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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

BEFORE THE NORTH CAROLINA UTILITES 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

DIRECT TESTIMONY AND EXHIBITS OF

MARIA ROUMPANI

ON BEHALF OF

SOUTHERN ALLIANCE FOR CLEAN ENERGY, SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, AND NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and current position.

A. My name is Maria Roumpani, and I am an independent consultant. I am the co-founder and managing director of ELO Engineering Consulting.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of the Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council (SACE, *et al.*) as well as on behalf of the North Carolina Sustainable Energy Association.

Q. Please describe your educational and occupational background.

A. I specialize in the economic and technical analysis of grid planning and operations issues. I have conducted analysis and submitted expert testimony or comments on integrated resource planning, plant economics, unit commitment practices, and power cost issues before state utility regulators in Arizona, Colorado, Kentucky, Michigan, Minnesota, North Carolina, Oregon, South Carolina, and Virginia.

Previously, I was the Technical Director at Strategen, a team globally recognized for its expertise in the electric power sector on issues relating to resource planning, with a focus on decarbonization, renewable energy, energy storage, utility rate design, and market entry strategy. At Strategen, I led economic and technical grid modeling engagements, including capacity expansion, production cost, and energy storage dispatch modeling. My clients included government entities and state bodies including the Oregon Public Utility Commission, the Kentucky Public

Service Commission, the Maryland Office of People's Counsel, the South Carolina Office of Regulatory Staff, non-governmental organizations, and trade associations, as well as large energy buyers.

Before joining Strategen in 2018, I contributed to the development of analytical tools used in the European Union's energy impact assessment studies. I have a Ph.D. from the Management Science and Engineering Department at Stanford University and a Master of Science in Electrical and Computer Engineering from the National Technical University of Athens, Greece.

My full resume is attached to this testimony as Exhibit MR-1.

Q. Have you previously submitted testimony before the North Carolina Utilities Commission (Commission)?

A. Yes. I testified before the Commission in Duke Energy's application for approval of its Carbon Plan in Docket E-100, Sub 179.

Q. Have you ever testified before any other state regulatory body?

A. Yes. I submitted written testimony on behalf of the Office of Regulatory Staff before the South Carolina Public Service Commission on Duke Energy Progress and Duke Energy Carolinas' annual fuel riders in Docket Nos. 2032-2-E and 2032-1-E, and in Docket No. UE 420 before the Oregon Public Utilities Commission regarding PacifiCorp's Transition Adjustment Mechanism. I have also testified before the Michigan Public Service Commission in the application of DTE Energy for the approval of its Integrated Resource Plan, and before the Colorado Public Utilities

Commission in Public Service Company of Colorado's application for approval of its 2021 Electric Resource Plan and Clean Energy Plan. Furthermore, I have supported numerous clients by providing technical support through written testimony, comments, and participating in technical workshops in a range of proceedings in Arizona, California, Colorado, Indiana, Kentucky, Michigan, Nevada, North Carolina, Oregon, South Carolina, and Utah. My work experience is set out in Exhibit MR-1.

Q. Please describe the purpose of your testimony.

A. The purpose of my direct testimony is to review and evaluate various components of the resource planning analysis and alternative pathways as outlined by Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), collectively Duke Energy (Duke or Companies) in their application for approval of their proposed carbon plan/integrated resource plan (CPIRP). While doing so, I explain my concerns with certain assumptions employed by the Companies and how those might have affected the development and evaluation of the CPIRP Pathways. I provide directional input as to how the Companies' analysis and near-term action plan could be improved to ensure that ratepayers are not exposed to unnecessary costs, risks, and environmental impacts.

Q. How is your testimony organized?

A. First, I provide an overview of Duke's CPIRP analysis, including the development of its supplemental analysis. I outline my concerns regarding the Companies' methodology and input assumptions, and how those have affected the development of the recommended portfolio. Next, I argue that the Companies' analysis overestimates the role of thermal resources by overstating their reliability contributions and ignoring future economic and policy risks associated with the continued operation of carbon-emitting resources. I discuss how the Companies' analysis underestimates the role of clean resources by imposing build limits on renewable resources and overstating the costs of energy storage and carbon-free resources. Finally, I summarize my recommendations.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings.

A. My findings are summarized below:

- The Pathways presented in Duke's CPIRP do not present a meaningful range of alternative portfolios. They all rely heavily on new gas generation, exposing ratepayers to significant risks. Despite the high number of pathways, variants, and sensitivities, the Commission and stakeholders are deprived of the opportunity to evaluate the trade-offs between portfolios that continue to rely heavily on fossil fuel generation on the one hand and potential portfolios that promote a cleaner and more flexible system through the deployment of no-regrets assets on the other (including renewable resources, energy storage, and demand side resources).
- The Pathways presented are not compliant with the U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions limits and

guidelines for existing coal-fired and new natural gas-fired power plants. Although the rules were not finalized at the time of Duke's analysis, viable compliance pathways should have been more thoroughly studied. Both the proposed coal retirement schedule and the new gas combined cycle (CC) buildout reflected in Pathway P3 Base and P3 Fall Supplemental are noncompliant.

- The Companies assume that natural gas assets are among the most reliable and cost-effective resources to meet demand growth and facilitate an energy transition. But these assumptions bet ratepayer dollars on the market, technology, and policy factors--all of which are beyond the Companies' control--advancing in a favorable manner. The riskiness of this choice is exacerbated by the magnitude of the proposed investment in new gas resources, which diverts resources from no-regrets options and locks in a suboptimal system that will not be flexible enough to adjust to changing conditions.
    - CC natural gas units solve a transient need during the Base Planning Period. The Companies will, however, seek to recover the costs for those gas units from customers in rates for decades to come. In the Companies' own modeling, the CC capacity factors fall significantly within the first decade of use as carbon-free energy replaces their generation - even without considering state and federal policy. The proposed CC units represent a temporary and expensive fix for the projected load growth at the

beginning of the next decade. Their selection in EnCompass stems from an artificial lack of alternatives at a time of high load growth. Accelerating the pace of clean no-regrets replacement resources, resources that the Companies would eventually need anyway (as the Companies' own modeling shows), is a better solution and will protect ratepayers from the cost of these capital-intensive gas assets – which can and should be avoided immediately or at least significantly reduced.

- CC natural gas units will face execution challenges. Compliance with the EPA rules when the Companies are proposing a gas fleet of this magnitude will present significant and likely insurmountable challenges. Beyond the technological barriers, the cost of compliance will significantly increase the cost of those assets, further increasing the risk of them becoming stranded for economic or policy reasons. This further highlights the urgency of studying alternative strategies to deploy additional no-regrets resources.
- There are alternatives that the Companies have not sufficiently explored within the set of portfolios presented in the CPIRP that could unlock cost and emission savings without the unnecessary risks of fossil fuel generation. Despite the Companies' claim of

pursuing a "diverse all-of-the-above resource portfolio,"[1] these have not been meaningfully studied. They include transmission enhancements to unlock additional renewable energy; additional demand side resources including behind the meter storage; load management options; and other solutions that could alleviate interconnection challenges. SACE, *et al.* witnesses Goggin, and Duncan provide additional supporting evidence.

- Renewable energy resources and energy storage are the most cost effective, least risk options in addressing the Companies' energy needs within the changing market and policy landscape. This is consistently shown in the Companies' own modeling, even when the Companies include unjustified cost adders. Their potential is only limited by the Companies' assumptions about what is feasible. Although execution challenges are undeniable, pushing for a faster deployment of these clean, no-regrets resources will result in cost savings, emissions reductions, and a system that can more effectively adapt to changing conditions including new load from economic development and technological advancements. Ratepayers would be better off if the Companies devoted resources to alleviating these execution concerns and lifting those limits, instead of their continuous effort to divert resources to riskier investments – such as the proposed gas units.

[1] Supplemental Direct Testimony of Glen Snider, Michael Quinto, Thomas Beatty, and Ben Passty on Behalf of Duke Energy Carolinas, LLC And Duke Energy Progress, LLC, at 16.

- Coal generation economics are worsening, driving retirements across the nation. Furthermore, coal generation is increasingly unreliable with many of the Companies' coal units underperforming during Winter Storm Elliott. Challenges around coal generation will keep increasing even during regular operations due to fuel supply issues, a declining workforce, and the lack of critical parts as technology becomes obsolete. Duke has acknowledged these challenges but is not moving quickly enough to retire some of its aging units and mitigate ratepayers' exposure to the associated costs and risks. On the contrary, it seems that the timing of retirements is primarily driven by the Companies' intention to invest in another fossil fuel resource that carries some of the same risks: natural gas.

Q. Please summarize your recommendations.

A. First and foremost, the Commission should not approve the 2023 CPIRP, Duke's recommended Pathway 3 (P3 Fall Supplemental), or the Companies' proposed Near-Term Action Plan (NTAP) in their current form. Specifically, I recommend that the Commission hold in abeyance any decision on Duke's proposed gas buildout, or at a minimum on the Companies' combined cycle (CC) buildout, due to the already existing cost, reliability, gas supply, and technical challenges that such a buildout would face. The final EPA section 111 rule, which Duke's analysis and portfolios fail to account for, is an especially important reason for the Commission to halt the Companies' plans to build new gas CC resources. I also recommend that in each of the Companies' applications for a Certificate of Public Convenience and Necessity for new gas plants, that the Commission should require the Companies to provide information as to whether the proposed gas resource was evaluated against a clean portfolio including all the possible Inflation Reduction Act (IRA) benefits. This evaluation should include the energy community bonus credit if the clean resource is constructed within an energy community as well as benefits from the Energy Infrastructure Reinvestment program (EIR).

Furthermore, I recommend that the Commission instruct the Companies to keep exploring earlier retirement options, especially for the Cliffside 5, Mayo 1, Marshall 1 and 2, and Roxboro units, while in their future planning analysis they continue to investigate the benefits of converting the Belews Creek units to operate 100% on natural gas.

Finally, as consistently shown in the Companies' modeling, clean energy resources should be added at a rate and scale above what is modeled in the Companies' preferred portfolio. I recommend that the Commission approve the solar, wind, and battery storage procurement levels identified in the Companies' P1 (Base Core) as a floor and instruct Duke to explore additional options to expedite the interconnection of new renewable and storage resources.

III. OVERVIEW OF THE COMPANIES' MODELING AND SUPPLEMENTAL PLANNING ANALYSIS

Q. Please provide a brief overview of the Companies' modeling analysis as filed on August 17, 2023.

A. For the proposed CPIRP filed in August 2023, the Companies used EnCompass, which was run with a planning horizon of 2050. EnCompass was used both in capacity expansion mode to generate resource portfolios and in production cost mode to simulate the portfolios' operations and estimate the associated costs and emissions. The Companies developed three Energy Transition Planning Pathways:

- Pathway 1, which achieves 70% CO2 emissions reductions from 2005 levels by 2030;
- Pathway 2, which achieves 70% CO2 emissions reductions from 2005 levels by 2033;
- Pathway 3, which achieves 70% CO2 emissions reductions from 2005 levels by 2035.

Within these Energy Transition Pathways, the Companies have modeled three Core Portfolios (P1 Base, P2 Base, and P3 Base) using base planning assumptions. Furthermore, the Companies developed 13 additional Portfolio Variants as well as ten Sensitivity Analysis Portfolios. Variants were developed by changing one or more inputs or assumptions, or by allowing or forcing a different mix of resources for each Pathway. For the Sensitivity Analysis Portfolios, inputs or assumptions were changed from the assumptions used to create the Portfolio Variants. Sensitivity Analysis Portfolios were exclusively focused on Pathway 3.

Q. Since the August 2023 filing, have the Companies notified the Commission and parties to the docket of any substantive and material changes to their 2023 CPIRP?

A. Yes, on November 30, 2023, the Companies filed supplemental testimony (Snider Supplemental) noting substantial, material changes to their load forecast since the preparation of the 2023 CPIRP.[2] The supplemental testimony noted that the Companies were in the process of finalizing an updated load forecast,[3] with increases being primarily driven by new economic development projects such as manufacturing and technology projects, that range from 150 MW to 500 MW and tend to have load factors higher than 90%.[4] Witness Snider further notes that:[5]

> In total, and on a preliminary basis, the Updated 2023 Fall Load Forecast shows a marked increase in projected peak load in the near-term planning horizon since the 2022 Carbon Plan, with approximately 4 GW of projected load growth between 2024 and 2030. To put this in perspective the current projected peak demand growth by 2030 is now approximately eight times the peak load growth projected in the 2022 Carbon Plan proceeding over the same time horizon. Furthermore, compared to the 2023 Spring load forecast used to develop the 2023 CPIRP, the peak load growth in the Updated 2023 Fall Load Forecast has increased by approximately 2 GW.

The Companies presented their Supplemental Planning Analysis on January 31, 2024, noting that it "builds on (but does not replace)" the

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[2] Supplemental Direct Testimony of Glen A. Snider on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, at 2.

[3] *Id.* at 5.

[4] *Id.* at 6.

[5] *Id.* at 7-8.

analysis of the August filing.[6] The Supplemental analysis included seven portfolios, mainly under Pathway P3.

Table 1: Portfolios analyzed in the Companies' Supplemental CPIRP analysis

	P1	*P2*	*P3*
Fall	Fall Supplemental	Fall Supplemental	Fall Supplemental
Sensitivity			Fall High Load
			Fall High Load Interruptible
			High CC/CT costs
Supplemental	No Carbon Constraints Fall Supplemental (P0)		

Q. What are your key concerns regarding the Companies' modeling approach, methodology, and assumptions?

A. There are several areas that raise concerns regarding the Companies' design of the Pathways and the assumptions used. These concerns fall under the following categories:

- The Companies have not presented a broad range of portfolios that would provide the Commission with meaningful insights about alternative ways of meeting North Carolina's energy resource needs. Specifically, despite the high number of variants, all portfolios include significant investment in new gas generation, which is presented as a least-cost, least-risk strategy due to the interconnection and other execution limitations associated with a faster deployment of renewable resources. However, the Companies do not present portfolios exploring strategies that could address those limitations. Those strategies include additional demand side resources, load management options,

[6] Supplemental Planning Analysis at 1.

transmission enhancements, and consideration of alternative load forecasts. SACE, *et al.* witnesses Goggin, Duncan, and Wilson provide additional supporting evidence.

- The Companies' modeling, although extensive, is overly restricted in the set of solutions it can select. Consequently, it can only provide results that are almost pre-determined. This reduces its informational value.
- The Companies' analysis overestimates the role of thermal resources and underestimates the associated risks and costs, thereby leading not only to more expensive but also significantly riskier portfolios than otherwise possible.
- The Companies' analysis overestimates the costs of clean energy resources and overly limits their potential. Still, the model finds clean resources to be more cost-effective in meeting the Companies' needs, but their selection is limited by the Companies' assumed limits.

Q. You have expressed concerns about the risks of including significant new gas generation in the Companies' recommended portfolio. Do you have reasons to worry that the Companies might not be including these risks in their analysis?

A. Yes. Throughout my testimony, I analyze the significant risks that these big, long-lived gas resources carry for ratepayers and how those risks have not been properly modeled and evaluated in the Companies' analysis. However, before diving into the specifics, it is worth highlighting that utilities are often insulated from some risks that ratepayers face. Ratepayers will, in all likelihood, be asked to cover the costs of a system even if that system becomes too expensive to operate and not flexible enough to adapt to changing economic and policy conditions, while utilities are not necessarily fully exposed to the same risks. In a recent brief prepared for the Environmental Defense Fund (EDF) and focusing specifically on Duke, EQ Research found that a shift towards greater amounts of natural gas generation has significant effects on the overall rates paid by electric utility customers, exposing them to greater rate volatility that is ultimately driven by volatility in natural gas prices.[7] Furthermore, the brief states that:

> Increases in fuel costs account for roughly 68% of the increase in the residential retail volumetric rate from 2017 to Q1 2024 in DEC territory, and roughly 46% in DEP territory. In other words, in the case of DEC, the amount of the total difference in rates between 2017 and Q1 2024 attributable to fuel costs is more than double the amount from all other rate components.[8]

For example, during periods of gas price spikes in 2022, the Commission was constrained to pass those significant increases to ratepayers.[9] In addition, during Winter Storm Elliott, North Carolina consumers faced both outages and significantly increased fuel and power costs because part of the generation fleet was either unavailable or subject to very high fuel and market prices. The Companies operated their fleet to minimize outages and costs at the time of the storm. They were, however,

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[7] EQ RESEARCH LLC, ISSUE BRIEF: THE ROLE OF FUEL COSTS IN DUKE ENERGY'S NORTH CAROLINA'S RETAIL RATES FROM 2017 THROUGH MARCH 2024 2 (2024), https://www.edf.org/sites/default/files/documents/Issue_Brief_Narrative_4_18_24.pdf.

[8] *Id.* at 1.

[9] For example, the Commission approved a partial settlement in a recent DEC fuel rider proceeding that required customers to pay $998 million under-recovery, albeit over a longer 16-month period. Order Approving Fuel Charge Adjustment, Docket No. E-7, Sub 1282, at 6, 18-19 (N.C.U.C., Aug. 23, 2023). In approving the partial settlement, the Commission rejected alternative proposals that would have provided more immediate ratepayer relief through the expedition of tax refund returns because this approach would "immediate[ly] increase in base rates and . . . result in certain rate classes receiving a lesser EDIT refund than they are currently being afforded." *Id.* at 18.

constrained by the existing -at the time- fleet and the underperformance of their units. Subsequent recovery of the associated costs during such an event shifts the risk of fuel price volatility and unit underperformance from the Companies to the ratepayers. Although regulatory oversight helps mitigate this risk, the reality is that ratepayers remain more exposed to those risks under the existing regulatory framework, a concern that calls for additional scrutiny in cases like the current CPIRP—*before* costs are incurred.

An even greater risk is associated with the gas units becoming stranded either due to policy or economic reasons, or the Companies incurring high costs to convert them to cleaner resources. In the case that the units become stranded, it is highly likely that ratepayers will still need to cover their costs, while the same applies in the event that hydrogen conversion (or others cost associated with compliance with federal policy) proves to be costlier than currently projected. The Companies will get to earn a rate of return on these big, capital-intensive assets, while ratepayers will carry the associated risks of the utility's investment. As history has shown, energy economics change rapidly; coal units have now become more economic to retire than to keep operating until the end of their depreciable lives. Even if those large gas assets were the least-cost option in this snapshot in time – which they are not— they should not be considered part of *a least-cost, least-risk* approach as they are locking ratepayers into a system that evidence suggests might become very expensive.

My recommendation is that the Companies should invest in a no-regrets, flexible portfolio, including demand side resources and transmission enhancements, while primarily consisting of modular, scalable, and quickly deployable clean energy resources that mitigate ratepayers' exposure to fuel price volatility, and the quickly changing market and policy environment.

IV. THE COMPANIES' ANALYSIS DOES NOT FULLY CAPTURE THE COSTS AND RISKS ASSOCIATED WITH CONTINUED FOSSIL FUEL GENERATION

Q. One of your primary concerns is that the Companies' analysis overestimates the role of thermal resources and underestimates the associated risks, thereby leading to suboptimal portfolios. Can you provide a justification for this concern?

A. Yes. The cost and risks of continued reliance on thermal assets have been underestimated in a variety of ways. Specifically, my concerns can be summarized as follows:

- The coal retirement schedule and proposed CC gas buildout, as modeled in P3 Base and P3 Fall Supplemental are not compliant with the EPA 111 rules.
- The reliability contributions of thermal resources are overstated. Coal and gas resources have largely been assumed to be able to provide their installed capacity during periods of system need,

significantly above what was recently experienced during Winter Storm Elliott.

- Reliance on aging coal units and a growing gas fleet will be significantly more expensive than currently assumed in the Companies' analysis.

My concerns are focused on the Companies' coal assets, and the proposed gas units.

A. The Companies' coal retirement plan should be further accelerated.

Q. Please provide a brief overview of the Companies' coal retirement analysis.

A. The Companies operate a fleet of 15 coal power plants, totaling a capacity of 9,294 MW.[10] As part of their modeling, the Companies performed a coal retirement analysis for each Energy Transition Pathway, as well as for the supplemental scenario without carbon constraints. This analysis started with a capacity expansion modeling run with endogenous selection of coal retirements, in which the model weighed the costs to continue to operate and maintain the coal units, and the production cost and emissions of the system against the cost and production cost benefits of resources that could be brought online while meeting the requirements of the system.[11] After the

[10] 2023 Carolinas Resource Plan, Appendix F, Table F-7, at 15. The Allen units 1 and 5 retirements are planned by the end of 2024. Cliffside 6 is assumed to continue operating on 100% natural gas beyond 2035. Thus, the Companies' initial coal analysis examined 12 units with a total capacity of 8,019 MW.

[11] 2023 Carolinas Resource Plan, Appendix F at 7.

optimal retirement dates were determined based on the endogenous retirement study, the Companies made some manual adjustments to allow for "more orderly and executable retirement schedules,"[12] and determined the coal retirement schedule. For their supplemental analysis, the Companies also updated the coal retirement analysis following the same process.[13] The retirement dates are shown in Table 2, with the shaded rows showing delayed retirement compared to the 2022 Carbon Plan.

Table 2: Coal Unit Retirement Schedule[14]

Unit	Utility	Winter Capacity [MW]	2022 Carbon Plan	2023 CPIRP					
				Base Core			Fall Supplemental		
				P1	P2	P3	P1	P2	P3
Allen 1	DEC	167	2024	2025	2025	2025	2025	2025	2025
Allen 5	DEC	259	2024	2025	2025	2025	2025	2025	2025
Belews Creek 1	DEC	1,110	2036	2030	2036	2036	2030	2036	2036
Belews Creek 2	DEC	1,110	2036	2030	2036	2036	2030	2036	2036
Cliffside 5	DEC	546	2026	2029	2031	2031	2029	2031	2031
Marshall 1	DEC	380	2029	2029	2029	2029	2029	2029	2029
Marshall 2	DEC	380	2029	2029	2029	2029	2029	2029	2029
Marshall 3	DEC	658	2033	2034	2032	2032	2034	2032	2032
Marshall 4	DEC	660	2033	2034	2032	2032	2034	2032	2032
Mayo 1	DEP	713	2029	2029	2031	2031	2029	2031	2031
Roxboro 1	DEP	380	2029	2029	2029	2029	2029	2029	2029
Roxboro 2	DEP	673	2029	2029	2029	2029	2029	2029	2034
Roxboro 3	DEP	698	2028-2034	2030	2033	2034	2030	2033	2034
Roxboro 4	DEP	711	2028-2034	2030	2033	2034	2030	2033	2029

[12] 2023 Carolinas Resource Plan, Appendix F at 12.

[13] Supplemental Direct Testimony of Glen Snider, Michael Quinto, Thomas Beatty, and Ben Passty on Behalf of Duke Energy Carolinas, LLC And Duke Energy Progress, LLC, at 14.

[14] *Compare* 2023 Carolinas Resource Plan, Appendix F, Table F-7, at 15 (detailing initial CPIRP coal retirement schedule) *and* Supplemental Planning Analysis, Table SPA 3-1, at 34 (detailing CPIRP coal retirement schedule developed in Supplemental Planning Analysis), *with* Appendix E - Quantitative Analysis, Docket No. E-100, Sub 179, Table E-47, at 49 (N.C.U.C., May 16, 2022) (detailing the Companies' coal retirement schedule from their 2022 Carbon Plan).

Q. How does the Companies' coal retirement schedule in the 2023 CPIRP compare to their 2022 Carbon Plan coal retirement schedule?

A. The currently proposed retirement plan significantly delays the retirement of certain units relative to the retirement plan included in the Companies' 2022 Carbon Plan. The retirement dates that have been delayed are highlighted in the table above, with the most notable ones being Cliffside 5 which changed from 2026 to 2029 in the initial filing and even further to 2031 in the supplemental analysis, as did Mayo 1.

Q. Do you have any concerns with the coal retirement schedule as included in the 2023 CPIRP?

A. Yes. Table 3 shows the cumulative coal capacity being retired in each pathway, including the P3 Fall Supplemental portfolio. Three observations are worth making:

(a) Retirements prior to 2030 have been significantly delayed in the recommended pathway of the current Carbon Plan (P3 Base and P3 Fall Supplemental) relative to the 2022 Carbon Plan. This is notable given the fact that the passage of the IRA has brought dramatic changes to the economics of coal retirements and the deployment of replacement capacity.

(b) There are no differences regarding the expected coal retirements before 2029 across the Companies' three pathways within the current plan. As such, the current range of portfolios does not provide any information, insight, or analyses regarding the potential benefits of retiring certain coal units earlier.

(c) Many coal retirements within P1 (Base and Fall Supplemental) of the 2023 CPIRP are condensed in a significantly narrow timeframe. P1 retires 6,500 MW of coal-fired capacity over just two years: 3,000 MW in 2029 and 3,500 MW in 2030. From a modeling standpoint, given the annual build limits on clean energy resources, retiring all this capacity at the same time artificially inflates costs associated with that Pathway. Furthermore, the only pathway that allows additional renewable resources to be selected in the near term (P1) retires Belews Creek (2,220 MW) in 2030 at the same time with other coal retirements (whereas in all other portfolios, the Belews Creek units are assumed to retire after 2035), so the model is still forced to select new gas units as the capacity need is exogenously set to be higher than even the increased limits for clean resources.

Given the issues noted above, the Companies' current plan not only delays coal retirements scheduled prior to 2030 compared to what was filed in 2022, but it also presents a binary choice between that delayed schedule or a much more aggressive and expensive one. This false dichotomy fails to capture the full range of options, depriving the Commission of useful information.

Table 3: Retiring Coal Capacity by year (MW)

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	2022 Carbon Plan (P3)	426	-	546	-	-	2,526	-	-	-	1,318	1,409	-	2,220
Base Core	**Pathway 1**	-	426	-	-	-	3,072	3,629	-	-	-	1,318	-	-
	Pathway 2	-	426	-	-	-	1,813	-	1,259	1,318	1,409	-	-	2,220
	Pathway 3	-	426	-	-	-	1,813	-	1,259	1,318	-	1,409	-	2,220
Fall Supplemental	**Pathway 1**	-	426	-	-	-	3,072	3,629	-	-	-	1,318	-	-
	Pathway 2	-	426	-	-	-	1,813	-	1,259	1,318	1,409	-	-	2,220
	Pathway 3	-	426	-	-	-	1,851	-	1,259	1,318	-	1,371	-	2,220

Q. Do you have any concerns with how the Company conducted the coal retirement analysis?

A. Yes. According to Companies' response to Public Staff DR 5-2, coal units were only allowed to retire starting in 2029 because "DEC and DEP were deficient capacity before this date and therefore would not be able to reliably retire coal capacity before 2029." However, the Companies have included resource limits in their modeling that are intended to capture these resource build limitations. Further restricting the timeline in which coal units can retire for the purpose of adhering to a constraint that the Companies included in the model undermines the role of an expansion model and prescribes what the solution should be. Even if one coal unit could economically retire in 2028 and be replaced by solar plus storage, this retirement would not be reflected in the results given the Companies' modeling constraints. It is worth noting that in both the Base and Fall Supplemental analysis, in P1, six of those units retire at the earliest available date, while P2 and P3 also have the Marshall units 1 and 2, and Roxboro units 1 and 2 retiring in 2029. In the supplemental analysis, the coal retirement schedule under pathways 1 and 2 remain the same. In P3 Fall Supplemental, the Roxboro units are grouped differently; still two of the units are retired as soon as the model allows them to. These results suggest that Duke's modeling constraints did in fact constrain coal retirements.

Q. Does the 2029 earliest coal retirement date differ from the Companies' assumptions in recent prior IRP dockets?

A. Yes. For example, the Companies evaluated the earliest practicable coal retirement year in the 2020 IRPs.[15] The 2023 CPIRP, however, delays the earliest retirement year for eight of the coal units as the Companies seem to further wait for new gas capacity to be constructed instead of evaluating all possible replacement options.

The earliest retirements for the Marshall and Roxboro units are pushed to 2029 as the Companies are proposing new gas capacity to replace them. Similarly, the retirement of the Belews Creek units, although allowed to economically occur in 2029, and actually selected to occur in 2033 in the supplemental coal retirement analysis,[16] is delayed until 2036. The Companies are relying on the availability of small modular nuclear reactors to replace that generation: "in part, because this site is well suited for and being pursued as the first early site permit for advanced nuclear, the Companies delayed the retirement of these units to 2036. This timeline is generally consistent with the timing planned for the first advanced nuclear small modular reactor unit coming online."[17]

Had the Companies acted earlier and faster to find clean replacement portfolios instead of waiting for a pre-determined resource

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[15] Duke Energy Carolinas 2020 Integrated Resource Plan, Docket No. E-100, Sub 165, Table A-11, at 175 (N.C.U.C., Sept. 1, 2020); Duke Energy Progress 2020 Integrated Resource Plan, Docket No. E-100, Sub 165, Table A-11, at 174 (N.C.U.C., Sept. 1, 2020).

[16] Supplemental Planning Analysis, Technical Appendix, Table SPA T-4, at 5.

[17] 2023 Carolinas Resource Plan, Appendix F at 14.

option to become available, coal retirements would not have to be delayed year after year.

Table 4: Earliest practical coal retirement schedule in 2020 IRP and earliest retirement schedule in 2023 CPIRP modeling

			2020 IRP		
Unit	Utility	Winter Capacity [MW]	Earliest Practicable Coal Retirement Year	Constraining Factor	Earliest retirement date in 2023 IRP modeling
Belews Creek 1	DEC	1,110	2029	Construction of onsite gas capacity, interstate	2029
Belews Creek 2	DEC	1,110	2029		2029
Cliffside 5	DEC	546	2026	Construction of onsite or offsite capacity	2029
Marshall 1	DEC	380	2028	Construction of onsite gas capacity	2029
Marshall 2	DEC	380	2028		2029
Marshall 3	DEC	658	2028		2029
Marshall 4	DEC	660	2028		2029
Mayo 1	DEP	713	2026	Build-up of transmission-advantageous battery energy storage	2029
Roxboro 1	DEP	380	2029	Construction of onsite gas capacity	2029
Roxboro 2	DEP	673	2029		2029
Roxboro 3	DEP	698	2028	Construction of onsite gas capacity	2029
Roxboro 4	DEP	711	2028		2029

Q. Have the Companies included all potential tax incentives or federal funding in the coal retirement analysis?

A. To a certain extent. The Companies have assumed that 60% of new stand-alone batteries will be sited at retired coal sites and will receive the Energy Community bonus. The way this is included in the capacity expansion model is by assuming that all storage assets will receive the same ITC percentage, representing an average of 60% of the battery storage projects receiving the 10% energy community bonus and 40% of the battery storage projects not receiving the 10% energy community bonus. Although the approach seems reasonable, it might lead to the analysis overlooking certain opportunities to replace coal capacity due to underestimating the federal incentives directly available for a replacement resource at a certain location.

Another program that could further support the economics of coal retirement is the Energy Infrastructure Reinvestment (EIR) program. Through the EIR, the Loan Program Office can finance projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations or enable operating energy infrastructure to avoid, reduce, utilize or sequester air pollutants or GHG emissions. According to the Companies response to SACE, et al. DR 11.12.1 "The Companies are considering the following types of projects for EIR program financing: new carbon-free generation resources (solar, onshore wind, battery storage) to the extent they are replacing retiring coal generation, existing nuclear uprates and improvement projects, existing hydro improvement projects, Bad Creek II expansion project costs within the program funding window, "RZEP" transmission expansion/upgrade projects, and distribution voltage optimization projects." However, according to the response to AGO DR 7.6c, potential interest rate savings for projects that might qualify for the EIR loan guarantee program were not included in Carbon Plan modeling. It is thus possible, that after considering the EIR, an earlier coal retirement schedule would be more economic than what is proposed in the 2023 CPIRP.

Two points worth making are (a) the urgency of considering these additional opportunities as the EIR loans should be approved by the end of

September 2026 while the bonus credit might not be available after 2032, and (b) the fact that clean energy resources stand to benefit more than fossil fuel resources from federal funding. If the Companies choose to oversee these available opportunities and pursue gas replacements or keep operating coal units, they will be missing potential savings.

i. Continued coal generation exposes ratepayers to policy risks.

Q. Please provide information about the recently announced EPA performance standards for GHG emissions from coal-fired units.

A. On May 11, 2023, the EPA proposed new GHG emissions limits and guidelines for existing coal-fired and new natural gas-fired power plants.[18] The final carbon pollution standards were announced in April 2024.[19] The EPA established timelines for compliance for existing coal units and new gas units based on performance standards and emission guidelines that reflect what is achievable through implementation of the best system of emission reduction (BSER).

For existing coal-fired steam electric generating units (EGUs), the final rule establishes subcategories based on the planned operating horizon of the unit:

[18] EPA, FACT SHEET, GREENHOUSE GAS STANDARDS AND GUIDELINES FOR FOSSIL FUEL-FIRED POWER PLANTS PROPOSED RULE 1 (2023), https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf.

[19] 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. 39798 (May 9, 2024) (to be codified at 40 C.F.R. pt. 60).

- Units that are intended to operate on or after January 1, 2039 (i.e., "long-term" units) will have a numeric emission rate limit based on the application of carbon capture and sequestration (CCS) with at least 90% capture, which they must meet on January 1, 2032.
- Units that are operating on or after January 1, 2032, and have committed to cease operations by January 1, 2039 (i.e., "medium-term" units) will have a numeric emission rate limit based on 40% natural gas cofiring that they must meet on January 1, 2030.
- Units that demonstrate that they plan to permanently cease operation prior to January 1, 2032, will have no emission reduction obligations under the rule.[20]

Q. How do these GHG rules impact the expected cost of the different pathways?

A. According to the coal retirement schedule in P2 and P3 (Base and Fall Supplemental), Belews Creek, and two of the Roxboro units fall in the Medium-term EGU category. Belews Creek has 50% natural gas co-firing capability and therefore might be able to comply. However, the P3 Fall Supplemental coal retirement schedule also includes the Roxboro units (2 and 3) operating after 2032 (without the installation of CCS). Thus, the P3 Fall Supplemental coal retirement schedule is noncompliant and should not

[20] *See* EPA, FINAL CARBON POLLUTION STANDARDS TO REDUCE GREENHOUSE GAS EMISSIONS FROM POWER PLANTS 7 (2024), https://www.epa.gov/system/files/documents/2024-04/cps-presentation-final-rule-4-24-2024.pdf.

be approved as part of a least-cost, least-risk portfolio. The coal retirement schedules of P2 (Base and Fall Supplemental) and P3 Base are also noncompliant, as they include two of the Roxboro units operating past 2032, without any additional emission reduction measures.

In P1 (Base and Fall Supplemental), Marshall units 3 and 4 would fall in the Medium-term EGUs category and could achieve the emissions rate reduction(s) by co-firing natural gas,[21] while the Belews Creek and Roxboro units would not have emission reductions obligations. Consequently, P1 (Base and Fall Supplemental) does not appear to present a compliance issue with regard to coal units.

The Companies' high load supplemental P3 sensitivities further delay coal retirement, with the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] generating post-2032 without a clear pathway outlining how to meet the emissions rate reduction standard.[22]

Still, although some plants can comply based on their co-firing capability, keeping those units online post 2032 will further increase ratepayers' exposure to potential fuel supply constraints and costs. On the other hand, replacing coal with carbon free resources beforehand in a timely manner will mitigate those costs and risks for North Carolina ratepayers.

[21] 2023 Carolinas Resource Plan, Appendix F, Table F-3 at 10.

[22] Confidential EnCompass Output file 4.3.2.11_P3 F23 Load - High Load - 37Cap - PC, tab Resource Annual

ii. Coal economics are worsening, driving retirements nationwide.

Q. Besides state and federal policy, are there other reasons to retire coal units?

A. The Companies' CPIRP filing makes it clear that coal assets are no longer economically sustainable. Appendix F lists some of the factors contributing to the increased cost and risk of coal generation and widespread retirement of coal plants across the US:

- **Reduced coal production from Lower Central Appalachia:** Coal sourced from Lower Central Appalachia has a lower sulfur dioxide content. With production in that region declining, the Companies will need to acquire higher sulfur dioxide coal, which increases environmental compliance costs.[23]
- **Worsening economies of scale:** Environmental regulations and reduced demand for coal are upending production, resulting in increased costs.[24]
- **Inelasticity of coal:** The coal supply chain does not respond quickly to demand volatility and faces disruption from natural gas.[25]
- **A declining coal workforce:** There are fewer qualified workers capable of operating coal plants and maintaining aging equipment, increasing labor costs.[26]

[23] 2023 Carolinas Resource Plan, Appendix F at 3.

[24] *Id*. at 5.

[25] *Id*. at 5.

[26] *Id*. at 5-6.

- **Rail transportation disruptions:** Railroad companies are switching from coal transportation to more profitable areas, increasing price volatility.[27]

A final factor incentivizing retirement is the increased concern around reliability, which I further discuss in the next section.

Q. Please comment on whether the Companies' concerns regarding the potential for continued and increasing costs associated with operating coal-fired assets is consistent with your experience across the nation.

A. The Companies' analysis is consistent with national trends that indicate an increase in coal generation costs. A recent study concluded that nearly all existing coal plants have multiple lower cost clean energy replacement options.[28] The same study estimated the median cost of coal generation operations to be $36 per MWh. In contrast, the study measured the median cost of *new* renewable resources to be $24 per MWh, after factoring in IRA benefits.

Q. Please explain whether these increased costs associated with coal-fired assets have led to increased and accelerated retirements of these units across the US.

A. The incremental cost of operating coal plants is driving coal retirements across the US. Utilities often cite cost in their decisions to retire coal assets. Between 2016 and 2020, Vistra Energy retired or announced the retirement

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[27] *Id*. at 2-3.

[28] MICHELLE SOLOMON ET AL., COAL COST CROSSOVER 3.0: LOCAL RENEWABLES PLUS STORAGE CREATE NEW OPPORTUNITIES FOR CUSTOMER SAVINGS AND COMMUNITY REINVESTMENT 1-2 (2023), https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.

of 16 GW of coal generation across Texas, Ohio, Massachusetts, and Illinois.[29] At the end of 2017, Vistra Energy announced the retirement of two coal units in Central Texas, stating that the "economic viability of [coal] plants has been in question for some time."[30] Regarding one plant, the company stated that "the standalone economics of the Sandow Complex no longer support continued investment in the site."[31] Furthermore, the "economically challenged" 1,300 MW Zimmer Power Plant in Ohio, for example, was scheduled to retire in 2027.[32] However, once Zimmer failed to clear PJM's capacity market auction in 2021, Vistra decided to shut down the plant in 2022.[33] In 2020, Birchwood Power announced that a 242 MW coal plant in Virginia would be retired before its power purchase agreement expired based on "market trends and facility economics."[34] In 2018, DPL announced that two facilities with coal-fired units in Ohio totaling 2,300 MW

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[29] Scott Carpenter, *Power Company Vistra To Replace Coal Plants With Giant Batteries*, FORBES (Sept. 30, 2020), https://www.forbes.com/sites/scottcarpenter/2020/09/30/power-company-will-shut-all-of-its-illinois-and-ohio-coal-plants-by-2027/?sh=bd62fd7f3cd9.

[30] *Luminant to Close Two Texas Power Plants: Decision a Result of Challenging Plant and Market Economics*, PRNewswire (Oct. 13, 2017), https://www.prnewswire.com/news-releases/luminant-to-close-two-texas-power-plants-300536238.html.

[31] *Id.*

[32] *See Vistra Accelerates Closure of Ohio Coal Plant to Mid-2022, Years Earlier Than Planned*, VISTRA CORP. (July 19, 2021), https://investor.vistracorp.com/2021-07-19-Vistra-Accelerates-Closure-of-Ohio-Coal-Plant-to-Mid-2022,-Years-Earlier-Than-Planned.

[33] *Id.*

[34] Darren Sweeney, *Birchwood Power Partners Announces Retirement of 242-MW Coal Plant in Virginia*, S&P GLOBAL (Feb. 25, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/birchwood-power-partners-announces-retirement-of-242-mw-coal-plant-in-virginia-57276615.

of generation were retired "in response to declining market conditions."[35] PJM is now requesting that retiring coal plants remain online under Reliability-Must-Run contract(s) despite their uneconomic status, resulting in significant additional costs for consumers until transmission projects are brought online.[36] This unfortunate situation in PJM shows that it is imperative for operators and regulators to act quickly, plan for timely retirements, including the necessary transmission upgrades and replacement resources, and avoid unnecessary future costs for ratepayers. In PacifiCorp's 2023 Integrated Resource Plan, its preferred portfolio called for the retirement or gas conversion of 1,153 MW of coal generation by 2025, with 2,999 MW in coal retirements or gas conversions by 2032 "driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives."[37]

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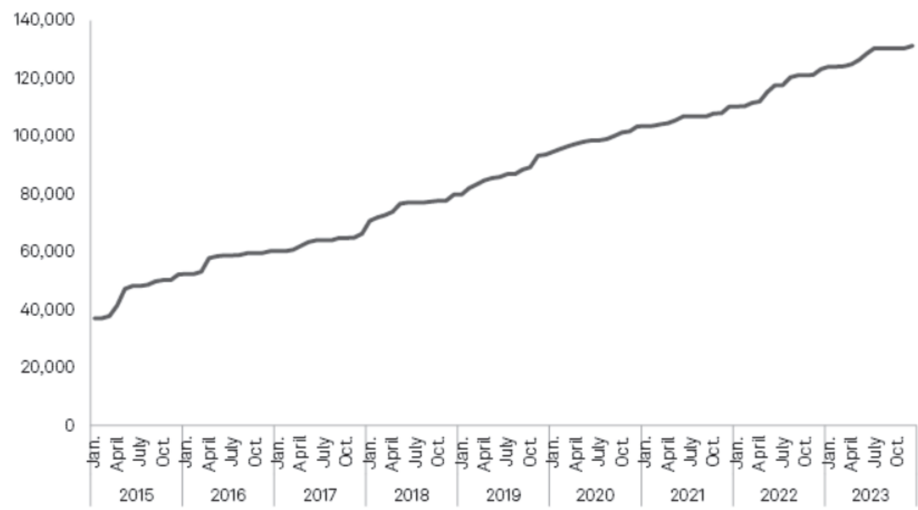
[35] *DPL Inc. Announces the Retirement of the J.M. Stuart and Killen Station Power Plants*, AES OHIO (May 31, 2018), https://www.aes-ohio.com/press-release/dpl-inc-announces-retirement-jm-stuart-and-killen-station-power-plants.

[36] Ethan Howland, *Maryland officials press FERC to reject PJM directive to Exelon for $785M in transmission upgrades*, UTILITY DIVE (Sept. 20, 2023), https://www.utilitydive.com/news/maryland-officials-press-ferc-to-reject-pjm-directive-to-exelon-for 785mi/694203/#:~:text=from%20your%20inbox.,Maryland%20officials%20press%20FERC%20to%20reject%20PJM%20directive%20to%20Exelon,plant%2C%20according%20to%20Maryland%20officials.

[37] PACIFICORP, 2023 INTEGRATED RESOURCE PLAN VOLUME I 19 (2023), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf.

The steady rate of coal generation retirements is depicted in Figure 1: Cumulative Coal Capacity Retirements (MW), below.

Figure 1: Cumulative Coal Capacity Retirements (MW)[38]



iii. Coal is increasingly unreliable.

Q. You also mentioned reliability concerns with respect to the operation of the coal units. Can you provide additional details?

A. Yes. Appendix F outlines the Companies' reliability concerns around both the availability of coal supply, as well as the availability of other material and equipment. With respect to coal supply, the key issues are the same as the ones outlined in the prior section: reduced coal production, declining workforce, and rail transportation disruptions. These risks do not just increase costs; they also pose a reliability threat to the system by making coal resources less dependable. Furthermore, the Companies face

[38] Darren Sweeney et al., *Further rounds of US coal retirements loom over fresh reliability concerns*, S&P CAPITAL IQ (Dec. 19, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/further-rounds-of-us-coal-retirements-loom-over-fresh-reliability-concerns-79795377.

challenges acquiring other material crucial for maintaining coal assets, which could lead to longer plant outages.[39] Specifically, Appendix F notes:

> As the components within these units age and the parts and workforce to reliably operate the coal fleet become increasingly harder to obtain, the Companies are further at risk of requiring significant investment to keep these units reliable for a potentially short life.[40]

As equipment becomes obsolete and critical plant parts are harder to find, there is an increased risk of longer outages, threats to reliability, and increased costs.

Q. Do you have any additional concerns regarding the ability of coal units to provide capacity during times of system need?

A. Yes. It is highly probable that under extreme weather conditions, the aging coal units could experience equipment issues resulting in significant outages that may take weeks or months to repair as critical components become harder to find. Coal capacity shortfalls are partly to blame for recent outages in the Companies' service territory. On December 23, 2022, cold weather caused by Winter Storm Elliott resulted in the Companies implementing rolling outages that ultimately impacted more than 300,000 customers across the Carolinas.[41] A report commissioned by the Office of Regulatory Staff in South Carolina (ORS Report) found that planned outages and plant failures were key contributing factors to the power

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[39] 2023 Carolinas Resource Plan, Appendix F at 2-6.

[40] *Id.* at 16.

[41] Order Making Findings and Directing Actions Related to Impact of Winter Storm Elliott, Docket No. M-100, Sub 163, at 5 (N.C.U.C., Dec. 22, 2023) (NCUC WSE Order).

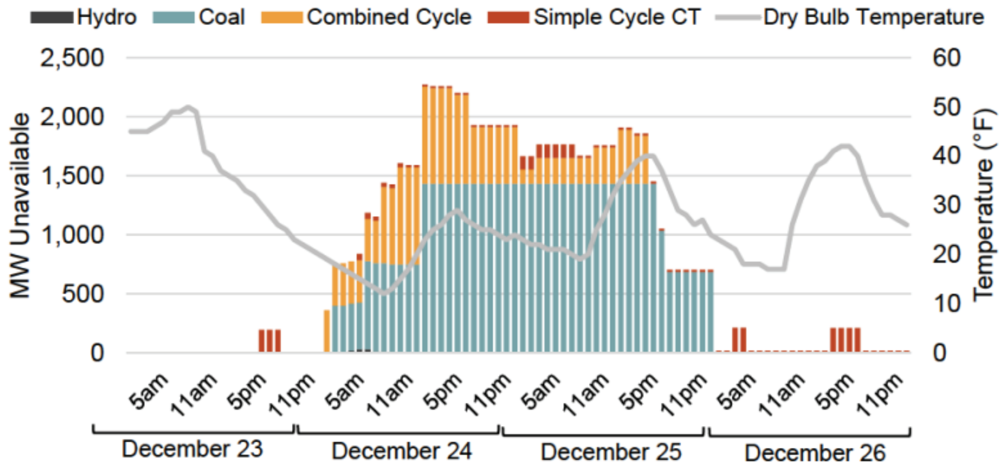
outage.[42] Citing a North American Electric Reliability Corporation (NERC) report, the Commission's Order Making Findings and Directing Actions Related to Impact of Winter Storm Elliot found that "freezing issues were one of the primary causes of unplanned generator outages during Winter Storm Elliott."[43] The order detailed numerous forced coal plant derates due to frozen lines, switches and other equipment failures caused by Winter Storm Elliott, all of which underscore the risks associated with continued reliance on aging, polluting assets.[44] As a result of these factors, coal plant outages accounted for the majority of planned and unplanned outages during Winter Storm Elliott, as depicted in Figure 2: Winter Storm Elliott Unplanned Outages below.

[42] Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC December 2022 Winter Storm Outages and Blackouts, Docket No. ND-2023-1-E, August 25, 2023, Prepared for the South Carolina Office of Regulatory Staff by GDS Associates, *available at* https://dms.psc.sc.gov/Attachments/Matter/ec372380-8639-406e-816e-fc9fe0d45cfd (ORS Report).

[43] NCUC WSE Report at 22.

[44] *Id*. at 22-23.

Figure 2: Winter Storm Elliott Unplanned Outages[45]



Q. Can you provide additional details on which coal units were derated or in outage during Winter Storm Elliott?

A. Yes. Winter Storm Elliott brought severe cold temperatures to the Carolinas on Friday, December 23 through Saturday, December 24, 2022. During the night, the Companies lost a significant part of their generation due to equipment malfunctions. This, in combination with the planned outage of the Robinson unit 2 (a nuclear asset),[46] as well as the reduced availability of market power from PJM,[47] led to System Operations calling on rotating load shed to temporarily disconnect groups of customers on a rotating basis to reduce load on the system. Coal units were the worst performers during this period, with some issues including:

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[45] ORS Report at 24.

[46] *Id.* at 27.

[47] *Id.* at 35-36.

- Marshall unit 1 (380 MW) went into a forced outage in November 2022 due to a boiler circulating pump failure. Vendor material delivery delayed the return to service through December.[48]
- Marshall unit 2 tripped off-line on December 20, 2022, due to boiler tube leaks, forcing an additional 380 MW of capacity off-line until December 26.[49]
- The largest forced derate during Winter Storm Elliott occurred at DEP's Roxboro plant. One of the plant's coal-reclaim conveyor belts failed and restricted operations at units 1 and 2. This condition resulted in an overall loss of 685 MW of generating capacity from December 24 through December 26.[50]
- Cliffside unit 5 also experienced a 100 MW derate.[51]
- Frozen sensing lines and frozen limestone resulted in a 336-350 MW derate of Mayo unit 1 from December 24 through December 25.[52]
- Roxboro units 3 and 4 also experienced derates of approximately 300 MW starting on December 24 until the evening of December 25.[53]

Many of these derates required repairs that were delayed due to out-of-stock parts, long lead times for replacements, or other equipment delivery issues. Even in cases where the outages or derates were not caused

[48] *See id.* at 26, 28.

[49] *Id.*

[50] *See id.* at 26, 33.

[51] *See* ORS Report at 26, 28.

[52] *See id.* at 26, 32.

[53] *See id.* at 26, 28, 29-30.

directly by weather, this experience underscores that coal resources are becoming too unreliable to depend on during periods of critical need.

Q. What were the impacts of the underperformance of the Companies' coal units during Winter Storm Elliott?

A. The underperformance of their fossil fuel units, particularly of the coal units detailed above, essentially forced the Companies to shed load, as they failed to provide continued reliable service and ultimately placed ratepayers at risk during a multi-day extreme weather event.[54] Outside of the load shedding hours, the underperformance of the coal units (among others) also led to increased costs from firm purchases. During hours 15:00 to 18:00, approximately half of DEP's coal capacity was unavailable.[55]

Q. Have the Companies considered the units' underperformance during Winter Storm Elliott in their analysis?

A. According to the Companies' Resource Adequacy study:[56]

> "Finally, the unit outage modeling was updated to be based on Generating Availability Data System (GADS) data from 2018-2022 including the performance of units during Winter Storm Elliot.
>
> Assumptions on capacity risk during winter weather events were also updated using the last five years of history. Both of these put upward pressure on reserve margin, and it is estimated these alone increased the reserve margin by 2.5%."

[54] Other contributing factors include the failure of the automatic load shedding tool, as well as the curtailment of PJM purchases.

[55] *See generally* ORS Report at 25 (detailing all generation plant outages by plant type).

[56] 2023 Resource Adequacy Study for Duke Energy Carolinas & Duke Energy Progress at 9-10.

In other words, 2022, the year of Winter Storm Elliott, was included as part of the historical dataset informing the Resource Adequacy study, contributing to the increase of the required reserve margin.

Q. Notwithstanding the Companies' consideration of Winter Storm Elliott in their resource adequacy study, do you agree that the increase in the reserve margin appropriately captures the reliability risks associated with the continued operation of coal units?

A. No. Increasing the reserve margin for the entire system does not capture this resource specific issue. The reserve margin is one of the most critical inputs in IRP modeling and largely drives investment decisions for new resources, particularly capacity resources. This required reserve margin is met by all resources (existing and new), each of which contributes differently based on the relevant resource type and capacity. Given the concerns analyzed before, the coal units' underperformance would be better captured through a downward adjustment of their firm capacity. However, instead of lowering the firm capacity of the coal resources, the Companies have chosen to increase the reserve margin. This raises two concerns, both of which stem from the fact that a universal increase of the reserve margin does not capture the fact that coal units underperformed relative to other resource types.

First, when the coal units retire, this increase in the reserve margin -- which is meant to capture the fleet's underperformance (much of which can be attributed to coal units) -- is not adjusted again. This static approach can result in an inflated reserve margin for the years that the coal units have retired, and an overbuild of the system. It also means that all pathways, independently of when the coal units retire, are developed to meet the same reserve margin over time. The reserve margin is not adjusted downwards again when the coal units retire, so a portfolio with an earlier retirement schedule still needs to meet an increased reserve margin that is ultimately compensating for the underperformance of retired units. This further increases the potential for overbuilt portfolios and makes them more expensive than they should be.

Second, the Companies' choice to increase the reserve margin as opposed to properly reflecting the firm capacity of coal resources results in an underestimation of the relative capacity contribution of other resource types. For example, when comparing the costs of retiring a 100 MW coal unit and replacing it with another resource of equivalent firm capacity, if the coal unit is erroneously assumed to provide 100MW of firm capacity, while storage is assumed to only provide 80% of its nameplate capacity for the reserve margin, then a storage asset of 125 MW would be needed. Had the firm capacity of coal been modeled appropriately (let us assume 80% or 80 MW of firm capacity as a simple example), then only 100 MW would be needed.

Thus, the Companies' modeling introduces a bias in favor of retaining coal resources in the system.

Q. Please explain how the Companies have modeled the firm capacity contribution of coal-fired assets.

A. Utilities have historically considered coal generation units to be available at their installed (*i.e.*, nameplate) capacity whenever needed. In other cases, utilities would only adjust the capacity contribution of coal units based on their historical outage rates. The Companies' modeling in the current plan assumes firm capacity contribution of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for all coal units, *i.e.*, during system peak, coal units are assumed to be able to provide their [BEGIN CONFIDENTIAL] [redacted].[END CONFIDENTIAL] Table 5 lists both the modeled capacity (*i.e.,* the installed capacity) and the firm capacity (*i.e.*, the amount of capacity each resource is assumed to contribute to the reserve margin) of the coal units in the Companies' EnCompass modeling. It is worth noting that the firm capacity contribution is the determining factor when approximating an asset's contribution to the planning reserve margin within the Companies' capacity expansion model. As shown below, the Companies' assumptions regarding the capacity contributions of coal assets inaccurately suggest that coal-fired resources are remarkably reliable, a mischaracterization that leads the Companies' planning tools to potentially overestimate the value of keeping coal units operating.[57]

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[57] The Companies argue that when determining the solar and battery effective load carrying capability values, they modeled load with a 4% outage rate which represents the high end of new thermal resources (Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study at 9), so that the capacity contributions of all resources are evaluated on a level playing field. As an example for comparison purposes, it is worth noting that according to confidential EnCompass input file "GFF Spring 2023 Updates," the Marshall units have forced outage rates of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Table 5: Assumed Firm Capacity of Coal Units (EnCompass inputs)[58]

	Capacity (MW) (Nov-March, April-Oct)	**Firm Capacity (MW)** (Nov-March, April-Oct)
Allen 1	[BEGIN CONFIDENTIAL] [redacted]	[redacted]
Allen 5	[redacted]	[redacted]
Belews Creek 1	[redacted]	[redacted]
Belews Creek 2	[redacted]	[redacted]
Cliffside 5	[redacted]	[redacted]
Cliffside 6	[redacted]	[redacted]
Marshall 1	[redacted]	[redacted]
Marshall 2	[redacted]	[redacted]
Marshall 3	[redacted]	[redacted]
Marshall 4	[redacted]	[redacted]
Mayo 1	[redacted]	[redacted]
Roxboro 1	[redacted]	[redacted]
Roxboro 2	[redacted]	[redacted]
Roxboro 3	[redacted]	[redacted]
Roxboro 4	[redacted]	[redacted] [END CONFIDENTIAL]

[58] Comparing Capacity and Firm Capacity data in EnCompass output file "P3 F23 Load - Base Load - 35Cap - 1 SC CC - P3 Retire - PC - 1.9.24" tab Resource Monthly.

Q. Please explain your key concerns regarding this apparent disconnect between the assumed and observed capacity contributions of coal-fired assets.

A. Primarily, the overestimation of the capacity contribution of existing thermal resources inflates their perceived value in the model, making their continued operation seem more economic than it really is and providing a false sense of reliability with regards to portfolios that include these assets. The effects of the inflated capacity contributions of the coal units are twofold:

(a) When modeling the endogenous retirement of coal resources, the model requires replacement resources to provide higher capacity contributions than the coal units' real contributions, inflating the resource need and the associated replacement cost relative to the continuous operation of the coal unit. Thus, the Companies' endogenous retirement analysis is biased towards keeping the coal units online longer.

(b) Because the reliability contribution of the thermal resources has been overestimated in the model, replacing them with carbon-free resources that are equivalent on an effective load carrying capability (ELCC) basis would actually result in a more reliable portfolio since the firm capacity of thermal resources is in reality lower than what was modeled and what the replacement resources would provide.

Given these effects, P3 (Base and Fall Supplemental), which keeps coal units operating longer than P1 (Based and Fall Supplemental), has incremental reliability risks compared to the P1 pathway or a portfolio that would replace the aging coal units with clean resources with capacity contributions equivalent to the assumed coal contributions.

Q. Please explain how the modeling of the capacity contribution of coal units should evolve to capture their availability during extreme weather events.

A. Availability considerations due to weather, supply, and intra-resource correlations should be applied to all resource types. Since the Companies use the ELCC methodology for variable renewable energy and energy-limited resources, the same methodology should be applied to thermal resources recognizing that all resources have limitations based on weather-dependence, potential for outages, flexibility constraints, and common points of failure (like fuel supply issues, especially in the case of gas generation). This improved approach is further explained in my discussion regarding modifications of the modeling of gas-fired assets.

iv. Recommendations for Duke's coal retirement schedule

Q. What is your recommendation to the Commission with respect to the Companies' proposed coal retirement schedule?

A. I recommend that the Commission instruct the Companies to keep exploring earlier retirement options, especially for the Cliffside 5, Mayo 1, Marshall 1 and 2, and Roxboro units. These resources have presented reliability issues and are expensive to keep online, as shown by the Companies' own modeling which retires them as soon as it is allowed to do so (even under the no carbon constraint scenario, the model retires Marshall 1 and 2 and Roxboro 1 and 2 in 2029 – as soon as it is allowed to). Retiring them in a staged approach prior to 2029 could result in cost savings and emissions reductions. It would also allow the Companies to pursue clean no-regrets replacement resources in a timely manner, resources that they would eventually need anyway, instead of delaying economic retirement until the first CC and combustion turbine (CT) resources are available for selection in 2029.

Furthermore, I understand that Duke conducted one variant analysis in which the Belews Creek units were converted to burn 100% natural gas in the original August filing. This P1 variant portfolio reduces new CT capacity by 425 MW by 2030, but otherwise results in a similar deployment of supply side resources in the near term. According to the Companies, the P1 variant was estimated to be slightly more expensive from a revenue requirement standpoint than the base P1 mainly due to the significant cost of ensuring firm natural gas transportation.[59] A gas conversion could alleviate some of the concerns of retiring significant coal capacity in a single year (for P1) and also provide an alternative option of maintaining this capacity in the system in a less risky way than investing billions of dollars for the construction of new CC units, which could soon become stranded. I recommend that the Commission instruct the Companies to keep exploring

[59] 2023 Carolinas Resource Plan, Appendix C at 51. In the Companies' confidential response to AGO 3.3, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] An appropriate reduction of the assumed cost of $5 billion discussed in the Direct Testimony of Witnesses Verderame, Donochod, and Hoeflich (at pages 20-21) would almost cancel out the assumed difference in portfolio costs.

this option *as an alternative to new CC units*, which would also be subject to significant costs for firm natural gas transportation.

B. The Companies understate the risks associated with natural gas assets.

Q. What is the capacity of the Companies' natural gas fleet today and the proposed incremental gas capacity in each of the core and supplemental portfolios?

A. The Companies' natural gas assets currently include 55 CTs, nine CC units, and one combined heat and power (CHP) unit, with a total capacity of 11,891 MW.[60] The CC and CT fleet currently accounts for 34% of the Companies' capacity.[61] All of the Companies' portfolios rely on the development of incremental natural gas assets and the uprating of existing natural gas assets. The Companies propose upgrades to seven existing CCs between 2023 and 2028,[62] and to repurpose Marshall coal units 1 and 2 to advanced CTs,[63] and Roxboro coal units 1 and 4 with CC assets by 2029.[64] Finally, the Companies propose to commission and place in service additional new CTs and CCs.[65] Each of the Companies' pathways forecasts

[60] 2023 Carolinas Resource Plan, Chapter 4, at 14.

[61] 2023 Carolinas Resource Plan, Chapter 3, Table 3-3, at 7.

[62] 2023 Carolinas Resource Plan, Appendix K, at 10.

[63] 2023 Carolinas Resource Plan, Chapter 4, at 5.

[64] The Companies' Supplemental Planning Analysis notes on page 5 that "[b]ased on execution considerations, the Companies updated the [retirement dates] for Roxboro, switching Unit 2 with Unit 4," reflecting that Roxboro 1 and 4 will be retire and their transmission capacity will be used as a part of a Generator Replacement Request for Person County CC 1.

[65] 2023 Carolinas Resource Plan, Chapter 4, at 30.

the expansion of gas assets, as denoted in Table 6, with the supplemental modeling resulting in additional CC units in each Pathway.

Table 6: Proposed Natural Gas Additions (GW)[66] [BEGIN CONFIDENTIAL]

			2029	2030	2031	2032	2033	2029-2033
CT	Base Core	P1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.5
		P2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.1
		P3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.1
	Fall Supplemental	P1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.1
		P2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.1
		P3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.1
CC	Base Core	P1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.7
		P2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.1
		P3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.1
	Fall Supplemental	P1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.1
		P2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.8
		P3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.8

[END CONFIDENTIAL]

Q. Please explain your key concerns with the Companies' approach to existing and new natural gas units, including its cost and risk implications for ratepayers.

A. My overall concern is that increasing the system's reliance on fossil fuels will be significantly costlier than the Companies have projected, while also carrying execution, reliability, and policy risks. Specifically:

- CC natural gas units solve a transient need during the Base Planning Period and are likely to become stranded. In the Companies' own modeling, the CC capacity factors fall significantly within the first decade of use as carbon free energy replaces their generation - even without considering state and

[66] Data collected from EnCompass output files for model runs:

GFF Spring 2023 - PC - P1 w Reliability CTs
GFF Spring 2023 - PC - P2
GFF Spring 2023 - PC - P3 w Reliability CTs
P1 F23 Load - Base Load - 1 SC CC - PC w Rel CT
P2 F23 Load - Base Load - 1 SC CC – PC
P3 F23 Load - Base Load - 1 SC CC – PC

federal policy. Their selection in EnCompass stems from an artificial lack of alternatives at a time of high load growth.

- The net cost of new gas resources is understated.
    - Even absent federal regulations, the Companies' analysis does not include the full costs of operating the proposed gas units in the future.
    - With the new final federal regulations, the units will require significant investments, the costs and risks of which are not considered in the CPIRP analysis.
- The reliability benefits of gas resources are overstated in a similar way to those of coal resources. In addition to the factors outlined for coal units, one of the most critical factors in determining the reliability of gas resources is fuel supply.

i. The CC units are selected due to an artificial lack of alternatives in the Companies' modeling but are replaced by carbon free resources as soon as the Companies' limits allow it.

Q. You mentioned that the proposed CC units solve a transient need. Please elaborate.

A. The Companies' load forecast includes unprecedented growth in the coming years. Clean energy resources will eventually serve that load. However, the Companies' analysis includes a limited number of years during which renewable resources are not allowed to scale quickly enough due to the assumed limits., resulting in a buildout of combined cycle generation. The graphs below visualize the issue in a simplified form. They focus on annual generation and do not include details about certain hours during the year during which all the CC units could be operating. Nonetheless, they serve to illustrate that these capital-intensive, long-lived assets are likely to become stranded with ratepayers covering their costs for decades to come while the assets are not being fully used.

The graphs visualize the generation from existing and proposed CCs starting in 2025, up to 2050. Generation after 2050 has not been modeled and is not depicted. The graph also includes horizontal lines showing the potential generation of each CC assuming a capacity factor equal to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[67] The capacity factor assumption was based on the capacity factor of CC1 in 2029 (in P3 Fall Supplemental) simply to visualize how each of the CC units could be adding energy to the system. A higher capacity factor would also be technically possible. The horizontal lines extend to the end of each CC's book life (35 years).[68] There is also a line showing generation from existing CC units. As clearly shown in the graph, the CC generation from either existing or new units is quickly replaced by carbon-free energy resources, once those become available in the model, It is also worth noting that the proposed CCs also displace some of the generation from existing CCs (the operation of which might be slightly costlier, but does not carry the significant incremental risks of investing in new CCs), raising a question around the

[67] Based on confidential EnCompass output file "P3 F23 Load - Base Load - 35Cap - 1 SC CC - P3 Retire - PC - 1.9.24.xlsx."

[68] Appendix C, Quantitative Analysis, Table C-26: CC Modeling Assumptions.

tradeoff between cost and risk between different options that the Companies have as they are deploying the carbon free resources they will eventually need.

Figure 3: Projected CC Generation in P3 Base and Fall Supplemental[69]

[BEGIN CONFIDENTIAL]

P3 Base
CC generation (GWh)

[redacted]

[69] Results from EnCompass output file for model runs:
GFF Spring 2023 - PC - P3 w Reliability CTs
P3 F23 Load - Base Load - 1 SC CC - PC

P3 Fall Supplemental
CC generation (GWh)

[redacted]

[END CONFIDENTIAL]

ii. Federal regulations increase the cost of natural gas assets.

Q. Would the EPA rules proposed in May 2023, and finalized in April 2024 impact the cost of the proposed gas generators?

A. Yes. As mentioned in Section IV(A).i, the EPA's Clean Air Act Section 111 rule sets additional limits on the operations of fossil fuel plants. For new and reconstructed fossil fuel-fired combustion turbines, EPA is proposing to create three subcategories based on the function the combustion turbine serves:

- a low load (peaking units) subcategory that consists of combustion turbines with a capacity factor of less than 20 percent. For this subcategory, EPA is proposing that the BSER is the use of lower emitting fuels (e.g., natural gas and distillate oil) with standards of performance below 160 lb CO_2/MMBtu.[70]

- an intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 and 40 percent. For this subcategory, EPA is proposing an emissions performance standard of 1,170 lb CO_2/MWh, with the BSER being the use of highly efficient simple cycle generation.
- and a base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines. For base load combustion turbines, the BSER includes two components to be initially implemented in two phases. Upon startup, the BSER is highly efficient combined cycle generation; starting on January 1, 2032, the affected facilities must meet a standard based on 90% capture of CO2, using CCS.

Q. When the CPIRP was prepared, the EPA rules were proposed, but not finalized. Did the Companies explore a compliance pathway?

A. Not fully. In their original filing, the Companies acknowledge that they did not have a viable plan as to how they would comply with the (then) proposed rules. They developed two supplemental portfolios based on the proposed version of the section 111 rule using P3 assumptions:[71]

[70] For a CT with a heat rate of 10,000 Btu/kWh, this would be 1,600 lb CO_2/MWh.

[71] 2023 Carolinas Resource Plan, Appendix C, at 100.

- The first portfolio limited the capacity factors of new CCs at or below 50% beginning when they come into service, and existing CCs above 300 MW at or below 50% beginning in 2030. All new CTs were restricted to operate at capacity factors at or below 20%.
- The second scenario assumed new gas units utilized hydrogen co-firing at 30% of total fuel volume by 2032 and 96% of total fuel volume by 2038. CTs were restricted to operate at or below 20% capacity factors.

The Companies did not examine a pathway of compliance based on the use of CCS:

> CCS has not been considered cost-effective due to the lack of suitable geology to sequester significant volumes of carbon in the Carolinas, and significant costs and challenges to develop interstate pipelines, including challenges related to permitting, property rights, and public acceptance, which would need to be overcome, to transport the captured CO2 to other regions suitable for sequestration.

The first EPA supplemental portfolio resulted in resource additions that exceeded the Companies' availability assumptions and increased present value revenue requirement (PVRR) by $3.6 billion.

The second EPA supplemental portfolio increased the expected PVRR by approximately $10.5 billion relative to the original P3 Base portfolio, while the Companies note that "volumes necessary to utilize the hydrogen compliance pathway are not thought to be achievable on the timelines presented in the EPA CAA Section 111 Proposed Rule."

Q. Have the Companies appropriately factored compliance risks?

A. No. As clearly shown, the Companies' pathways do not adequately factor in compliance costs. By investing in new gas plants, the Companies lock customers into a risky pathway with no clear avenue to comply with the then proposed and now final regulation. The lack of a viable compliance option reveals how risky the presented Pathways are. Investing in such high volumes of new gas generation cannot be considered a least-cost, least-risk portfolio, especially when compared to a more balanced approach with additional no-regrets investments in renewable energy, energy storage, demand response, and energy efficiency, technologies that are not subject to policy risks, and have exhibited reliable and consistent cost declines.

Q. What are the implications of the final EPA rules for P3 or P3 Fall?

A. The cost of the P3 portfolios, and all CPIRP portfolios will be significantly higher than currently forecasted, as they all heavily rely on new gas CC generation. The new CC generation, as modeled in the Base and Fall Supplemental portfolios, would fall in the baseload category.

The Companies could explore different options to enable the P3 portfolios to comply, all of which present challenges. First, emissions could be reduced by installing CCS. This option seems to have been rejected by the Company based on cost and implementation concerns. Another option could be to convert the units to burn hydrogen by 2032 at a percentage that would achieve the emissions reduction standard. As previously mentioned, the Companies have also expressed concerns about their ability to achieve this noting that "volumes necessary to utilize the hydrogen compliance pathway are not thought to be achievable on the timelines presented in the EPA CAA Section 111 Proposed Rule." The final rules further accelerate this timeline: the proposed rules included CCS and hydrogen co-firing compliance pathways: 90% CCS by 2035, or hydrogen blending of 30% in 2032 and 96% in 2038. The final rules set a standard based on application of CCS with 90% capture *by 2032*. According to EPA, the same standard could be met by co-firing 96% (by volume) low-GHG hydrogen,[72] i.e. the modeled requirement of 30% co-firing by 2032 even in the Companies' supplemental portfolio would not meet the standard.

Even if technically feasible, the supplemental EPA portfolio, which included lower standards, was estimated to be $11.4 billion more expensive than P3,[73] while the delta for P3 Fall Supplemental would be even higher, given the additional CC capacity included.

Finally, the Companies might be able to comply by reducing the capacity factor of the units, which would, however, significantly reduce the value they can deliver to the system. Limiting the capacity factor of those resources would significantly reduce the units' energy value and make them a much higher cost resource on a $/MWh basis. The graph below shows the projected generation from proposed CC units in P3 Fall Supplemental,

[72] 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. 39798, 39916 (May 9, 2024) (to be codified at 40 C.F.R. pt. 60).

[73] 2023 Carolinas Resource Plan, Chapter 3, at 22.

and the maximum energy they could deliver if those were to operate under a 40% capacity factor limit – making them a very expensive resource.

Figure 4: Projected Generation from Proposed CC units in P3 Fall Supplemental & Comparison with a 40% capacity factor limit

[BEGIN CONFIDENTIAL]

Generation from new CC units (GWh)

[redacted]

[END CONFIDENTIAL]

iii. The Companies' analysis fails to capture costs associated with the continued operation of the proposed gas resources.

Q. A primary concern is that the Companies' analysis has not considered all costs associated with operating gas resources. Please provide additional information.

A. The Companies intend to upgrade existing natural gas CTs and CCs to enable hydrogen combustion, while they move forward with installing new hydrogen-capable dispatchable gas assets. Their assumptions include hydrogen blend percentages of:

(i) 1% by volume / 0.333% by heat content, beginning 2035;

(ii) 2% by volume / 0.666% by heat content; beginning 2038; and

(iii) 3% by volume / 1% by heat content; beginning 2041.

Beginning in 2040, hydrogen peaking CTs are eligible for selection in the capacity expansion model and are assumed to operate exclusively on hydrogen. New gas units existing or added prior to 2040 will also incur conversion costs. If the conversion coincides with regularly scheduled combustor replacement work, the Companies estimate costs to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for CTs and CCs respectively.[74] To put this in perspective, these estimates are approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the units' assumed capital cost.[75] This estimate is highly speculative with a lack of real-world examples to draw from, while it might also be missing several cost components. Converting the units to operate 100% on hydrogen would require significant upgrades beyond what would be needed to achieve a 30% blend, upgrades that the Companies do not detail since the technology is not yet available: Table K-1 explicitly states that "combustion system for 100% Hydrogen" is not included in the base scope and will be considered in the future as it is not yet available from vendors. Similarly, the item "Inlet fuel piping designed for Hydrogen capability (pipe size, stainless steel materials, valves, connections, etc.)"

[74] Companies' confidential response to Public Staff Data Request No. 6-2(b).

[75] Calculated using the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] cost for CC resources and the cost input of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] (New J CC CapEx) in confidential EnCompass input file "CPIRP 2023 - Supplemental Filing Base Updates."

includes up to 30% hydrogen capability in the base scope, while 100% capability would require significant upgrades. Furthermore, the Companies' state that the initial blend assumption (~0.33% by heat content, ~1% by volume in 2035) is expected to require minimal-to-no physical enhancements to existing natural gas lines to accept hydrogen, however amongst other items, natural gas pipeline tariffs will likely need to be updated to accept increased volumes of hydrogen.[76] Above the initial blend assumption (1-3% by volume), it is currently unknown at what blend-level incremental costs for enhancements will be incurred. It is expected that line enhancements and/or new pipeline infrastructure will be required to handle increased hydrogen volumes. Given these statements, it is reasonable to assume that the Companies' conversion estimates miss critical cost components for blends above 1% by volume.

In sum, in addition to the uncertainty surrounding the costs associated with the conversion and hydrogen operation of those units, it is also unclear what has been included in the analysis. This will have a higher impact on portfolios that heavily rely on new gas resources. For example, P3 will be more heavily impacted than P1 (both Base and Fall Supplemental), which means that the delta between the costs of the portfolios is incorrect. A portfolio with no new gas would be insulated from this incremental cost.

[76] Appendix C at 46.

Q. Are there any other risks associated with hydrogen blending?

A. The development of hydrogen infrastructure and supply presents another significant risk for the Companies. The existing gas network is unsuitable for hydrogen since it is more permeable than methane and poses a greater safety risk.[77] The Companies acknowledge these risks, stating, "There are risks that high blends could lead to pipe material embrittlement, which is a limitation to injecting hydrogen into existing natural gas piping."[78] Natural gas local distribution companies have estimated that enabling hydrogen blending would require significant capital costs, including the replacement of leak-prone pipes.[79] [BEGIN CONFIDENTIAL] [redacted].[80] [END CONFIDENTIAL]

Furthermore, for hydrogen to really be low-GHG fuel, it needs to be produced by electrolysis that is powered by carbon free energy. To date, the production of hydrogen via electrolysis remains limited and expensive compared to other production technologies.[81] Given the low round-trip

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[77] Cailin Wang et al., *Study on Hydrogen Embrittlement Susceptibility of X80 Steel Through In-Situ Gaseous Hydrogen Permeation and Slow Strain Rate Tensile Tests*, 48 Int'l J. of Hydrogen Energy 243-56 (Jan. 1, 2023), https://www.sciencedirect.com/science/article/pii/S0360319922044664.

[78] 2023 Carolinas Resource Plan, Appendix K, at 8.

[79] Con Edison, Gas System Long-Term Plan, NY PSC 23-G-0147 (May 31, 2023), https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-G-0147, at 69.

[80] Companies' confidential response to Public Staff Data Request No. 6-2(f).

[81] Docket ID No. EPA-HQ-OAR-2023-0072, US EPA, Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document, at 33

efficiency of converting electric power to hydrogen and back to electric power,[82] the renewable energy needed to produce the amount of hydrogen for CC generation of the proposed magnitude would be very high. As a point of comparison, in 2031-2034 the annual solar generation in Duke's P3 Fall supplemental is at a similar level with the electricity generated from the new CCs. Under an assumption of a 50% round-trip efficiency and a 96% hydrogen blending by volume, the carbon free energy required to produce the low-GHG hydrogen for the CCs would be equivalent to a system that is two thirds of the Companies' solar capacity. This clean electricity would be used solely to produce hydrogen through electrolysis, which would then be transported and stored to be used as a fuel to generate electricity, incurring costs and losses at every step of this process.

iv. The reliability contribution of natural gas assets is overstated.

Q. Please explain what factors might contribute to the reduced reliability contribution of a natural gas asset.

A. A number of factors can lead to a gas unit being partially or fully unavailable to generate at a time of peak system demand. Some of those factors include:

- weather related issues;
- fuel supply issues; and

[82] Tom DiChristopher, *Hydrogen technology faces efficiency disadvantage in power storage race*, S&P GLOBAL, (June 24, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/hydrogen-technology-faces-efficiency-disadvantage-in-power-storage-race-65162028.

- non-weather related equipment issues.

Q. How have each of these factors jeopardized reliability in the Companies' service territory in the past, given the Companies' reliance on gas?

A. Yes. During Winter Storm Elliott, several gas units experienced outages due to both weather and non-weather equipment issues, as well as due to fuel supply issues.

The cold weather caused forced outages or derates of a number of natural gas plants including a loss of 359 MW from the Dan River unit 9 CC, and a 273 MW derate of the Smith unit 8 CC plant.[83] DEC's Dan River unit 9 tripped off-line just before midnight on December 23 due to frozen instrumentation, resulting in a loss of 360 MW of generating capacity. Dan River unit 9 was not returned to service until after midnight on December 25. DEP's Smith Unit 8 experienced issues with frozen instrumentation lines that resulted in an overall plant derate of 273 MW at 8:40 AM on December 24. A small portion of the tubing that leads to the pressure transmitters was found to be uninsulated, which allowed it to freeze.

Furthermore, the ORS Report identified several derates resulting from fuel supply constraints, noting that:

> Three (3) of Duke Energy's generation plants were forced off-line or forced to derate on December 24 and 25 due to insufficient natural gas pressure delivered from the Williams Transcontinental interstate pipeline ("Transco"), Piedmont Natural Gas Pipeline ("PNG"), and Fort Hill Natural Gas Authority ("Fort Hill"). The DEC Clemson CHP facility tripped off-line at 8:00 AM on December 24 due to low natural gas pressure from Fort Hill and was off-line until 2:15 PM. The DEC Buck

[83] NCUC WSE Order at 22, 23; ORS Report at 31.

> NGCC Station ("Buck") did not receive enough natural gas pressure to operate at full load and was derated by 120 to 178 MW starting at 9:45 AM on December 24. Duke Energy stated the Buck derate did not contribute to the Load Shed Event on December 24 because it occurred after the peak demand period.
>
> On December 25, the DEC Dan River NGCC Station ("Dan River") was also forced to derate by 100 to 338 MW throughout the day due to low natural gas pressure. According to Duke Energy, the Dan River derate did not contribute to the Load Shed Event because it occurred the day after on December 25.

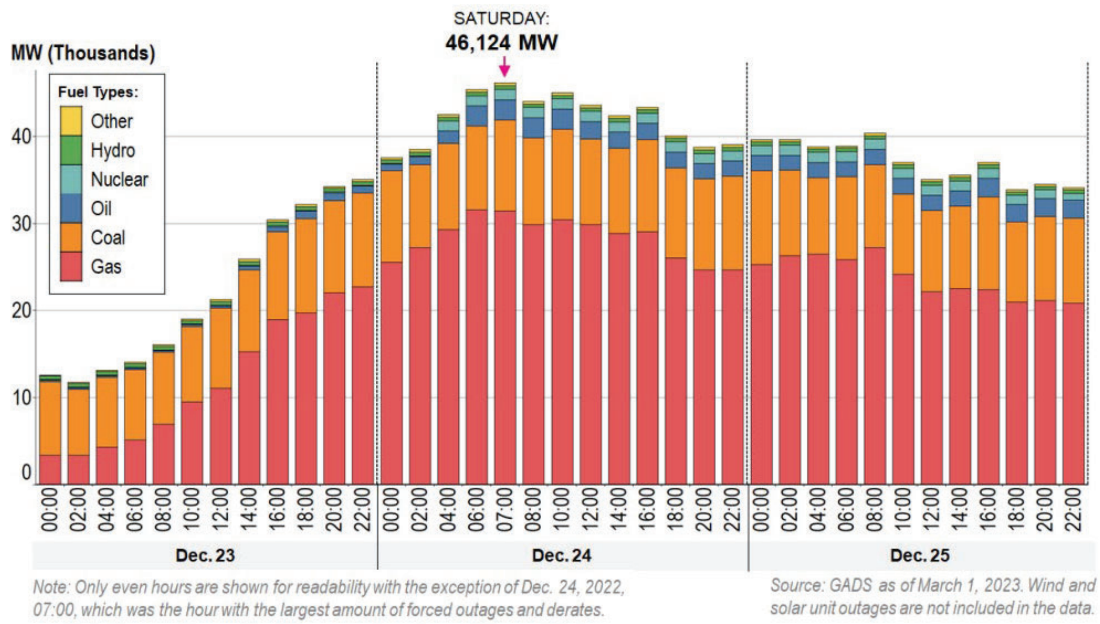
Moreover, some of the Companies' CTs experienced start-up or other failures and were unavailable during the critical peak period of December 24. Start-up failures of DEP's Blewett simple cycle natural gas CT units 1, 2, and 4 kept 51 MW off-line during the critical peak period of December 24. DEC's 95 MW Mill Creek CT unit 7 tripped while using fuel oil in the early hours of December 25 and was brought back on-line by switching to natural gas later that morning.

Q. Looking at the PJM footprint, how did natural gas units perform during Winter Storm Elliott?

A. Based on a report recently released by PJM, out of the 6,596 GWh gas generation that could have been generated during the three-day event, 1,519 GWh or 23% of the total was unavailable, with the majority of gas outages being attributed to gas supply issues.[84]

[84] PJM, *Winter Storm Elliott, Event Analysis and Recommendation Report* (Jul. 17, 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

Figure 5: Dec. 23 and Dec. 24 Forced Outages by fuel type (PJM Winter Storm Elliott Event Analysis and Recommendation Report)



Q. Please explain how the Companies have modeled the capacity contributions of gas assets.

A. The Companies' assumptions suggest that natural gas CT and CC assets are among the most reliable resources to meet demand growth. Table 7 lists the capacity of the proposed natural gas units (P3 Fall Supplemental, 2033), as well as their assumed firm capacity in the Companies' EnCompass modeling.

Table 7: Assumed Firm Capacity of new gas capacity (P3 Fall, 2033)

	Capacity (MW) (Nov-March, April-Oct)	**Firm Capacity (MW)** (Nov-March, April-Oct)
DEC CCG2 2X1 GC, DEC CCG2 DF GC	[BEGIN CONFIDENTIAL] [redacted]	[redacted]
DEC CCG2 2X1 SC, DEC CCG2 DF SC	[redacted]	[redacted]
DEP CCG2 2X1 DS, DEP CCG2 DF DS	[redacted]	[redacted]
DEC CTJ MB	[redacted]	[redacted] [END CONFIDENTIAL]

Q. Have the Companies incorporated the impact of forced outages in the capacity accreditation of new gas resources?

A. Not directly. As explained in my response above, the firm capacity modeled in EnCompass is [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] However, the Companies claim to have done this by adjusting the firm capacity contribution of renewable resources:[85]

> In determining the effective load carrying capability (ELCC, or firm capacity contribution) of renewable resources, Astrapé recognized that new gas resources do not provide 100% ELCC due to forced outages. To adjust for this, renewables were not compared against a perfect load but rather a load that reflected a 4% derate. The 4% outage rate represents the high end of new thermal resources such as new combined cycle or combustion turbine resources. Thus, renewables ELCC values were calculated relative to the performance of a new gas resource which allows renewables and new gas resources to be evaluated on a level playing field in EnCompass.

Q. Does the ELCC adjustment of renewable resources address your concern around the overestimation of the capacity contribution of thermal resources?

A. No. First, it is not entirely clear to me why the Companies chose to adjust the ELCC of renewable resources instead of properly reducing the capacity credit of new gas resources by their forced outage rate. However, most importantly, adjusting only for the forced outage rate is not sufficient. Several other factors, including correlated outages—such as extreme weather and fuel supply disruptions, have an impact on a resource's ability to provide energy and capacity at times of need.

Q. What is the impact of overestimating the capacity contribution of thermal resources?

[85] Companies' response to SACE et al. Data Request No. 8-2-2.

A. In this case, overestimating the capacity contribution of a new gas resource can make it seem more economic than other resource options. A recent report by Astrapé Consulting provides an example of how the economic ranking of resources can change depending on whether the capacity contribution of thermal resources properly estimates the potential impacts of weather and fuel availability.[86] In the 2022 report, Astrapé used the same Strategic Energy & Risk Valuation Model (SERVM) relied on by Duke in its reliability, reserve margin, and ELCC modeling and studies, and showed that thermal generation capacity contributions are generally inflated by values ranging up to 20% due to the lack of consideration of common mode,[87] weather dependent, and fuel supply outages. This is particularly relevant considering the drivers behind high demand and outages are usually correlated to extreme weather events such as Winter Storm Elliott. This means that methodologies that estimate the reliability contributions of gas resources without considering such correlations routinely overstate the reliability contribution of these resources.

Using a test system, Astrapé found that fuel supply outages alone could have as much as a 6.2% impact on the accreditation of conventional resources during winter. The effects of fuel supply risks, along with weather-dependent outages account for an additional 5.6% and 10% accreditation

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[86] Joel Dison, et al., *Accrediting Resource Adequacy Value to Thermal Generation*, Astrapé Consulting (Mar. 30, 2022), https://www.astrape.com/wp-content/uploads/2022/10/Accrediting-Resource-Adequacy-Value-to-Thermal-Generation-1.pdf (2022 Astrapé Report).

[87] A "common mode outage" refers to simultaneous outages of multiple components due to a common cause.

impact in summer and winter respectively. The electric power sector is intricately intertwined with the natural gas delivery network, which provides fuel often with minimal storage at or near power plants. Consequently, interrelated outages stemming from fuel supply breakdowns have evolved into a prominent reliability concern, particularly in winter months when numerous power facilities can concurrently encounter disruptions in their fuel supplies. The events that transpired in Texas in February 2021 (Winter Storm Uri) and in the Eastern Interconnection in December 2022 (Winter Storm Elliott) serve as recent illustrations, underscoring the dilemma operating gas resources given their susceptibility to simultaneous supply interruptions.

The two tables below, taken from the aforementioned Astrapé report, illustrate the potential impacts of not fully considering the risks related to fuel supply, weather-dependent, and correlated outages when comparing gas-fired capacity to battery energy storage systems (BESS). Table 8 below shows an example bid evaluation of four resources: a battery and three other hypothetical thermal assets that are all subject to different type of outages. While all three of the thermal resources (units 2-4) are subject to equivalent forced outage rate (EFOR) outages, unit 3 is also susceptible to weather dependent outages (WDO), and unit 4 is additionally vulnerable to fuel unavailability impacts. In Table 8, the reliability contribution of the battery is evaluated using an ELCC methodology not dissimilar from that used by the Companies, while thermal resources are evaluated using an unforced capacity (UCAP) methodology. The UCAP method only discounts the capacity contribution of thermal assets based on their forced outage rate, which accounts for 5% in this example. As Table 8 shows, when counting the capacity contributions of all thermal assets using a UCAP methodology, the evaluation is unable to find clear distinctions between Units 2-4 and ranks them as equally economic and reliable despite their different risks. In addition, the UCAP methodology results in the battery system being ranked last in terms of price evaluation given the fact that the ELCC method does include evaluation of the risks omitted by the UCAP methodology.

Table 8: Example Bid Evaluation Using UCAP[88]

Resource	Type	ICAP MW	Bid Price ($)	EFOR (%)	ELCC/ UCAP %	Eq MW	Eval Price ($)
Unit 1	BESS	100	100.0		85%	85	117.6
Unit 2	EFOR Only	100	100.0	5%	95%	95	105.3
Unit 3	EFOR + WDO	100	100.0	5%	95%	95	105.3
Unit 4	EFOR + WDO + Fuel	100	100.0	5%	95%	95	105.3

In contrast, Table 9, below, incorporates all the applicable adjustment factors to units 2 through 4, specifically for the winter season. In this new example, which properly assesses the risks inherent to units 2 through 4, the price evaluation now clearly shows differentiation between the thermal units. Moreover, Table 9 also shows that, when considering all applicable adjustment factors, BESS is more economic than the thermal asset.

Although not specific to Duke's system, these two tables demonstrate how the overestimation of the capacity contribution of thermal resources such as gas CTs and CCs has the potential to inflate the reliability of portfolios dependent on gas and artificially limit the amount of otherwise economic capacity from other sources.

Table 9: Example Bid Evaluation Using ELCC[88]

	Type	ICAP MW	Bid Price ($)	EFOR (%)	Adjust (%)	ELCC (%)	Equiv MW	Eval Price ($)
Unit 1	BESS	100	100.0			85.0%	85	117.6
Unit 2	EFOR Only	100	100.0	5%	1.4%	93.6%	93.6	106.8
Unit 3	EFOR + WDO	100	100.0	5%	8.90%	86.1%	86.1	116.1
Unit 4	EFOR + WDO + Fuel	100	100.0	5%	15.80%	79.2%	79.2	126.3

Q. Please summarize your key concerns regarding overestimating the capacity contributions of natural gas assets in the IRP.

A. As previously described regarding coal assets, overstating the capacity or reliability contributions of natural gas assets in assumptions and modeling can cause long-term planning models to select an insufficient portfolio that provides a false sense of reliability and increases costs to ratepayers without bolstering the security of their service. The natural gas plant outages during Winter Storm Elliott demonstrate that gas assets are not perfectly dependable and that reliance on them in fact entails significant risks. This is critically important considering that the Companies' estimation of gas CC and CT firm capacity is equal to their installed capacity and does not reflect all their relevant risks. In contrast, the Companies evaluate zero-carbon dispatchable alternatives such as batteries using an ELCC methodology that *does* account for said risks, which places alternatives to gas-fired assets on an uneven playing field. When relying upon a model with such

[88] 2022 Astrapé Report.

analytical inconsistencies for decision making, there is the potential to divert investment towards natural gas assets that may not deliver the expected reliability benefits, leading to a misallocation of resources.

Q. Please explain how the Companies could modify their assumptions regarding the reliability contributions of natural gas assets to ensure that future plans are aligned with the goals of cost-minimization and reliability.

A. The Energy Systems Integration Group (ESIG) Redefining Resource Adequacy Task Force, a task force consisting of resource adequacy experts from across the country, developed a report to provide an overview of capacity accreditation.[89] The two key considerations from this work are the importance of (1) ensuring that capacity accreditation methods are applied to all resources, not just wind, solar, and battery storage, in a consistent, nondiscriminatory manner, and (2) ensuring there is a linkage between resource accreditation and real-world operations. Across the United States, utilities have transitioned to evaluating thermal resource capacity contributions using an ELCC methodology. For example, the California Public Utilities Commission has adopted a planning approach that evaluates all existing and candidate resources using an ELCC method as part of its IRP proceedings.[90]

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[89] Energy Systems Integration Group, *Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. A Report of the Redefining Resource Adequacy Task Force* (Feb. 2023), https://www.esig.energy/new-design-principles-for-capacity-accreditation.

[90] California Public Utilities Commission, Modeling Advisory Group Webinar on Reliability Filing Requirements for Load Serving Entities' 2022 Integrated Resource Plans - Results of PRM and ELCC Studies, updated presentation slides (Jul. 29, 2022) https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-

For future CPIRP analyses, the Commission should direct the Companies to modify their methodology to assess the firm capacity of thermal resources in the same way all other supply side alternatives are evaluated.

Q. Do you have any concerns with the Companies' SERVM reliability testing of their portfolios, particularly their exogenous selection of CTs if reliability targets are not met?

A. Yes. In addition to inflating the capacity contribution of thermal assets and underestimating certain cost components, the Companies' analysis seems to further favor new gas capacity. Specifically, their reliability verification step utilized SERVM to evaluate the Loss of Load Expectation (LOLE) of each portfolio for the years 2033 and 2038. If the LOLE target was not met, then the Companies included incremental gas resources. Of the original core portfolios, both P1 and P3 include these "forced-in" gas resources, while only P1 Fall of the supplemental analysis seems to include forced-in gas resources. Specifically, for P1 Base, the Companies accelerated approximately [BEGIN CONFIDENTIAL] [redacted].[91] [END CONFIDENTIAL]

Q. Please elaborate on your concerns with this approach.

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procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/20220729-updated-fr-and-reliability-mag-slides.pdf.

[91] Comparing EnCompass files for model runs: "P1 F23 Load - Base Load - 1 SC CC – PC" and "P1 F23 Load - Base Load - 1 SC CC - PC w Rel CT."

A. The reliability step can ensure that the presented portfolios are reliable, and using SERVM is reasonable given the Companies' use of the tool in the reserve margin and ELCC studies. However, I disagree with the Companies' choice to only include incremental gas resources to address any reliability issues observed in these runs. There is no indication that the Companies considered battery energy storage or anything other than CTs in the evaluation for ensuring portfolios meet the reliability benchmark.[92] Incremental CT resources would only result in higher portfolio costs. On the other hand, including storage assets could result in significantly lower cost increases, given the additional grid benefits that they can deliver. By forcing in CTs without an economic assessment beforehand, the Companies bias their portfolios towards incremental gas resources and can distort the cost differential between pathways.

Q. What is your recommendation with respect to the reliability step?

A. In line with other recommendations in my testimony, I recommend that the Companies' reliability step be modified to consider all available resource types, including energy storage and renewable resources, when determining how to address any reliability gaps.

v. The proposed CC buildout should not be considered part of a least-cost, least-risk portfolio.

Q. What is your conclusion for the proposed gas units?

[92] Appendix C, at 72-76.

A. The Companies' proposal to include new natural gas units at this magnitude, despite the recognized policy and cost risks, is not prudent. As explained throughout my testimony, both the capacity and energy value of the CC resources have been overestimated in the CPIRP analysis, while their cost has been underestimated. Under the proposed CC buildout, ratepayers will not only have to pay for expensive resources in the near term but will also be locked in to cover the cost of those assets even if they become stranded, a highly likely scenario.

I recommend that the Commission hold in abeyance any decision on Duke's proposed gas buildout, or at a minimum on the Companies' CC buildout, due to the already existing cost, reliability, gas supply, and technical challenges that such a buildout would face. The final EPA section 111 rule, which Duke's analysis and portfolios fail to account for, is an especially important reason for the Commission to halt the Companies' plans to build new gas CC resources.

V. THE COMPANIES' MODELING LIMITS THE ROLE OF RENEWABLE ENERGY RESOURCES

Q. You mentioned previously that the Companies' analyses limit the role of renewable energy resources and energy storage. Could you detail how the analyses, and how their assumptions limit the role of said assets?

A. The Companies' analyses limit the pivotal role that clean energy resources can play.

- One critical aspect involves the imposition of build limits on renewable resources. The model consistently selects solar and wind resources and is only constrained by the Company-assumed interconnection limits. Although interconnecting large amounts of renewable resources can be a challenge, the Companies have not presented a plan of how to address this and build these resources as an alternative to natural gas. SACE, *et al.* witness Goggin testifies that "these limits do not reflect reality, and there are many potential solutions to the interconnection challenges Duke claims in its attempt to justify these limits".

- The Companies have assumed a cost adder for P1 (Base and Fall Supplemental), that are not sufficiently justified, and further complicate the comparison of an already limited set of portfolios presented before the Commission. This cost adder introduces a bias against P1, a portfolio that includes higher levels of renewable resources, painting a less favorable picture for technologies that would otherwise provide significant value as they do not carry additional policy risks, are more economic, and mitigate ratepayers' exposure to fuel price volatility, all while reducing emissions and facilitating compliance with the EPA section 111 rules.
- Finally, the Companies' analysis fails to consider the full range of available resource options, and overly focuses on certain

technologies, reducing the plan's flexibility to adjust to changing market, technology, and policy conditions.

A. Renewable resources are more cost effective than gas resources, are consistently selected in the Companies' modeling, and are only limited by Company-assumed limits.

Q. What is the Companies' current and planned solar capacity?

A. The Companies' system had 4,650 MW of utility-scale solar at the end of 2022.[93] In addition to those deployed assets, the Companies recently procured 965 MW of solar capacity during 2022 through a mix of power purchasing agreements (PPAs) with third parties and utility-owned solar. Furthermore, they are planning the upcoming 2024 solar Request for Proposals (RFP) process as well as additional solar and solar plus storage (SPS) procurements in 2025-2026.[94]

Q. Have the Companies assumed limits on the development of incremental solar capacity starting in 2028?

A. Yes. The Companies have interconnection assumptions designed to establish solar limits reflecting the amount of solar that can be reliably interconnected year-over-year. These assumptions (and the associated solar limits) bar incremental solar additions, even if those additions could be economic.

According to the Companies, the limits are mainly informed by the current 14 red-zone expansion projects (part of the plan called RZEP 1.0),

[93] 2023 Carolinas Resource Plan, Appendix I, at 4.

[94] Direct Testimony of Maura Farver, Justin LaRoche, and Laurel Meeks, at 12-17.

which are planned to be in service by mid-2027 and will enable more solar to be interconnected on an annual basis by 2028.[95] The Companies also note that a second phase of red-zone expansion plan projects, RZEP 2.0, will further increase the amount of solar that can interconnect on an annual basis starting 2031.[96] The solar interconnection limits used by the Companies across the core pathways assume completion of RZEP 1.0 and 2.0, but the Companies have also considered a future in which RZEP 2.0 is not completed through the Portfolio Variant P2 Low Solar Availability scenario.[97]

Q. Do you have any concerns about the level of interconnection limits assumed?

A. Yes. First, I recognize that Duke will have to address some execution issues as they will be interconnecting significant amounts of solar in years 2028-2030 and that including these considerations through some kind of model constraint is not unreasonable. However, it is important to carefully review those limits, especially when they are binding, like in the near-term for this CPIRP and when the model selects the maximum amount available per year. Binding annual limits mean that in the near-term, solar selected by the model is fully dictated by these Duke-assumed limits. Consequently, the limits also impact the deployment of other resources as the model runs out of solar to select. After reviewing the assumed levels, SACE, *et al.* witness

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95 Companies' response to NC AGO Data Request No. 2-1, at 1.

96 *Id.*

97 *Id.* at 2.

Goggin outlines several of his concerns with the interconnection limits, as well as recommendations as to how the Companies could pursue additional solar.

Q. Have the Companies assumed limits on the development of incremental onshore wind resources?

A. Yes. According to the Companies' response to AGO Data Request 2.5, the Companies believe 2031 is a reasonable assumption for the first year of availability of onshore wind and this is their base modeling assumption in the August filing and the P3 Fall Supplemental portfolios. This is a year later than the assumed availability in the 2022 Carbon Plan. The same response states that one of the factors that shifted the first year of availability was that development for onshore wind was not approved in the 2022 Carolinas Carbon Plan. I recommend that the Commission direct the Companies to expedite activities associated with the development of onshore wind projects and to continue to evaluate whether incremental wind resources could be procured prior to 2030.

Q. You mentioned earlier that the model consistently selects renewable energy resources, which proves that they are cost effective. Please elaborate.

A. The assumed interconnection levels and resulting model limits are binding in the near- and intermediate-term for all three Base Portfolios (August 2023) and for P1 and P2 Fall Supplemental. This means that the model selects the maximum amount of solar allowed, and that absent these interconnection limits, the model would select more solar and achieve an even lower cost portfolio.

Tables 10 and 11 shows the levels of solar, onshore wind, and CC resources that are allowed to be selected under each pathway, as well as the levels that are actually selected (cumulative limits also exist but are not included for simplicity).[98] Both solar and wind are always selected as cost effective up to the maximum allowed amount under all three Base portfolios. In contrast, in P1 Base, the model does not select another CC unit in 2030, although available, but it exhausts the available renewable resources.

It is worth noting that in the Companies' supplemental analysis, when renewable resources become available earlier (P1 and P2 Fall Supplemental), the model selects incremental amounts. For example, in P1 Fall Supplemental, the model selects [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of wind in 2030 and again exhausts all solar available.

[98] The model can also select other resources including offshore wind and capacity resources like CT and batteries.

Table 10: Annual Build Limits for Solar, Onshore Wind, and CC resources (MW) under the core pathways in the Companies' August filing

[BEGIN CONFIDENTIAL] [redacted]

Table 11: Annual Build Limits for Solar, Onshore Wind, and CC resources (MW) under the Fall supplemental pathways in the Companies' January filing

[redacted]

[END CONFIDENTIAL]

Q. Please detail how the Companies' assumptions regarding the availability of solar and wind capacity affect ratepayers.

A. The Companies' assumptions regarding the availability of renewable resources are most restrictive in the early years of their analysis, *i.e.,* through 2032. As a result, they are important for determining the Companies' near-term action plan. Based on the Companies' own analysis, renewable resources are cost effective, and a lower cost portfolio could be developed if the Companies were able to address some of the interconnection and execution concerns and relax the assumed limits. Instead, given its inability to select more solar, the model includes new CC resources. It is also worth mentioning that the model's preference for renewable resources does not even consider federal policy and other risks: solely from an economic standpoint, renewable resources are preferred.

B. The Companies' modeling includes cost adders that are unreasonable and introduce bias against specific resource types and portfolios, making the transition to a cleaner grid appear more costly.

Q. The Companies added a "20% cost risk premium to the capital costs for the scope, scale, and pace of resource additions in P1" for the purposes of comparing the cost of the presented pathways.[99] Is this reasonable?

A. No. In addition to the limited range of portfolios, the Companies take an extra step to undermine the one portfolio that includes higher levels of renewable resources. This way, they complicate the cost comparison of the

[99] 2023 Carolinas Resource Plan, Chapter 3, at 16.

different pathways, further reducing the informational value of this analysis for the Commission and stakeholders. The Companies include a proxy risk premium - informed by “the procurement experience and professional judgement of the Companies' SMEs, considering factors such as how an expedited time frame paired with significant increases in resource needs would impact procurement processes across all resource types.”[100] This approach is not reasonable, especially because the Company has chosen not to quantify other risks, as explained throughout my testimony. The significant cost adder applies to all resources, even at levels that are not subject to any premium in other portfolios. For example, the cost of the Bad Creek Pumped hydro increases 20% under P1. The 20% cost adder also applies over the entire time horizon, even though the Companies otherwise note that their three base pathways converge over time. The sole purpose of this adder seems to be to undermine P1 when comparing the costs with P2 and P3. In the case of P1 Fall, the PVRR is inflated by more than [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] due to this adder.[101]

Q. Have the Companies included any other cost adder intended to capture the cost uncertainty for new resources?

A. Yes. According to Appendix E:[102]

> The costs projections used for 2023 modeling have shown significant increases across all supply-side technology options due to these cost

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[100] Companies’ response to SACE et al. Data Request No. 5-14-1.

[101] *See* “PSDR 1-7 CONFIDENTIAL_P1 Fall Supplemental PVRR ONLY_SPA.xlsx.” The estimate can be found by comparing the “PVRR paste” tab, when adjusting the “Adder” of the Overview tab from 1.2 to 1.

[102] 2023 Carolinas Resource Plan, Appendix E, at 8.

> pressures. Contingency has also been raised in the near-term for all technologies since actual project installations have shown greater uncertainty in the ability to obtain fixed-price contracts. This contingency "penalty" is reduced each year before being completely eliminated in the 2030 cost projections.

The 8% cost adder affects resources in the near term and essentially puts a penalty on any portfolio that attempts a faster deployment of resources. The adder is eliminated in 2030, largely allowing gas resources to be constructed without the penalty. The adder further undermines the cost effectiveness of replacing coal units with renewable resources and energy storage (even if one were to remove the earliest coal retirement date). Still, the model selects the maximum number of allowed solar resources.

Q. Do you agree with those adders?

A. No. I am not denying that in the recent past there have been supply chain issues. However, the Companies have included build limits, recent cost estimates that were supposed to reflect these trends, a contingency penalty that penalizes renewables in the near term, and a 20% risk premium that further undermines the faster deployment of clean resources. All these adjustments exceed any reasonable assumption that the Companies could make and result in suboptimal portfolios that cannot even be meaningfully compared.

Q. Do you have any other observations regarding the use of those adders?

A. Yes. Going back to my observations in the previous section, despite all these adders, clean energy resources are consistently selected by the model. Absent build limits, more solar and wind would still be selected as clearly shown in the supplemental analysis.

C. Energy storage can deliver additional grid benefits that are not fully captured in the analysis.

Q. Can you provide a brief overview of energy storage's benefits and how these are included in resource planning analysis?

A. Energy storage can deliver several electricity-grid services. Those can include bulk system services (capacity and energy arbitrage), ancillary services (regulation, spin/non-spin reserves, voltage support, black start, frequency response), transmission and distribution services (upgrade deferrals, congestion relief), as well as customer management services (resiliency, charge reductions).

Q. Have the Companies' incorporated those benefits in their analysis?

A. The Companies have incorporated some of them, mainly bulk system services. It is important however to note that capturing all the values that batteries can provide in a single model is and will remain a challenge, as those values include more interactions than what capacity expansion modeling has traditionally included. Capturing those benefits would require modeling distribution and transmission benefits, ancillary services requirements and how these might change with renewables deployment, as well as intra-hour modeling. Thus, I am not arguing that Duke's CPIRP should have included all of them, at least not in the Companies' 2023 CPIRP analysis. Witness Duncan recommends that the Commission require the Company to file a Distribution Resource Plan as a part of their CPIRP, while witness Goggin states that "Transmission planning must be synchronized with generation planning for it to truly be an "integrated" resource plan and reliably serve customers at least cost." Both indicate that the Companies will need to move their planning towards a more integrated approach considering resource, transmission, and distribution planning, which would better capture some of those benefits.

Q. Can you provide additional information on the energy storage benefits that capacity expansion modeling cannot capture, resulting in an underestimation of the role of energy storage?

A. Yes. To start with, energy storage has flexibility benefits representing the technology's ability to respond to grid needs even on an intra-hour basis. This way, energy storage reduces costs associated with ramping up or down thermal generation that would otherwise have to respond to the changing grid needs. Second, energy storage can deliver value by eliminating or deferring transmission and distribution investments.

Q. Why is the omission of these flexibility benefits important?

A. The Companies seem to have incorporated integration charges for solar resources in their modeling. These charges represent costs resulting from real-time variability of the resource's availability that can result in incremental fuel costs and ramp up/down of thermal generation. They are modeled as variable costs in the Companies' modeling both for solar, as well as for solar plus storage resources. Specifically, new DEC solar has an integration charge of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] MWh in 2022 which escalates at [BEGIN

CONFIDENTIAL] [redacted] [END CONFIDENTIAL] annually, while the charge for DEP solar is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] MWh in 2022 escalating at [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] annually.[103] Since the Companies model integration costs, they should have also included the analogous flexibility savings that energy storage can provide. Energy storage could significantly reduce those costs, as it can flexibly and quickly respond to changing needs without needing fuel and or the same amount thermal generation needs to ramp up or down. This benefit has not been modeled, and thus, the cost of portfolios that include higher energy storage is overstated while investment in the technology is lower than the optimal level.

Q. Do you know of other utilities incorporating flexibility benefits in their IRP analyses?

A. Yes. Other utilities are now approximating this flexibility value, showcasing its importance despite system differences. Having said that, the values calculated in other IRPs cannot be applied on a one-to-one basis in Duke's CPIRP analysis.

In PacifiCorp's 2021 (as well as its preliminary 2023) IRP, it included a "granularity" adjustment meant to capture the difference between the value that batteries (or other flexible resources) can provide in models of different time resolutions. Specifically, PacifiCorp states that:

> As detailed during the 2023 IRP public-input process, the granularity adjustment reflects the difference in economic value between an hourly

[103] EnCompass Input File GFF Fall 2022_Resolved Data_5-11-2023

> 8760 cost calculation in ST modeling, and the seven-block per month representation used in the LT model. This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn't fully capture the effect of storage duration limits.[104,105]

According to slides shared by PacifiCorp during the 2021 IRP public-input process, this undervaluation ranged between $25/kW-year and $50/kW-year for the second half of this decade.[106]

In its 2023 IRP, Portland General Electric noted that "[w]hen additional resources are added to the system, some new resources can be used to serve load and avoid higher-cost market purchases, as well as enable the re-dispatch of existing resources, thereby affecting the flexibility needs of the system. At the same time, other resources may increase the flexibility needed." PGE calculated flexibility benefits and integration cost for each of the new resources, with the former ranging from $17/kW-yr. to $21/kW-yr. in 2030 for 2- to 8- hour batteries.[107] DTE's 2022 IRP also modeled flexibility benefits associated with batteries reducing renewable

[104] PacifiCorp's 2023 Integrated Resource Plan, Volume I (Mar. 31, 2023), https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf, at 221.

[105] "LT" refers to the long-term model, which corresponds to the capacity expansion step, while "ST" refers to the short-term model, which corresponds to the production cost step.

[106] PacifiCorp, *Integrated Resource Plan: 2021 IRP Public-Input Meeting* (Jun. 25, 2021), www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp%202021%20IRP_PIM_July_30_%202021.pdf, at 36.

[107] Portland General Electric's 2023 Clean Energy Plan and Integrated Resource Plan, Table 47 (Jun. 30, 2023), https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf.

energy integration costs; with values ranging from $3.38/kW-yr in 2026 to $67.85/kW-yr. in 2035.[108] Other flexible resources could also receive the credit but that would need to reflect incremental start up and fuel costs as appropriate.

Q. Are there other grid services that energy storage can provide and have not been modeled?

A. Energy storage can also deliver transmission and distribution deferral benefits or facilitate the interconnection of other new resources by addressing constraints in the system. As the Companies currently assess their transmission needs and plan for the future, they should evaluate the technology's potential to defer or even avoid certain upgrades, especially the ones that complicate or delay coal retirements or limit interconnection of clean resources.

Q. Do you have a recommendation with respect to modeling energy storage benefits?

A. Yes. Although, as stated before, I recognize that capturing all benefits in a single model is challenging both from a data and computational perspective, I recommend that if the Companies plan to include the integration costs that are driven by incremental renewables, then the value that energy storage delivers by mitigating those costs should also be accounted for. This saving estimate should be included in the capacity expansion model.

[108] DTE Electric Company's 2022 Integrated Resource Plan, Qualifications and Direct Testimony of Laura K. Mikulan, Michigan Public Service Commission, Case No. U-21193 (Nov. 3, 2022) https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000004qW9sAAE, at LKM-65 (Table 10).

With respect to transmission and distribution benefits, I recommend that the Companies reduce any transmission upgrade costs or qualitative factors as appropriate when considering storage replacements in their retirement analysis.

VI. THE COMPANIES' MODELING DOES NOT CONSIDER ALL EMERGING TECHNOLOGIES AND INTRODUCES PATH-DEPENDENCY RISK

Q. Have the Companies included emerging technologies in their modeling?

A. Yes, but only a subset. Specifically, the Companies have included nuclear technologies, hydrogen assets, and offshore wind, but have not included long duration energy storage (LDES).

Q. Please summarize your concerns around the Companies' treatment of emerging technologies.

A. Duke has chosen to over-rely on certain technologies, while ignoring others. To the extent that this over-reliance shapes a path that makes the system less flexible to adapt to changing technological, market, and policy conditions in the future, it is problematic. Specifically, I am concerned that the Companies' reliance on future resources might impact the deployment of resources in the near term. Keeping an uneconomic unit online while near-term, cost-effective replacement options are available is not always prudent, even if it is possible a better option might become available in the longer term under more favorable conditions. There is a trade-off between cost and risk that the Commission should not overlook.

Q. Please detail the Companies' assumptions regarding the availability of new nuclear resources.

A. The Companies' base assumptions include two emerging nuclear technologies: advanced reactors (ARs) and Small Modular Reactors (SMRs). SMRs could provide the system with bulk, dispatchable carbon-free energy by the mid-2030s, specifically 2035 for the core pathways. ARs use a non-water coolant, which allows for efficiency gains compared to the SMR light-water reactors and is available in the core pathways beginning in 2038.[109]

Q. Please detail your concerns regarding the availability and costs associated with incremental nuclear deployments based on your experience across the nation.

A. My concern is that the Companies' assumptions regarding the expected in service dates and costs of emerging nuclear technologies might be ambitious considering the state of these novel technologies. Because of this, the Companies' analysis has the potential to lock ratepayers into funding novel technologies that could face material delays and increase ratepayer costs beyond what is foreseen in the Companies' analyses.

A clear example of the volatility of these factors can be found in the recent cancellation of NuScale's six-reactor, 462 MW SMR project in Idaho, which was terminated despite significant federal backing as the in-service date slipped from 2026 to 2029.[110] Furthermore, emerging nuclear

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[109] 2023 Carolinas Resource Plan, Appendix C, at 38-39.

[110] Kathryn Porter, *The West's only licensed small reactor project is dead. It's a blow for green energy*, The Telegraph (Dec. 18, 2023), https://www.telegraph.co.uk/news/2023/12/18/nuscale-smr-cancellation-green-energy-net-zero-blow/.

technologies have not been commercially deployed at scale, making any forecast of overnight costs inherently uncertain. The potential for materially greater costs played a significant role in the cancellation of the NuScale project, where costs ballooned from $5.3 to $9.3 billion between 2019 and 2023. Much like the conventional light-water Vogtle unit 3 delays which experienced a 7-year delay and cost increases of more than 100%,[111] NuScale's cancellation highlights that nuclear development is incredibly complex and prone to delays.

Q. Given that the in-service date for the first SMR in the Companies' recommended portfolio is in 2035, which is outside of the near-term action plan term, why is it important to review the assumptions around it in this 2023 plan?

A. Although the first SMR in the Companies' recommended portfolio is outside the near-term action plan, it is important to review it right now, because there are implications for the near-term action plan, as well as costs that ratepayers might have to face in the longer term that could be avoided if the Companies planned for a more flexible system.

For example, the Companies' preferred pathway, P3 Fall Supplemental, delays retirement of Belews Creek, which represents 2,200 MW of coal capacity, from 2030 in P1 Fall Supplemental or 2033 in the coal retirement analysis to 2036 in P3.[112] One of the justifications for this delay is the fact that the Companies are confident future emerging nuclear

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[111] Julie Kozeracki, et al., *Pathways to Commercial Liftoff: Advanced Nuclear*, U.S. Dep't of Energy (Mar. 2023), https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Advanced-Nuclear-vPUB.pdf.

[112] Supplemental Planning Analysis Technical Appendix, Table SPA T-4, at 5.

technology deployments will be able to utilize the site and/or interconnection associated with Belews Creek by 2035. However, there are no-regrets options available right now. These include solar, wind, and storage, as well as demand side resources. Even if we assume that SMRs at the cost and timeline modeled were a more economic option than investing in renewable resources right now, there is still a high probability of that scenario not materializing as currently forecasted by the Companies, in which case, ratepayers might be locked into a system with expensive, aging fossil fuel units and no ability to build up the necessary capacity from other resources in time. Thus, the Companies might be essentially pushing execution challenges in the future all while paying for uneconomic resources.

Q. Have the Companies stated plans to replace Belews Creek with nuclear capacity in past IRPs?

Yes, In DEC's IRP 2020 IRP, it is noted that "…a 684 MW small modular nuclear reactor plant is added to the DEC system at the beginning of 2030. For a long lead time infrastructure project such as this, the retirements of one of the Belews Creek units was delayed from 2028 to 2030 to maintain planning reserve capacity until the SMR can be operational." A footnote to this statement notes that "the first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEC." Thus, although I am confident that the Companies will follow market and technology developments and keep adjusting their plans, they should also recognize that by not fully appreciating the uncertainty around such technologies, they are introducing path-dependency risk and limiting the adjustments they can eventually make to a much smaller (and potentially much worse) subset of pathways than would be otherwise available. For example, if SMRs do not become available in 2035 or are significantly more expensive, the Companies might need to extend the operations of a plant that will be facing increasing costs, and policy constraints, a risk that can be avoided.

Q. You also mentioned that you are concerned because the Companies have selectively modeled some emerging technologies but not others. Please elaborate.

A. The Companies have selected and are relying heavily on hydrogen assets but have not included longer energy storage options as selectable resources in the analysis. It is reasonable to plan for some form of clean capacity resource in the future given the increasingly stringent regulatory environment. This could be provided by energy storage, green-hydrogen CTs, or a different emerging technology. The relative cost of those technologies will keep evolving, but by investing in approximately 2 GW of gas CTs right now on the assumption that market and technological advancements outside of the Companies' control will all follow the Companies' projections, the Companies are significantly reducing their ability to take advantage of the full spectrum of technological and market developments.

Specifically, the Companies only modeled batteries as a generic unit for economic selection within EnCompass. Three options of batteries were included, all sized at 100 MW: 4-, 6-, and 8-hour li-ion, but a storage asset of longer duration was not available for selection. Appendix E of the Companies' 2023 Carbon Plan justifies the exclusion of any storage technology besides lithium ion noting that, while there are dozens of storage technologies, the majority of them have not reached commercial status.[113] The Companies also noted that the technologies included in the model represent their current expectations for short and medium duration storage and that they will continue to evaluate the potential for LDES to reach commercial status and include it in their modeling eventually.[114]

Q. Is the Companies' rationale to exclude additional storage alternatives, particularly LDES, consistent with your experience across the US?

A. No, the Companies' decision to refrain from modeling additional storage alternatives, particularly LDES, for the totality of the period studied is inconsistent with the pace at which LDES technologies are becoming commercially available and economically viable, the Companies' need for additional capacity alternatives, and regional analyses regarding the reliability of future assets.

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[113] 2023 Carolinas Resource Plan, Appendix E, at 5.

[114] *Id.*

First, while the majority of energy storage deployments to date have been 4-hour assets, this is largely due to the current grid needs and regulatory framework. In California, as of July 1, 2023, 5,600 MW of energy storage capacity has been brought online and is fully integrated into the electrical grid.[115] While most of these additions are four-hour resources given California's regulatory landscape, which currently values energy storage contributions as a function of the capacity they can provide for four or more hours, eight-hour lithium-ion solutions are feasible and have been procured.[116] Beyond lithium-ion assets, a suite of long-duration energy storage technologies, like iron-air storage systems, are commercially ready for the planning period and have been procured by entities such as Xcel in Minnesota.[117] As such, it is unreasonable for the Companies to exclude said storage alternatives with durations beyond eight hours for the totality of the period studied, especially considering when other technologies that are not yet commercially available have been fully modeled (*e.g.*, emerging nuclear technologies and hydrogen assets).

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[115] California ISO, *New Storage Milestone Reached for the California Grid; More than 5,000 MW Now Available for Dispatch* (Jul. 11, 2023), www.caiso.com/Documents/new-storage-milestone-reached-for-the-california-grid-more-than-5000-mw-now-available-for-dispatch.pdf.

[116] Cameron Murray, *California Utility Signs PPA with NextEra for Eight-Hour Energy Storage Project*, Energy Storage News (Apr. 11, 2023), https://www.energy-storage.news/california-utility-signs-ppa-with-nextera-for-eight-hour-energy-storage-project.

[117] Ethan Howland, *Minnesota PUC Approves Xcel's Plan to Install a 10-MW/1,000-MWh Form Energy Battery System*, Utility Dive (Jul. 7, 2023, https://www.utilitydive.com/news/minnesota-puc-xcel-form-energy-battery-sherco-solar/685460/.

Q. What is your recommendation around the inclusion of emerging technologies in the Companies' analysis?

A. I am not arguing that nuclear technology could not further develop and enable clean portfolios. Rather, my position is that the timing and cost of these technologies are highly uncertain. The same applies to hydrogen assets. Building a system based on a deterministic future that assumes the most favorable developments for some emerging technologies can be risky and leave the Companies and ratepayers exposed and with significantly less flexibility should that future not materialize. On the other hand, focusing investment on already available and economic resources, like solar, wind, and storage, at an accelerated pace is a preferrable, no-regrets strategy. I recognize that these should not be the only resources considered during the full planning horizon and I believe that technological advancements will enable a broader set of novel, supply side solutions. My recommendation is rather that the Companies should include this consideration about flexibility to adjust to the changing conditions into their planning and that they include a broader range of emerging technologies, so that they can better explore those advancements, even if they do not happen as currently projected in their 2023 analysis.

VII. RECOMMENDATIONS AND CONCLUSIONS

Q. Please summarize your findings.

A. My findings are summarized below:

- The Pathways presented in Duke's CPIRP do not present a meaningful range of alternative portfolios. They all rely heavily on new gas generation creating a false narrative of a binary choice between new gas units or an unreliable system. This false dichotomy fails to capture the full range of options, depriving the Commission of useful information.
- Renewable energy resources and energy storage are the most cost effective, least risk option in addressing the Companies' energy needs within the changing market and policy landscape as consistently shown in the Companies' own modeling.
- There are additional alternatives that the Companies have not sufficiently explored that could unlock cost and emission savings without the unnecessary risks of fossil fuel generation. They include: transmission enhancements to unlock additional renewable energy, additional demand side resources including behind the meter storage, load management options, and other solutions that could alleviate interconnection challenges. SACE, *et al.* witnesses Goggin and Duncanprovide additional supporting evidence.
- The Companies' own modeling indicates that the proposed CC units solve a transient need with carbon-free resources replacing CC generation energy as soon as it is allowed by Duke-imposed limits.

Accelerating the pace of no regrets clean, energy deployment is a better solution compared to the temporary and expensive fix of soon-to-become-stranded or underutilized CC resources.

- The Pathways presented are not compliant with the EPA GHG emissions limits and guidelines for existing coal-fired and new natural gas-fired power plants. The cost of compliance will dramatically increase the cost of the CC resources.

Q. Please summarize your recommendations.

A. First and foremost, the Commission should not approve the 2023 CPIRP, Duke's recommended Pathway 3 (P3 Fall Supplemental), or the Companies' proposed NTAP in their current form. Specifically, I recommend that the Commission hold in abeyance any decision on Duke's proposed gas buildout, or at a minimum on the Companies' CC buildout, due to the already existing cost, reliability, gas supply, and technical challenges that such a buildout would face. The final EPA section 111 rule, which Duke's analysis and portfolios fail to account for, is an especially important reason for the Commission to halt the Companies' plans to build new gas CC resources. I also recommend that in each of the Companies' CPCN applications for new gas plants, that the Commission should require the Companies to provide information as to whether the proposed gas resource was evaluated against a clean portfolio including all the possible Inflation Reduction Act (IRA) benefits. This evaluation should include the energy community bonus credit if the clean resource is constructed within an energy community as well as benefits from the Energy Infrastructure Reinvestment program (EIR).

Furthermore, I recommend that the Commission instruct the Companies to keep exploring earlier retirement options, especially for the Cliffside 5, Mayo 1, Marshall 1 and 2, and Roxboro units, while in their future planning analysis they continue to investigate the benefits of converting the Belews Creek units to operate 100% on natural gas.

Finally, as consistently shown in the Companies' modeling, clean energy resources should be added at a rate and scale above what is modeled in the Companies' preferred portfolio. I recommend that the Commission approve the solar, wind, and battery storage procurement levels identified in the Companies' P1 (Base Core) as a floor and instruct Duke to explore additional options to expedite the interconnection of new renewable and storage resources.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony and Exhibits of Maria Roumpani on behalf of the Southern Alliance for Clean Energy, Sierra Club, Natural Resources Defense Council, and the North Carolina Sustainable Energy Association either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 28th day of May, 2024.

/s/ David L. Neal
David L. Neal

Exhibit MR-1

Maria Roumpani Resume

Maria Roumpani

ELO Engineering Consulting
maria@eloec.gr

Professional Summary

Maria is an expert in energy system planning and an energy modeler. She focuses on the economic and technical analysis of grid planning and operations issues and has experience in capacity expansion optimization, production cost simulations, and energy storage dispatch modeling. Maria has submitted expert testimony and comments on integrated resource planning, plant economics, unit commitment practices, and power cost issues and her clients include consumer advocates, public interest organizations, energy project developers, government agencies, and large energy buyers.

Education

PhD, Management Science & Engineering
Stanford University, 2018

MSc, Electrical and Computer Engineering
National Technical University of Athens, 2009

Work Experience

Founder, ELO Engineering Consulting (March 2024 – Present)

- Works on electric regulatory and energy planning issues.

Technical Director | Strategen Consulting (2018 – March 2024)

- Led firmwide technical and economic modeling and analysis to support consulting engagements. Specialized in the use of modeling tools to inform grid planning and decarbonization issues.

Research Assistant | Precourt Institute for Energy, Stanford University (2011 – 2017)

- Conducted research in a wide range of topics, from game theoretical approaches in electricity markets to behavioral economics.

Researcher | Energy, Economics, & Environment Modeling laboratory, National Technical University of Athens, (2009-2010, 2015)

- Contributed to the development of mathematical models:
    - Capacity expansion of electricity supply
    - Wholesale electricity market competition model

Expert Testimony

- Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc. on behalf of the South Carolina Office of Regulatory Staff,
  Public Service Commission of South Carolina, Docket No 2023-2-E, Testimony
- Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC, on behalf of the South Carolina Office of Regulatory Staff,
  Public Service Commission of South Carolina, Docket No 2023-1-E, Testimony
- Virginia Electric and Power Company 2023 IRP, on behalf of Advanced Energy United
  Virginia State Corporation Commission, Case No. PUR-2023-00066, Testimony
- DTE 2022 IRP, on behalf of the Michigan Energy Innovation Business Council
  Michigan Public Service Commission, Case U-21193, Testimony
- Duke Energy Carolinas and Duke Energy Progress 2022 Carbon Plan, on behalf of the Tech Customers
  North Carolina Utilities Commission, Docket E-100, Sub 179, Testimony
- Public Service Company of Colorado, on behalf of Sierra Club
  Colorado Public Utilities Commission, Proceeding No. 21A-0141E, Testimony

Selection of other Relevant Experience

- Assessment of Clean Energy Alternatives to New Natural Gas Resources: Duke Energy Indiana Combined Cycle Project (2023)
- Assessment of Clean Energy Alternatives to New Natural Gas Resources: Part 2 (2023)
- Alternative Resource Plan for Salt River Project's Integrated System Plan (2022)
- Analysis of Arizona Public Service's Integrated Resource Plan (2021)
- Alternative Resource Plan Analysis for Tucson Electric Power (2020)
- Long Duration Energy Storage for California's Clean Reliable Grid (2020)
- Energy Storage Alternatives for a Proposed Peaking Power Plant, Report (2021) | Additional Analysis (2022)