional fossil fuel generation. Instead, DEP's ELCC framework is ultimately premised on the faulty assumption that gas generation, in theory, is always available to provide capacity. Given DEP is winter planning, *see, e.g.*, tr. vol. 4, 17, and historical precedent most exemplified by Winter Storm Elliott, Joint Application Exhibit 1A Appendix M: Reliability and Operational Resilience at 23, the Applicants have not met their burden and demonstrated that the Proposed Facility would maintain or improve grid reliability.

C. The Proposed Facility is not in the public interest as it presents unreasonable and unnecessary risks to ratepayers.

The Proposed Facility is not in the public interest as ratepayers will be forced to pay for a generation asset that may not be needed and would be underutilized. The forecasted large-load growth that is primarily driving the need for the Proposed Facility may not fully materialize. In addition, the Proposed Facility's capacity factor drops precipitously "to 46 percent by 2040 and only 13 percent from 2050 on," however the construction costs and many of the operating

[26] *Id.* at 24.
[27] Winter Storm Elliott Order at 27.

costs are fixed or highly volatile. Tr. vol. 4, 217.

Duke Energy's "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." *Id.* at 209. This point is underscored by DEP witness Quinto, who notes that the Proposed Facility's capacity "is strictly needed for meeting load growth in DEP."[28] Tr. vol. 3, 42. DEP's CPIRP analysis projected 3,883 MW of large load customer growth, which increased by 52 percent in Duke Energy's most recent large load customer report. Tr. vol. 4, 208.

As noted by several CPIRP intervenors, Duke Energy's load forecast, which included both a traditional, aggregate retail forecast capturing economic development and a new, standalone economic development load forecast, did not adequately address the potential for double-counting large load customer growth. *Id.* at 207. Thus, the projected large load forecast may be an overcount. *Id.* at 207. If all or at least enough of the projected large load customer growth fails to materialize, DEP ratepayers would be forced to pay for unneeded generation and all the volatile fuel costs that would come with it.

Moreover, Duke Energy's modeling reveals that the Proposed Facility will be underutilized and functionally operate as a peaker beginning in the 2040s. However, much of the cost to operate the Proposed Facility, in particular FT, would not decrease in line with the generation asset's reduced output. *See id.* at

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[28] *See infra* III.A.ii. regarding potential for Roxboro CC1 to match energy supplied by all four Roxboro coal units through 2041.

281. The projected pipeline capital costs and FT costs for the Proposed Facility are staggering, with the interstate pipeline capital costs amounting to approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and the annual, combined intrastate and interstate FT costs for the Proposed Facility totaling approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** Tr. vol. 4, 282, 283. Evidence presented at the hearing revealed that the intrastate FT contract for the Proposed Facility will last **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** while the terms of the interstate FT contract could **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** SACE CONFIDENTIAL Cross Mitchell Direct Ex. 1 (Official Confidential Ex. vol. 4, 42). Given the span of these contracts, it is possible the cost to secure firm transportation for the Proposed Facility could run into the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** prior to the end of the Proposed Facility's assumed, 35-year useful life.

Mitigating ratepayer exposure to these cost risks is eminently feasible. If the Commission were to grant the Applicants a CPCN, N.C.G.S. § 62-110.1(e1) explicitly provides that it "may review the certificate to determine whether changes in the probable future growth of the use of electricity indicate that the public convenience and necessity require modification or revocation of the certificate," with the Commission authorized to modify or revoke a CPCN if "completion of the generating facility is no longer in the public interest."

Replacement, carbon-free resources selected through an all-source procurement could reduce stranded asset and fuel cost risk and support the Commission's consideration of "resource and fuel diversity" and "other methods for providing reliable, efficient, and economical electric service." N.C.G.S. §§ 62-110.1(d), (e). Given the Proposed Facility's 2030 operational start date, DEP would have five years to "construct or otherwise obtain alternative[] resources," which is more than doable given the short lead time for renewables and battery storage. Tr. vol. 4, 226. Renewable and battery storage resources are also "more modular resource additions than combined cycle units," so procurements could be modified in response to load fluctuations and "market conditions." Tr. vol. 4, 225, 226.

Lastly, a properly designed fuel cost sharing mechanism, targeted large load tariffs, and a CPCN condition providing reasonable assurances that DEP ratepayers would be held harmless from certain cost overruns could mitigate a large share of the incremental costs stemming from the Proposed Facility. As the Commission has done in past CPCN proceedings, *see, e.g.*, Cliffside Order at 34-35, it could make the CPCN in the instant case conditional on Applicants satisfying certain requirements. The Commission ruling DEP cites in opposition to the validity of CPCN cost recovery conditions dealt with whether the Commission should impose a rebuttal presumption barring cost recovery of excessive construction costs, rather than a fuel cost sharing mechanism.[29]

[29] Order Issuing Certificate of Public Convenience and Necessity with Conditions, *In the Matter of*

However, more importantly, the Commission has more recently granted Duke Energy in the most recent CPIRP order "reasonable assurance of future recovery for . . . specific project development costs in a future cost recovery proceeding." Joint Application Ex. 1A CPIRP Order at 121-22. It stands to reason that the Commission, in its discretion, could provide DEP reasonable assurances of fuel cost recovery in a future fuel rider proceeding or general rate case, but only up to a certain percentage, or reasonable assurances that DEP ratepayers will be held harmless in future general rate cases or cost recovery proceedings from any changes to the Proposed Facility's cost estimate that stem from tariffs and supply chain shortages. *See also* N.C.G.S. § 62-133.2(f)("Nothing in this section shall invalidate or preempt any condition adopted by the Commission and accepted by the utility in any proceeding that would limit the recovery of costs by any electric public utility under this section.").

IV. CONCLUSION

The Applicants have failed to show that the Proposed Facility is part of the least-cost path to achieve compliance with N.C.G.S. § 62-110.9 as there are cheaper, cleaner alternatives to meet the alleged resource need. Similarly, the Applicants have not adequately demonstrated that the Proposed Facility will maintain or improve upon the adequacy and reliability of the existing grid as gas infrastructure experiences significant weather constraints during winter peaks. Ultimately, the construction and operation of the Proposed Facility are not in the

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Application of Duke Energy Carolinas, LLC, for a Certificate of Public Convenience and Necessity to Construct a 402-MW Natural Gas-Fired Combustion Turbine Generating Facility in Lincoln County, North Carolina, Docket No. E-7, Sub 1134, at 38 (N.C.U.C. Dec. 7, 2017).

public interest, given that ratepayers will be forced to pay for a generation asset that may not be needed and will be underutilized.

SACE therefore respectfully requests that the Commission:

1. Deny the Application.
2. Require DEP to issue an all-source request for proposals 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. Require DEP to 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. DEP should also focus on streamlining and removing bottlenecks in its interconnection process.
4. Direct DEP to develop tariff proposals in any future large load customer docket(s). 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.
5. If the Commission were to approve the Application, impose the following conditions:
   a. 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 DEP and its ratepayers

b. Require DEP to request modification or revocation of the Applicants' CPCN if enough of the large load customers driving the need for the Proposed Facility fail to materialize.

c. Provide reasonable assurances that DEP ratepayers will be held harmless in future general rate cases or cost recovery proceedings from any changes to the Proposed Facility's cost estimate that stem from tariffs and supply chain shortages.

Respectfully submitted this the 21st day of August, 2025.

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CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the foregoing Post-Hearing Brief on behalf of the Southern Alliance for Clean Energy by electronic mail.

This the 21st day of August, 2025.

/s/ Munashe Magarira
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