STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	))))))	**DIRECT TESTIMONY AND EXHIBITS OF BRIAN C. COLLINS ON BEHALF OF CIGFUR II & III**

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INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of a group of intervenors designated as the Carolina Industrial Group for Fair Utility Rates II ("CIGFUR II") and the Carolina Industrial Group for Fair Utility Rates III ("CIGFUR III") (collectively, "CIGFUR"). CIGFUR is a group of non-residential retail customers that purchase power from Duke Energy Progress, LLC ("DEP") and/or Duke Energy Carolinas, LLC ("DEC") (collectively, "Duke" or the "Companies").

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A Duke submitted its proposed 2023-2024 Biennial Carbon Plan and Integrated Resource Plan ("CPIRP" or the "Carbon Plan") on August 17, 2023, and filed its supporting testimony on September 1, 2023. Duke filed the supplemental testimony of Glen A. Snider on November 30, 2023, and then filed its supplemental update to its CPIRP on January 31, 2024, followed by a Second Amended Petition for Approval on April 30, 2024. These filings were made pursuant to the North Carolina Utilities Commission's ("Commission" or "NCUC") December 30, 2022 *Order Adopting Initial Carbon Plan and Providing Direction for Future Planning* ("Carbon Plan Order"). Duke is required to update its CPIRP every two years.

In my testimony I will address various issues in the CPIRP filings, primarily as it relates to customer bill impacts and reliability. I will also provide certain recommendations to the Commission for its consideration.

Q DID THE COMMISSION DIRECT THAT PARTIES SUBMITTING TESTIMONY IN THIS PROCEEDING ORGANIZE THEIR TESTIMONY BY ISSUE?

A Yes. As directed by the Commission's February 21, 2024 *Order Establishing Additional Procedures for Expert Witness Hearing*, Duke submitted on March 6, 2024 their proposed index of "Designated Issues" to assist the Commission in its review and consideration of the Companies' proposed 2023-2024 CPIRP and supporting testimony. As a result, the portion of my testimony, after the Introduction followed by the Findings and Recommendations sections, addresses specific topics and sub-issues which are identified in accordance with the designated issues list developed by Duke.

Q WHAT ARE THE COMPANIES REQUESTING IN THIS PROCEEDING?

A The Companies' Second Amended Petition filed on April 30, 2024 states their specific requests, which are replicated below. The Companies request that the Commission adopt the CPIRP and take the following actions:

(1) Affirm that the Companies' 2023-2024 CPIRP modeling, including the Supplemental Planning Analysis, is reasonable for planning purposes and presents a reasonable plan for achieving the State's authorized CO2 emissions reductions targets in a manner consistent with the requirements of N.C.G.S. § 62-110.9 and prudent utility planning.

(2) Approve near-term supply-side development and procurement activities identified above for 2024-2026 (over and above the resources selected and approved in the 2022 Carbon Plan Order) and take the following specific actions:

(a) Deem the following resources as being selected in the 2023 CPIRP, in all cases subject to the obligation to obtain a CPCN (where applicable) and require the Companies to keep the Commission apprised of material changes in assumed pricing or schedule:

(i) 235 MW of solar and solar plus storage to be procured through an RFP conducted in 2024 (incremental to the 1,350 MW of solar and solar plus storage approved by the Carbon Plan Order for the same period to address experienced and forecasted attrition);

(ii) 2,700 to 3,460 MW of new controllable solar generation to be procured in RFPs conducted in 2025 and 2026 (subject to CTPC approval of RZEP 2.0 projects), a substantial portion of which is assumed to be paired with storage;

(iii) 1,100 MW of battery storage (targeting 475 MW stand-alone storage and 625 MW storage paired with solar incremental to the 1,600 MW storage approved in Carbon Plan Order) for procurement and development in 2024 to 2026 to achieve commercial operation by 2031;

(iv) 1,200 MW of onshore wind to achieve commercial operation by 2033;

(v) 1,325 MW of additional CTs to achieve commercial operation by 2031;

(vi) 5,600 MW of additional CCs to achieve commercial operation by 2033;

(vii) 1,834 MW pumped storage hydro at the Bad Creek II facility to be placed into service by 2034.

(b) Approve the Companies' plans to continue development activities in 2024-2026 to support the future availability of SMRs to ensure that these breakthrough technologies are available options for the Companies' customers on the timelines identified in the Plan;

(c) Approve the Companies' plans to pursue activities in 2024-2026 to support the acquisition and future availability of offshore wind by issuing an ARFI in early 2025 for up to 2,400 MW of offshore wind off the coast of North Carolina to better determine the cost and availability of offshore wind resource options for the Companies' customers on the timelines identified in the Plan;

(d) Make the following additional determinations with respect to the initial development activities for onshore wind, pumped storage hydro, and advanced nuclear as described in Chapter NC:

(i) Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the updated Carbon Plan and necessary to enable execution of onshore wind and Bad Creek II as well as potential selection of SMRs in the future to be available on the timeline for achieving the Interim Target identified in the Plan;

(ii) The Companies are authorized to incur project development costs up to $65.6 million for the development of three annual tranches of onshore wind through 2026 for purposes of achieving 1,200 MW in service by 2033;

(iii) The Companies are authorized to incur project development costs up to $165 million for the development of pumped storage hydro from 2023 through 2026;

(iv) The Companies are authorized to incur initial development costs up to $1.4 million to develop and administer an ARFI to assess the assess the cost of procuring up to 2,400 MW of offshore wind located off the North Carolina coast;

(v) Pursuant to N.C.G.S. § 62-110.7, the Companies are authorized to incur project development costs up to $75 million through 2024 plus an additional $365 million through 2026 for the development of advanced nuclear resources;

(vi) The Commission's approval of the Companies' request to incur project development costs constitutes reasonable assurance of cost recoverability in a future general rate case subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and

(vii) That in the event these long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO2 emission reduction targets, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time;

(3) Approve proposed actions with respect to existing supply-side resources, including continued disciplined pursuit of SLRs and pursuing power uprate projects for the Companies' existing nuclear fleet as described in Appendix J as well as through the planned CC unit flexibility projects as described in Appendix K;

(4) Approve the Companies' updated schedule for planned coal retirements in the near- and intermediate term supported in Appendix F and the Supplemental Planning Analysis as reasonable for planning purposes;

(5) Approve and find reasonable the Companies' continued use of 1% of eligible load annual utility energy efficiency savings in the CPIRP modeling as a base assumption and that such target is reasonable and appropriate for future planning purposes;

(6) Acknowledge the need for the RZEP 2.0 projects identified in Table L-7 of Appendix L; and

(7) Grant such other and further relief as the Commission deems just and proper.[1]

FINDINGS AND RECOMMENDATIONS

Q WHAT ARE YOUR FINDINGS AND RECOMMENDATIONS FOR THE COMMISSION?

A My findings and recommendations are as follows:

1. Duke's preferred Pathway 3 in its CPIRP, updated in its Supplemental Analysis filed on January 31, 2024, results in the retirement of approximately 8,400 MW of coal fired generation on the Duke system by 2035. Because of the size of Duke's system and the scale of the necessary renewable and clean resources to replace coal fired generation, this level of generation retirement and its timing raises legitimate concerns regarding customer impacts, both in terms of reliability and rate impacts for customers.
2. As implied in the Carbon Plan Order, reliability is paramount. The importance of a reliable grid was particularly demonstrated by the events of Winter Storm Elliot in December 2022.
3. In this proceeding, Duke specifically requests the Commission affirm its modeling as reasonable and requests approval of certain Near-Term Action Planning ("NTAP") items as reasonable and necessary to reliably serve electric loads under the changing energy landscape and implement its Carbon Plan in North Carolina.
4. With respect to its NTAP items, Duke is requesting Commission pre-approval to incur specific project development costs for long lead item resources including onshore wind ($64.5 million), pumped hydro storage ($165 million) and advanced nuclear ($440 million).
5. The specific resources incremental to the August 2023 filing that Duke has included in its Supplemental Analysis update amount to over 7 GW and now includes offshore wind, as well as additional natural gas fired capacity, solar, and battery storage.
6. Duke claims that the primary reason for the January 31, 2024 Supplemental Analysis filing was due to what Duke considers expected extraordinary load

[1] *See* the Companies' Verified Second Amended Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, at 29-33 (April 30, 2024), Docket No. E-100, Sub 190.

growth on its system requiring incremental resources that it claims should now be included in its CPIRP as compared to the August 2023 filing.

7. According to Duke, the forecasted 2038 winter peak has increased from 35.5 GW in the August 2023 filing to 37.6 GW in the January 2024 filing, an increase of 2.1 GW or approximately 5%. The annual energy forecast has increased from 182 TWh to 206 TWh, an increase of 24 TWh or approximately 12%. This is a significant increase in expected load for both DEC and DEP operations in North Carolina.

8. The total cumulative capital spend for the CPIRP in Duke's August 2023 filing was $92 billion by 2038. In the January 2024 update, Duke now estimates its total cumulative capital spend by 2038 to be $128 billion. **This is a significant increase of approximately $36 billion or approximately 39% in less than 6 months.**

9. In the August 2023 filing, Duke estimated customer bill impacts growing at a Compound Annual Growth Rate ('CAGR") of approximately 2.2% for DEP and 2.9% for DEC for the period 2024-2038. In the January 2024 update, Duke now estimates customer bill impacts growing at a CAGR of approximately 3.4% for DEP and 3.7% for DEC for the period 2024-2038. These are significant annual compounding increases.

10. Duke's revised forecasted CAGRs result in cumulative customer bill increases of approximately 60% for DEP and 66% for DEC by 2038 as compared to 2024 rate levels. These are significant bill impacts for customers, and do not even include all expected costs that Duke will incur for executing its Carbon Plan. As a result, these estimates are conservative.

11. For perspective, the current estimated bill impacts by 2038 vs. current rates in 2024 would amount to an approximate **$1.5 million per month increase** for a 50-MW industrial customer taking transmission service with a 90% load factor. Considering that these estimates are understated because they do not reflect all costs necessary to implement the Carbon Plan, nor costs unrelated to implementation of the Carbon Plan, the expected level of future bill increases for customers is concerning and should give the Commission great pause. The magnitude of the expected bill increase is a threat to the competitiveness of industrial customers in Duke's service territories, not to mention the threats to Duke's residential customers.

12. Along these lines, it should also be noted that Duke's residential customers will also see approximate increases of $87 per month by 2038 based on Duke's estimated CAGRs in the January 31, 2024 filing. Again, these are extraordinary increases—and conservative estimates—and should be concerning to the Commission.

13. The actual customer rate impacts experienced by 2038 will likely be much higher because the CPIRP includes only estimated generic transmission costs,

including both interconnection and network upgrade costs and do not reflect the complete transmission investment costs necessary to implement the Companies' CPIRP. Furthermore, these impacts also do not account for non-CPIRP investments in generation, transmission and distribution.

14. Regarding reliability, the present law requires that reliability should improve or not be harmed. Because of the unprecedented level of intermittent resources planned for the Duke system to replace historically reliable coal fired generation, the Commission should be flexible and give the Company as much time as is required in meeting its emissions reductions. More time is needed for implementing the CPIRP due to uncertainty in load growth, resource costs, supply constraints, and the viability of new and unproven resource technologies to enable reliable operation of the Duke system.

15. Duke examined other Pathways for 70% carbon emissions reductions by 2030. However, there is increased cost and risk in reliably meeting the interim 70% target by 2030. As a result, I recommend that the Commission not require Duke to meet the 70% emission reductions target by 2030.

16. Because of the risks and the uncertainties in implementing the CPIRP, Duke has recognized that its recommended 2035 target for 70% emissions reductions via its preferred Pathway 3 could change. The Commission has the discretion to determine optimal timing, as well as the appropriate generation and reserve mix to achieve the least cost path to compliance. Importantly, it must only take all *reasonable* steps to implement the Carbon Plan.

17. On top of the uncertainty regarding the assumptions in the CPIRP, one particularly troubling concern is the unknown impact if joint planning had been performed by Duke on a combined basis for both DEP and DEC. The lack of joint planning by DEC and DEP is a significant impediment to developing a least cost plan for emission reductions that can be approved by the Commission.

18. As a result of the discretion afforded the Commission and the requirement for the Commission to take only those *reasonable* steps in implementing the CPIRP, I recommend the Commission require Duke to model a scenario in which DEC and DEP are sharing capacity for planning purposes to protect ratepayers from the risk of the Companies' overspending and overbuilding in the interim. Per the Companies' expectation, the merger would be effective approximately January 1, 2027.

19. Certainty should be reached on the merger of DEP and DEC as soon as possible to avoid Duke's progression down a path that could have adverse consequences on customers in terms of both reliability and bill impacts if the optimal resources on a combined DEP and DEC joint planning basis are not selected for replacing coal fired generation as part of the Near-Term Action Plan and otherwise. If this is not possible, the Commission should consider

delaying the timeline for achieving the interim emissions reduction targets set forth in House Bill 951.

20. I also recommend that the Commission establish rate mitigation measures for customers with respect to CPIRP implementation. More specifically, I recommend that the Commission consider implementing rate mitigation measures to protect ratepayers from the unprecedented and extraordinary exposure of rate increases associated with CPIRP implementation. This is a reasonable, important, and necessary customer protection. Rate mitigation could be in the form of a rate phase-in over a specified period of time after Duke is granted an increase in a rate case to recover costs associated with implementing the Carbon Plan. Parameters around this rate mitigation could be developed through collaboration with Duke, the Public Staff, and customers.

21. Though the Company is required to file an updated CPIRP every 2 years, the current environment is dynamic with respect to load growth, resource costs and availability, supply constraints, and resource technology development, creating uncertainty regarding reliability and bill impacts for customers. Therefore, I recommend that the Commission require updates from Duke every 6 months regarding the progress of the CPIRP. This is a reasonable requirement, especially in light of the extraordinary load increase that occurred less than 6 months after Duke's CPIRP filing in August 2023, as well as the significant rate impacts Duke projects.

22. Specifically, I recommend that the Company be required to file with the Commission status reports every 6 months, identifying any major developments in the process. These reports should include an update to the approved Portfolio's (or Portfolios', as the case may be) Present Value of Revenue Requirements ("PVRR"), total capital spend, and estimated customer rate impacts. More frequent updates are needed on the process beyond just the 2-year updated formal filing. This would be another customer protection and complement the biennial filing, warn the Commission if the circumstances have changed regarding the preferred CPIRP, and help the Commission and the Companies "check and adjust" sooner rather than later.

23. I also recommend that the Company include estimated rate impacts in the proposed 6 month reports for all expected investment on its system, including the non-CPIRP investments. This will give the Commission a holistic view of the expected customer rate impacts on the horizon.

1. Planning Objectives in a Changing Energy Landscape

Q HAVE YOU REVIEWED THE CPIRP AND TESTIMONY OF THE COMPANIES WITH RESPECT TO THEIR PLANNING OBJECTIVES?

A Yes. I have reviewed the Companies' testimony and the CPRIP as it relates to the Companies' planning objectives.

Q PLEASE SUMMARIZE THE COMPANIES' PLANNING OBJECTIVES.

A The Companies describe their core planning objectives as maintaining or improving the reliability of the electric grid while achieving carbon dioxide emissions reduction targets established by law in a least-cost manner for customers over the long run.

Q WHAT HAS THE COMMISSION SAID IN THE INITIAL CARBON PLAN ORDER REGARDING RELIABILITY?

A The Commission has said the following with respect to reliability at page 56 of its Initial Carbon Plan Order dated December 30, 2022:

> The Commission concludes that ensuring system reliability and compliance with mandatory reliability standards in the face of the ongoing energy transition is a requirement of state law, is an obligation uniquely held by Duke and overseen by this Commission, and is nonnegotiable for the continued health and well-being of all North Carolinians.

The Commission recognizes that reliability is <u>**nonnegotiable**</u> and should not be compromised.

Q DO YOU AGREE THAT RELIABILITY IS PARAMOUNT?

A Yes. As a result, reliability of electric service provided to Duke's customers must not be compromised regardless of the timing of emissions reduction targets. In addition, however, emissions reductions cannot occur at *any* cost. Without some constraints on risk and exposure related to rate increases, implementation of the CPIRP imperils affordability of the Companies' rates charged to customers.

Q UNDER THE COMPANIES' PLANNING OBJECTIVES, WHAT ARE SOME OF THE KEY CHALLENGES IN BALANCING EMISSIONS REDUCTION TARGETS WITH MAINTAINING ELECTRIC SYSTEM RELIABILITY?

A One of the main challenges for implementing the Companies' Carbon Plan is replacing coal generation with reliable capacity as the coal units retire. Transitioning to more variable and intermittent renewable generation resources requires balancing reliability with both the magnitude of the costs recovered from customers and emissions reductions. To meet emissions reductions and maintain reliability will require new resources like energy storage in considerable scale to maintain reliable service around the clock to customers as the Company transitions from coal fired resources.

Q HOW DO THE COSTS OF THE COMPANIES' ENERGY TRANSITION IMPACT CUSTOMERS' RATES?

A Adding many new replacement resources for the Companies' coal fired units over a relatively short time period comes with high upfront capital costs that are recovered through customer rates. As a result, the Companies forecast higher bills for customers as resources are brought online. However, if not balanced properly, costs recovered from customers for replacement generation could rise to unsustainable levels that burden customers, cause demand erosion among non-residential customers, and have serious ripple effects throughout the State's economy. This is troubling. My concerns with the customer rate impacts associated with the Companies' Carbon Plan will be further discussed in detail in Section 7 of my testimony.

Q HOW CAN RELIABILITY AND COST IMPACTS TO CUSTOMERS BE BALANCED WITH EMISSIONS REDUCTION TIMELINES?

A Evaluating different transition timelines allows for exploration of the tradeoffs inherent in a capital spending plan of the magnitude contemplated by Duke's proposed Carbon Plan. A slower-paced transition out of coal-fired generation would reduce near-term costs and risks but challenge emissions reduction targets, which are aspirational. Faster timelines for emissions reductions may not be feasible without jeopardizing reliability or affordability. An optimized pathway is needed to balance these competing priorities in a reasonable manner and all reasonable assumptions must be considered. However, as mentioned previously, reliability should not be compromised and indeed, the Commission and Duke are legally required by G.S. 62-110.9(3) to "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."

Q WHAT OTHER CONSIDERATIONS ARE IMPORTANT IN FINDING AN APPROPRIATE BALANCE WITH REGARD TO EMISSION REDUCTIONS?

A Execution risk and uncertainty are also critical to the implementation of the Carbon Plan. Availability of timely replacement resources, transmission infrastructure needs, and projected replacement resource costs all carry uncertainty that could impact future reliability and customer bill impacts. As a result, regulatory flexibility to adjust future plans is critical given the dynamics of factors like new environmental policies, the advancement of new generation technologies, and market conditions that will continue shaping the best path forward for emissions reductions while maintaining reliability and minimizing customer rate impacts.

While Duke emphasizes maintaining reliability, its preferred portfolio would require unprecedented additions of non-dispatchable and/or relatively new generation technology resources. At the same time, the plan shows electricity bills will rise substantially under any transition pathway, with the Pathway 3 Fall Base portfolio projecting average annual increases of almost 4% compounded annually through 2038. These mounting costs cause concern, as even small rate hikes or supply disruptions could greatly impair the competitiveness of industrial customers and their viability to continue operating in energy-intensive industries in North Carolina.

Q WHAT OTHER RISKS EXIST IN REGARD TO CARBON EMISSIONS REDUCTIONS?

A In its Supplemental Analysis, Duke proposes more measured retirements of coal plants than its initial plan filed in August 2023, recognizing that premature shutdowns of historically reliable coal generating units threaten both affordability and reliability if replacement capacity is delayed or insufficient. However, uncertainties remain regarding fuel security for new replacement generating resources, as the Companies rely heavily on meeting ambitious natural gas, hydrogen, and carbon capture targets well beyond 2050. Technology commercialization on such a scale presents high execution risk for the implementation of the Carbon Plan.

Q DO YOU HAVE ANY OTHER CONCERNS?

A Yes. Another concern is customers could be overburdened with excess or stranded generation if the appropriate generation resource mix and timing is not selected. The Commission must judiciously balance interests to avoid misaligned investments in replacement generation that result in adverse rate impacts to customers. Duke must not be given *carte blanche* to gold plate its generation system in the name of an aspirational emissions reduction target.

While Duke has analyzed many portfolios, more scrutiny of costs, risks and customer impacts seems prudent before finalizing major resource decisions locking in decades of rate hikes for Duke's customers. Uncertainty always exists, but this uncertainty combined with the most recent extraordinary customer rate impacts—before the CPIRP-related rate impacts have even started to be felt by customers—warrants the Commission taking an extremely judicious approach to approval of any Near-Term Action Plans and extending the timeframe for achieving the interim emissions reduction goals to give the Company more time to implement its Carbon Plan, especially in light of the Companies' plan to merge into a combined capacity planning entity. This will be described in more detail in Section 16 of my testimony.

2. <u>Modeling (Methodology, Key Assumptions, and Other Modeling Issues)</u>

Q HAVE YOU REVIEWED THE COMPANIES' TESTIMONY AND CPIRP WITH RESPECT TO ITS MODELING METHODOLOGY AND KEY ASSUMPTIONS?

A Yes. I have reviewed the Companies' testimony as well as its CPIRP, including its modeling methodology and key assumptions.

Q PLEASE SUMMARIZE THE CPIRP MODELING METHODOLOGY USED BY THE COMPANIES.

A Duke uses a capacity expansion modeling approach to evaluate different resource portfolios and identify least-cost options to ensure reliability and meet emissions targets. The primary model used is the EnCompass capacity expansion model from Anchor Power Solutions. Production cost modeling is also done with a separate module in EnCompass, with reliability modeling performed using SERVM.

The Companies developed the CPIRP using a modeling framework that incorporates capacity expansion, production cost simulation, and reliability analysis to evaluate portfolios of demand-side and supply-side resources. The modeling encompasses DEC and DEP service areas, which are modeled as separate jurisdictions within a consolidated system operations framework.

Q DID DUKE APPLY THE SAME CAPACITY EXPANSION MODELING APPROACH AND ANALYTICAL METHODOLOGIES USED TO DEVELOP ITS INITIAL PLAN FILED AUGUST 2023 IN ITS SUPPLEMENTAL UPDATE IN JANUARY 2024?

A Yes. Duke relied upon the same modeling tools but incorporated updated inputs, including an increased load forecast, to conduct its Supplemental Analysis. This was intended to further inform resource planning in the dynamic energy transition. Key assumptions in the CPIRP include the following:

- Updated 2023 Fall Load Forecast projecting significant load growth due to economic growth, population growth, and the growth of electrification, including electric vehicles;
- Updates to natural gas fuel supply assumptions based on Mountain Valley Pipeline ("MVP") pipeline progress;
- Updates to financial assumptions for cost of capital and generic resource capital/operating costs;
- Refined resource availability assumptions based on current market conditions;
- Inclusion of a Continued Economic Development load forecast scenario;
- Limited coal retirement adjustments but Duke's Supplemental Analysis continues the coal replacement strategy filed in August 2023. Coal units are retired according to Duke's updated economic analysis that considers costs to maintain versus retrofit units;
- Same planning reserve margin and reliability targets;
- Resource costs - Duke develops cost estimates for different generation technologies considering capital, fuel, O&M, and other factors;
- Resource performance - Duke models the capacity value and hourly generation profiles of different weather-dependent and dispatchable resources; and
- Transmission - Duke considers transmission expansion needs and options to integrate new resources using generic transmission interconnection and network upgrade costs.

Q ARE THERE CERTAIN ASSUMPTIONS IN DUKE'S CPIRP THAT REQUIRE PARTICULARLY CLOSE MONITORING BY THE COMMISSION?

A Yes, based on my review of the Supplemental Analysis testimony, there are key assumptions that are important for the Commission to continue monitoring closely going forward:

1. Electric load forecast assumptions: As noted several times by Duke, the rapid pace of economic development and load growth in the Carolinas introduces significant uncertainty. The Companies will need to stay attuned to trends to ensure planning aligns with evolving needs.

2. Natural gas fuel supply and price assumptions: Securing adequate long-term gas supplies and managing fuel price risk are critical given the planned reliance on new gas generation. Updates to pipeline infrastructure and market conditions warrant ongoing evaluation.
3. Technology cost and availability assumption: Costs and timelines for resources like offshore wind, solar, batteries, hydrogen-capable gas fired generation, and advanced nuclear are still developing. Continued monitoring of experience curves and supply chains is prudent.
4. Economic conditions and load factor assumptions: Inflation, interest rates, and customer demand patterns like electric vehicle adoption trends could materially impact costs and load profiles. Flexibility will be important.
5. Policy and regulatory assumptions: Future carbon reduction targets, tax incentives, transmission approvals, and other policies could shape optimal resource plans.
6. Transmission: The level of actual and total transmission investment necessary to implement the CPIRP.

Q IS AN UPDATE OF THE CPIRP EVERY TWO YEARS ADEQUATE FOR EFFECTIVE COMMISSION MONITORING IN LIGHT OF THE CHANGING CIRCUMSTANCES IMPACTING DUKE'S ENERGY TRANSITION?

A No, not in my opinion. Given all of the present uncertainty surrounding the assumptions and inputs to the CPIRP, more frequent updates to the Commission are required to better inform the Commission, such as reports filed every 6 months by Duke that inform the Commission on the progress of the Carbon Plan. This recommendation requiring more frequent updates to the Commission will be explained later in my testimony in more detail. The need for more frequent updates and reporting to the Commission is vital considering the magnitude of expected customer rate impacts and is an important customer protection.

Q IS THERE A KEY MODELING SCENARIO THAT IS MISSING FROM THE COMPANIES' CPIRP ANALYSIS?

A Yes. Though the Companies must separately plan their systems at the present time, a hypothetical scenario involving a merged DEC and DEP utility with joint planning seems prudent in order to accurately gauge whether the Companies are progressing down the most appropriate least-cost path given that the Companies are planning to consummate a merger effective approximately January 1, 2027. Though the Commission at present cannot approve a plan assuming joint planning, the Commission should be informed as to how joint planning will impact the Company's preferred portfolio in its CPIRP. Such information is useful and another important data point for the Commission's consideration.

Q WHAT ARE THE BENEFITS OF A MERGED UTILITY IN TERMS OF RESOURCE PLANNING?

A Merging the DEP and DEC utilities allows for more efficient resource planning. For example, the Companies can deploy the most cost-effective generation sources in locations where they are most effective (wind speed, proximity to load centers, access to gas pipelines, access to existing electric transmission, etc.). Because new generating resources' locations impact the level of electric transmission and gas infrastructure investment, joint planning will likely have a significant impact on the level of investment and total cumulative capital spend for Duke required to implement its Carbon Plan, materially impacting rates. To approve a Carbon Plan that does not allow DEP and DEC to share capacity resources for planning purposes benefits Duke by enabling it to overspend and overbuild at the expense of ratepayers, who will be footing the bill for the gold-plating of Duke's generation system.

Requiring Duke to submit the results of a modeling scenario in which DEP and DEC were merged and could share capacity resources for planning purposes would facilitate the development of a more resilient grid that can more effectively handle fluctuations in energy demand, extreme weather events, and potential disruptions. This collaborative approach would also likely lead to more cost-effective solutions, ultimately benefiting customers through potentially lower electricity rates.

Q CAN THE COMMISSION DETERMINE THAT THE CURRENT DUKE PREFERRED PATHWAY 3 IS THE LEAST COST PLAN AT THIS POINT IN TIME?

A No, I don't believe it can. Based on the Company's testimony, a merger appears certain, subject to the Commission's approval, as well as the approval of other regulators. Without such a planning scenario that depicts this development, the Commission would be hard pressed to determine that any planning scenario that does not involve a merged entity is least cost, as required by G.S. 62-110.9(1) and (2).

Q AS A RESULT OF THIS UNCERTAINTY, WHAT DO YOU RECOMMEND?

A I recommend that the Commission require Duke to submit a modeling scenario in which DEP and DEC are merged for planning purposes, and thus able to "share" capacity resources. In the interim, and so as to prevent Duke from overbuilding and overspending, I recommend the Commission consider whether to extend the timeframe for achieving the interim emissions reduction targets set forth by HB 951 for projects over certain capacity and cost thresholds, until at least after the approximate effective date of the DEC and DEP merger, currently estimated to be January 1, 2027, so long as doing so would not adversely impact reliability or the Companies' ability to serve load. This recommendation is by no means meant to prevent Duke from investing in necessary infrastructure subject to appropriate Commission approval to enable it to reliably operate and serve its current and expected electric demand. This recommendation is further described in Section 16 of my testimony.

3. Coal Unit Retirement Analysis

Q PLEASE SUMMARIZE DUKE'S APPROACH FOR RETIRING ITS COAL GENERATING UNITS.

A According to Duke, its approach to retiring its coal generating units in its Carbon Plan involves a phased and strategic transition towards cleaner energy sources. Duke's proposed Carbon Plan includes the retirement of coal units based on their age, efficiency, and environmental impact. Duke aims to replace the retired coal units in the near-term with a combination of natural gas fired turbines, batteries, renewable energy sources, and energy efficiency measures.

Q HAS DUKE UPDATED ITS COAL RETIREMENT PLAN IN ITS JANUARY 2024 FILING?

A The Companies conducted supplemental coal retirement analysis using the same process outlined in Appendix F of the initial Carbon Plan filing submitted in August 2023. This update analysis determined that only very limited schedule adjustments were needed compared to the Pathway 3 Portfolio P3 retirements.

Q HOW DOES DUKE CONSIDER RELIABILITY RISK IN ITS COAL RETIREMENT ANALYSIS?

A The Companies aim to retire coal units in a manner that preserves operational flexibility to respond to ongoing uncertainties like future load development and timing of new resource additions needed to replace retiring coal capacity while maintaining reliability to customers. Retaining flexibility in the coal generating unit retirements is vital and allows the Companies to adapt their transition away from coal. This approach attempts to mitigate risk for customers by ensuring reliability is maintained during the energy transition.

Q COULD THE COAL RETIREMENT TIMELINE CHANGE?

A Yes, the timeline for coal retirements presented in the Supplemental Planning Analysis could potentially change in the future based on certain changing circumstances.

While the Companies aim to retire coal units according to the schedule currently proposed, the analysis recognizes that some adjustments may be warranted in future CPIRP filings depending on how certain key uncertainties are resolved.

Q WHAT FACTORS COULD LEAD TO CHANGES IN THE PROPOSED COAL RETIREMENT TIMELINE?

A Key factors that could potentially lead to changes in coal retirements include: future load growth differing materially from current projections and delays in the commercial operation of new resources that utilize developing technology replacing retiring coal capacity as outlined in the Execution Plan.

Economic factors, such as changes in natural gas fuel costs, electricity demand, and the cost of renewable energy technologies could influence Duke's coal retirement timeline. If there are significant shifts in any of these or other factors, Duke must reassess its retirement plans and make necessary adjustments.

Ensuring the reliability and resilience of the power grid is crucial during the transition from coal to other energy sources and should not be compromised. If there are challenges or delays in developing replacement capacity from alternative energy sources, or from building the necessary transmission assets to accommodate these new resources, Duke must modify its timeline to ensure a smooth and reliable transition.

Technological advancements in clean energy technologies, such as improvements in renewable energy generation or energy storage systems, could impact Duke's coal retirement timeline. If these advancements do not materialize as expected for the deployment of clean energy alternatives, Duke may need to consider slowing the pace of its coal unit retirement plans.

Q ARE THERE RISKS OF RETIRING COAL UNITS TOO QUICKLY?

A Yes. Coal-fired power plants have historically been a reliable source of baseload power for Duke’s customers, meaning they can generate a consistent and continuous supply of electricity. If the retirement of the Duke coal fleet happens too quickly without adequate replacement capacity, there could be a strain on the energy supply. This could potentially lead to power shortages, power quality issues, blackouts, or increased dependence on other sources of energy that may not be as reliable.

Coal-fired power plants provide a stable and consistent source of power that can help maintain grid stability. The retirement of these plants will require additional investments in grid infrastructure, energy storage, and flexible generation technologies to ensure a reliable and resilient electricity grid. Without proper planning and investment, the grid could become less stable and more susceptible to disruptions.

Because the retirement of coal-fired power plants requires significant investments in new infrastructure and technologies to replace the lost capacity, this transition is costly based on current estimates. The financial burden is passed on to Duke's customers through higher electricity rates. It is important to carefully plan and manage the transition to minimize the economic impact on Duke's customers.

Q DOES THE LEVEL OF TRANSMISSION INVESTMENT NECESSARY TO IMPLEMENT THE CARBON PLAN POSE A RISK TO THE CURRENT COAL GENERATION RETIREMENT TIMELINE?

A Yes, the level of transmission infrastructure investment can be a risk to the pace of Duke's retirement of its coal units.

As Duke retires its coal units, the integration of renewable energy sources, such as wind and solar, becomes crucial. The location of these replacement resources affects the level of necessary transmission investment. The availability and capacity of transmission infrastructure play a significant role in facilitating the transmission of renewable energy from generation sites to load centers. If there is insufficient transmission infrastructure or limitations in the grid's capacity to handle increased renewable energy generation, it can slow down the retirement of coal units. Duke may need to wait for network transmission upgrades or build new network transmission lines to accommodate the transmission of renewable energy, which could impact the retirement timeline for its coal-fired generation fleet.

The retirement of coal units requires a reliable and stable grid to ensure uninterrupted power supply to customers. Duke must ensure that the transmission system can handle the increased load from alternative energy sources and maintain grid stability. If significant investments are required to upgrade the transmission infrastructure to meet these requirements, it could potentially delay the retirement of coal units.

In addition to integrating renewable energy resources, Duke will need to interconnect these new generation sources, such as natural gas power plants and energy storage systems to the grid to compensate for the loss of coal generation. The availability of transmission infrastructure and the ability to connect these new sources to the grid can impact the retirement timeline. If there are limitations or delays in interconnecting these new generation sources due to inadequate transmission infrastructure, it can also delay the retirement process.

The development of transmission infrastructure involves planning, permitting, and regulatory processes, which can take time. If there are delays in obtaining necessary approvals for transmission projects, this too can impact the retirement timeline.

Q HAS DUKE MADE A DEFINITIVE CASE FOR MEETING THE INTERIM EMISSIONS REDUCTION GOALS BY 2035?

A Based on uncertainty in terms of the cost of replacement generation resources, as well as the timing and availability of such resources, coupled with the current and expected load growth and other uncertainties, I do not believe the Company has made a definitive case.

I believe more time is warranted to ensure reliability and address customer rate impacts. Flexibility in meeting emissions reductions targets is key, and with the prospect of continued load growth along with uncertainty in various assumptions and the availability of appropriate replacement resources, the current timeline is questionable.

As I stated earlier in my testimony, maintaining existing reliability is paramount. The Commission should exercise the discretion it has been delegated by the North Carolina General Assembly to extend emissions reductions targets if reliability or unconstrained rate increases are at risk.

4. Load Forecast

Q HAVE YOU REVIEWED DUKE'S TESTIMONY AND CPIRP WITH RESPECT TO ITS EXPECTED LOAD GROWTH?

A Yes.

Q PLEASE SUMMARIZE THE SIGNIFICANCE OF THE COMPANIES' LOAD FORECASTS.

A It is very important to be as accurate as possible with load forecasting for the Carbon Plan implementation. Load growth will be an important factor that influences the pace of coal retirements as well as the addition of new resources on Duke's system. That being said, forecasting too much load growth will result in overbuilding of resources. It is important to avoid overbuilding as this will unnecessarily increase costs recovered from customers through increased rates.

Q DID DUKE SUPPLEMENT ITS 2023-2024 CPIRP IN JANUARY 2024 BECAUSE OF LOAD GROWTH?

A Yes. According to Duke, the Companies supplemented the CPIRP as a result of extraordinary load growth that is expected to now occur on its system. In her testimony, Ms. Bowman indicates that economic development in the Companies' service area is driving significant increases in electricity demand above what was forecasted in the Company's August 2023 CPIRP filing.

Q IS THERE ALSO SIGNIFICANT RESIDENTIAL LOAD GROWTH FORECASTED ON DUKE'S SYSTEM?

A Yes. The Companies have stated the following in Appendix C, at page 62:

> The Companies are experiencing significant new load growth stemming from favorable economic developments, residential population growth and the increasing adoption of electric vehicles.

They further state at page 40 of Chapter 4:

> Continued load growth in the Carolinas due to economic development, population increase, electrification trends and EV adoption has the potential to impact the Plan as the Companies work to meet customer needs and ensure reliability.

Q IS IT APPROPRIATE FOR ALL CUSTOMER CLASSES TO SHARE IN THE COSTS RECOVERED FROM RATEPAYERS FOR RESOURCES SELECTED IN THE CPIRP TO REPLACE COAL-FIRED GENERATION AND MEET LOAD GROWTH?

A Yes. Customers are all in this together and no one customer class should bear 100% of resource generation expansion needed to meet load growth and retire coal fired capacity in an orderly, reliable fashion. Doing so would be problematic and also would be unjustified from a cost of service basis, which remains the law of the land in utility ratemaking in North Carolina. While load growth may be accelerating the timing of generation investments that replace coal generation, early retirement of Duke's coal fleet plus the buildout of "clean" replacement capacity is the driving force behind the Companies' CPIRP and as a result, increasing rates for all customers, including for large industrial customers.

Q DO LARGE INDUSTRIAL CUSTOMERS BENEFIT THE OVERALL DUKE SYSTEM?

A Yes. Revenues from large non-residential retail customers help benefit all customers and all customer classes by contributing to the Company's fixed costs that would otherwise be paid by other customer classes, including residential customers. If one or more large customers shifts load to facilities outside North Carolina and/or closes one or more facilities in North Carolina, the revenue requirement Duke was recovering from that customer would then get absorbed by all other customers, including residential customers. As a result, it is imperative to ensure customer impacts are reasonable for all customers, including for industrial customers so that they can remain competitive and continue operating and providing high-paying jobs for residential customers in North Carolina.

Q ARE THERE WAYS THAT NEW ECONOMIC LOADS CAN BE PART OF THE COMPANY'S CPIRP SOLUTION?

A Yes. To the extent that these customers can reduce load at times of peak, this will help reduce the amount of new capacity that needs to be built by Duke to meet system demand. It is important more than ever for the Company to develop attractive demand response and energy efficiency programs for customers, especially large non-residential customer loads to shrink the challenge of meeting emissions reductions targets.

Q WHAT WOULD AN ATTRACTIVE DEMAND RESPONSE PROGRAM LOOK LIKE FROM CIGFUR'S PERSPECTIVE?

A CIGFUR'S perspective on demand response programs is provided in Section 11 of my testimony.

Q ARE THE COSTS OF NEW DEMAND RESPONSE PROGRAMS REQUIRED TO BE RECOVERED THROUGH THE DSM RIDER?

A No. Designing a demand response program that both benefits the system and is workable for large non-residential customers is ultimately a matter of rate design that does not necessarily need to be part of the Companies' suite of DSM programs recovered through the DSM Rider. Duke should be flexible and get creative in developing solutions that attract non-residential customers to participate in demand response programs, regardless of whether the costs of such programs are recovered through DSM Rider.

5. Planning Reserve Margin / 2023 Resource Adequacy Study

Q WHAT IS A RESERVE MARGIN?

A Reserve margin refers to the amount of additional generating capacity above expected peak load that a utility plans to have available to reliably serve its customers. It is expressed as a percentage of expected peak load. Setting an adequate reserve margin is important for reliability, as it allows utilities to handle unexpected conditions like extreme weather, load growth, and significant generator outages.

Q HAS DUKE INCREASED ITS RESERVE MARGIN?

A Yes. The resource adequacy study conducted by Astrape Consulting on behalf of Duke modeled various reserve margin levels to determine the reliability risk and calculate Loss of Load Expectation ("LOLE") metrics. An LOLE of 0.1 days/year, equivalent to one day in 10 years of expected firm load shed, is commonly used in the industry as the standard for adequate reliability. The study examined scenarios where DEC and DEP were islands without assistance, as well as base cases where they could receive market assistance. For the combined base case, Astrape recommended a minimum 22% winter reserve margin, up from 17% in the previous 2020 study. Major drivers for the 5% increase in reserve margin were updated generator performance data, economic load forecast errors, and decreased availability of neighbor assistance through imports. The results are presented in terms of winter reserve margins because Duke Energy is considered a winter-peaking and winter-planning utility, with most resource adequacy risk occurring in winter months. An effective load carrying capability ("ELCC") study was also conducted to determine the capacity value provided by different levels of wind and solar resources on the Duke systems.

Q WHAT DOES AN INCREASED RESERVE MARGIN MEAN?

A The higher reserve margin means Duke must ensure it has more generating capacity than peak load in the planning period in order to operate the system reliably. Achieving the increased reserve margin is a driver of Duke's need for new generation resources and impacts the timing of planned coal unit retirements due to the "replace before retire" approach. The Astrape analysis found that Duke would not have adequate capacity to retire its remaining coal units without replacement resources based on the higher reserve margin requirements. Future load forecast increases or changes to availability/timing of replacement resources could require adjustments to Duke's coal retirement schedule as well.

Q DO YOU HAVE ANY CONCERNS WITH THE INCREASED RESERVE MARGIN?

A Yes. The lack of joint capacity resource planning by DEC and DEP could result in a higher reserve margin than would be necessary as compared to a portfolio that assumed joint planning by both DEC and DEP. To the extent the resource mix is different under a merger scenario, there could be an impact on the reserve margin as a result of different concentrations and types of clean energy generation resources used to replace coal fired generation. This is yet another reason to require Duke to supplement its analysis with a scenario that assumes joint planning and sharing of capacity resources and for the Commission to employ maximum flexibility and discretion by extending the timeline for implementation of the Carbon Plan until there is certainty regarding the anticipated merger between DEC and DEP.

6. Natural Gas Supply and Hydrogen

Q HAVE YOU REVIEWED THE COMPANIES' TESTIMONY AND CPIRP AS IT RELATES TO NATURAL GAS SUPPLY AND HYDROGEN?

A Yes. The Company claims that natural gas will continue to play an important role in meeting electricity demand and enabling the transition to renewable energy.

Q IS SIGNIFICANT INFRASTRUCTURE EXPECTED TO BE NEEDED TO ENSURE SUPPLY OF BOTH NATURAL GAS AND HYDROGEN?

A Yes. Ensuring both adequate natural gas supply and delivery infrastructure is critical. The Companies need additional firm transportation capacity on interstate pipelines to reliably serve existing and planned natural gas-fired generation. This includes projects like MVP. Pipeline infrastructure projects face increasing regulatory, permitting, and other legal challenges, which in turn presents an execution risk to the Company's Carbon Plan, which calls for more gas fired generation on its system to replace coal fired resources.

The Companies are also developing new hydrogen-capable natural gas power plants, including combined cycles and combustion turbines. As a result, significant hydrogen infrastructure buildout will be needed.

Renewable natural gas and hydrogen are being explored as potential low-carbon fuels, but face challenges around supply, infrastructure, costs, and specifications.

Q COULD ENVIRONMENTAL REGULATIONS ALSO IMPACT THE ECONOMICS OF GAS-FIRED ASSETS?

A Yes. Environmental regulations could impact the operation of new gas plants, requiring capacity restrictions, hydrogen use, or carbon capture and storage ("CCS") to meet lower emissions limits going forward. Ensuring adequate gas and hydrogen supplies and developing energy infrastructure will be crucial for the Company to be successful in using gas fired resources to enable the transition to lower carbon resources over the coming decades. Considerable investment and progress on these technologies will be required.

Q ARE THERE RISKS WITH NATURAL GAS UNITS BECOMING STRANDED INVESTMENTS?

A Yes. The Companies propose to use new CC and CT natural gas turbines as a bridge from coal fired resources to batteries. However, continued operation of these new gas-fired units beyond 2050 would require these units to be operated on hydrogen to eliminate carbon emissions and achieve carbon neutrality as contemplated by House Bill 951. This could be a challenge. If hydrogen capability is not achievable for the new gas-fired units Duke plans on its system, these units could be retired early and further increasing costs for customers.

Q IS THERE ADDITIONAL RISK WITH CONVERTING NEW GAS FIRED UNITS TO HYDROGEN FUEL?

A Yes, both operationally and financially. The technology for hydrogen capable units needs to be improved to a point it can be produced to scale. In addition, the Company has used proxy values for the costs of hydrogen capable assets since these cost estimates are not yet available from original equipment manufacturers ("OEM"). Therefore, there is risk in the Carbon Plan that the costs of these units have not been accurately captured by Duke, understating the true cost of these units to customers and the corresponding PVRR of each Carbon Plan resource portfolio.

7. Pathways, Portfolios, and Portfolio Comparison and Evaluation

Q HAVE YOU REVIEWED THE TESTIMONY AND CPIRP WITH RESPECT TO THE COMPANIES' EVALUATED PATHWAYS AND PORTFOLIOS?

A Yes.

Q WHAT PATHWAY PORTFOLIO HAVE THE COMPANIES SELECTED?

A The Companies' have selected Pathway 3, P3 Fall Base as the preferred portfolio.

Q IS P3 FALL BASE THE LEAST COST PORTFOLIO?

A Of the portfolios studied, Pathway 3 Fall Base has what Duke estimates would be the lowest cost with a PVRR of $149 billion through 2038.

However, with all of the uncertainties and concerns described throughout my testimony, it is impossible to characterize the Company's preferred P3 Fall Base as the "least cost" portfolio. Though it is <u>lower</u> cost relative to the other portfolios examined by Duke, there are costs not included in the analysis that if modeling assumptions were modified to include them, could result in the P3 Fall Base not being the least-cost path for implementing the Carbon Plan after all. For example, all transmission costs for implementing the Carbon Plan, which are location specific, are not included in the CPIRP, and would likely vary significantly with the specific resource mix in a portfolio. Furthermore, if joint planning by DEC and DEP was used to develop a portfolio, this could very well result in a lower cost, least-cost plan as compared to P3 Fall Base.

Q WHAT IS THE CURRENT GOAL FOR 70% EMISSIONS IN PATHWAY 3?

A Under the Companies' proposed P3 Fall Base, the current goal for achieving 70% emission reductions is the year 2035.

Q DOES DUKE RECOGNIZE THAT THIS DATE MAY CHANGE?

A Yes. For example, achieving the interim 70% carbon emissions reduction goal by 2035 under a continued high load growth scenario may necessitate delaying the target year for achieving the emission reductions goals.

Q WHAT ITEMS COULD CAUSE THE DATE TO EXTEND BEYOND 2035?

A The use of emerging zero carbon technology and fuel sources which may hold promise but are not currently known to be viable resource options could extend the date. Limitations on expanding natural gas pipeline delivery systems, which are critical in relying on planned new gas-fired generation to be available during peak period conditions also very well could cause a delay in the implementation of the Carbon Plan.

Q IS DUKE ABLE TO MEET ITS 70% EMISSIONS REDUCTIONS TARGET BY THE YEAR 2030 AS MODELED IN PORTFOLIO 1?

A No. According to the Company's testimony, Duke has stated the following:

> Because it is not possible to achieve the Interim Target by 2030 using the Companies' already aggressive base case assumptions for new resource

availability, P1 Base, the Core Portfolio corresponding to Pathway 1, shows new resources added to the Companies' electric system at a rate that exceeds the Companies' expectations for what will be feasible to connect without jeopardizing system reliability.[2]

Q DID HB 951 DELEGATE DISCRETION TO THE COMMISSION IN IMPLEMENTING THE CARBON PLAN?

A Yes. HB 951 delegates broad discretion to the Commission in developing and implementing the Carbon Plan in accordance with certain parameters, including that the Carbon Plan must comply with least-cost principles and must maintain or improve the reliability of the electric grid.

Q ARE THE COMPLIANCE TIMEFRAMES FLEXIBLE?

A The time frames for compliance with carbon emissions reductions are aspirational goals, not mandates. Moreover, the legislation delegates to the Commission the flexibility to extend the 2030 compliance target until 2032 for any reason, and then to delay it further—until 2034 or beyond—"in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid."[3]

The Commission has been empowered with this discretion because the Legislature saw fit to delegate it; the Commission should use this discretion to the fullest extent in order to comply with the least-cost and reliability mandates. Minimizing carbon emissions

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[2] IRP and Near-Term Actions Panel testimony, Page 21, Lines 15-20.
[3] G.S. 62-110.9(4).

is the objective, but so too is proceeding with the transition to lower carbon resources in an orderly fashion while still maintaining service reliability, power quality, and competitive utility rates to customers based on the least-cost set of investments necessary to implement the Carbon Plan.

Q HOW DO THE RESOURCES IN DUKE'S SUPPLEMENTAL CPIRP FILED ON JANUARY 31, 2024 COMPARE TO THE RESOURCES INCLUDED IN THE CPIRP FILED IN AUGUST 2023?

A The supplemental filing includes additional resources as a result of an increased load forecast, deemed the P3 Fall Base portfolio submitted by the Companies. A summary of the resource differences between the Carbon Plan associated with the P3 Base and P3 Fall Base portfolio load forecasts is summarized in the Company's filing. I have included that summary as Exhibit BCC-1.

Q HOW DOES THE COST OF THE UPDATED CPIRP COMPARE TO THE INITIAL CPIRP FILED IN AUGUST 2023?

A The cumulative capital spend for the CPIRP filed in August 2023 was identified as $44 billion by 2033 and $92 billion by 2038. The Company with its January 2024 filing now forecasts cumulative capital spend of $61 billion by 2033 and $128 billion by 2038 in its January 2024 filing. These are increases of $17 billion (approximately 39%) by 2033 and $36 billion by 2038 (approximately 39%), respectively.

Q ARE THERE COSTS THAT WILL IMPACT CUSTOMER RATE INCREASES DUE TO THE COMPANIES' CPIRP THAT ARE NOT INCLUDED IN THE CPIRP?

A Yes. For example, all costs for transmission investment necessary to implement the CPIRP have not been included in the customer rate impacts and could be significant.

Q FOR THE COSTS THAT DUKE DID INCLUDE, CAN YOU SUMMARIZE THE ESTIMATED BILL IMPACTS FOR CUSTOMER CLASSES EXPECTED UNDER THE COMPANIES' JANUARY 2024 UPDATE DUE TO THE CUMULATIVE CAPITAL SPEND TO IMPLEMENT THE CPIRP FORECASTED BY DUKE?

A Yes. Customers will see Compound Annual Growth Rates ("CAGR") of approximately 3.4% for DEP customers and 3.7% for DEC customers for the period 2024-2038.

Q HOW DO THESE CUSTOMER RATE IMPACTS IN THE CPIRP SUPPLEMENTAL ANALYSIS COMPARE TO THE IMPACTS PROVIDED IN THE COMPANIES' AUGUST 2023 FILING?

A The impacts in the August 2023 filing involved CAGRs of 2.2% for DEP and 2.9% for DEC.

Q HAVE YOU ESTIMATED RATE IMPACTS ON AN INDUSTRIAL CUSTOMER FOR THE PERIOD 2024- 2038 USING THE CAGRS FROM DUKE'S JANUARY 2024 SUPPLEMENTAL ANALYSIS?

A Yes. Applying the above CAGR percentages to the rates in effect as of January 2024 for a typical industrial customer using 50 MW at a 90% load factor and taking service at transmission voltage, I have calculated the costs for a typical industrial customer. The estimated **monthly** increase for this hypothetical customer would be approximately $1.5 million by 2038. I have attached my analysis of the rates impacts as Exhibit BCC-2.

Q ARE THE ESTIMATED COST INCREASES A CONCERN FOR CUSTOMERS?

A Yes, these cost impacts are a concern and present an existential threat to non-residential customers' ability to remain competitive in North Carolina. Because these cost increases do not include all of the expected increases resulting from the Carbon Plan, the increases are likely understated, not to mention the fact that the Companies' will continue to make non-CPIRP related investments and recover those costs through rates, and these CPIRP cost estimates do not factor in non-CPIRP related spending. This level of cost increase is alarming and very likely conservative, which add to the level of alarm.

Q PLEASE DESCRIBE THE CURRENT BUSINESS CLIMATE IN NORTH CAROLINA.

A North Carolina has fostered a tremendous business climate. With 2020 being the exception, the trend for manufacturing job levels has been increasing since approximately 2010, along with average manufacturing wages also increasing during that time. While much progress has been made, the forecasted bill increases resulting from the Carbon Plan pose an existential threat to that progress. If increases reach a point where businesses in North Carolina are no longer competitive, manufacturing employment will most certainly decline.

Q DO CIGFUR MEMBER COMPANIES CONSTITUTE A SIGNIFICANT PORTION OF THE INDUSTRIAL BASE OF DUKE'S SERVICE AREA?

A Yes. CIGFUR members are major employers in the counties where they have facilities, and the jobs and local tax revenues they provide are vital to the local and State economies. Together, CIGFUR members provide many thousands of direct jobs in the Duke service areas. Remaining competitive and maintaining payrolls for CIGFUR members are vital to the local economies where they are located.

Q PLEASE DESCRIBE HOW ELECTRICITY COSTS IMPACT CIGFUR MEMBERS.

A Many CIGFUR members use power for around-the-clock manufacturing operations, operating at high load factors. A high load factor means a customer is using relatively more energy in relation to the demand for power. Energy usage is a much larger portion of the total bill for a large high load factor customer as compared to a smaller, lower load factor customer.

Energy costs are essential to the manufacturing processes of these customers. In addition, energy costs are one of the most important factors considered when manufacturers are making business decisions such as where to locate new facilities, expand existing facilities, assess where it may no longer be competitive to operate, or make the difficult decision to potentially reduce operations or even close facilities. Along these lines, Duke's large non-residential customers in North Carolina have to compete not just regionally, but nationally and globally, for the siting or expansion of facilities that in turn employ North Carolinians, injecting large revenues into the local tax base, and stimulating the local economy directly and indirectly through the economic multiplier effect. Any increase in costs places significant added pressure on industrial customers in North Carolina to remain competitive when doing business in this State.

Especially in light of global competitive concerns—both externally for customers and internally for capital—market forces increasingly dictate production decisions for large manufacturers. It is no surprise, then, that electricity-intensive industrial customers show dramatic responses to changes in electricity prices. A material change in the cost of electricity has the potential to impact employment, production, and investment levels for large customers such as CIGFUR members, significantly impacting the local communities where they are located.

Q WHAT IS THE ECONOMIC IMPACT OF AN INDUSTRIAL CUSTOMER IN NORTH CAROLINA?

A According to a study performed for Duke by Dr. Julius Wright, which I have attached as Exhibit BCC-3, the loss of a single manufacturing job is worth approximately $500,000 in lost economic output to the economy of the state of North Carolina, and results in the loss of 1 to 3 additional supporting jobs.

According to the U.S. Bureau of Economic Analysis, current manufacturing employment in North Carolina is at approximately 450,000 jobs. As a result of the multiplying effect, manufacturing in North Carolina supports additional jobs in the amount of approximately 450,000 to 1.3 million in North Carolina.

It should also be noted that manufacturing in the State of North Carolina also represents approximately $105 billion in Gross Domestic Product .

Q AS RESULT, WHAT REASONABLE STEPS DO YOU RECOMMEND THE COMMISSION TAKE?

A As a result of the discretion afforded the Commission and the requirement for the Commission to take only *reasonable* steps in implementing the CPIRP, I recommend that the Commission order Duke to submit the modeling results of a scenario in which DEP and DEC are sharing capacity resources for planning purposes and that the Commission employ maximum flexibility and discretion by extending the timeline for implementation of the Carbon Plan until there is certainty regarding the anticipated merger between DEC and DEP. Per the Companies' expectation, the merger would be effective approximately January 1, 2027. Taking a judicious approach to Near-Term Actions related to the Carbon Plan implementation until certainty is reached on the merger of DEP and DEC would reduce the risk of Duke's progression down a path that could have significant adverse consequences on customers in terms of both reliability and bill impacts if the optimal resources on a combined DEP and DEC basis are not selected for replacing coal fired generation.

I also recommend that the Commission establish rate mitigation measures for customers with respect to CPIRP implementation. This is reasonable, necessary, and important from a customer protection standpoint. Rate mitigation could be in the form of a rate phase-in over a specified period after Duke is granted an increase in a rate case, as well as more frequent reporting so the Commission can check and adjust as needed. Without militantly guarding against gold-plating, Duke can and will overspend and overbuild at the expense of customers. Parameters around these and other rate mitigation concepts could be developed and presented to the Commission for review following collaboration among Duke, the Public Staff, and customers.

Though the Company is required to file an updated CPIRP every 2 years, the current environment is dynamic with respect to load growth, resource costs and availability, supply constraints, and technology development, creating significant unknowns and uncertainty regarding reliability and bill impacts for customers. Therefore, I recommend that the Commission should require updates every 6 months from Duke regarding the progress of the CPIRP. This is a reasonable requirement, especially in light of the extraordinary load increase that occurred 6 months after the Companies' CPIRP filing in August 2023.

Specifically, I recommend that the Company be required to file with the Commission status reports every 6 months, identifying any major developments in the process. These reports should include updates to the approved Portfolio's or Portfolios' PVRR, total capital spend, and estimated customer rate impacts. More frequent updates are needed beyond just the 2-year updated formal filing contemplated by House Bill 951. This would be another customer protection measure and complement the biennial filing by providing a checkpoint to warn the Commission if the circumstances have changed regarding the approved CPIRP Portfolio(s) and help the Commission require the Companies to check and adjust sooner rather than later. Due to the exhaustive list of concerns and uncertainties described in my testimony, the Commission should not wait for 2-year updates.

I also recommend that the Company include estimated rate impacts in these proposed 6-month reports for all investment on its system, including the non-CPIRP investments. This will give the Commission a holistic view of the expected customer rate impacts.

8. Execution Plan

Q HAVE YOU REVIEWED THE TESTIMONY AND CPIRP WITH RESPECT TO THE COMPANIES' EXECUTION PLAN?

A Yes. The Companies' Execution Plan prides a detailed roadmap for implementing the Carbon Plan. The roadmap consists of the following per the Companies' CPIRP, Chapter 4:

> The major components of the Plan include: 1) Existing Supply-Side Resources, 2) New Supply-Side Resources, 3) Transmission System Planning and 4) Grid Edge and Customer Programs. In addition, at the end of this Chapter, the Companies have provided information and a proposed timeline on the potential merger of DEC and DEP utility operations.[4]

Q ARE THE CARBON PLAN ACTIONS PROPOSED BY THE COMPANIES INTERRELATED?

A Yes. The Company has stated the following:

> Many of these actions are interdependent on one another to achieve the planning objectives of complying with applicable laws and regulations, while maintaining or improving upon the reliability of the system, increasing power supply diversity, reducing emissions, and balancing the costs and risks of an orderly energy transition and industry exit from coal. Therefore, the activities in this Execution Plan should be viewed as a complete plan that work together in concert to facilitate a risk-balanced and

[4] CPIRP, Chapter 4: Execution Plan., page 2.

> orderly transition of the Companies' systems to meet the challenges described in Chapter 1 (Planning for a Changing Energy Landscape).[5]

Q IS THE PROPOSED MERGER A VITAL COMPONENT OF THE COST-EFFECTIVENESS OF THE COMPANY'S EXECUTION PLAN?

A Yes. Per the Company:

> The Companies plan to initiate regulatory proceedings in the near term to merge DEC and DEP, which will consolidate the Companies' system operations functions, to facilitate a more cost-effective and efficient energy transition for customers.[6]

Q WHAT HAS DUKE STATED WITH RESPECT TO THE IMPORTANCE OF THE MERGER?

A The Company has stated the following:

> While DEC and DEP consolidated system operations is modeled in the Plan as discussed in Chapter 2 and Appendix C, a fully merged DEC and DEP is not explicitly part of this Execution Plan.
>
> * * *
>
> While this Resource Plan does not at this time assume fully merged utilities; future long-term planning assumptions will be appropriately aligned as the workstream progresses.[7]

Q DOES DUKE RECOGNIZE THAT ITS PLANNING ASSUMPTIONS WILL NEED TO BE ADJUSTED AS A RESULT OF THE OUTCOME OF THE MERGER?

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[5] *Ibid.*
[6] *Ibid*, page 12.
[7] Ibid, page 38

A Yes.

Q COULD THE MERGER SIGNIFICANTLY IMPACT THE TYPE AND AMOUNT OF RESOURCES SELECTED IN THE CARBON PLAN?

A Yes. As a result of joint planning, the resource mix, timing, and amount of resources could be significantly impacted, affecting both the PVRR of the plan and the resulting customer impacts. In the near term, it could also result in Duke overbuilding and overspending.

Q COULD ADVERSE CONSEQUENCES BE AVOIDED IF THE CARBON PLAN WERE DEVELOPED WITH JOINT PLANNING BETWEEN DEP AND DEC?

A Yes. Joint planning would help the Commission oversee a more orderly energy transition, mitigate some of the risk of gold-plating to the utility's generation system, and avoid incorrect decisions in terms of resource selections that that would otherwise result in adverse customer impacts in terms of both costs and reliability.

Q WHAT RISKS HAVE THE COMPANY IDENTIFIED WITH THE EXECUTION OF ITS CARBON PLAN?

A Primary risks have been identified by the Companies, including the following which I consider to be significant risks:

> **Supply Chain and Workforce Needs:** Material and equipment supply chain disruptions may lead to construction delays or inability to develop certain types of programs or projects on the timeline identified or at the costs or amounts assumed in the modeling. Shortages in qualified craft and engineering labor may cause delays or increased costs in constructing new energy resource facilities and supporting infrastructure or implementing new programs.

> **Infrastructure Dependencies:** Coordinated proactive transmission planning and timely construction of the significant transmission that will be needed to interconnect new resources present a key interdependency and timing risk. Future uncertainty or inability to secure additional interstate pipeline firm transportation causes increased fuel assurance risk, increased customer fuel cost exposure and potentially delayed coal retirements. Also, the inability to secure flexible coal supply through coal unit end of life may accelerate the need for their capacity replacement.[8]

Q DO YOU HAVE ANY COMMENTS ON THE ABOVE RISKS?

A Yes. With respect to workforce risk, this certainly is a legitimate concern, especially in light of the fact that in addition to Duke, both Georgia Power and TVA in the southeastern United States are experiencing similar circumstances with strong load growth and the need to build additional resources, particularly plans to build gas-fired generation. This could stress not only the skilled workforce necessary for implementing the Carbon Plan, but also the availability of resources, including gas-fired assets and batteries that Duke requires for implementation of its Carbon Plan.

Q ARE THERE OTHER EXECUTION RISKS ASSOCIATED WITH THE CARBON PLAN?

A Yes. Developing the necessary firm natural gas pipeline capacity required for gas units to be an adequate replacement resource for coal-fired generation capacity is a risk. Lack of firm capacity may render the system reliability unclear and uncertain at the very least.

Pipeline capacity will need to be installed to serve the new combined cycle and combustion turbine units, to support their ability to provide service during peak periods.

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[8] *Ibid*, pages 39-40.

Specifically, the Companies' Carbon Plan anticipates installing natural gas fired units and then converting them to hydrogen-fueled generation during the Carbon Plan. After this conversion, the natural gas pipeline capacity previously used to operate the natural gas generation will likely no longer be used by the Companies. As such, the revenue stream to the pipeline company could be impaired, which could be a significant economic factor in a pipeline utility's willingness to make capital investments to expand pipeline capacity in the Carolinas for new gas-fired generation.

The Companies' assumption that they will convert natural gas facilities to burn hydrogen rather than natural gas has not been fully developed. Green hydrogen is typically based on separating hydrogen from water. As such, the new gas units and existing gas units will have to have a source of hydrogen production which likely will require large sources of water. This would require either locating the new gas facilities near adequate water supply or the development of hydrogen pipelines from a source of hydrogen production that then deliver hydrogen to the new generating facility. The Companies' proposed CPIRP does not fully develop these details.

In addition, the Companies' plan for SLRs assumes nuclear stations' lives will be extended and is not based on a detailed review of the individual nuclear stations, or the potential capital investment that could be required by the Nuclear Regulatory Commission ("NRC") as a condition of granting the SLRs, needed to accomplish the objectives of the Carbon Plan. Further, the NRC likely will require significant retrofits of the existing nuclear stations in order to grant an SLR, and this material cost has not been included by Duke in their Carbon Plan. As such, a major source of carbon-free generation, Duke's nuclear stations, has not been accurately modeled by the Companies, resulting in an inaccurate estimate of the economics of the Carbon Plan.

9. Near-Term Actions: Supply-Side Development and Procurement Activities

Q HAVE YOU REVIEWED THE TESTIMONY AND CPIRP WITH RESPECT TO THE COMPANIES' NEAR-TERM ACTIONS?

A Yes.

Q DO YOU HAVE ANY GENERAL COMMENTS WITH RESPECT TO SUPPLY SIDE DEVELOPMENT ACTIVITIES?

A Yes. It should be pointed out that CIGFUR is resource agnostic and that the Carbon Plan should utilize a resource portfolio of resources that is least cost, results in maintaining system reliability, and minimizes customer rate impacts. CIGFUR firmly believes that there are pros and cons associated with each and every type of electricity generation resource type. Each different resource type has trade-offs that should be considered objectively and holistically. That said, I do comment on concerns related to various resources to be employed by Duke in its Carbon Plan.

a. Battery Storage

Q DO YOU HAVE ANY GENERAL COMMENTS WITH RESPECT TO BATTERY STORAGE AT THIS TIME?

A I would note that the Companies' portfolio is expected to contain a significant amount of battery storage. Other utilities such as PacifiCorp have experienced supply constraints related to batteries. To the extent Duke experiences supply constraints as well could impact the timeline of the Carbon Plan implementation.

b. New Gas

Q DO YOU HAVE ANY GENERAL COMMENTS WITH RESPECT TO NEW GAS AT THIS TIME?

A To the extent new gas-fired capacity is placed into service, the Companies' proposed plan of converting natural gas-fueled facilities to hydrogen-fueled facilities in the near term creates another economic restriction on the development of new firm natural gas pipeline capacity. A pipeline utility company would only be willing to invest in a new pipeline capacity to the extent it has a viable and stable marketplace for the pipeline capacity. If Duke's plan is to have temporary use of the pipeline capacity, only to later switch the fuel from natural gas to hydrogen, the viability of the new pipeline capacity may be placed in jeopardy.

As mentioned previously, the costs assumed for hydrogen capable gas units are proxy values developed by Duke, and as a result could be understated in the Carbon Plan, adding further uncertainty to the actual costs of the P3 Fall Base portfolio.

c. Advanced Nuclear

Q DO YOU HAVE ANY GENERAL COMMENTS WITH RESPECT TO ADVANCED NUCLEAR AT THIS TIME?

A This is an area that requires further development and if technology advances do not occur as quickly as envisioned by Duke, could potentially delay implementation of the Carbon

Plan. Because of these risks, the Company has stated publicly that they are **not** committed to Advanced Nuclear or offshore wind:

> Duke has also proposed additional solar and battery storage as well as some options not yet widely commercially available, such as hydrogen-capable gas plants, advanced nuclear and offshore wind.
>
> "**We are not committing to [offshore wind or advanced nuclear] at this point**," Savoy said. "We need more resources, and we've put options in front of commissioners. But we don't plan on being a first mover on these resources."[9]

The recent whitepaper jointly released by the National Association of Regulatory Utility Commissioners ("NARUC") and the National Association of State Energy Officials ("NASEO"), which is identified and attached hereto as Exhibit BCC-4, is informative on the discussion of new nuclear generation resources.

d. Offshore Wind

Q DO YOU HAVE ANY GENERAL COMMENTS WITH RESPECT TO OFFSHORE WIND AT THIS TIME?

A Like with Advanced Nuclear resources, the Companies have stated publicly that they are not committed to this technology. There are many risks associated with offshore wind, including the level of transmission investment required—particularly where, as here, the location of the potential new generation is not located close in proximity to load centers—in addition to expected resource costs and the costs for hurricane hardening.

[9] Duke increases 5-year capital plan to $73B on load growth projections, S&P Capital IQ (Feb. 8, 2024) (emphasis added).

Q ARE YOU AWARE OF ANY OFFSHORE WIND PROJECTS THAT HAVE BEEN RECENTLY CANCELED?

A I am aware of offshore wind projects being canceled in New Jersey. Some projects planned in Maryland such as Skipjack are uncertain:

> Maryland's nascent offshore wind energy industry suffered a major blow late Thursday when one of the two companies planning to install wind turbines off the coast of Ocean City announced that it was "repositioning" its plans, pulling out of its agreement with the state and seeking alternative financial arrangements to keep the project going.
>
> * * *
>
> A statement Ørsted issued late Thursday said the projected revenue from the state's clean energy credits, which cap what the company can charge ratepayers for its wind power, is "no longer commercially viable because of today's challenging market conditions, including inflation, high interest rates and supply chain constraints."
>
> * * *
>
> Ørsted's announcement isn't altogether surprising. The company in the fall abandoned plans to build two offshore wind developments off the coast of New Jersey, and at the time hinted that it was reevaluating its Maryland commitments. It also sought to revise contracts last year for a proposed offshore wind project off the coast of Long Island, a petition the New York Public Service Commission rejected as being too costly for ratepayers. Throughout its activities over the past year, the company has cited "macroeconomic challenges" facing the entire industry.[10]

[10] "Md. offshore wind developer announces 'repositioning' of project, seeks new financial support," Maryland Matters (Jan. 25, 2024).

10. Near-Term Actions: Existing Resources

a. Existing Gas Fleet (Flexibility Projects)

Q DO YOU HAVE ANY GENERAL COMMENTS WITH RESPECT TO THE EXISTING GAS FLEET?

A I do not have comments at this time but do reserve the right to provide comments in the future.

b. Existing Nuclear (SLRs and Uprate Projects)

Q DO YOU HAVE ANY GENERAL COMMENTS WITH RESPECT TO THE EXISTING NUCLEAR FLEET?

A The cost of SLRs for the Companies' existing nuclear fleet, which was omitted from Duke's proposed Carbon Plan, should be included in the Carbon Plan's cost because it is likely a significant and material cost. This is important in order to determine more complete and accurate customer rate impact projections associated related to implementation of Duke's Carbon Plan.

11. Advancing Grid Edge and Customer Programs

Q HAVE YOU REVIEWED THE TESTIMONY AND CPIRP WITH RESPECT TO THE COMPANIES' GRID EDGE AND CUSTOMER PROGRAMS?

A Yes.

Q DO YOU HAVE ANY GENERAL COMMENTS?

A In order to shrink the challenge with regard to replacing coal fired generation, it is imperative that Duke maximize participation in DSM and EE programs by offering attractive programs and/or rate tariffs for its non-residential customers, encouraging these customers to employ demand-side solutions in a cost-effective manner, to the benefit of all other customers and the system as a whole.

I strongly agree with the premise that conservation and demand-side management should be an important part of the Carbon Plan. To realize the maximum benefits of energy efficiency and demand-side management measures, the Companies must provide a clear economic signal produced through tariff rate mechanisms that incentivizes customers to change consumption, invest in new energy assets, or modify operational and/or production procedures to change load shape, shifting load from high-cost, constrained periods to low-cost, non-constrained periods, or to reduce consumption overall.

For example, designing interruptible and curtailment rates with interruptible credits that are aligned with the avoided costs of supply-side resources will create economic incentives for customers to pursue demand-side management and energy efficiency programs and actions.

Duke's proposed Carbon Plan assumes energy efficiency and demand-side management program participation from Duke's customers. However, to maximize the amount of viable customer participation in such programs, the outline and design of curtailment rates and interruptible rates, and the associated benefits to customers of participating in these programs, need to be carefully considered and implemented by Duke.

Q IS THERE AN EXISTING PROGRAM AT ANOTHER UTILITY THAT CIGFUR BELIEVES WOULD BE APPROPRIATE FOR DUKE TO IMPLEMENT?

A Yes. CIGFUR maintains that an emergency demand response program similar to that offered by Southern California Edison ("SCE") through its Base Interruptible Program ("BIP") and corresponding Emergency Load Reduction Program ("ELRP") would be appropriate and allow flexible industry load to be a valuable resource to Duke.

Q WHAT ARE SOME KEY BENEFITS OF SCE'S BIP PROGRAM?

A The BIP program is utilized by SCE and the CAISO to help ensure power continues to flow to customers, benefiting the system and lowering costs across all ratepayers, and helping in reaching carbon emissions reduction initiatives. SCE's BIP provides grid system relief during times of either or both supply and/or grid constraints. It also helps to support variable output from a growing mix of renewable energy facilities and avoids emissions from mitigating the need for peaking units. Customers are issued monthly bill credits in exchange for giving SCE the call-option for quick load reductions under predefined system triggers regardless of events called.

Q ARE THERE IMPROVEMENTS OR MODIFICATIONS THAT DUKE COULD MAKE TO ONE OF ITS EXISTING PROGRAMS THAT WOULD HELP MAXIMIZE PARTICIPATION BY NON-RESIDENTIAL CUSTOMER ON THE DUKE SYSTEM?

A Yes. Certain modifications to Duke's PowerShare® program would help incentivize participation in the program. One recommended modification would be to include a tiered structure with a value differential in the bill credits provided to customers reflecting the relative benefits provided to the system at different notice intervals, duration periods, and frequency of events called.

Another recommended modification would be related to the economic or non-emergency curtailment option. This modification would have the economic option function independent from the Mandatory Curtailment Option in order to enable non-residential customers with different load profiles and usage needs to participate in either or both program options, thus maximizing potential participation.

Q WHY ARE THESE SUGGESTED MODIFICATIONS IMPORTANT AND NECESSARY?

A CIGFUR recognizes that demand response initiated as quickly as possible provides maximal value to the Companies and the system. However, demand response initiated at different notice intervals also provides value to the Companies and the system. Because demand response initiated less rapidly also provides value, albeit to a lesser extent, the Companies could structure PowerShare® to offer a value differential in the credit provided to reflect the relative benefits provided to the system at different notice intervals. This could also apply to other program aspects that could have tiers to maximize flexibility and customer participation, including duration of a call event, frequency of events called, etc. This would allow customers who are able to participate to select the flavor on the menu that best works for their operations, thereby attracting customers to participate that may not have otherwise been willing to do so under a less customizable, less flexible program with less program option varieties.

Modifications to PowerShare® are necessary because load flexibility and responsiveness is not a one-size-fits-all analysis. The Companies should offer a variety of demand response program options so that a customer's participation in the program can be tailored to the customer's unique need and load profiles.

The Companies have some non-residential customers which would otherwise potentially be willing and able to participate in PowerShare® but which cannot participate in the programs as presently designed because they would not be able to safely shed load within the current required response times.

Modifying the PowerShare® program to reflect differential value provided by different response times is important to maximize the number of non-residential customers who choose to participate in a voluntary demand response program. Maximizing the number of non-residential customers who choose to participate in demand response programs is important both to assist in meeting carbon emissions reduction goals, and because the more demand response that Duke can deploy on its system, the less capital it might need for building new generation assets, which would help mitigate some customer rate impacts related to Carbon Plan investments.

12. <u>Transmission System Planning and Grid Transformation</u>

Q HAVE YOU REVIEWED THE TESTIMONY AND CPIRP WITH RESPECT TO ITS TRANSMISSION SYSTEM PLANNING?

A Yes.

Q DO YOU HAVE GENERAL COMMENTS WITH RESPECT TO THE THREE AREAS IDENTIFIED BY DUKE?

A Yes. I have previously identified transmission planning as an area that adds uncertainty to the Carbon Plan, both in terms of costs and reliability. As noted, transmission system planning will be a key area for the Commission to monitor and that will impact the costs and customer impacts related to the Carbon Plan. It is essential that transmission planning be conducted jointly with generation planning, as transmission investments and their costs will be dependent upon the location of generating resources that replace Duke's coal fired generation.

13. <u>Ensuring Reliability and Operational Resilience</u>

Q HAVE YOU REVIEWED THE TESTIMONY AND CPIRP WITH RESPECT TO ENSURING RELIABILITY AND OPERATIONAL RESILIENCE OF DUKE'S SYSTEM?

A Yes, with respect to receiving continuous service from Duke, and with respect to receiving adequate power quality.

Q IS RELIABILITY IMPORTANT FOR INDUSTRIAL CUSTOMERS?

A Yes.

Q WHAT DID THE COMMISSION'S DECEMBER 30, 2022 INITIAL CARBON PLAN ORDER INDICATE WITH RESPECT TO RELIABILITY?

A The Commission's Order approving the Initial Carbon Plan indicated that the Commission has the discretion in implementing the Carbon Plan due to the importance and significance of reliability. As stated previously, the Commission has stated that reliability is nonnegotiable.

Q HAS THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ("NERC") PROVIDED ANY TESTIMONY BEFORE THE NORTH CAROLINA LEGISLATURE REGARDING ITS CONCERNS WITH RELIABILITY AS THE GRID TRANSITIONS TO CLEAN GENERATING RESOURCES?

A Yes. Dave Krueger from the SERC Reliability Corporation ("SERC"), one of the six NERC entities, testified before the North Carolina Energy Policy Committee on March 26, 2024 to discuss reliability challenges arising from the changing resource mix on the electricity grid. SERC is one of six regional entities working with NERC to ensure the reliability, resilience, and security of the bulk power system across 16 states through auditing, enforcing standards, and providing technical expertise. His testimony is provided as Exhibit BCC-5.

In his testimony, he indicated that the generation resource mix is rapidly transforming as traditional baseload plants retire and are being replaced primarily by natural gas and variable renewable energy resources like wind and solar. The pace and complexity of change presents significant reliability risks that need to be addressed. As baseload plants shut down, replacement energy comes from resources that do not inherently provide the same operating features essential for reliability known as essential reliability services ("ERS"). These ERS services include frequency and voltage support that are critical for stable grid operations. Until energy storage advances, sufficient flexible and dispatchable generation will still be required to balance the grid. New transmission is also key to support renewable energy from remote locations and provide operational flexibility. Additionally, natural gas dependency elevates weather risks to fuel supply. Overall, the grid is more sensitive to extreme weather with the evolving portfolio. Managing the pace of change remains a central challenge.

He further opined that with traditional dispatchable resources retiring, resource adequacy involves more complex supply forecasting to match variable generation output to demand. Emerging demand-side factors like electrification and distributed energy resources add further complexity.

He indicated that maintaining ERS services for system stability like frequency and voltage control is important as well, but variable renewable technologies do not inherently provide these capabilities that conventional plants offer. Advancements are needed for renewables to emulate these services through technologies like smart inverters and batteries, but solutions will require time and commercialization. Additionally, fewer conventional plants reduces available blackstart resources needed to restore power after blackouts. Managing the transformation pace remains paramount given electricity's critical societal functions and interconnected regional impacts.

Q DO YOU AGREE WITH SERC'S TESTIMONY?

A I do. Duke Energy's Carbon Plan has several reliability risks and concerns associated with the plan. Based on my review of the Companies' testimony and CPIRP, these risks include:

1. Transition challenges: The retirement of coal-fired generation by 2035 requires a significant transition to alternative energy sources such as natural gas, renewable energy, and energy storage. This transition may pose challenges in terms of infrastructure development, grid integration, and ensuring a reliable and stable power supply.

2. Intermittency of renewable energy: Renewable energy sources like wind and solar power are intermittent in nature, meaning they depend on weather conditions. This intermittency can lead to fluctuations in power generation, which may impact the reliability and stability of the electricity grid. Adequate measures need to be in place to ensure a consistent and reliable power supply, as well as adequate power quality, during periods of low renewable energy generation.

3. Energy storage limitations: Energy storage technologies, such as batteries, are crucial for storing excess renewable energy and providing backup power during periods of low generation. However, the current state of energy storage technologies may not be sufficient to meet the demand and ensure reliable power supply in the absence of coal-fired generation. Scaling up energy storage infrastructure may require significant investment and time.

4. Grid resilience: The retirement of coal-fired generation may have implications for the resilience of the electricity grid. Coal power plants often provide baseload power, which is essential for maintaining grid stability. It is crucial to ensure that the transition to alternative energy sources does not compromise the grid's ability to handle peak demand and maintain stability during unforeseen events or emergencies.

Q DO YOU ALSO HAVE CONCERNS REGRADING POWER QUALITY AS WELL?

A Yes. Power quality is also an important aspect of reliability, especially for large industrial customers such as members of CIGFUR who can suffer severe adverse consequences to their operations due to “blips” on the system that last a mere handful of milliseconds. Concerns with power quality on the Duke system as Duke transitions from coal fired generation to clean generation sources under the Carbon Plan include the following:

1. Voltage and frequency fluctuations: The retirement of coal-fired generation and the increased reliance on renewable energy sources can lead to voltage and

frequency fluctuations. Renewable energy generation, such as solar and wind, is intermittent and can cause variations in power supply. These fluctuations can affect the stability and reliability of the electricity grid, potentially leading to power quality issues for consumers.

2. Power factor variations: Power factor is an important parameter that measures the efficiency of electrical power transmission and distribution. The transition to alternative energy sources may introduce power factor variations due to the different characteristics of renewable energy generation. Power factor variations can lead to efficiency losses, increased energy consumption, and potential equipment damage.

3. Harmonic distortions: Harmonic distortions occur when there are non-linear loads in the power system, such as certain types of electronic equipment. The retirement of coal-fired generation and the integration of renewable energy sources can introduce additional harmonic distortions into the grid. These distortions can negatively impact power quality, affecting the performance and lifespan of sensitive equipment.

4. Grid stability challenges: Coal-fired power plants typically provide baseload power, which helps maintain grid stability. The retirement of these plants and the increased reliance on intermittent renewable energy sources can pose challenges to grid stability. Sudden changes in power generation can lead to voltage instabilities and frequency deviations, potentially causing power outages and other power quality issues.

5. Reactive power management: Reactive power is required for voltage control and maintaining the stability of the electrical grid. The transition to renewable energy sources may require careful management of reactive power to ensure proper voltage regulation. Inadequate reactive power management can lead to voltage fluctuations, which can impact the reliability and quality of power supply.

Because of the unprecedented investment in resources to replace 8,400 MW of coal-fired generation, and the coordination of replacement resources with developing technology, as much time as possible is needed for Duke's proposed Carbon Plan transition in order to maintain reliability and prevent power quality issues on its system.

14. Requests for Relief and "Selection" of Resources to Execute Carbon Plan

Q HAVE YOU REVIEWED THE TESTIMONY AND CPIRP WITH RESPECT TO THE COMPANIES' REQUESTED RELIEF AND SELECTION OF RESOURCES TO EXECUTE THE CARBON PLAN?

A Yes.

Q HOW DO YOU RESPOND TO THE COMPANIES' REQUESTS?

A As the Company indicated, the activities in its Execution Plan, including the selection of specific resources, are interrelated. One of the key activities in the Companies' Execution Plan is the merger of DEP and DEC. For the reasons previously described, it would seem the most prudent route would be to require the Companies to submit a scenario that assumes shared capacity resources for planning purposes to ensure that the approved portfolio does not enable the Companies to overspend and overbuild in the short term. For the same reason, the Commission should employ maximum flexibility and discretion by extending the timeline for implementation of the Carbon Plan until there is certainty regarding the anticipated merger between DEC and DEP, thereby enabling them to jointly plan their systems and reduce the risk to ratepayers that Duke may gold-plate its generation system. This will be further discussed in Section 16 of my testimony. As previously indicated, this is by no means a recommendation to prevent Duke from making appropriate investments approved by the Commission to reliably serve both existing and future customer loads.

That being said, there are several critical aspects of the Companies' Carbon Plan which diminish their ability to identify the least-cost resource portfolio over the planning period. These deficiencies relate to certain infrastructure necessary to reliably operate new generating facilities, uncertainty with respect to subsequent license renewals ("SLRs") for

Duke's existing nuclear fleet, the expected remaining operating lives of new pipeline infrastructure, and thoughtful consideration of the use of carbon emission offsets to manage the selection of unproven resources while continuing to make progress toward carbon emissions reduction goals.

All utilities including Duke have a natural economic interest to select investments funded by the utility and included in rate base. These types of investments grow the utility and enhance shareholder value by growing rate base, which in turn increases utilities' earnings and dividend-paying ability. While financial integrity and strong credit standing are important for enabling efficient and economic investments in prudent utility infrastructure, this balance also requires selection of investments that produce the least possible costs and risks borne by ratepayers while also achieving financial protections for the utility. While Duke has selected an all-of-the-above approach for resources, including unproven and costly technologies, it is important for Duke and the Commission to get the resource selection correct and not merely invest in a particularly technology for the sake of doing so in the near term.

In establishing these carbon emissions reduction infrastructure investments, the design targets should consider a balance between achieving carbon emissions reduction targets when weighed against competing objectives, including least-cost planning, and maintaining or improving the reliability of the existing grid through investments in proven resources with demonstrated operating performance and which can provide high-quality power at competitive rates.

15. Dual State Planning for the Carolinas' System

Q HAVE YOU REVIEWED THE COMPANIES TESTIMONY AND CPIRP WITH RESPECT TO DUAL STATE PLANNING?

A Yes.

Q DO YOU HAVE ANY COMMENTS?

A To the extent the CPIRP moves forward and is not approved by both commissions in North Carolina and South Carolina, and/or to the extent otherwise recoverable costs of the infrastructure under the Carbon Plan are uncertain in one or both jurisdictions, then the Commission should be clear that any infrastructure costs that would be allocated to the South Carolina jurisdiction under a load share methodology will not be borne by customers in North Carolina if disallowed in South Carolina. In other words, the decades-long benefit of the dual-state system planning and rate-setting methodology should be a requirement for moving forward with the current version of the Carbon Plan, and Duke's North Carolina customers' responsibility for Carbon Plan compliance costs should be limited only to the North Carolina load ratio share of the dual system common production and transmission infrastructure costs.

If South Carolina rejects cost recovery in its jurisdiction, those costs not allowed to be recovered in South Carolina should not be reallocated to the North Carolina jurisdiction or otherwise included in retail rates in North Carolina. In this instance, the Commission should require Duke to explain its back-up plan to limit investments in the joint jurisdictional Carbon Plan to only those that will reasonably be reflected in rates—at least unless and until the regulatory risk of disallowance in South Carolina is resolved—while not restricting Duke's ability to maintain service quality and reliability to customers in North Carolina.

16. Merger

Q HAVE YOU REVIEWED THE COMPANIES' TESTIMONY AND CPIRP WITH RESPECT TO THE PLANNED MERGER OF DEC AND DEP?

A Yes.

Q WHAT HAVE THE COMPANIES INDICATED WITH RESPECT TO THE MERGER OF DEP AND DEC?

A They have stated that they plan to merge in the near-term with an approximate effective date of January 1, 2027.

Q PLEASE DESCRIBE YOUR CONCERNS REGARDING THE MERGER'S IMPACT ON THE IMPLEMENTATION OF THE CARBON PLAN.

A This is a resource planning proceeding and the Commission should decide the merger issue in a separate proceeding. That said, the lack of system resource planning on a combined basis across DEP and DEC is troubling. This should be, at the very least, modeled in a hypothetical scenario by Duke.

Q ARE DEC AND DEP ALLOWED TO JOINTLY PLAN THEIR SYSTEMS IN THE CONTEXT OF SHARING CAPACITY RESOURCES?

A No. It is my understanding that DEP and DEC may not rely on system-wide resource planning for capacity unless/until the two utilities have consummated a legal merger.

Q WHAT IS THE IMPACT OF SEPARATELY PLANNING FOR BOTH THE DEC AND DEP SYSTEMS?

A As a result, the Carbon Plan is modeled based on DEP and DEC being separate utilities that are not allowed to share capacity resources for planning purposes. This is true of the current Carbon Plan IRP presently in effect, which was approved by the Commission on December 30, 2022.

This modeling constraint has likely resulted in the inclusion of a not-insignificant amount of unnecessary incremental capacity in Duke's Carbon Plan, adding significant Carbon Plan costs and rate impacts on the backs of ratepayers.

Duke plans to merge as described in the Carbon Plan and in the Companies' supporting testimony. It is my understanding that the Companies plan to seek regulatory approval in 2025, hoping to obtain all such necessary approvals (NCUC, PSCSC, and FERC) in approximately 2026, with the first legal date of a new merged entity, assuming all regulatory approvals were obtained, of January 1, 2027.

To the extent that the Carbon Plan can be implemented using assumptions of shared system-wide capacity resources, this could significantly reduce the capacity expansion called for by the currently modeling with separate planning for both DEC and DEP, thereby reducing overall costs of the Carbon Plan and reducing customer rate impacts.

Using a January 1, 2027 effective date of a DEP and DEC merger, this means the first opportunity the Commission would have to "check and adjust" the then-in-effect Carbon Plan and approve updated modeling based on a merged entity using system-wide capacity planning assumptions would be December 31, 2028.

That said, in the interim between now and December 31, 2028, both DEP and DEC will have spent 6 years (between December 30, 2022 and December 31, 2028) building new generation assets based on non-merged capacity planning assumptions, very likely resulting in a plan that is not least-cost for ratepayers as required by law. By December 31, 2028, it will likely be too late to avoid or ameliorate extremely harmful ratepayer impacts. In fact, the train has already left the station as we sit here today. The Companies have already started filing with the Commission applications for certificates of public convenience and necessity for new gas-fired capacity. However, it is not too late to prevent the train from becoming a runaway train.

Q WHAT DO YOU RECOMMEND?

A As a result of the discretion afforded the Commission and the requirement for the Commission to take only ***reasonable*** steps in implementing the CPIRP, I recommend that the Commission require Duke to model a sensitivity assuming DEC and DEP are merged entities allowed to share capacity resources for planning purposes and for the Commission to employ maximum flexibility and discretion by extending the timeline for implementation of the Carbon Plan until there is certainty regarding the anticipated merger between DEC and DEP. Per the Companies' expectation, the merger would be effective approximately January 1, 2027. These recommendations are important until certainty is reached on the merger of DEP and DEC is prudent and would avoid Duke's progression down a path that could have adverse consequences on customers in terms of both reliability and bill impacts if the optimal resources on a combined DEP and DEC basis are not selected for replacing coal-fired generation.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Guam Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kansas Corporation Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Maryland Public Service Commission, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Carolina Utilities Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oklahoma Corporation Commission, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Washington Utilities and Transportation Commission, the Public Service Commission of Wisconsin, and the

Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 1,000 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.